CABOT OIL & GAS CORP
Form 10-Q
October 29, 2007

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UNITED STATES

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, 2007

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934.**

Commission file number 1-10447

CABOT OIL & GAS CORPORATION

(Exact name of registrant as specified in its charter)

DELAWARE	**04-3072771**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification Number)**

1200 Enclave Parkway, Houston, Texas 77077

(Address of principal executive offices including ZIP Code)

(281) 589-4600

(Registrant s telephone number, including area code)

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 and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨

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

Large accelerated filer x Accelerated filer ¨ Non-accelerated filer ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No x

As of October 24, 2007, there were 97,097,573 shares of Common Stock, Par Value $.10 Per Share, outstanding.

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PART I. FINANCIAL INFORMATION

ITEM 1. Financial Statements

CABOT OIL & GAS CORPORATION

CONDENSED CONSOLIDATED STATEMENT OF OPERATIONS (Unaudited)

(In thousands, except per share amounts)	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
OPERATING REVENUES				
Natural Gas Production	**$ 140,300**	$ 140,261	**$ 431,178**	$ 436,931
Brokered Natural Gas	**15,179**	17,075	**66,357**	67,389
Crude Oil and Condensate	**15,084**	26,435	**39,289**	80,283
Other	**285**	973	**1,429**	5,703
	170,848	184,744	**538,253**	590,306
OPERATING EXPENSES				
Brokered Natural Gas Cost	**13,223**	15,282	**57,973**	59,924
Direct Operations - Field and Pipeline	**20,996**	19,893	**57,131**	55,478
Exploration	**8,766**	13,561	**21,243**	39,972
Depreciation, Depletion and Amortization	**37,744**	32,088	**105,401**	96,815
Impairment of Unproved Properties	**5,841**	3,826	**16,150**	11,289
Impairment of Oil & Gas Properties (Note 2)	**4,614**		**4,614**	
General and Administrative	**9,715**	10,715	**40,960**	38,482
Taxes Other Than Income	**14,379**	14,366	**42,123**	44,439
	115,278	109,731	**345,595**	346,399
Gain / (Loss) on Sale of Assets	**(49)**	229,733	**12,293**	229,944
INCOME FROM OPERATIONS	**55,521**	304,746	**204,951**	473,851
Interest Expense and Other	**3,921**	6,978	**11,464**	19,151
Income Before Income Taxes	**51,600**	297,768	**193,487**	454,700
Income Tax Expense	**16,147**	108,748	**68,111**	165,651
NET INCOME	**$ 35,453**	$ 189,020	**$ 125,376**	$ 289,049
Basic Earnings Per Share	**$ 0.37**	$ 1.96	**$ 1.29**	$ 2.98
Diluted Earnings Per Share	**$ 0.36**	$ 1.92	**$ 1.28**	$ 2.92
Weighted Average Common Shares Outstanding	**97,068**	96,459	**96,899**	97,097
Diluted Common Shares (Note 5)	**98,439**	98,324	**98,122**	99,016

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

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CABOT OIL & GAS CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEET (Unaudited)

(In thousands, except share amounts)	**September 30, 2007**	**December 31, 2006**
ASSETS		
Current Assets		
Cash and Cash Equivalents	**$ 14,451**	$ 41,854
Accounts Receivable, Net	**82,845**	116,546
Income Taxes Receivable	**17,650**	24,512
Inventories	**36,202**	32,997
Deferred Income Taxes	**7,995**	9,386
Derivative Contracts (Note 7)	**27,411**	81,982
Other Current Assets	**11,281**	8,405
Total Current Assets	**197,835**	315,682
Properties and Equipment, Net (Successful Efforts Method) (Note 2)	**1,810,023**	1,480,201
Deferred Income Taxes	**36,213**	30,912
Other Assets	**33,175**	7,696
	$ 2,077,246	$ 1,834,491
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities		
Accounts Payable	**$ 152,453**	$ 147,680
Current Portion of Long-Term Debt	**20,000**	20,000
Deferred Income Taxes	**11,289**	31,962
Income Taxes Payable	**4,179**	9,282
Accrued Liabilities	**35,744**	42,103
Total Current Liabilities	**223,665**	251,027
Long-Term Liability for Pension Benefits (Note 10)	**9,233**	7,219
Long-Term Liability for Postretirement Benefits (Note 10)	**19,599**	18,204
Long-Term Debt (Note 4)	**295,000**	220,000
Deferred Income Taxes	**424,267**	347,430
Other Liabilities	**53,698**	45,413
Commitments and Contingencies (Note 6)		
Stockholders Equity		
Common Stock:		
Authorized 120,000,000 Shares of $0.10 Par Value in 2007 and 2006, respectively		
Issued and Outstanding 102,296,678 Shares and 101,418,220 Shares in 2007 and 2006, respectively	**10,230**	10,142
Additional Paid-in Capital	**431,679**	417,995
Retained Earnings	**683,214**	565,591
Accumulated Other Comprehensive Income (Note 8)	**12,351**	37,160
Less Treasury Stock, at Cost:		
5,204,700 Shares in both 2007 and 2006	**(85,690)**	(85,690)
Total Stockholders Equity	**1,051,784**	945,198
	$ 2,077,246	$ 1,834,491

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

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CABOT OIL & GAS CORPORATION

CONDENSED CONSOLIDATED STATEMENT OF CASH FLOWS (Unaudited)

(In thousands)	**Nine Months Ended September 30, 2007**	**2006**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	**$ 125,376**	$ 289,049
Adjustments to Reconcile Net Income to Cash Provided by Operating Activities:		
Depreciation, Depletion and Amortization	**105,401**	96,815
Impairment of Unproved Properties	**16,150**	11,289
Impairment of Oil & Gas Properties	**4,614**	
Deferred Income Tax Expense	**66,930**	31,514
Gain on Sale of Assets	**(12,293)**	(229,944)
Exploration Expense	**21,243**	39,972
Stock-Based Compensation Expense and Other	**13,543**	12,262
Changes in Assets and Liabilities:		
Accounts Receivable, Net	**33,701**	51,851
Income Taxes Receivable	**251**	12,239
Inventories	**(3,205)**	(16,504)
Other Current Assets	**(2,876)**	(3,447)
Other Assets	**(24,510)**	(438)
Accounts Payable and Accrued Liabilities	**(33,570)**	(34,137)
Income Taxes Payable	**8,364**	95,278
Other Liabilities	**16,297**	6,007
Stock-Based Compensation Tax Benefit	**(6,857)**	(5,756)
Net Cash Provided by Operating Activities	**328,559**	356,050
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital Expenditures	**(416,963)**	(344,620)
Proceeds from Sale of Assets	**5,826**	322,987
Exploration Expense	**(21,243)**	(39,972)
Net Cash Used in Investing Activities	**(432,380)**	(61,605)
CASH FLOWS FROM FINANCING ACTIVITIES		
Increase in Debt	**85,000**	195,000
Decrease in Debt	**(10,000)**	(135,000)
Sale of Common Stock Proceeds	**2,314**	3,620
Stock-Based Compensation Tax Benefit	**6,857**	5,756
Purchase of Treasury Stock		(46,492)
Dividends Paid	**(7,753)**	(5,832)
Net Cash Provided by Financing Activities	**76,418**	17,052
Net (Decrease) / Increase in Cash and Cash Equivalents	**(27,403)**	311,497
Cash and Cash Equivalents, Beginning of Period	**41,854**	10,626
Cash and Cash Equivalents, End of Period	**$ 14,451**	$ 322,123

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

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

1. FINANCIAL STATEMENT PRESENTATION

During interim periods, Cabot Oil & Gas Corporation (the Company) follows the same accounting policies used in its Annual Report to Stockholders and its Annual Report on Form 10-K for the year ended December 31, 2006 filed with the Securities and Exchange Commission (SEC). The interim financial statements should be read in conjunction with the notes to the financial statements and information presented in the Company s 2006 Annual Report to Stockholders and its Annual Report on Form 10-K. In management s opinion, the accompanying interim condensed consolidated financial statements contain all material adjustments, consisting only of normal recurring adjustments, necessary for a fair presentation. Additionally, certain amounts have been reclassified to conform to the fiscal year 2007 presentation. The results for any interim period are not necessarily indicative of the expected results for the entire year.

Our independent registered public accounting firm has performed a review of these condensed consolidated interim financial statements in accordance with standards established by the Public Company Accounting Oversight Board (United States). Pursuant to Rule 436(c) under the Securities Act of 1933, this report should not be considered a part of a registration statement prepared or certified by PricewaterhouseCoopers LLP within the meanings of Sections 7 and 11 of the Act.

On February 23, 2007, the Board of Directors declared a 2-for-1 split of the Company s common stock in the form of a stock distribution. The stock dividend was distributed on March 30, 2007 to stockholders of record on March 16, 2007. All common stock accounts and per share data have been retroactively adjusted to give effect to the 2-for-1 split of the Company s common stock. The effect on the December 31, 2006 Balance Sheet was a reduction to Additional Paid-in Capital and an increase to Common Stock of $5.1 million.

Effective January 1, 2007, the Company adopted the provisions of Financial Accounting Standards Board (FASB) Interpretation (FIN) No. 48, Accounting for Uncertainty in Income Taxes-an interpretation of FASB Statement No. 109. While there was no impact upon adoption on January 1, 2007, the Company made an adjustment to net interest expense of $1.0 million during the first nine months of 2007 for incremental interest expense that is more likely not payable than payable. For further information regarding the adoption of FIN 48, please refer to Note 12 of the Notes to the Condensed Consolidated Financial Statements.

Recently Issued Accounting Pronouncements

In May 2007, the FASB issued Staff Position (FSP) No. FIN 48-1, Definition of *Settlement* in FASB Interpretation No. 48, which amends FIN 48 and provides guidance concerning how an entity should determine whether a tax position is effectively, rather than the previously required ultimately, settled for the purpose of recognizing previously unrecognized tax benefits. In addition, FSP No. FIN 48-1 provides guidance on determining whether a tax position has been effectively settled. The guidance in FSP No. FIN 48-1 is effective upon the initial January 1, 2007 adoption of FIN 48. Companies that have not applied this guidance must retroactively apply the provisions of this FSP to the date of the initial adoption of FIN 48. The Company has adopted FSP No. FIN 48-1 and no retroactive adjustments are necessary.

In April 2007, the FASB issued FSP No. FIN 39-1, Amendment of FASB Interpretation No. 39, to amend FIN 39, Offsetting of Amounts Related to Certain Contracts. The terms conditional contracts and exchange contracts used in FIN 39 have been replaced with the more general term derivative contracts. In addition, FSP No. FIN 39-1 permits the offsetting of recognized fair values for the right to reclaim cash collateral or the obligation to return cash collateral against fair values of derivatives under certain circumstances, such as under master netting arrangements. Additional disclosure is also required regarding a Company s accounting policy with respect to offsetting fair value amounts. The guidance in FSP No. FIN 39-1 is effective for fiscal years beginning after November 15, 2007, with early application allowed. The effects of initial adoption should be recognized as a change in accounting principle through retrospective application for all periods presented. The Company does not believe that the adoption of FSP No. FIN 39-1 will have a material impact on its financial position, results of operations or cash flows.

In February 2007, the FASB issued Statement of Financial Accounting Standards (SFAS) No. 159, The Fair Value Option for Financial Assets and Financial Liabilities, including an amendment of FASB Statement No. 115, which permits companies to choose, at specified dates, to measure certain eligible financial instruments at fair value. The objective of this Statement is to reduce volatility in preparer reporting that may be caused as a result of measuring related financial assets and liabilities differently and to expand the use of fair value measurements. The provisions of the Statement apply only to entities that elect to use the fair value option and to all entities with available-for-sale and trading securities. Additional disclosures are also required for instruments for which the fair value option is elected. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. No retrospective application is allowed, except for companies that choose to adopt early. At the effective date, companies may elect the fair value option for eligible items that exist at that date, and the effect of the first remeasurement to fair value must be reported as a cumulative-effect adjustment to the opening balance of retained earnings. The Company is currently evaluating what impact, if any, SFAS No. 159 will have on its financial position or results of operations.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements, which establishes a formal framework for measuring fair values of assets and liabilities in financial statements that are already required by United States generally accepted accounting principles (GAAP) to be measured at fair value. SFAS No. 157 clarifies guidance in FASB Concepts Statement (CON) No. 7 which discusses present value techniques in measuring fair value. Additional disclosures are also required for transactions measured at fair value. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. The Company is currently evaluating what impact SFAS No. 157 may have on its financial position or results of operations.

2. PROPERTIES AND EQUIPMENT, NET

Properties and equipment, net are comprised of the following:

(In thousands)	**September 30, 2007**	**December 31, 2006**
Unproved Oil and Gas Properties	**$ 113,279**	$ 114,108
Proved Oil and Gas Properties	**2,503,136**	2,109,045
Gathering and Pipeline Systems	**223,758**	205,473
Land, Building and Improvements	**5,051**	4,976
Other	**35,992**	34,067
	2,881,216	2,467,669
Accumulated Depreciation, Depletion and Amortization	**(1,071,193)**	(987,468)
	$ 1,810,023	$ 1,480,201

At September 30, 2007, the Company did not have any capitalized suspended well costs that have been capitalized for greater than one year after drilling.

At December 31, 2006, the Company had four projects that had $0.1 million of exploratory well costs that were capitalized since 2005 for a period greater than one year. This amount related to three projects comprised of preliminary costs incurred in the preparation of well sites where drilling had not commenced as of December 31, 2006. In 2007, it was determined not to drill these projects and associated costs were expensed. Also included in the December 31, 2006 amount was another well that had completed drilling in January 2007 and was awaiting completion results before confirmation of proved reserves could be made. That well was completed in 2007 and proved reserves were recorded in the first quarter of 2007.

During the third quarter of 2007, the Company recorded an impairment of approximately $4.6 million on the Castor field in Bienville Parish, Louisiana in the Gulf Coast region resulting from two non-commercial development completions. This impairment charge was recorded due to the capitalized cost of the fields

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exceeding the future undiscounted cash flows. This charge has been reflected in the quarterly results and was measured based on discounted cash flows utilizing a discount rate appropriate for risks associated with the related field. There were no impairments of proved oil and gas properties during the nine months ended September 30, 2006.

Disposition of Assets

On September 29, 2006, the Company substantially completed the sale of its offshore portfolio and certain south Louisiana properties to Phoenix Exploration Company LP for a gross sales price of $340.0 million. The Company received approximately $333.3 million in net proceeds from the sale. In addition to the net gain of $231.2 million ($144.5 million, net of tax) recorded for the year ended December 31, 2006, the Company recorded a net gain of $12.3 million ($7.7 million, net of tax) in the Condensed Consolidated Statement of Operations for the nine months ended September 30, 2007, which included cash proceeds of $5.8 million received in the first quarter of 2007, $2.1 million in purchase price adjustments and $4.4 million that had been deferred until legal title to certain properties could be assigned.

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3. ADDITIONAL BALANCE SHEET INFORMATION

Certain balance sheet amounts are comprised of the following:

(In thousands)	**September 30, 2007**	**December 31, 2006**
ACCOUNTS RECEIVABLE, NET		
Trade Accounts	**$ 71,496**	$ 102,023
Joint Interest Accounts	**15,691**	18,574
Other Accounts	**110**	501
	87,297	121,098
Allowance for Doubtful Accounts	**(4,452)**	(4,552)
	$ 82,845	$ 116,546
INVENTORIES		
Natural Gas and Oil in Storage	**$ 28,969**	$ 22,717
Tubular Goods and Well Equipment	**6,725**	7,680
Pipeline Imbalances	**508**	2,600
	$ 36,202	$ 32,997
OTHER CURRENT ASSETS		
Drilling Advances	**$ 1,043**	$ 651
Prepaid Balances	**9,900**	7,416
Other Accounts	**338**	338
	$ 11,281	$ 8,405
ACCOUNTS PAYABLE		
Trade Accounts	**$ 10,149**	$ 28,569
Natural Gas Purchases	**9,221**	8,356
Royalty and Other Owners	**31,391**	37,230
Capital Costs	**85,315**	59,524
Taxes Other Than Income	**4,757**	4,805
Drilling Advances	**2,252**	1,506
Wellhead Gas Imbalances	**3,251**	2,288
Other Accounts	**6,117**	5,402
	$ 152,453	$ 147,680
ACCRUED LIABILITIES		
Employee Benefits	**$ 11,601**	$ 13,575
Current Liability for Pension Benefits	**67**	67
Current Liability for Postretirement Benefits	**577**	577
Taxes Other Than Income	**15,051**	15,696
Interest Payable	**4,422**	5,995
Other Accounts	**4,026**	6,193
	$ 35,744	$ 42,103

OTHER LIABILITIES

Rabbi Trust Deferred Compensation Plan	**$**	**15,587**	$	6,077
Accrued Plugging and Abandonment Liability		**24,156**		22,655
Other Accounts		**13,955**		16,681
	$	**53,698**	$	45,413

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4. LONG-TERM DEBT

At September 30, 2007, the Company had $85 million of borrowings outstanding under its revolving credit facility at a weighted-average interest rate of 6.1%. The credit facility provides for an available credit line of $250 million, which can be expanded up to $350 million, either with the existing banks or new banks. The term of the credit facility expires in December 2009. The credit facility is unsecured. The available credit line is subject to adjustment from time to time on the basis of the projected present value (as determined by the banks petroleum engineer) of estimated future net cash flows from certain proved oil and gas reserves and other assets of the Company. While the Company does not expect a reduction in the available credit line, in the event that it is adjusted below the outstanding level of borrowings, the Company has a period of six months either to reduce its outstanding debt to the adjusted credit line available with a requirement to provide additional borrowing base assets or to pay down one-sixth of the excess during each of the six months.

In addition to borrowings under the credit facility, the Company had the following debt outstanding at September 30, 2007:

- $60 million of 12-year 7.19% Notes due in November 2009, which consisted of $40 million of long-term debt and $20 million of current portion of long-term debt, to be repaid in three remaining annual installments of $20 million in November of each year
- $75 million of 10-year 7.26% Notes due in July 2011
- $75 million of 12-year 7.36% Notes due in July 2013
- $20 million of 15-year 7.46% Notes due in July 2016

The Company believes it is in compliance in all material respects with its debt covenants.

5. EARNINGS PER SHARE

Basic Earnings per Share (EPS) is computed by dividing net income (the numerator) by the weighted average number of common shares outstanding for the period (the denominator). Diluted EPS is similarly calculated except that the denominator is increased using the treasury stock method to reflect the potential dilution that could occur if stock options and stock awards outstanding at the end of the applicable period were exercised for common stock.

The following is a calculation of basic and diluted weighted average shares outstanding for the three and nine months ended September 30, 2007 and 2006:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	**2006**	**2007**	**2006**
Weighted-Average Shares - Basic	**97,067,586**	96,459,378	**96,898,663**	97,096,978
Dilution Effect of Stock Options and Awards at End of Period	**1,371,747**	1,864,520	**1,223,609**	1,919,262
Weighted-Average Shares - Diluted	**98,439,333**	98,323,898	**98,122,272**	99,016,240
Weighted-Average Stock Awards and Shares Excluded from Diluted Earnings per Share due to the Anti-Dilutive Effect	**143,613**		**331,996**	

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6. COMMITMENTS AND CONTINGENCIES

Contingencies

The Company is a defendant in various legal proceedings arising in the normal course of its business. All known liabilities are accrued based on management s best estimate of the potential loss. While the outcome and impact of such legal proceedings on the Company cannot be predicted with certainty, management believes that the resolution of these proceedings through settlement or adverse judgment will not have a material adverse effect on the Company s condensed consolidated financial position or cash flow. Operating results, however, could be significantly impacted in the reporting periods in which such matters are resolved.

West Virginia Royalty Litigation

In December 2001, the Company was sued by two royalty owners in West Virginia state court for an unspecified amount of damages. The plaintiffs requested class certification and alleged that the Company failed to pay royalty based upon the wholesale market value of the gas, that the Company had taken improper deductions from the royalty and that it failed to properly inform royalty owners of the deductions. The plaintiffs also claimed that they are entitled to a 1/8th royalty share of the gas sales contract settlement that the Company reached with Columbia Gas Transmission Corporation in 1995 bankruptcy proceedings. The Court entered an order on June 1, 2005 granting the motion for class certification.

The parties have reached a tentative settlement, pursuant to which the Company will pay $11.6 million to the class members. The Company and the class members also agreed in the tentative settlement to a methodology for payment of future royalties and the reporting format such methodology will take. The tentative settlement is not final or binding until approved by the Court. A hearing for final approval of the settlement is tentatively scheduled for December 18, 2007. A reserve has been established that management believes is adequate based on its estimate of the probable outcome of this case.

Commitment and Contingency Reserves

The Company has established reserves for certain legal proceedings. The establishment of a reserve involves an estimation process that includes the advice of legal counsel and subjective judgment of management. While management believes these reserves to be adequate, it is reasonably possible that the Company could incur approximately $7.8 million of additional loss with respect to those matters in which reserves have been established. Future changes in the facts and circumstances could result in the actual liability exceeding the estimated ranges of loss and amounts accrued.

While the outcome and impact on the Company cannot be predicted with certainty, management believes that the resolution of these proceedings through settlement or adverse judgment will not have a material adverse effect on the condensed consolidated financial position or cash flow of the Company. Operating results, however, could be significantly impacted in the reporting periods in which such matters are resolved.

Firm Gas Transportation Agreements

The Company has incurred, and will incur over the next several years, demand charges on firm gas transportation agreements. The agreements provide firm transportation capacity rights on pipeline systems in Canada, the West region and the East region. The remaining terms on these agreements range from less than one year to 20 years and require the Company to pay transportation demand charges regardless of the amount of pipeline capacity utilized by the Company.

The amount of demand charges on firm gas transportation agreements decreased in the first nine months of 2007 by approximately $1.8 million from the amount previously disclosed in the Company s Annual Report on Form 10-K for the year ended December 31, 2006. For further information on these future obligations, please refer to Note 7 of the Notes to the Consolidated Financial Statements in the Annual Report on Form 10-K for the year ended December 31, 2006.

Drilling Rig Commitments

In its Annual Report on Form 10-K for the year ended December 31, 2006, the Company disclosed that it had commitments on seven drilling rigs under contract in the Gulf Coast and that one of these rigs had not yet been delivered. This rig was delivered in April 2007. As of September 30, 2007, the total commitment decreased by $0.2 million in the aggregate from the amount disclosed in the Annual Report on Form 10-K (decreased by $5.7 million in 2007, increased by $0.1 million in 2008 and increased by $5.4 million in 2009). For further information on these future obligations, please refer to Note 7 of the Notes to the Consolidated Financial Statements in the Annual Report on Form 10-K for the year ended December 31, 2006.

7. DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITY

The Company periodically enters into derivative commodity instruments to hedge its exposure to price fluctuations on natural gas and crude oil production. Under the Company s revolving credit agreement, the aggregate level of commodity hedging must not exceed 100% of the anticipated future equivalent production during the period covered by these cash flow hedges. At September 30, 2007, the Company had 25 cash flow hedges open: 23 natural gas price collar arrangements and two crude oil collar arrangements. At September 30, 2007, a $26.9 million ($16.8 million, net of tax) unrealized gain was recorded in Accumulated Other Comprehensive Income, along with a $27.4 million short-term derivative receivable, a $1.1 million short-term derivative liability (included within Accrued Liabilities on the Balance Sheet), a $1.0 million long-term derivative receivable (included within Other Assets on the Balance Sheet) and a $0.4 million long-term derivative liability (included within Other Liabilities on the Balance Sheet). The change in the fair value of derivatives designated as hedges that is effective is initially recorded to Accumulated Other Comprehensive Income. The ineffective portion, if any, of the change in the fair value of derivatives designated as hedges, and the change in fair value of all other derivatives, is recorded currently in earnings as a component of Natural Gas Production and Crude Oil and Condensate Revenue, as appropriate. During the first nine months of 2007 and 2006, there was no ineffectiveness recorded in the Condensed Consolidated Statement of Operations.

Assuming no change in commodity prices, after September 30, 2007 the Company would expect to reclassify to the Condensed Consolidated Statement of Operations, over the next 12 months, $16.4 million in after-tax income associated with commodity hedges. This reclassification represents the net short-term receivable associated with open positions currently not reflected in earnings at September 30, 2007 related to anticipated 2007 and 2008 production.

During the first nine months of 2007, the Company entered into four new natural gas collar contracts and one new crude oil collar contract covering a portion of its 2008 production. As of September 30, 2007, natural gas price collars for the full 2008 year will cover 13,018 Mmcf of production at a weighted average floor of $8.01 per Mcf and a weighted average ceiling of $10.28 per Mcf. As of September 30, 2007, the crude oil price collar for the full 2008 year will cover 366 Mbbls of production at a floor of $60.00 per Bbl and a ceiling of $80.00 per Bbl.

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8. COMPREHENSIVE INCOME

Comprehensive Income includes Net Income and certain items recorded directly to Stockholders Equity and classified as Accumulated Other Comprehensive Income. The following table illustrates the calculation of Comprehensive Income for the three and nine month periods ended September 30, 2007 and 2006:

		Three Months Ended					Nine Months Ended			
		September 30,					September 30,			
(In thousands)		**2007**		**2006**			**2007**		**2006**	
Accumulated Other Comprehensive Income / (Loss) - Beginning of Period			**$ 14,051**		$ 15,330			**$ 37,160**		$ (15,115)
Net Income		**$ 35,453**		$ 189,020			**$ 125,376**		$ 289,049	
Other Comprehensive Income / (Loss):										
Reclassification Adjustment for Settled Contracts, net of taxes of $10,917, $3,242, $22,598 and $6,523, respectively		**(17,966)**		(5,290)			**(37,186)**		(10,643)	
Changes in Fair Value of Hedge Positions, net of taxes of $(7,144), $(18,913), $(2,035) and $(40,292), respectively		**11,756**		30,859			**2,699**		65,740	
Defined Benefit Pension and Postretirement Plans:										
Amortization of Net Obligation at Transition, net of taxes of $(60) and $(179)	**$98**					**$ 295**				
Amortization of Prior Service Cost, net of taxes of $(103) and $(310)	**170**					**510**				
Amortization of Net Loss, net of taxes of $(122) and $(364)	**200**					**598**				
Total Defined Benefit Pension and Postretirement Plans, net of taxes of $(285), $ -, $(853) and $ -, respectively	**468**	**468**				**1,403**	**1,403**			
Foreign Currency Translation Adjustment, net of taxes of $(2,456), $38, $(5,029) and $(525), respectively		**4,042**		(60)			**8,275**		857	
Total Other Comprehensive Income / (Loss)		**(1,700)**	**(1,700)**	25,509	25,509		**(24,809)**	**(24,809)**	55,954	55,954
Comprehensive Income		**$ 33,753**		$ 214,529			**$ 100,567**		$ 345,003	
Accumulated Other Comprehensive Income - End of Period			**$ 12,351**		$ 40,839			**$ 12,351**		$ 40,839

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Changes in the components of accumulated other comprehensive income, net of taxes, for the nine months ended September 30, 2007 were as follows:

Accumulated Other Comprehensive Income *(In thousands)*	**Net Gains / (Losses) on Cash Flow Hedges**	**Defined Benefit Pension and Postretirement Plans**	**Foreign Currency Translation Adjustment**	**Total**
Balance at December 31, 2006	$ 51,239	$ (14,168)	$ 89	$ 37,160
Net change in unrealized gains on cash flow hedges, net of taxes of $20,563	(34,487)			(34,487)
Net change in defined benefit pension and postretirement plans, net of taxes of $(853)		1,403		1,403
Change in foreign currency translation adjustment, net of taxes of $(5,029)			8,275	8,275
Balance at September 30, 2007	**$ 16,752**	**$ (12,765)**	**$ 8,364**	**$ 12,351**

9. ASSET RETIREMENT OBLIGATIONS

The following table reflects the changes in the asset retirement obligations during the nine months ended September 30, 2007:

(In thousands)	
Carrying amount of asset retirement obligations at December 31, 2006	$ 22,655
Liabilities added during the current period	1,159
Liabilities settled and divested during the current period	(432)
Current period accretion expense	774
Carrying amount of asset retirement obligations at September 30, 2007	**$ 24,156**

Accretion expense was $0.8 million and $1.1 million, respectively, for the nine months ended September 30, 2007 and 2006 and is included within Depreciation, Depletion and Amortization expense on the Company s Condensed Consolidated Statement of Operations.

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10. PENSION AND OTHER POSTRETIREMENT BENEFITS

The components of net periodic benefit costs for the three and nine months ended September 30, 2007 and 2006 were as follows:

(In thousands)	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
Qualified and Non-Qualified Pension Plans				
Current Period Service Cost	**$ 733**	$ 680	**$ 2,199**	$ 2,040
Interest Cost	**692**	583	**2,076**	1,749
Expected Return on Plan Assets	**(754)**	(521)	**(2,262)**	(1,473)
Amortization of Prior Service Cost	**36**	44	**108**	132
Amortization of Net Loss	**272**	303	**816**	909
Net Periodic Pension Cost	**$ 979**	$ 1,089	**$ 2,937**	$ 3,357
Postretirement Benefits Other than Pension Plans				
Current Period Service Cost	**$ 211**	$ 197	**$ 646**	$ 591
Interest Cost	**273**	219	**812**	658
Plan Termination Gain		(21)		(64)
Amortization of Net Loss	**55**	8	**152**	24
Amortization of Prior Service Cost	**238**	238	**714**	714
Amortization of Net Obligation at Transition	**158**	158	**474**	474
Total Postretirement Benefit Cost	**$ 935**	$ 799	**$ 2,798**	$ 2,397

Employer Contributions

The funding levels of the pension and postretirement plans are in compliance with standards set by applicable law or regulation. The Company previously disclosed in its financial statements for the year ended December 31, 2006 that it expected to contribute less than $0.1 million to its non-qualified pension plan and approximately $0.6 million to the postretirement benefit plan during 2007. It is anticipated that these contributions will be made in the fourth quarter of 2007. The Company does not have any required minimum funding obligations for its qualified pension plan in 2007. Subsequent to September 30, 2007, the Company determined that a $5 million contribution to the qualified pension plan would be made in the fourth quarter of 2007.

11. STOCK-BASED COMPENSATION

Incentive Plans

Under the Company s 2004 Incentive Plan, incentive and non-statutory stock options, stock appreciation rights (SARs), stock awards, cash awards and performance awards may be granted to key employees, consultants and officers of the Company. Non-employee directors of the Company may be granted discretionary awards under the 2004 Incentive Plan consisting of stock options or stock awards. In the first quarter of 2007, the Board of Directors eliminated the automatic award of an option to purchase 15,000 shares (pre 2-for-1 split) of common stock on the date the non-employee directors first join the board of directors. In its place, the Board of Directors will consider an annual fixed dollar stock award which is competitive with the Company s peer group. A total of 5,100,000 shares of common stock may be issued under the 2004 Incentive Plan. Under the 2004 Incentive Plan, no more than 1,800,000 shares may be used for stock awards that are not subject to the achievement of performance based goals, and no more than 3,000,000 shares may be issued pursuant to incentive stock options.

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Stock-Based Compensation Expense

Compensation expense charged against income for stock-based awards during the first nine months of 2007 and 2006 was $12.7 million and $12.2 million, pre-tax, respectively, and is included in General and Administrative Expense in the Condensed Consolidated Statement of Operations. Of this expense, $1.9 million and $3.2 million were incurred during the third quarters of 2007 and 2006, respectively.

For further information regarding Stock-Based Compensation, please refer to Note 10 of the Notes to the Consolidated Financial Statements in the Annual Report on Form 10-K for the year ended December 31, 2006.

Restricted Stock Awards

Restricted stock awards vest either at the end of a three year service period, or on a graded-vesting basis of one-third at each anniversary date over a three year service period. Under the graded-vesting approach, the Company recognizes compensation cost over the three year requisite service period for each separately vesting tranche as though the awards are, in substance, multiple awards. For awards that vest at the end of the three year service period, expense is recognized ratably using a straight-line expensing approach over three years. For all restricted stock awards, vesting is dependant upon the employees continued service with the Company, with the exception of employment termination due to death, disability or retirement.

The fair value of restricted stock grants is based on the average of the high and low stock price on the grant date. The maximum contractual term is three years. In accordance with SFAS No. 123(R), the Company accelerated the vesting period for retirement-eligible employees for purposes of recognizing compensation expense in accordance with the vesting provisions of the Company s stock-based compensation programs for awards issued after the adoption of SFAS No. 123(R). The Company used an annual forfeiture rate ranging from 0% to 3.3% based on the Company s ten year history for this type of award to various employee groups.

During the first nine months of 2007, there were 51,500 shares of restricted stock granted with a grant date per share value of $32.89. These awards vest at the end of a three year service period commencing in July 2007. Compensation expense recorded for all unvested restricted stock awards for the first nine months of 2007 and 2006 was $2.6 million and $4.8 million, respectively. Included in 2007 and 2006 restricted stock expense was $0.1 million and $0.5 million, respectively, related to the immediate expensing of shares granted to retirement-eligible employees.

Restricted Stock Units

Restricted stock units are granted from time to time to non-employee directors of the Company. The fair value of these units is measured at the average of the high and low stock price on grant date and compensation expense is recorded immediately. These units immediately vest and are paid out when the director ceases to be a director of the Company.

During the first nine months of 2007, 24,654 restricted stock units were granted with a grant date per share value of $35.49. The compensation cost, which reflects the total fair value of these units, recorded in the first quarter of 2007 was $0.9 million. During the second quarter of 2006, the Company recorded $0.9 million of expense related to restricted stock units.

Stock Options

Stock option awards are granted with an exercise price equal to the fair market price (defined as the average of the high and low trading prices of the Company s stock at the date of grant) of the Company s stock at the date of grant. The grant date fair value of a stock option is calculated by using a Black-Scholes model. Compensation cost is recorded based on a graded-vesting schedule as the options vest over a service period of three years, with one-third of the award becoming exercisable each year on the anniversary date of the grant.

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Stock options have a maximum contractual term of five years. No forfeiture rate is assumed for stock options granted to directors due to the forfeiture rate history for these types of awards for this group of individuals.

During the first nine months of 2007, there were no stock options granted. Compensation expense recorded during the first nine months of 2007 and 2006 for amortization of stock options was $0.1 million and $0.2 million, respectively.

Stock Appreciation Rights

During the first nine months of 2007, the Compensation Committee granted 107,200 SARs to employees. These awards allow the employee to receive any intrinsic value over the $35.22 grant date fair market value that may result from the price appreciation on a set number of common shares during the contractual term of seven years. All of these awards have graded-vesting features and will vest over a service period of three years, with one-third of the award becoming exercisable each year on the anniversary date of the grant. As these SARs are paid out in stock, rather than in cash, the Company calculates the fair value in the same manner as stock options, by using a Black-Scholes model.

The assumptions used in the Black-Scholes fair value calculation for SARs are as follows:

	Nine Months Ended September 30, 2007
Weighted-Average Value per Stock Appreciation Right Granted During the Period [1]	**$ 11.26**
Assumptions	
Stock Price Volatility	**32.6%**
Risk Free Rate of Return	**4.6%**
Expected Dividend	**0.2%**
Expected Term (in years)	**4.0**

(1) *Calculated using the Black-Scholes fair value based method.*

Compensation expense recorded during the first nine months of 2007 and 2006 for SARs was $1.3 million and $0.7 million, respectively. Included in the 2007 amount was $0.5 million related to the immediate expensing of shares granted to retirement-eligible employees.

Performance Share Awards

During 2007, the Compensation Committee granted three types of performance share awards to employees for a total of 387,100 performance shares. The performance period for two of these awards commences on January 1, 2007 and ends December 31, 2009. Both of these types of awards vest at the end of the three year performance period.

Awards totaling 98,200 performance shares are earned, or not earned, based on the comparative performance of the Company s common stock measured against sixteen other companies in the Company s peer group over a three year performance period. The grant date per share value of the equity portion of this award was $30.72. Depending on the Company s performance, employees may receive the aggregate of up to 100% of the fair market value of a share of common stock payable in common stock plus up to 100% of the fair market value of a share of common stock payable in cash.

Awards totaling 196,500 performance shares are earned, or not earned, based on the Company s internal performance metrics rather than a peer group. The grant date per share value of this award was $35.22. These awards represent the right to receive up to 100% of the award in shares of common stock. The actual number of shares issued at the end of the performance period will be determined based on the Company s performance against three performance criteria set by the Company s Compensation Committee. An employee will earn one-third of the award granted for each internal performance metric that the Company meets at the end of the performance period. These performance criteria measure the Company s average production, average finding costs and average reserve replacement over three years. Based on the Company s probability assessment at September 30, 2007, it is currently considered probable that these three criteria will be met.

The third performance share award, totaling 92,400 performance shares, with a grant date per share value of $35.22, has a three-year graded vesting schedule, vesting one-third on each anniversary date following the date of grant, provided that the Company has positive operating income for the year preceding the vesting date. If the Company does not have positive operating income for the year preceding a vesting date, then the portions of the performance shares that would have vested on that date will be forfeited. As of September 30, 2007, it is considered probable that this performance metric will be met.

For all awards granted to employees after January 1, 2006, an annual forfeiture rate ranging from 0% to 5.0% has been assumed based on the Company s history for this type of award to various employee groups.

For awards that are based on the internal metrics (performance condition) of the Company and for awards that were granted prior to the adoption of SFAS No. 123(R) on January 1, 2006, fair value is measured based on the average of the high and low stock price of the Company on grant date and expense is amortized over the three year vesting period. To determine the fair value for awards that were granted after January 1, 2006 that are based on the Company s comparative performance against a peer group (market condition), the equity and liability components are bifurcated. On the grant date, the equity component was valued using a Monte Carlo binomial model and is amortized on a straight-line basis over three years. The liability component is valued at each reporting period by using a Monte Carlo binomial model.

The three primary inputs for the Monte Carlo model are the risk-free rate, volatility of returns and correlation in stock price movement. The risk-free rate was generated from the Federal Reserve website for constant maturity treasuries for six-month, one, two and three year bonds and is set equal to the yield, for the period over the remaining duration of the performance period, on treasury securities as of the reporting date. Volatility was set equal to the annualized daily volatility measured over a historic four year period ending on the reporting date. A sample of correlation statistics were reviewed between the Company and its peers and the average ranged between 87% and 93%.

The following assumptions were used as of September 30, 2007 for the Monte Carlo model to value the liability component of the peer group measured performance share awards. The equity portion of the award has already been valued on the date of grant using the Monte Carlo model and this portion was not marked to market.

	As of September 30,
	2007
Risk Free Rate of Return	4.0% - 4.9%
Stock Price Volatility	33.7%
Correlation in Stock Price Movement	90%
Expected Dividend	0.3%

The liability component for all outstanding market condition performance share awards ranged from $6.98 to $27.38 at September 30, 2007. The long-term liability for all market condition performance share awards, included in Other Liabilities in the Condensed Consolidated Balance Sheet, at September 30, 2007 and 2006 was $1.9 million and $1.6 million, respectively. The short-term liability, included in Accrued Liabilities in the Condensed Consolidated Balance Sheet, at September 30, 2007 and 2006, for certain market condition performance share awards was $4.1 million and $0.4 million, respectively.

Total compensation cost recognized for both the equity and liability components of all performance share awards during the nine months ended September 30, 2007 and 2006 was $7.7 million and $5.6 million, respectively.

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12. UNCERTAIN TAX POSITIONS

In June 2006, the FASB issued FIN 48, Accounting for Uncertainty in Income Taxes an Interpretation of FASB Statement No. 109. This Interpretation provides guidance for recognizing and measuring uncertain tax positions as defined in SFAS No. 109, Accounting for Income Taxes. FIN 48 prescribes a two-step process for accounting for income tax uncertainties. First, a threshold condition of more likely than not should be met to determine whether any of the benefit of the uncertain tax position should be recognized in the financial statements. If the recognition threshold is met, FIN 48 provides additional guidance on measuring the amount of the uncertain tax position. Under FIN 48, the Company may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. Guidance is also provided regarding derecognition, classification, interest and penalties, interim period accounting, transition and increased disclosure of these uncertain tax position. FIN 48 is effective for fiscal years beginning after December 15, 2006.

The Company adopted the provisions of FIN 48 on January 1, 2007. As a result of the implementation of FIN 48, the Company recognized no change to the liability for unrecognized tax benefits.

The Company recognizes accrued interest related to uncertain tax positions in Interest Expense and Other and accrued penalties in General and Administrative expense in the Condensed Consolidated Statement of Operations, which is consistent with the recognition of these items in prior reporting periods. As of January 1, 2007, the Company had recorded a liability of approximately $0.9 million for interest. During the first nine months of 2007, the Company reversed this liability and recorded interest receivable of $0.1 million. This resulted in an adjustment to net interest expense of $1.0 million. As of September 30, 2007, the Company determined that no accrual for penalties was appropriate.

As of January 1, 2007, after the implementation of FIN 48, the Company s unrecognized tax benefits were $1.0 million. This amount, if recognized, would not affect the effective tax rate. As of September 30, 2007, it is reasonably possible that the 2001-2004 years currently pending before the IRS Appeals Division will be settled within the next twelve months. Discussions are ongoing with the taxing authorities regarding these years. The amounts recorded reflect the Company s best estimate as to the ultimate resolution of these matters. For the nine months ended September 30, 2007, the unrecognized tax benefit increased by $1.4 million. The amount of unrecognized tax benefits, if recognized, would not have a significant impact on the effective tax rate.

It is possible that the amount of unrecognized tax benefits will change in the next twelve months. The Company does not expect that a change would have a significant impact on its results of operations, financial position or cash flows.

The U.S. federal statute of limitations remains open for years 2001 and onward. State income tax returns are generally subject to examination for a period of three to four years after filing of the respective return. The state impact of any federal changes remains subject to examination by various states for a period of up to one year after formal notification to the states. Years still open to examination by state authorities in major jurisdictions include Texas and West Virginia (2001 onward). The Company is not currently under examination, nor has it been notified of an upcoming examination, by West Virginia. The Company has been audited by Texas for report years through 2006. The audits were resolved successfully and no material adjustments were needed.

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of

Cabot Oil & Gas Corporation:

We have reviewed the accompanying condensed consolidated balance sheet of Cabot Oil & Gas Corporation and its subsidiaries (the Company) as of September 30, 2007, the related condensed consolidated statement of operations for each of the three and nine month periods ended September 30, 2007 and 2006, and the condensed consolidated statement of cash flows for the nine month periods ended September 30, 2007 and 2006. These interim financial statements are the responsibility of the Company s management.

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

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

We have previously audited in accordance with the standards of the Public Company Accounting Oversight Board (United States) the consolidated balance sheet as of December 31, 2006 and the related consolidated statements of operations, comprehensive income, stockholders equity, and cash flows for the year then ended, management s assessment of the effectiveness of the Company s internal control over financial reporting as of December 31, 2006 and the effectiveness of the Company s internal control over financial reporting as of December 31, 2006; and in our report dated February 28, 2007, which included an explanatory paragraph related to the adoption of Statement of Financial Accounting Standards No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R), we expressed unqualified opinions thereon. The consolidated financial statements and management s assessment of the effectiveness of internal control over financial reporting referred to above are not presented herein. In our opinion, the information set forth in the accompanying condensed consolidated balance sheet information as of December 31, 2006, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
October 29, 2007

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

The following review of operations for the three and nine month periods ended September 30, 2007 and 2006 should be read in conjunction with our Condensed Consolidated Financial Statements and the Notes included in this Form 10-Q and with the Consolidated Financial Statements, Notes and Management s Discussion and Analysis included in the Cabot Oil & Gas Annual Report on Form 10-K for the year ended December 31, 2006.

Overview

Operating revenues for the nine months ended September 30, 2007 decreased by $52.0 million, or nine percent, from the nine months ended September 30, 2006 due to decreased equivalent production resulting from the disposition of our offshore portfolio and certain south Louisiana properties to a third party, which was substantially completed in the third quarter of 2006 (the 2006 south Louisiana and offshore properties sale), which accounted for approximately 9.0 Bcf of natural gas production and 705 Mbbls of crude oil production sold in the nine months ended September 30, 2006, and, to a lesser extent, decreased realized commodity prices. Natural gas revenues decreased by $5.7 million, or one percent, for the nine months ended September 30, 2007 as compared to the nine months ended September 30, 2006. The decrease is due to a decrease in natural gas production as a result of the 2006 south Louisiana and offshore properties sale, as well as a slight decrease in realized prices. Oil revenues decreased by $41.0 million, or 51%, for the first nine months of 2007 as compared to the first nine months of 2006. This decrease is primarily due to a decrease in crude oil production as a result of the 2006 south Louisiana and offshore properties sale as well as a decrease in crude oil realized prices in the first nine months of 2007 as compared to the first nine months of 2006. Excluding $70.3 million and $47.3 million, respectively, of natural gas and crude oil revenues from our 2006 results attributable to the 2006 south Louisiana and offshore properties sale, natural gas revenues for the first nine months of 2007 would have increased by 18% and crude oil revenues would have increased by 19%. Brokered natural gas revenues decreased by $1.0 million due to a decrease in brokered volumes, offset in part by an increase in sales price.

Our realized natural gas price for the nine months ended September 30, 2007 was $7.15 per Mcf, one percent lower than the $7.22 per Mcf price realized in the same period of the prior year. Our realized crude oil price was $62.17 per Bbl, six percent lower than the $66.42 per Bbl price realized in the same period of the prior year. These realized prices include realized gains and losses resulting from commodity derivatives (costless collars). For information about the impact of these derivatives on realized prices, refer to the Results of Operations section. Commodity prices are determined by factors that are outside of our control. Historically, commodity prices have been volatile and we expect them to remain volatile. Commodity prices are affected by changes in market demands, overall economic activity, weather, pipeline capacity constraints, storage levels, basis differentials and other factors. As a result, we cannot accurately predict future natural gas, NGL and crude oil prices and, therefore, cannot accurately predict revenues.

On an equivalent basis, our production for the first nine months of 2007 decreased by five percent from the first nine months of 2006. For the nine months ended September 30, 2007, we produced 64.1 Bcfe compared to production of 67.8 Bcfe for the comparable period of the prior year. Natural gas production was 60.3 Bcf and oil production was 632 Mbbls for the first nine months of 2007. Natural gas production decreased by less than one percent when compared to the comparable period of the prior year, which had production of 60.5 Bcf. This decrease was primarily a result of a decline in production in the Gulf Coast, partially offset by increased production in the West and East regions associated with an increase in the drilling program and an increase in Canada due to increased pipeline capacity in Canada for the Hinton field. The Gulf Coast region experienced an overall decrease in natural gas production of 4.1 Bcf, or 17%. Excluding 9.0 Bcf of natural gas production related to the 2006 south Louisiana and offshore properties sale, the Gulf Coast region would have experienced a 4.9 Bcf, or 33%, increase in production in the first nine months of 2007 compared to the first nine months of 2006, primarily as a result of increased drilling in the Minden and McCampbell fields and recompletions in the Raymondville field. Oil production decreased by 577 Mbbls, or 48%, from 1,209 Mbbls in the first nine months of 2006 to 632 Mbbls produced in the first nine months of 2007. This was primarily the result of a decrease of 558 Mbbls in the Gulf Coast region. Excluding 705 Mbbls of crude oil production related to the 2006 south Louisiana and offshore properties sale, oil production would have increased by 25% in the first nine months of 2007 compared to the first nine months of 2006, due primarily to the increase in drilling and workover activity in the McCampbell field, and to a lesser extent, in the Minden field. Oil production remained relatively flat in the East region, decreased slightly in the West region due to natural decline and increased by six Mbbls in Canada.

In response to continued weakness in Rocky Mountain natural gas prices, we shut-in 10 Mmcf per day of the West region s gas production for the month of October. Production is expected to resume in November.

We had net income of $125.4 million, or $1.29 per share, for the nine months ended September 30, 2007 compared to net income of $289.0 million, or $2.98 per share, for the comparable period of the prior year. The decrease in net income is primarily due to a $229.7 million gain on sale of assets that was recognized in the third quarter of 2006 resulting from the 2006 south Louisiana and offshore properties sale. For the nine months ended September 30, 2007, the gain on sale of assets was $12.3 million. In addition, operating revenues decreased by $52.0 million due to decreases in crude oil and natural gas production revenues, as discussed above. Partially offsetting this revenue decrease was a decrease in total operating expenses of $0.8 million in the first nine months of 2007 as compared to the first nine months of 2006, primarily due to decreased exploration charges and, to a lesser extent, taxes other than income and brokered costs, partially offset by increased depreciation, depletion and amortization (DD&A), impairment expenses and general and administrative expenses. This decrease in operating expenses also reflected reduced expenses in 2007 due to the 2006 south Louisiana and offshore properties sale. These impacts, along with a $7.6 million decrease in interest and other expenses, reduced income before taxes by $261.2 million and consequently decreased income tax expense by $97.6 million. Also contributing to the decrease in income taxes was the decrease in the effective tax rate primarily due to a reduction in our overall state income tax liability.

In addition to production volumes and commodity prices, finding and developing sufficient amounts of crude oil and natural gas reserves at economical costs are critical to our long-term success. In 2007, we expect to spend approximately $600 million in capital and exploration expenditures. Funding of the program will come from operating cash flow, existing cash and increased borrowings, if required. For the nine months ended September 30, 2007, approximately $478.7 million has been invested in our exploration and development efforts.

During the nine months ended September 30, 2007, we drilled 359 gross wells (346 development, 6 exploratory and 7 extension wells) with a success rate of 98% compared to 301 gross wells (278 development, 14 exploratory and 9 extension wells) with a success rate of 97% for the comparable period of the prior year. For the full year of 2007, we plan to drill approximately 480 gross wells compared to 387 gross wells drilled in 2006.

We remain focused on our strategies of pursuing lower risk drilling opportunities that provide more predictable results and selectively pursuing impact exploration opportunities as we accelerate drilling on our accumulated acreage position. In the current year we have allocated our planned program for capital and exploration expenditures among our various operating regions. We believe these strategies are appropriate in the current industry environment and will continue to add shareholder value over the long term.

The preceding paragraphs, discussing our strategic pursuits and goals, contain forward-looking information. Please read Forward-Looking Information for further details.

Financial Condition

Capital Resources and Liquidity

Our primary sources of cash for the nine months ended September 30, 2007 were from funds generated from the sale of natural gas and crude oil production, borrowings under our revolving credit facility and, to a lesser extent, proceeds from the sale of assets. Cash flows provided by operating activities were primarily used to fund development and, to a lesser extent, exploratory expenditures, and to pay dividends. See below for additional discussion and analysis of cash flow.

Operating cash flow fluctuations are substantially driven by commodity prices and changes in our production volumes. Prices for crude oil and natural gas have historically been volatile, including seasonal influences characterized by peak demand and higher prices in the winter heating season; however, the impact of other risks and uncertainties, as described in our Annual Report on Form 10-K for the year ended December 31, 2006, have also influenced prices throughout the recent years. In addition, fluctuations in cash flow may result in an increase or decrease in our capital and exploration expenditures. See Results of Operations for a review of the impact of prices and volumes on sales.

Our working capital is also substantially influenced by these variables discussed above. From time to time, our working capital will reflect a surplus, while at other times it will reflect a deficit. This fluctuation is not unusual. We believe we have adequate liquidity available to meet our working capital requirements.

	Nine Months Ended September 30,	
(In thousands)	**2007**	**2006**
Cash Flows Provided by Operating Activities	**$ 328,559**	$ 356,050
Cash Flows Used in Investing Activities	**(432,380)**	(61,605)
Cash Flows Provided by Financing Activities	**76,418**	17,052
Net (Decrease) / Increase in Cash and Cash Equivalents	**$ (27,403)**	$ 311,497

***Operating Activities*.** Net cash provided by operating activities in the first nine months of 2007 decreased by $27.5 million over the comparable period in 2006. This decrease is primarily due to a decrease in working capital changes as well as a decrease in net income due to decreased equivalent production and commodity prices. Key components impacting net operating cash flows are commodity prices, production volumes and operating costs. Average crude oil realized prices decreased by six percent for the first nine months of 2007 versus the 2006 period and average realized natural gas prices decreased by one percent over the same period. Equivalent production volumes decreased by approximately five percent in the first nine months of 2007 compared to the comparable period in 2006. We are unable to predict future commodity prices, and as a result, cannot provide any assurance about future levels of net cash provided by operating activities.

***Investing Activities*.** The primary uses of cash in investing activities are capital spending and exploration expense. We establish the budget for these amounts based on our current estimate of future commodity prices. Due to the volatility of commodity prices, our capital expenditures budget may be periodically adjusted during any given year. Cash flows used in investing activities increased by $370.8 million from the first nine months of 2006 compared to the first nine months of 2007. The increase from 2006 to 2007 is due to a decrease of $317.2 million in the 2007 period in proceeds from the sale of assets and an increase of $72.3 million in the 2007 period in capital expenditures, partially offset by reduced exploration expenditures of $18.8 million.

***Financing Activities*.** Cash flows provided by financing activities were $76.4 million for the first nine months of 2007, and were comprised of a net increase in borrowings under our revolving credit facility, proceeds from the exercise of stock options and the tax benefit received from stock-based compensation payments, partially offset by dividend payments. Cash flows provided by financing activities were $17.1 million for the nine months ended September 30, 2006, due to inflows from the net increase in borrowings under our revolving credit facility, the tax benefit received from stock-based compensation and proceeds from the exercise of stock options, partially offset by payments made to purchase treasury stock and to pay dividends.

At September 30, 2007, we had $85 million of borrowings outstanding under our credit facility at a weighted-average interest rate of 6.1%. The credit facility provides for an available credit line of $250 million, which can be expanded up to $350 million, either with the existing banks or new banks. The available credit line is subject to adjustment on the basis of the present value of estimated future net cash flows from proved oil and gas reserves (as determined by the banks petroleum engineer) and other assets. The revolving term of the credit facility ends in December 2009. We strive to manage our debt at a level below the available credit line in order to maintain excess borrowing capacity. Management believes that we have the ability to finance through new debt or equity offerings, if necessary, our capital requirements, including potential acquisitions.

Our Board of Directors has authorized a share repurchase program under which we may purchase shares of our common stock in the open market or in negotiated transactions. There is no expiration date associated with the authorization. During the nine months ended September 30, 2007, we did not repurchase any shares of our common stock. All purchases executed to date have been through open market transactions. The maximum number of shares that may yet be purchased under the plan as of September 30, 2007 was

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4,795,300. See Unregistered Sales of Equity Securities and Use of Proceeds Issuer Purchases of Equity Securities in Item 2 of Part II of this quarterly report.

Capitalization

Information about our capitalization is as follows:

(In millions)	September 30, 2007	December 31, 2006
Debt [(1)]	**$ 315.0**	$ 240.0
Stockholders Equity	**1,051.8**	945.2
Total Capitalization	**$ 1,366.8**	$ 1,185.2
Debt to Capitalization	**23%**	20%
Cash and Cash Equivalents	**$ 14.5**	$ 41.9

(1) *Includes $20.0 million of current portion of long-term debt at both September 30, 2007 and December 31, 2006. Includes $85.0 million and $10.0 million of borrowings outstanding under our revolving credit facility at September 30, 2007 and December 31, 2006, respectively.*

During the nine months ended September 30, 2007, we paid dividends of $7.8 million on our common stock. A regular dividend has been declared for each quarter since we became a public company in 1990. After the March 2007 2-for-1 stock split, the dividend was increased to $0.03 per share per quarter, or a 50% increase from pre-split levels.

Capital and Exploration Expenditures

On an annual basis, we generally fund most of our capital and exploration activities, excluding any significant oil and gas property acquisitions, with cash generated from operations and, when necessary, our revolving credit facility. We budget these capital expenditures based on our projected cash flows for the year.

The following table presents major components of capital and exploration expenditures for the nine months ended September 30, 2007 and 2006:

	Nine Months Ended September 30,	
(In millions)	2007	2006
Capital Expenditures		
Drilling and Facilities	$ **404.8**	$ 300.6
Leasehold Acquisitions	**17.8**	35.4
Pipeline and Gathering	**17.5**	16.4
Other	**16.8**	2.0
	456.9	354.4
Proved Property Acquisitions	**0.6**	6.6
Exploration Expense	**21.2**	40.0
Total	$ **478.7**	$ 401.0

We plan to drill approximately 480 gross wells in 2007. This drilling program includes approximately $600 million in total capital and exploration expenditures. See the Overview discussion for additional information regarding the current year drilling program. We will continue to assess the natural gas and crude oil price environment and may increase or decrease the capital and exploration expenditures accordingly.

Contractual Obligations

During the nine months ended September 30, 2007, certain events have occurred changing the amounts previously reported in our contractual obligations table for drilling rig commitments and firm gas transportation agreements in our Annual Report on Form 10-K for the year ended December 31, 2006.

Our firm gas transportation agreements provide firm transportation capacity rights on pipeline systems in Canada, the West region and the East region. These amounts are payable over the next 20 years. The transportation demand charges under these agreements that we are estimated to pay, regardless of the amount of pipeline capacity we utilize, decreased in the first nine months of 2007 by approximately $1.8 million from the total $85.1 million figure previously disclosed in our Annual Report on Form 10-K. This is due to released volumes on one contract in the West region as well as a change in the start date of a contract in Canada due to facility construction delays. As of September 30, 2007, demand charges for 2007, 2008, 2010 and 2011, respectively, are expected to be $7.9 million, $7.5 million, $4.2 million and $3.8 million, a decrease of $2.0 million and $0.7 million and an increase of $0.5 million and $0.4 million from the amounts previously disclosed. As of September 30, 2007, demand charges for 2009 and the 2012-2027 periods are expected to be $7.1 million and $52.8 million, respectively, which is consistent with the amounts previously disclosed in our Annual Report on Form 10-K.

Drilling rig commitments decreased by $0.2 million from the $120.3 million figure reported in our Annual Report on Form 10-K for the year ended December 31, 2006.

For further information, please refer to Firm Gas Transportation Agreements and Drilling Rig Commitments under Note 6 in the Notes to the Condensed Consolidated Financial Statements.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations are based upon condensed consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted and adopted in the United States. The preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. See our Annual Report on Form 10-K for the year ended December 31, 2006, for further discussion of our critical accounting policies.

Effective January 1, 2007, we adopted the provisions of FIN 48, Accounting for Uncertainty in Income Taxes-an interpretation of FASB Statement No. 109. This adoption did not have a material impact on any of our financial statements.

Results of Operations

Third Quarters of 2007 and 2006 Compared

We reported net income in the third quarter of 2007 of $35.5 million, or $0.37 per share. During the corresponding quarter of 2006, we reported net income of $189.0 million, or $1.96 per share. Net income decreased in the third quarter of 2007 by $153.5 million, primarily due to a decrease in operating income of $249.1 million due to the inclusion in the third quarter of 2006 of the gain on sale of assets of $229.7 million primarily from the 2006 south Louisiana and offshore properties sale. Operating revenues decreased by $13.8 million, largely due to a decrease in crude oil production revenues and brokered natural gas revenues. Operating expenses increased by $5.6 million between quarters largely due to higher DD&A and impairment charges, partially offset by reduced exploration expense and brokered natural gas cost. Partially offsetting these decreases to net income was a decrease in expenses of $95.6 million resulting from a combination of lower income tax expense as well as interest and other expenses. Income tax expense was lower in the 2007 period as a result of lower income before income taxes in the 2007 period compared to the 2006 period combined with a decrease in the effective tax rate primarily due to a reduction in our overall state income tax liability.

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Natural Gas Production Revenues

Our average total company realized natural gas production sales price, including the realized impact of derivative instruments, was $6.80 per Mcf for the three months ended September 30, 2007 compared to $6.76 per Mcf for the comparable period of the prior year. These prices include the realized impact of derivative instrument settlements which increased the price by $1.40 per Mcf in 2007 and $0.41 per Mcf in 2006. There was no revenue impact from the unrealized change in derivative fair value for the three months ended September 30, 2007 or 2006.

	Three Months Ended September 30,		Variance	
	2007	**2006**	**Amount**	**Percent**
Natural Gas Production *(Mmcf)*				
East	**6,276**	5,930	346	6%
Gulf Coast	**6,790**	8,029	(1,239)	(15)%
West	**6,580**	6,124	456	7%
Canada	**990**	652	338	52%
Total Company	**20,636**	20,735	(99)	
Natural Gas Production Sales Price *($/Mcf)*				
East	**$ 7.37**	$ 7.41	$ (0.04)	(1)%
Gulf Coast	**$ 7.82**	$ 7.13	$ 0.69	10%
West	**$ 5.47**	$ 5.84	$ (0.37)	(6)%
Canada	**$ 4.95**	$ 5.09	$ (0.14)	(3)%
Total Company	**$ 6.80**	$ 6.76	$ 0.04	1%
Natural Gas Production Revenue *(In thousands)*				
East	**$ 46,267**	$ 43,958	$ 2,309	5%
Gulf Coast	**53,101**	57,216	(4,115)	(7)%
West	**36,027**	35,770	257	1%
Canada	**4,905**	3,317	1,588	48%
Total Company	**$ 140,300**	$ 140,261	$ 39	
Price Variance Impact on Natural Gas Production Revenue *(In thousands)*				
East	**$ (253)**			
Gulf Coast	**4,719**			
West	**(2,413)**			
Canada	**(143)**			
Total Company	**$ 1,910**			
Volume Variance Impact on Natural Gas Production Revenue *(In thousands)*				
East	**$ 2,562**			
Gulf Coast	**(8,834)**			
West	**2,670**			
Canada	**1,731**			
Total Company	**$ (1,871)**			

The increase in Natural Gas Production Revenue is primarily due to the slight increase in realized natural gas sales prices, partially offset by a slight decrease in natural gas production. The decrease in the realized natural gas production and increase in prices resulted in a net revenue increase of $0.1 million. After removing from the third quarter 2006 results $18.8 million of natural gas revenues and 2,721 Mmcf of natural gas production associated with the 2006 south Louisiana and offshore properties sale, total natural gas revenue would have increased by $18.9

million, or 16%, and natural gas production would have increased by 2,622 Mmcf, or 14%, from the third quarter of 2006 to the third quarter of 2007.

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Brokered Natural Gas Revenue and Cost

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Variance Amount	Variance Percent
Sales Price *($/Mcf)*	**$ 7.14**	$ 6.96	$ 0.18	3%
Volume Brokered *(Mmcf)*	**2,126**	2,453	(327)	(13)%
Brokered Natural Gas Revenues *(In thousands)*	**$ 15,179**	$ 17,075		
Purchase Price *($/Mcf)*	**$ 6.22**	$ 6.23	$ (0.01)	
Volume Brokered *(Mmcf)*	**2,126**	2,453	(327)	(13)%
Brokered Natural Gas Cost *(In thousands)*	**$ 13,223**	$ 15,282		
Brokered Natural Gas Margin *(In thousands)*	**$ 1,956**	$ 1,793	$ 163	9%

(In thousands)	
Sales Price Variance Impact on Revenue	**$ 383**
Volume Variance Impact on Revenue	**(2,278)**
	$ (1,895)

(In thousands)	
Purchase Price Variance Impact on Purchases	**$ 21**
Volume Variance Impact on Purchases	**2,037**
	$ 2,058

The increased brokered natural gas margin of $0.2 million is a result of an increase in sales price and decrease in purchase price, offset in part by a decrease in the volumes brokered, in the third quarter of 2007 over the same period in the prior year.

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Crude Oil and Condensate Revenues

Our average total company realized crude oil sales price was $70.85 per Bbl for the third quarter of 2007. Our average total company realized crude oil sales price was $69.80 per Bbl for the third quarter of 2006. There was no realized or unrealized impact of derivative instruments in the third quarter of 2007 or 2006.

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Variance Amount	Variance Percent
Crude Oil Production *(Mbbl)*				
East	**7**	6	1	17%
Gulf Coast	**153**	319	(166)	(52)%
West	**49**	52	(3)	(6)%
Canada	**4**	2	2	100%
Total Company	**213**	379	(166)	(44)%
Crude Oil Sales Price *($/Bbl)*				
East	**$ 68.12**	$ 64.67	$ 3.45	5%
Gulf Coast	**$ 71.16**	$ 70.10	$ 1.06	2%
West	**$ 70.85**	$ 68.53	$ 2.32	3%
Canada	**$ 63.47**	$ 69.53	$ (6.06)	(9)%
Total Company	**$ 70.85**	$ 69.80	$ 1.05	2%
Crude Oil Revenue *(In thousands)*				
East	**$ 494**	$ 379	$ 115	30%
Gulf Coast	**10,903**	22,391	(11,488)	(51)%
West	**3,439**	3,565	(126)	(4)%
Canada	**248**	100	148	148%
Total Company	**$ 15,084**	$ 26,435	$ (11,351)	(43)%
Price Variance Impact on Crude Oil Revenue *(In thousands)*				
East	**$ 25**			
Gulf Coast	**163**			
West	**113**			
Canada	**(24)**			
Total Company	**$ 277**			
Volume Variance Impact on Crude Oil Revenue *(In thousands)*				
East	**$ 90**			
Gulf Coast	**(11,651)**			
West	**(239)**			
Canada	**172**			
Total Company	**$ (11,628)**			

The decrease in production offset in part by an increase in realized crude oil prices resulted in a net revenue decrease of $11.3 million. The decrease in oil production is mainly the result of the 2006 south Louisiana and offshore properties sale in the Gulf Coast region. After removing from the third quarter 2006 results $15.0 million of crude oil revenues and 213 Mbbls of crude oil production associated with the 2006 south Louisiana and offshore properties sale, total crude oil revenue would have increased by $3.6 million, or 32%, and crude oil production would have increased by 47 Mbbls, or 28%, from the third quarter of 2006 to the third quarter of 2007.

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Impact of Derivative Instruments on Operating Revenues

The following table reflects the realized impact of cash settlements and the net unrealized change in fair value of derivative instruments:

	Three Months Ended September 30,			
	2007		2006	
(In thousands)	Realized	Unrealized	Realized	Unrealized
Operating Revenues - Increase to Revenue				
Cash Flow Hedges				
Natural Gas Production	**$ 28,882**	**$**	$ 8,532	$
Crude Oil				
Total Cash Flow Hedges	**$ 28,882**	**$**	$ 8,532	$

We are exposed to market risk on derivative instruments to the extent of changes in market prices of natural gas and oil. However, the market risk exposure on these derivative contracts is generally offset by the gain or loss recognized upon the ultimate sale of the commodity.

Other Operating Revenues

Other operating revenues decreased by $0.7 million between the third quarter of 2007 and the third quarter of 2006 primarily due to the fact that, during the third quarter of 2006, we had an increase in revenue related to net profits interests that originated in 2006.

Operating Expenses

Total costs and expenses from operations increased by $5.6 million in the third quarter of 2007 compared to the same period of 2006. The primary reasons for this fluctuation are as follows:

Depreciation, Depletion and Amortization increased by $5.6 million in the third quarter of 2007. This is primarily due to the impact on the DD&A rate of negative reserve revisions due to lower prices at the end of 2006, higher capital costs and commencement of production in an East Texas field.

Exploration expense decreased by $4.9 million primarily due to a $5.5 million decrease in dry hole expense in the 2007 period compared with the 2006 period. Dry hole expense decreased in the West and Canada and increased in the Gulf Coast quarter over quarter. A partial offset to this decrease was an increase in geological and geophysical expenses of $0.5 million, largely related to an increase in Canada.

Impairment of Oil and Gas Properties increased by $4.6 million due to an impairment recorded in the 2007 period in the Gulf Coast region resulting from two non-commercial development completions in a small field in north Louisiana.

Impairment of Unproved Properties increased by $2.1 million in the third quarter of 2007 compared to the third quarter of 2006, primarily due to increased lease acquisition costs during 2006.

Brokered Natural Gas Cost decreased by $2.1 million from the third quarter of 2006 to the third quarter of 2007. See the preceding table titled Brokered Natural Gas Revenue and Cost for further analysis.

Interest Expense, Net

Interest expense, net decreased by $3.0 million in the third quarter of 2007 due to lower credit facility borrowings, a lower interest weighted-average interest rate on our revolving credit facility borrowings and a lower outstanding principal amount of our 7.19% fixed rate debt. Weighted average borrowings under our credit facility based on daily balances were approximately $57 million during the third quarter of 2007 compared to approximately $113 million during the third quarter of 2006. In addition, interest expense decreased due to the reversal of a FIN 48 interest payable. See Note 12 of the Notes to the Condensed Consolidated Financial Statements for further details on our FIN 48 interest.

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Income Tax Expense

Income tax expense decreased by $92.6 million. The effective tax rate for the third quarter of 2007 and 2006 was 31.3% and 36.5%, respectively. The decrease in the effective tax rate is primarily due to a reduction in our overall state income tax liability for 2007. Ongoing discussions are taking place with state authorities regarding the tax liabilities relating to the 2006 south Louisiana and offshore properties sale. The state income tax liability recorded as of September 30, 2007, reflects our best estimate as to the resolution of these matters.

Nine Months of 2007 and 2006 Compared

We reported net income in the first nine months of 2007 of $125.4 million, or $1.29 per share. During the corresponding period of 2006, we reported net income of $289.0 million, or $2.98 per share. This decrease of $163.6 million in net income was primarily due to a decrease in operating income of $268.8 million resulting from the gain on sale of assets of $229.9 million included in the 2006 period, partially offset by a $97.6 million decrease in income tax expense and a $7.6 million decrease in interest and other expenses in the 2007 period.

The decrease in operating income was primarily the result of an increase in the 2006 period of $217.6 million in gain on sale of assets primarily from the 2006 south Louisiana and offshore properties sale. Additionally, there was a $52.0 million decrease in the 2007 period in operating revenues, offset in part by a decrease of $0.8 million in operating expenses. The decrease in operating revenues was the result of lower overall production and realized commodity prices. The decrease in operating expenses was primarily the result of reduced exploration expense and, to a lesser extent, taxes other than income and brokered natural gas cost, partially offset by increases in DD&A and impairment expenses and general and administrative expenses.

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Natural Gas Production Revenues

Our average total company realized natural gas production sales price, including the realized impact of derivative instruments, was $7.15 per Mcf for the nine months ended September 30, 2007 compared to $7.22 per Mcf for the comparable period of the prior year. These prices include the realized impact of derivative instrument settlements, which increased the price by $0.99 per Mcf in 2007 and $0.28 per Mcf in 2006. There was no revenue impact from the unrealized change in derivative fair value for the nine months ended September 30, 2007 or 2006.

	Nine Months Ended September 30,		**Variance**	
	2007	**2006**	**Amount**	**Percent**
Natural Gas Production *(Mmcf)*				
East	**18,199**	17,581	618	4%
Gulf Coast	**19,724**	23,881	(4,157)	(17)%
West	**19,402**	17,272	2,130	12%
Canada	**2,992**	1,778	1,214	68%
Total Company	**60,317**	60,512	(195)	
Natural Gas Production Sales Price *($/Mcf)*				
East	**$ 7.76**	$ 8.09	$ (0.33)	(4)%
Gulf Coast	**$ 7.95**	$ 7.41	$ 0.54	7%
West	**$ 6.00**	$ 6.19	$ (0.19)	(3)%
Canada	**$ 5.63**	$ 6.10	$ (0.47)	(8)%
Total Company	**$ 7.15**	$ 7.22	$ (0.07)	(1)%
Natural Gas Production Revenue *(In thousands)*				
East	**$ 141,253**	$ 142,248	$ (995)	(1)%
Gulf Coast	**156,745**	176,888	(20,143)	(11)%
West	**116,330**	106,953	9,377	9%
Canada	**16,850**	10,842	6,008	55%
Total Company	**$ 431,178**	$ 436,931	$ (5,753)	(1)%
Price Variance Impact on Natural Gas Production Revenue *(In thousands)*				
East	**$ (5,996)**			
Gulf Coast	**10,648**			
West	**(3,616)**			
Canada	**(1,394)**			
Total Company	**$ (358)**			
Volume Variance Impact on Natural Gas Production Revenue *(In thousands)*				
East	**$ 5,001**			
Gulf Coast	**(30,791)**			
West	**12,993**			
Canada	**7,402**			
Total Company	**$ (5,395)**			

The decrease in Natural Gas Production Revenue is due to the decrease in production as well as the decrease in realized natural gas sales prices. Prices were lower in all regions except for the Gulf Coast for the first nine months of 2007 over the prior year nine months. The decreases in realized natural gas prices and production resulted in a net revenue decrease of $5.7 million. After removing from the first nine months 2006 results $70.3 million of natural gas revenues and 9,023 Mmcf of natural gas production associated with properties in the Gulf Coast region sold in the 2006 south Louisiana and offshore properties sale, total natural gas revenue would have increased by $64.6 million, or 18%, and natural gas production would have increased by 8,828 Mmcf, or 17%, from the first nine months of 2006 to the first nine months of 2007.

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Brokered Natural Gas Revenue and Cost

	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006	Variance Amount	Variance Percent
Sales Price *($/Mcf)*	**$ 8.40**	$ 8.13	$ 0.27	3%
Volume Brokered *(Mmcf)*	**7,903**	8,292	(389)	(5)%
Brokered Natural Gas Revenues *(In thousands)*	**$ 66,357**	$ 67,389		
Purchase Price *($/Mcf)*	**$ 7.34**	$ 7.23	$ 0.11	2%
Volume Brokered *(Mmcf)*	**7,903**	8,292	(389)	(5)%
Brokered Natural Gas Cost *(In thousands)*	**$ 57,973**	$ 59,924		
Brokered Natural Gas Margin *(In thousands)*	**$ 8,384**	$ 7,465	$ 919	12%

(In thousands)	
Sales Price Variance Impact on Revenue	**$ 2,134**
Volume Variance Impact on Revenue	**(3,163)**
	$ (1,029)

(In thousands)	
Purchase Price Variance Impact on Purchases	**$ (869)**
Volume Variance Impact on Purchases	**2,817**
	$ 1,948

The increased brokered natural gas margin of approximately $1.0 million is driven by an increase in sales price that outpaced the increase in purchase price, partially offset by a decrease in the volumes brokered in the first nine months of 2007 over the same period in the prior year.

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Crude Oil and Condensate Revenues

Our average total company realized crude oil sales price was $62.17 per Bbl for the first nine months of 2007. The 2007 price includes the realized impact of derivative instrument settlements which increased the price by $0.29 per Bbl. Our average total company realized crude oil sales price was $66.42 per Bbl for the first nine months of 2006. There was no realized impact of derivative instruments in the first nine months of 2006. There was no unrealized impact of derivative instruments in the first nine months of 2007 or 2006.

	Nine Months Ended September 30,		Variance	
	2007	**2006**	**Amount**	**Percent**
Crude Oil Production *(Mbbl)*				
East	**20**	19	1	5%
Gulf Coast	**462**	1,020	(558)	(55)%
West	**136**	162	(26)	(16)%
Canada	**14**	8	6	75%
Total Company	**632**	1,209	(577)	(48)%
Crude Oil Sales Price *($/Bbl)*				
East	**$ 60.78**	$ 63.29	$ (2.51)	(4)%
Gulf Coast	**$ 62.27**	$ 66.71	$ (4.44)	(7)%
West	**$ 62.81**	$ 64.99	$ (2.18)	(3)%
Canada	**$ 54.97**	$ 65.90	$ (10.93)	(17)%
Total Company	**$ 62.17**	$ 66.42	$ (4.25)	(6)%
Crude Oil Revenue *(In thousands)*				
East	**$ 1,215**	$ 1,220	$ (5)	
Gulf Coast	**28,760**	67,967	(39,207)	(58)%
West	**8,527**	10,545	(2,018)	(19)%
Canada	**787**	551	236	43%
Total Company	**$ 39,289**	$ 80,283	$ (40,994)	(51)%
Price Variance Impact on Crude Oil Revenue *(In thousands)*				
East	**$ (50)**			
Gulf Coast	**(2,053)**			
West	**(296)**			
Canada	**(156)**			
Total Company	**$ (2,555)**			
Volume Variance Impact on Crude Oil Revenue *(In thousands)*				
East	**$ 45**			
Gulf Coast	**(37,154)**			
West	**(1,722)**			
Canada	**392**			
Total Company	**$ (38,439)**			

The decrease in the realized crude oil production combined with the decline in realized prices resulted in a net revenue decrease of $41.0 million. The decrease in oil production is mainly the result of the 2006 south Louisiana and offshore properties sale in the Gulf Coast region. After removing from the first nine months 2006 results $47.3 million of crude oil revenues and 705 Mbbls of crude oil production associated with properties in the Gulf Coast region sold in the 2006 south Louisiana and offshore properties sale, total crude oil revenue would have increased by $6.3 million, or 19%, and crude oil production would have increased by 128 Mbbls, or 25%, from the first nine months of 2006 to the first nine months of 2007.

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Impact of Derivative Instruments on Operating Revenues

The following table reflects the realized impact of cash settlements and the net unrealized change in fair value of derivative instruments:

	Nine Months Ended September 30,			
	2007		2006	
(In thousands)	Realized	Unrealized	Realized	Unrealized
Operating Revenues - Increase to Revenue				
Cash Flow Hedges				
Natural Gas Production	**$ 59,601**	**$**	$ 17,166	$
Crude Oil	**182**			
Total Cash Flow Hedges	**$ 59,783**	**$**	$ 17,166	$

We are exposed to market risk on derivative instruments to the extent of changes in market prices of natural gas and oil. However, the market risk exposure on these derivative contracts is generally offset by the gain or loss recognized upon the ultimate sale of the commodity.

Other Operating Revenues

Other operating revenues decreased by $4.3 million between the nine months ended September 30, 2007 and the nine months ended September 30, 2006 primarily due to a larger amount of net profits interest in 2006 and a decrease in our payout liability in the first quarter of 2006 associated with a favorable legal ruling.

Operating Expenses

Total costs and expenses from operations decreased by $0.8 million in the first nine months of 2007 compared to the same period of 2006. The primary reasons for this fluctuation are as follows:

Exploration expense decreased by $18.8 million in the first nine months of 2007, primarily as a result of a decrease in total dry hole expense of $17.2 million, primarily in the Gulf Coast and West regions and Canada. In addition, there was a decrease in geophysical and geological expenses of $2.3 million, primarily due to a decrease in the Gulf Coast region, offset in part by an increase in Canada.

Depreciation, Depletion and Amortization increased by $8.6 million in the first nine months of 2007 over the first nine months of 2006. This is primarily due to the impact on the DD&A rate of negative reserve revisions due to lower prices at the end of 2006, higher capital costs and commencement of production in an East Texas field.

Impairment of Unproved Properties increased by $4.9 million in the first nine months of 2007 compared to the first nine months of 2006, primarily due to increased lease acquisition costs during 2006.

Impairment of Oil and Gas Properties increased by $4.6 million in the first nine months of 2007 compared to the first nine months of 2006, due an impairment recorded in the 2007 period in the Gulf Coast region resulting from two non-commercial development completions in a small field in north Louisiana.

General and Administrative expense increased by $2.5 million in the first nine months of 2007 primarily due to compensation related expenses, which increased by approximately $1.3 million, and increased stock compensation charges of $0.5 million. Partially offsetting this was a decrease in expenses for professional services for litigation.

Taxes Other Than Income decreased by $2.3 million in the nine months ended September 30, 2007 compared to the nine months ended September 30, 2006, primarily due to decreased production taxes of $3.7 million as a result of decreased natural gas and crude oil volumes and prices, partially offset by an increase in ad valorem and franchise taxes.

Brokered Natural Gas Cost decreased by $1.9 million from the first nine months of 2006 to the first nine months of 2007. See the preceding table labeled Brokered Natural Gas Revenue and Cost for further analysis.

Direct Operations expense increased by $1.6 million as a result of higher lease maintenance expense, compressor charges, disposal and treating expenses and personnel expenses, partially offset by lower outside operated properties expense.

Interest Expense, Net

Interest expense, net decreased by $7.4 million in the first nine months of 2007 due to lower credit facility borrowings, a lower weighted-average interest rate on our revolving credit facility borrowings, a lower outstanding principal amount of our 7.19% fixed rate debt and increased interest income from our short term investments. Weighted average borrowings under our credit facility based on daily balances were approximately $21 million during the first nine months of 2007 compared to approximately $81 million during the first nine months of 2006. In addition, interest expense decreased due to the reversal of FIN 48 interest payable. During the first nine months of 2007, we recorded net interest income related to FIN 48 of $1.0 million.

Income Tax Expense

Income tax expense decreased by $97.6 million due to a comparable decrease in our pre-tax income, primarily as a result of the decrease in revenues. The effective tax rate for the first nine months of 2007 and 2006 was 35.2% and 36.4%, respectively. The decrease in the effective tax rate is primarily due to a reduction in our overall state income tax liability for 2007. Ongoing discussions are taking place with state authorities regarding the tax liabilities relating to the 2006 south Louisiana and offshore properties sale. The state income tax liability recorded as of September 30, 2007, reflects our best estimate as to the resolution of these matters.

Recently Issued Accounting Pronouncements

In May 2007, the FASB issued FSP No. FIN 48-1, Definition of *Settlement* in FASB Interpretation No. 48, which amends FIN 48 and provides guidance concerning how an entity should determine whether a tax position is effectively, rather than the previously required ultimately, settled for the purpose of recognizing previously unrecognized tax benefits. In addition, FSP No. FIN 48-1 provides guidance on determining whether a tax position has been effectively settled. The guidance in FSP No. FIN 48-1 is effective upon the initial January 1, 2007 adoption of FIN 48. Companies that have not applied this guidance must retroactively apply the provisions of this FSP to the date of the initial adoption of FIN 48. We have adopted FSP No. FIN No 48-1and no retroactive adjustments are necessary.

In April 2007, the FASB issued FSP No. FIN 39-1, Amendment of FASB Interpretation No. 39, to amend FIN 39, Offsetting of Amounts Related to Certain Contracts. The terms conditional contracts and exchange contracts used in FIN 39 have been replaced with the more general term derivative contracts. In addition, FSP No. FIN 39-1 permits the offsetting of recognized fair values for the right to reclaim cash collateral or the obligation to return cash collateral against fair values of derivatives under certain circumstances, such as under master netting arrangements. Additional disclosure is also required regarding a Company s accounting policy with respect to offsetting fair value amounts. The guidance in FSP No. FIN 39-1 is effective for fiscal years beginning after November 15, 2007, with early application allowed. The effects of initial adoption should be recognized as a change in accounting principle through retrospective application for all periods presented. We do not believe that the adoption of FSP No. FIN 39-1 will have a material impact on our financial position, results of operations or cash flows.

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities, including an amendment of FASB Statement No. 115, which permits companies to choose, at specified dates, to measure certain eligible financial instruments at fair value. The objective of this Statement is to reduce volatility in preparer reporting that may be caused as a result of measuring related financial assets and liabilities differently and to expand the use of fair value measurements. The provisions of the Statement apply only to entities that elect to use the fair value option and to all entities with available-for-sale and trading securities. Additional disclosures are also required for instruments for which the fair value option is elected. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. No retrospective application is allowed, except for companies that choose to adopt early. At the effective date, companies may elect the fair value option for eligible items that exist at that date, and the effect of the first remeasurement to fair value must be reported as a cumulative-effect adjustment to the opening balance of retained earnings. We are currently evaluating what impact, if any, SFAS No. 159 will have on our financial position or results of operations.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements, which establishes a formal framework for measuring fair values of assets and liabilities in financial statements that are already required by United States GAAP to be measured at fair value. SFAS No. 157 clarifies guidance in CON No. 7 which discusses present value techniques in measuring fair value. Additional disclosures are also required for transactions measured at fair value. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. We are currently evaluating what impact SFAS No. 157 may have on our financial position or results of operations.

Forward-Looking Information

The statements regarding future financial performance and results, market prices and the other statements which are not historical facts contained in this report are forward-looking statements. The words expect, project, estimate, believe, anticipate, intend, budget, plan, predict and similar expressions are also intended to identify forward-looking statements. Such statements involve risks and uncertainties, including, but not limited to, market factors, market prices (including regional basis differentials) of natural gas and oil, results for future drilling and marketing activity, future production and costs and other factors detailed herein and in our other Securities and Exchange Commission filings. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual outcomes may vary materially from those indicated.

ITEM 3. Quantitative and Qualitative Disclosures about Market Risk

Derivative Instruments and Hedging Activity

Our hedging strategy is designed to reduce the risk of price volatility for our production in the natural gas and crude oil markets. A hedging committee that consists of members of senior management oversees our hedging activity. Our hedging arrangements apply to only a portion of our production and provide only partial price protection. These hedging arrangements limit the benefit to us of increases in prices, but offer protection in the event of price declines. Further, if our counterparties defaulted, this protection might be limited as we might not receive the benefits of the hedges. Please read the discussion below and Note 7 of the Notes to the Condensed Consolidated Financial Statements for a more detailed discussion of our hedging arrangements.

Hedges on Production Options

From time to time, we enter into natural gas and crude oil collar agreements with counterparties to hedge price risk associated with a portion of our production. These cash flow hedges are not held for trading purposes. Under the collar arrangements, if the index price rises above the ceiling price, we pay the counterparty. If the index price falls below the floor price, the counterparty pays us. During the first nine months of 2007, natural gas price collars covered 31,813 Mmcf, or 53%, of our first nine months of 2007 gas production, with a weighted average floor of $8.99 per Mcf and a weighted average ceiling of $12.19 per Mcf.

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At September 30, 2007, we had open natural gas price collar contracts covering a portion of our 2007 and 2008 production as follows:

		Natural Gas Price Collars		
Contract Period	Volume in Mmcf		Weighted Average Ceiling / Floor *(per Mcf)*	Net Unrealized Gain *(In thousands)*
As of September 30, 2007				
Fourth Quarter 2007	10,721	$	12.19 / $8.99	
Three Months Ended December 31, 2007	**10,721**	**$**	**12.19 / $8.99**	**$ 22,223**
First Quarter 2008	3,237	$	10.28 / $8.01	
Second Quarter 2008	3,237		10.28 / 8.01	
Third Quarter 2008	3,272		10.28 / 8.01	
Fourth Quarter 2008	3,272		10.28 / 8.01	
Full Year 2008	**13,018**	**$**	**10.28 / $8.01**	**$ 5,968**

During the first nine months of 2007, a crude oil price collar covered 273 Mbbls, or 43%, of our first nine months of 2007 oil production, with a floor of $60.00 per Bbl and a ceiling of $80.00 per Bbl.

At September 30, 2007, we had two open crude oil price collar contracts covering a portion of our 2007 and 2008 production as follows:

	Crude Oil Price Collars		
Contract Period	Volume in Mbbl	Ceiling / Floor *(per Bbl)*	Net Unrealized Loss *(In thousands)*
As of September 30, 2007			
Fourth Quarter 2007	92	$ 80.00 / $60.00	
Three Months Ended December 31, 2007	**92**	**$ 80.00 / $60.00**	**$ (255)**
First Quarter 2008	91	$ 80.00 / $60.00	
Second Quarter 2008	91	80.00 / 60.00	
Third Quarter 2008	92	80.00 / 60.00	
Fourth Quarter 2008	92	80.00 / 60.00	
Full Year 2008	**366**	**$ 80.00 / $60.00**	**$ (1,003)**

We are exposed to market risk on these open contracts, to the extent of changes in market prices of natural gas and crude oil. However, the market risk exposure on these hedged contracts is generally offset by the gain or loss recognized upon the ultimate sale of the commodity that is hedged.

The preceding paragraphs contain forward-looking information concerning future production and projected gains and losses, which may be impacted both by production and by changes in the future market prices of energy commodities. See Forward-Looking Information for further details.

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ITEM 4. Controls and Procedures

As of the end of the current reported period covered by this report, the Company carried out an evaluation, under the supervision and with the participation of the Company s management, including the Company s Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of the Company s disclosure controls and procedures pursuant to Rule 13a-15 of the Securities Exchange Act of 1934 (the Exchange Act). Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company s disclosure controls and procedures are effective, in all material respects, with respect to the recording, processing, summarizing and reporting, within the time periods specified in the Commission s rules and forms, of information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act.

There were no changes in the Company s internal control over financial reporting that occurred during the most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. Legal Proceedings

The information set forth under the caption West Virginia Royalty Litigation in Note 6 of the Notes to the Condensed Consolidated Financial Statements in Item 1 of Part I of this Quarterly Report on Form 10-Q is incorporated by reference in response to this item.

ITEM 1A. Risk Factors

For additional information about the risk factors facing the Company, see Item 1A of Part I of the Company s Annual Report on Form 10-K for the year ended December 31, 2006.

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

Issuer Purchases of Equity Securities

The Board of Directors has authorized a share repurchase program under which the Company may purchase shares of common stock in the open market or in negotiated transactions. There is no expiration date associated with the authorization. During the nine months ended September 30, 2007, the Company did not repurchase any shares of common stock. All purchases executed to date have been through open market transactions. The maximum number of shares that may yet be purchased under the plan as of September 30, 2007 was 4,795,300.

ITEM 6. Exhibits

15.1	Awareness letter of PricewaterhouseCoopers LLP
31.1	302 Certification - Chairman, President and Chief Executive Officer
31.2	302 Certification - Vice President and Chief Financial Officer
32.1	906 Certification

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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.

	CABOT OIL & GAS CORPORATION (Registrant)
October 29, 2007	By: /s/ Dan O. Dinges Dan O. Dinges Chairman, President and Chief Executive Officer (Principal Executive Officer)
October 29, 2007	By: /s/ Scott C. Schroeder Scott C. Schroeder Vice President and Chief Financial Officer (Principal Financial Officer)
October 29, 2007	By: /s/ Henry C. Smyth Henry C. Smyth Vice President, Controller and Treasurer (Principal Accounting Officer)