CABOT OIL & GAS CORP
Form 10-Q
October 28, 2011
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

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

For the quarterly period ended September 30, 2011

o **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)

Three Memorial City Plaza

840 Gessner Road, Suite 1400, Houston, Texas 77024

(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 o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No o

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

Large accelerated filer x	Accelerated filer o
Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

As of October 24, 2011, there were 104,494,374 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, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
OPERATING REVENUES				
Natural Gas	**$ 218,521**	$ 192,026	**$ 588,976**	$ 526,424
Brokered Natural Gas	**9,467**	11,675	**38,947**	49,896
Crude Oil and Condensate	**33,158**	19,234	**79,792**	60,427
Other	**971**	1,127	**4,124**	3,901
	262,117	224,062	**711,839**	640,648
OPERATING EXPENSES				
Brokered Natural Gas Cost	**8,204**	10,281	**33,362**	43,342
Direct Operations	**27,292**	26,466	**76,878**	73,796
Transportation and Gathering	**19,768**	4,932	**48,710**	13,488
Taxes Other Than Income	**7,042**	8,489	**21,070**	31,135
Exploration	**20,190**	9,665	**31,090**	28,324
Impairment of Oil and Gas Properties		35,789		35,789
Depreciation, Depletion and Amortization	**90,293**	85,355	**250,642**	235,579
General and Administrative	**27,949**	21,077	**78,254**	49,675
	200,738	202,054	**540,006**	511,128
Gain / (Loss) on Sale of Assets	**3,854**	265	**36,408**	5,411
INCOME FROM OPERATIONS	**65,233**	22,273	**208,241**	134,931
Interest Expense and Other	**18,517**	16,758	**53,928**	47,439
Income Before Income Taxes	**46,716**	5,515	**154,313**	87,492
Income Tax Expense	**18,234**	1,617	**58,268**	33,215
NET INCOME	**$ 28,482**	$ 3,898	**$ 96,045**	$ 54,277
Earnings Per Share				
Basic	**$ 0.27**	$ 0.04	**$ 0.92**	$ 0.52
Diluted	**$ 0.27**	$ 0.04	**$ 0.91**	$ 0.52
Weighted-Average Shares Outstanding				
Basic	**104,285**	103,955	**104,232**	103,889
Diluted	**105,460**	105,225	**105,316**	105,144
Dividends Per Common Share	**$ 0.03**	$ 0.03	$ **0.09**	$ 0.09

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, 2011**	**December 31, 2010**
ASSETS		
Current Assets		
Cash and Cash Equivalents	**$ 62,928**	$ 55,949
Accounts Receivable, Net	**101,612**	94,488
Income Taxes Receivable	**10,158**	
Inventories	**28,296**	29,667
Derivative Instruments	**100,489**	16,926
Other Current Assets	**6,554**	5,978
Total Current Assets	**310,037**	203,008
Properties and Equipment, Net (Successful Efforts Method)	**4,103,317**	3,762,760
Other Assets	**59,043**	39,263
	$ 4,472,397	$ 4,005,031
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities		
Accounts Payable	**$ 207,798**	$ 229,981
Income Taxes Payable		25,957
Deferred Income Taxes	**31,975**	
Accrued Liabilities	**49,204**	47,897
Total Current Liabilities	**288,977**	303,835
Pension and Postretirement Benefits	**39,443**	34,053
Long-Term Debt	**1,205,000**	975,000
Deferred Income Taxes	**785,146**	714,953
Asset Retirement Obligation	**74,784**	72,311
Other Liabilities	**35,877**	32,179
Total Liabilities	**2,429,227**	2,132,331
Commitments and Contingencies		
Stockholders Equity		
Common Stock:		
Authorized 240,000,000 Shares of $0.10 Par Value in 2011 and 2010 Issued 104,492,690 Shares and 104,210,084 Shares in 2011 and 2010, respectively	**10,449**	10,421
Additional Paid-in Capital	**730,985**	720,920
Retained Earnings	**1,235,059**	1,148,391
Accumulated Other Comprehensive Income/(Loss)	**70,026**	(3,683)
Less Treasury Stock, at Cost:		
202,200 Shares in 2011 and 2010, respectively	**(3,349)**	(3,349)
Total Stockholders Equity	**2,043,170**	1,872,700
	$ 4,472,397	$ 4,005,031

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, 2011	2010
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 96,045	$ 54,277
Adjustments to Reconcile Net Income to Cash Provided by Operating Activities:		
Depreciation, Depletion and Amortization	250,642	235,579
Impairment of Oil and Gas Properties		35,789
Deferred Income Tax Expense	57,381	30,465
(Gain) / Loss on Sale of Assets	(36,408)	(5,411)
Exploration Expense	13,851	10,473
Unrealized Loss / (Gain) on Derivative Instruments	950	(162)
Amortization of Debt Issuance Costs	3,317	8,298
Stock-Based Compensation, Pension and Other	42,432	12,886
Changes in Assets and Liabilities:		
Accounts Receivable, Net	(7,124)	4,842
Income Taxes	(36,115)	4,937
Inventories	1,371	(4,353)
Other Current Assets	(832)	3,070
Accounts Payable and Accrued Liabilities	(9,941)	(14,252)
Other Assets and Liabilities	(203)	(8,838)
Stock-Based Compensation Tax Benefit		(108)
Net Cash Provided by Operating Activities	375,366	367,492
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital Expenditures	(668,987)	(658,123)
Proceeds from Sale of Assets	82,109	21,033
Net Cash Used in Investing Activities	(586,878)	(637,090)
CASH FLOWS FROM FINANCING ACTIVITIES		
Borrowings from Debt	330,000	300,000
Repayments of Debt	(100,000)	(10,000)
Dividends Paid	(9,379)	(9,348)
Capitalized Debt Issuance Costs	(1,025)	(13,696)
Other	(1,105)	72
Net Cash Provided by Financing Activities	218,491	267,028
Net Increase / (Decrease) in Cash and Cash Equivalents	6,979	(2,570)
Cash and Cash Equivalents, Beginning of Period	55,949	40,158
Cash and Cash Equivalents, End of Period	$ 62,928	$ 37,588

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 on Form 10-K for the year ended December 31, 2010 (Form 10-K) filed with the Securities and Exchange Commission (SEC). The interim financial statements should be read in conjunction with the notes to the consolidated financial statements and information presented in the 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 statement. The results for any interim period are not necessarily indicative of the expected results for the entire year.

Certain reclassifications have been made to prior year statements to conform to current year presentation. These reclassifications have no impact on previously reported net income.

With respect to the unaudited financial information of the Company as of September 30, 2011 and for the three and nine months ended September 30, 2011 and 2010, PricewaterhouseCoopers LLP reported that they have applied limited procedures in accordance with professional standards for a review of such information. However, their separate report dated October 28, 2011 appearing herein states that they did not audit and they do not express an opinion on that unaudited financial information. Accordingly, the degree of reliance on their report on such information should be restricted in light of the limited nature of the review procedures applied. PricewaterhouseCoopers LLP is not subject to the liability provisions of Section 11 of the Securities Act of 1933 for their report on the unaudited financial information because that report is not a report or a part of the registration statement prepared or certified by PricewaterhouseCoopers LLP within the meaning of Sections 7 and 11 of the Act.

Recently Issued Accounting Pronouncements

In May 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2011-04, Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS. The amendments in ASU No. 2011-04 generally represent clarifications of Topic 820, but also include some instances where a particular principle or requirement for measuring fair value or disclosing information about fair value measurements has changed. ASU No. 2011-04 results in common principles and requirements for measuring fair value and for disclosing information about fair value measurements in accordance with U.S. GAAP and IFRS. The amendments in ASU No. 2011-04 are to be applied prospectively. For public entities, the amendments are effective for interim and annual periods beginning after December 15, 2011. Early application by public entities is not permitted. The Company does not expect this guidance to have a significant impact on its consolidated financial position, results of operations or cash flows.

In June 2011, the FASB issued ASU No. 2011-05, Presentation of Comprehensive Income, requiring most entities to present items of net income and other comprehensive income either in one continuous statement referred to as the statement of comprehensive income or in two separate, but consecutive, statements of net income and other comprehensive income. The new requirements are effective for public entities for fiscal years (including interim periods) beginning after December 15, 2011. The Company does not expect this guidance to have a significant impact on its consolidated financial position, results of operations or cash flows.

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2. PROPERTIES AND EQUIPMENT, NET

Properties and equipment, net are comprised of the following:

(In thousands)		September 30, 2011		December 31, 2010
Proved Oil and Gas Properties	**$**	**5,377,363**	$	4,794,650
Unproved Oil and Gas Properties		**505,131**		490,181
Gathering and Pipeline Systems		**237,666**		237,043
Land, Building and Other Equipment		**79,109**		86,248
		6,199,269		5,608,122
Accumulated Depreciation, Depletion and Amortization		**(2,095,952)**		(1,845,362)
	$	**4,103,317**	$	3,762,760

At September 30, 2011, the Company did not have any projects that had exploratory well costs that were capitalized for a period of greater than one year after drilling.

In the third quarter of 2010, the Company recorded a $35.8 million impairment of oil and gas properties due to continued price declines and limited activity in two south Texas fields. These fields were reduced to fair value of approximately $15.4 million using discounted future cash flows. The fair value of these fields was based on significant inputs that were not observable in the market and are considered to be Level 3 inputs as defined in ASC 820. Refer to Note 8 for more information and a description of fair value hierarchy. Key assumptions include (1) oil and natural gas prices (adjusted to quality and basis differentials), (2) projections of estimated quantities of oil and gas reserves and production, (3) estimates of future development and production costs and (4) risk adjusted discount rates (14% at September 30, 2010).

Haynesville/Bossier Shale Joint Ventures

During the first nine months of 2011, the Company entered into two participation agreements with third parties related to certain of its Haynesville and Bossier Shale leaseholds in east Texas. Under the terms of the participation agreements, the third parties agreed to fund 100% of the cost to drill and complete certain Haynesville and Bossier Shale wells in the related leaseholds over a multi-year period in exchange for a 75% working interest in the leaseholds. During the first nine months of 2011, the Company received a reimbursement of drilling costs incurred of approximately $11.2 million associated with the wells that had commenced drilling prior to the execution of the participation agreements.

In May 2011, the Company sold certain of its Haynesville and Bossier Shale oil and gas properties in east Texas to a third party. The Company received approximately $47.0 million in cash proceeds and recognized a $34.2 million gain on sale of assets.

Other Divestitures

In July 2011, the Company entered into a purchase and sale agreement to sell certain oil and gas properties located in Colorado, Utah and Wyoming to BreitBurn Energy Partners L.P. for $285 million. This transaction closed on October 6, 2011 and is subject to certain post-closing adjustments scheduled to occur in the fourth quarter of 2011. The net book value associated with the oil and gas properties and the related asset retirement obligation held for sale as of September 30, 2011 were $291.3 million and $12.1 million, respectively, and are included in Properties and Equipment, Net and Asset Retirement Obligation, respectively, in the Condensed Consolidated Balance Sheet.

In June 2010, the Company sold its Woodford shale prospect located in Oklahoma to Continental Resources Inc. The Company received approximately $15.9 million in cash proceeds and recognized a $10.3 million gain on sale of assets.

In July 2010, the Company sold certain oil and gas properties located in Colorado to Patera Oil & Gas LLC for approximately $3.0 million. During the second quarter of 2010, the Company recognized an impairment loss of approximately $5.8 million associated with the proposed sale of these properties. The impairment charge was included in Gain / (Loss) on Sale of Assets in the Condensed Consolidated Statement of Operations. Fair value of the impaired properties was determined using a market approach which considered the execution of a purchase and sale agreement the Company entered into on June 30, 2010. Accordingly, the inputs associated with the fair value of these properties were considered Level 2 in the fair value hierarchy.

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3. ADDITIONAL BALANCE SHEET INFORMATION

Certain balance sheet amounts are comprised of the following:

(In thousands)	September 30, 2011	December 31, 2010
ACCOUNTS RECEIVABLE, NET		
Trade Accounts	**$ 98,661**	$ 91,077
Joint Interest Accounts	**5,871**	4,901
Other Accounts	**810**	2,603
	105,342	98,581
Allowance for Doubtful Accounts	**(3,730)**	(4,093)
	$ 101,612	$ 94,488
INVENTORIES		
Natural Gas in Storage	**$ 18,633**	$ 13,371
Tubular Goods and Well Equipment	**10,150**	17,072
Pipeline Imbalances	**(487)**	(776)
	$ 28,296	$ 29,667
OTHER CURRENT ASSETS		
Drilling Advances	**$ 821**	$ 2,796
Prepaid Balances	**3,499**	2,925
Restricted Cash	**2,234**	
Deferred Income Taxes		257
	$ 6,554	$ 5,978
OTHER ASSETS		
Rabbi Trust Deferred Compensation Plan	**15,503**	15,788
Debt Issuance Costs	**18,744**	22,061
Derivative Instruments	**23,453**	
Other Accounts	**1,343**	1,414
	$ 59,043	$ 39,263
ACCOUNTS PAYABLE		
Trade Accounts	**$ 18,570**	$ 27,401
Natural Gas Purchases	**6,047**	3,596
Royalty and Other Owners	**43,025**	36,034
Accrued Capital Costs	**127,489**	146,824
Taxes Other Than Income	**2,477**	2,655
Wellhead Gas Imbalances	**4,498**	5,142
Other Accounts	**5,692**	8,329
	$ 207,798	$ 229,981
ACCRUED LIABILITIES		
Employee Benefits	**$ 15,921**	$ 10,790
Pension and Postretirement Benefits	**1,688**	1,688
Taxes Other Than Income	**15,151**	14,576
Interest Payable	**15,708**	19,488
Other Accounts	**736**	1,355
	$ 49,204	$ 47,897
OTHER LIABILITIES		
Rabbi Trust Deferred Compensation Plan	**$ 24,362**	$ 21,600
Derivative Instruments		2,180
Other Accounts	**11,515**	8,399
	$ 35,877	$ 32,179

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4. LONG-TERM DEBT

The Company s debt consisted of the following:

(In thousands)	September 30, 2011	December 31, 2010
Long-Term Debt		
7.33% Weighted-Average Fixed Rate Notes	**$ 95,000**	$ 95,000
6.51% Weighted-Average Fixed Rate Notes	**425,000**	425,000
9.78% Notes	**67,000**	67,000
5.58% Weighted-Average Fixed Rate Notes	**175,000**	175,000
Credit Facility	**443,000**	213,000
	$ 1,205,000	$ 975,000

The Company s revolving credit facility provides for an available line of credit of $900 million and contains an accordion feature allowing the Company to increase the available credit line to $1.0 billion, if any one or more of the existing banks or new banks agree to provide such increased commitment amount. Effective April 1, 2011, the lenders under the Company s revolving credit facility approved an increase in the Company s Borrowing Base from $1.5 billion to $1.7 billion as part of the annual redetermination under the terms of the credit facility. The Company s plan to sell certain oil and gas properties located in Colorado, Utah and Wyoming, triggered an interim redetermination of the Company s Borrowing Base and the $1.7 billion Borrowing Base was reaffirmed by the lenders effective September 27, 2011.

At September 30, 2011, the Company had $443.0 million of borrowings outstanding under its revolving credit facility at a weighted-average interest rate of 4.0% and $456.8 million available for future borrowings. In addition, the Company had letters of credit outstanding at September 30, 2011 of $0.3 million.

5. EARNINGS PER COMMON SHARE

Basic 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 outstanding stock options and stock appreciation rights were exercised and stock awards were vested at the end of the applicable period.

The following is a calculation of basic and diluted weighted-average shares outstanding:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In thousands)	2011	2010	2011	2010
Weighted-Average Shares - Basic	**104,285**	103,955	**104,232**	103,889

Dilution Effect of Stock Options, Stock Appreciation Rights and Stock Awards at End of Period	**1,175**	1,270	**1,084**	1,255
Weighted-Average Shares - Diluted	**105,460**	105,225	**105,316**	105,144
Weighted-Average Stock Awards and Shares Excluded from Diluted Earnings per Share due to the Anti-Dilutive Effect				220

6. COMMITMENTS AND CONTINGENCIES

Contingencies

The Company is a defendant in various legal proceedings arising in the normal course of business. When deemed necessary, the Company establishes reserves for certain legal proceedings. All known liabilities are accrued based on an estimation process that includes the advice of legal counsel and subjective judgment of management. 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.

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Environmental Matters

On November 4, 2009, the Company and the Pennsylvania Department of Environmental Protection (PaDEP) entered into a single settlement agreement (Consent Order) covering a number of separate, unrelated environmental issues occurring in 2008 and 2009, including releases of drilling mud and other substances, record keeping violations at various wells and alleged natural gas contamination of 13 water wells in Susquehanna County, Pennsylvania. The Company paid an aggregate $120,000 civil penalty with respect to all the matters covered by the Consent Order, which were consolidated at the request of the PaDEP.

On April 15, 2010, the Company and the PaDEP reached agreement on modifications to the Consent Order (First Modified Consent Order). In the First Modified Consent Order, the PaDEP and the Company agreed that the Company will provide a permanent source of potable water to 14 households, most of which the Company has already been supplying with water. The Company agreed to plug and abandon three vertical wells in close proximity to two of the households and to bring into compliance a fourth well in the nine square mile area of concern in Susquehanna County. The Company agreed to complete these actions prior to any new well drilling permits being issued for drilling in Pennsylvania, and prior to initiating hydraulic fracturing of seven wells already drilled in the area of concern. The Company also agreed to postpone drilling of new wells in the area of concern until all obligations under the consent orders are fulfilled. In addition, the Company agreed to take certain other actions if requested by the PaDEP, which could include the plugging and abandonment of up to 10 additional wells. Under the First Modified Consent Order, the Company paid a $240,000 civil penalty and agreed to pay an additional $30,000 per month until all obligations under the First Modified Consent Order are satisfied.

On July 19, 2010, the Company and the PaDEP entered a Second Modification to Consent Order (Second Modified Consent Order) under which the Company and the PaDEP agreed that the Company has satisfactorily plugged and abandoned the three vertical wells and brought the fourth well into compliance. As a result, the Company and the PaDEP agreed that the PaDEP will commence the processing and issuance of new well drilling permits outside the area of concern so long as the Company continues to provide temporary potable water and offers to provide gas/water separators to the 14 households. No penalties were assessed under the Second Modified Consent Order.

As required by the Second Modified Consent Order, the Company made offers to provide whole-house water treatment systems to the 14 households. As required by the First Modified Consent Order, on August 5, 2010 the Company filed with the PaDEP its report, prepared by its experts, finding that the Company s well drilling and development activities are not the source of methane gas reported to be in the groundwater and water wells in the area of concern.

Despite the Company s vigorous efforts to comply with the various consent orders, in a September 14, 2010 letter to the Company, the PaDEP rejected the Company s expert report and determined that the Company s drilling activities continue to cause the unpermitted discharge of natural gas into the groundwater and continue to affect residential water supplies in the area of concern. The PaDEP directed the Company, in accordance with the First Modified Consent Order, to plug or take other remedial actions at the remaining 10 wells and to contact the PaDEP to discuss connecting the impacted water supplies into a community public water system to permanently eliminate the continuing adverse affect to those water supplies.

The Company believed that it was in full compliance with the various consent orders. In a September 28, 2010 reply letter to the PaDEP, the Company disagreed with the PaDEP s rejection of the Company s expert report, disagreed that the remaining 10 wells continue to impact groundwater and affect residential water supplies and disagreed that a community public water system is necessary or feasible. The Company believed that offering installation of a whole-house water treatment system to the 14 households constituted compliance with the Company s obligations under these consent orders.

On December 15, 2010, the Company entered a global settlement agreement and new consent order with the PaDEP (Global Settlement Agreement), which supersedes the Consent Order, the First Modified Consent Order and the Second Modified Consent Order. Under the Global Settlement Agreement, among other things, the Company agreed to pay a total of $4.2 million into separate escrow accounts for the benefit of each affected household, pay $500,000 to the PaDEP to reimburse the PaDEP for its costs, remediate two wells in the affected area, provide pressure, water quality and well headspace data to the PaDEP and offer water treatment to the affected households. The Global Settlement Agreement settles all outstanding issues and claims that are known and that could have been brought against the Company by the PaDEP relating to the wells in the affected area and the Consent Order, the First Modified Consent Order and the Second Modified Consent Order. It also allows the Company to begin hydraulic fracturing and to commence drilling new wells in the affected areas after providing the PaDEP with well pressure data. Under the Global Settlement Agreement, the Company has no obligation to connect the impacted water supplies to a community public water system.

On January 11, 2011, certain of the affected households appealed the Global Settlement Agreement to the Pennsylvania Environmental Hearing Board. A hearing on the merits of this appeal is not expected to occur until 2012.

As of the date of this report, the Company is in continuing discussions with the PaDEP to address the results of the Company s well pressure tests, water quality sampling and well headspace screenings. The Company requested PaDEP approval to resume hydraulic fracturing and new well drilling operations in the affected area, along with a request to cease temporary water deliveries to the affected

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households. On October 18, 2011, the PaDEP concurred that temporary water deliveries to the property owners who are subject to the Global Settlement Agreement are no longer required.

As of September 30, 2011, the Company has paid $1.3 million in fines and penalties to the PaDEP related to this matter, paid $2.0 million to seven of the affected households and accrued a $2.2 million settlement liability that represents the unpaid escrow balance, which is included in Other Liabilities in the Condensed Consolidated Balance Sheet.

Transportation Agreements

During the first nine months of 2011, the Company amended certain gas transportation and gathering agreements with third party pipelines that increased the minimum daily quantity, increased the transportation fee and/or extended the term of the agreement.

Future minimum obligations under gas transportation agreements as of September 30, 2011 are as follows:

(In thousands)		
2011	$	11,969
2012		57,066
2013		56,965
2014		56,965
2015		56,965
Thereafter		555,268
	$	**795,198**

For further information on the Company s gas transportation agreements, please refer to Note 8 of the Notes to the Consolidated Financial Statements in the Form 10-K.

Drilling Rig Commitments

As of September 30, 2011, the Company has a three-year drilling rig commitment for its capital program in the Marcellus Shale in northeast Pennsylvania commencing in the fourth quarter of 2011. As of September 30, 2011, the aggregate minimum future drilling rig commitment was approximately $20.4 million.

7. DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

The Company periodically enters into commodity derivative instruments to hedge its exposure to price fluctuations on natural gas and crude oil production. The Company s credit agreement restricts the ability of the Company to enter into commodity hedges other than to hedge or mitigate risks to which the Company has actual or projected exposure or as permitted under the Company s risk management policies and not subjecting the Company to material speculative risks. All of the Company s derivatives are used for risk management purposes and are not held for trading purposes. As of September 30, 2011, the Company had 42 derivative contracts open: 27 natural gas price swap arrangements, five natural gas collar arrangements, six natural gas basis swaps, one crude oil price collar arrangement and three crude oil price swap arrangements. During the first nine months of 2011, the Company entered into 31 new derivative contracts covering anticipated natural gas and crude oil production for 2011, 2012 and 2013.

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As of September 30, 2011, the Company had the following outstanding commodity derivatives:

[redacted]					
Derivatives Designated as Hedging Instruments					
[redacted]					
Natural Gas Swaps	$5.18	per Mcf	98,302	Mmcf	Oct. 2011 - Dec. 2012
[redacted]					
Natural Gas Collars	$6.17 Ceiling/ $5.13 Floor	per Mcf	17,805	Mmcf	Jan. 2013 - Dec. 2013
[redacted]					
Crude Oil Swaps	$106.20	per Bbl	92	Mbbl	Oct. 2011 - Dec. 2011
[redacted]					
[redacted]					
Natural Gas Basis Swaps	$(0.27)	per Mcf	16,123	Mmcf	Jan. 2012 - Dec. 2012

The change in fair value of derivatives designated as hedges that is effective is recorded to Accumulated Other Comprehensive Income / (Loss) in Stockholders Equity in the Condensed Consolidated Balance Sheet. The ineffective portion of the change in fair value of derivatives designated as hedges, and the change in fair value of derivatives not designated as hedges, are recorded currently in earnings as a component of Natural Gas Revenue and Crude Oil and Condensate Revenue, as appropriate, in the Condensed Consolidated Statement of Operations.

The following disclosures reflect the impact of derivative instruments on the Company s condensed consolidated financial statements:

Effect of Derivative Instruments on the Condensed Consolidated Balance Sheet

		Fair Value Asset (Liability)	
(In thousands)	**Balance Sheet Location**	**September 30, 2011**	**December 31, 2010**
Derivatives Designated as Hedging Instruments			
Commodity Contracts	Derivative Instruments (current assets)	**$ 102,908**	$ 16,926
Commodity Contracts	Other Assets	**24,164**	
		127,072	16,926
Derivatives Not Designated as Hedging Instruments			
Commodity Contracts	Derivative Instruments (current assets)	**(2,419)**	
Commodity Contracts	Other Assets	**(711)**	
Commodity Contracts	Other Liabilities		(2,180)
		(3,130)	(2,180)
		$ 123,942	$ 14,746

At September 30, 2011 and December 31, 2010, unrealized gains of $127.1 million ($78.8 million, net of tax) and $16.9 million ($10.5 million, net of tax), respectively, were recorded in Accumulated Other Comprehensive Income / (Loss). Based upon estimates at September 30, 2011, the Company expects to reclassify $63.8 million in after-tax income associated with its commodity hedges from Accumulated Other Comprehensive

Income / (Loss) to the Condensed Consolidated Statement of Operations over the next 12 months.

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Effect of Derivative Instruments on the Condensed Consolidated Statement of Operations

Derivatives Designated as Hedging Instruments (In thousands)	Amount of Gain (Loss) Recognized in OCI on Derivatives (Effective Portion) Three Months Ended September 30, 2011	2010	Nine Months Ended September 30, 2011	2010	Location of Gain (Loss) Reclassified from Accumulated OCI into Income (In thousands)	Amount of Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion) Three Months Ended September 30, 2011	2010	Nine Months Ended September 30, 2011	2010
Commodity Contracts	**$ 98,143**	$ 24,758	**$ 159,030**	$ 79,514	Natural Gas Revenues	**$ 21,170**	$ 39,461	**$ 48,318**	$ 109,714
					Crude Oil and Condensate Revenues	**1,382**	5,160	**566**	14,522
						$ 22,552	$ 44,621	**$ 48,884**	$ 124,236

For the three and nine months ended September 30, 2011 and 2010, respectively, there was no ineffectiveness recorded in our Condensed Consolidated Statement of Operations related to our derivative instruments.

Derivatives Not Designated as Hedging Instruments (In thousands)	Location of Gain (Loss) Recognized in Income on Derivatives	Three Months Ended September 30, 2011	2010	Nine Months Ended September 30, 2011	2010
Commodity Contracts	Natural Gas Revenues	**$ (64)**	$ (193)	**$ (950)**	$ 162

Additional Disclosures about Derivative Instruments and Hedging Activities

The use of derivative instruments involves the risk that the counterparties will be unable to meet their obligation under the agreement. The Company enters into derivative contracts with multiple counterparties in order to limit its exposure to individual counterparties. The Company also has netting arrangements with all of its counterparties that allow it to offset payables against receivables from separate derivative contracts with that counterparty.

The counterparties to the Company s derivative instruments are also lenders under its credit facility. The Company s credit facility and derivative instruments contain certain cross default and acceleration provisions that may require immediate payment of its derivative liability in certain situations.

8. FAIR VALUE MEASUREMENTS

Accounting Standards Codification (ASC) 820, Fair Value Measurements and Disclosures, established a formal framework for measuring fair values of assets and liabilities in financial statements that are already required by generally accepted accounting principles (GAAP) to be measured at fair value. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The transaction is based on a hypothetical transaction in the principal or most advantageous market considered from the perspective of the market participant that holds the asset or owes the liability.

The Company utilizes market data or assumptions that market participants who are independent, knowledgeable and willing and able to transact would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. The Company attempts to utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. The Company is able to classify fair value balances based on the observability of those inputs. ASC 820 establishes formal fair value hierarchy based on the inputs used to measure fair value. The hierarchy gives the highest priority to Level 1 measurements and the lowest priority to Level 3 measurements.

The Company has classified its assets and liabilities into these levels depending upon the data relied on to determine the fair values. For further information regarding the fair value hierarchy, refer to Note 14 of the Notes to the Consolidated Financial Statements in the Form 10-K.

Non-Financial Assets and Liabilities

The Company discloses or recognizes its non-financial assets and liabilities, such as impairments of long-lived assets, at fair value on a nonrecurring basis. During the nine month period ended September 30, 2010, the Company recorded an impairment related to certain oil and gas properties. Refer to Note 2 for additional disclosures related to fair value associated with the impaired properties.

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As none of the Company s other non-financial assets and liabilities were impaired as of September 30, 2011 and 2010 and no other fair value measurements were required to be recognized on a non-recurring basis, additional disclosures are not provided.

Financial Assets and Liabilities

Our financial assets and liabilities are measured at fair value on a recurring basis. The following fair value hierarchy table presents information about the Company s financial assets and liabilities measured at fair value on a recurring basis as of September 30, 2011 and December 31, 2010:

(In thousands)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of September 30, 2011
Assets				
Rabbi Trust Deferred Compensation Plan	$ 15,503	$	$	**$ 15,503**
Derivative Contracts			123,942	**123,942**
Total Assets	$ 15,503	$	$ 123,942	**$ 139,445**
Liabilities				
Rabbi Trust Deferred Compensation Plan	$ 24,362	$	$	**$ 24,362**
Derivative Contracts				
Total Liabilities	$ 24,362	$	$	**$ 24,362**

(In thousands)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of December 31, 2010
Assets				
Rabbi Trust Deferred Compensation Plan	$ 15,788	$	$	$ 15,788
Derivative Contracts			16,926	16,926
Total Assets	$ 15,788	$	$ 16,926	$ 32,714
Liabilities				
Rabbi Trust Deferred Compensation Plan	$ 21,600	$	$	$ 21,600
Derivative Contracts			2,180	2,180
Total Liabilities	$ 21,600	$	$ 2,180	$ 23,780

The Company s investments associated with its Rabbi Trust Deferred Compensation Plan consist of mutual funds and deferred shares of the Company s common stock that are publicly traded and for which market prices are readily available.

The derivative contracts were measured based on quotes from the Company s counterparties. Such quotes have been derived using valuation models that consider various inputs including current market and contractual prices for the underlying instruments, quoted forward prices for natural gas and crude oil, volatility factors and interest rates, such as a LIBOR curve for a similar length of time as the derivative contract term as applicable. These estimates are verified using relevant NYMEX futures contracts or are compared to multiple quotes obtained from counterparties for reasonableness. The Company measured the non-performance risk of its counterparties by reviewing credit default swap spreads for the various financial institutions in which it has derivative transactions, while non-performance risk of the Company is evaluated using a market credit spread provided by the Company s bank. The impact of non-performance risk relative to the Company s derivative contracts was $1.5 million and $0.5 million at September 30, 2011 and December 31, 2010, respectively.

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The following table sets forth a reconciliation of changes in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy:

(In thousands)	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Balance at beginning of period	**$ 48,415**	$ 87,803	**$ 14,746**	$ 112,307
Total Gains / (Losses) (Realized or Unrealized):				
Included in Earnings (1)	**22,488**	44,428	**47,934**	124,398
Included in Other Comprehensive Income	**75,591**	(19,863)	**110,146**	(44,722)
Settlements	**(22,552)**	(44,621)	**(48,884)**	(124,236)
Transfers In and/or Out of Level 3				
Balance at end of period	**$ 123,942**	$ 67,747	**$ 123,942**	$ 67,747

(1) A loss of $0.1 million and $1.0 million for the three and nine months ended September 30, 2011, respectively, and a loss of $0.2 million and a gain of $0.2 million for the three and nine months ended September 30, 2010, respectively, was unrealized and included in Natural Gas Revenues in the Condensed Consolidated Statement of Operations.

There were no transfers between Level 1 and Level 2 measurements for the three and nine months ended September 30, 2011 and 2010.

Fair Value of Other Financial Instruments

The estimated fair value of financial instruments is the amount at which the instrument could be exchanged currently between willing parties. The carrying amounts reported in the Condensed Consolidated Balance Sheet for cash and cash equivalents, accounts receivable and accounts payable approximate fair value due to the short-term maturities of these instruments.

The fair value of long-term debt is the estimated cost to acquire the debt, including a credit spread for the difference between the issue rate and the period end market rate. The credit spread is the Company s default or repayment risk. The credit spread (premium or discount) is determined by comparing the Company s fixed-rate notes and credit facility to new issuances (secured and unsecured) and secondary trades of similar size and credit statistics for both public and private debt. The fair value of all of the notes and credit facility is based on interest rates currently available to the Company.

The Company uses available market data and valuation methodologies to estimate the fair value of debt. The carrying amounts and fair values of long-term debt are as follows:

(In thousands)	September 30, 2011 Carrying Amount	September 30, 2011 Estimated Fair Value	December 31, 2010 Carrying Amount	December 31, 2010 Estimated Fair Value

Long-Term Debt	**$**	**1,205,000**	**$**	**1,339,410**	$	975,000	$	1,100,830

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9. COMPREHENSIVE INCOME / (LOSS)

Comprehensive Income / (Loss) includes Net Income and certain items recorded directly to Stockholders Equity and classified as Accumulated Other Comprehensive Income / (Loss). The following tables illustrate the calculation of Comprehensive Income / (Loss) for the three and nine months ended September 30, 2011 and 2010:

					Three Months Ended September 30,			
(In thousands)			**2011**				**2010**	
Net Income			**$**	**28,482**			$	3,898
Other Comprehensive Income / (Loss), net of taxes:								
Reclassification Adjustment for Settled Contracts, net of taxes of $8,570 and $17,158, respectively				**(13,982)**				(27,463)
Changes in Fair Value of Hedge Positions, net of taxes of $(37,314) and $(9,608), respectively				**60,829**				15,150
Defined Benefit Pension and Postretirement Plans:								
Effect of Plan Termination and Amendment, net of taxes of $0 and $(752), respectively	**$**				$	1,242		
Net Loss due to Remeasurement, net of taxes of $1,614 and $0, respectively		**(2,487)**						
Settlement, net of taxes of $(930) and $(785), respectively		**1,516**				1,280		
Amortization of Net Obligation at Transition, net of taxes of $(60) and $(60), respectively		**98**				98		
Amortization of Prior Service Cost, net of taxes of $(87) and $(82), respectively		**141**				131		
Amortization of Net Loss, net of taxes of $(954) and $(1,248), respectively		**1,559**		**827**		2,038		4,789
Foreign Currency Translation Adjustment, net of taxes of $(6) and $6, respectively				**31**				(42)
Total Other Comprehensive Income / (Loss)				**47,705**				(7,566)
Comprehensive Income / (Loss)			**$**	**76,187**			$	(3,668)

					Nine Months Ended September 30,			
(In thousands)			**2011**				**2010**	
Net Income			$	**96,045**			$	54,277
Other Comprehensive Income / (Loss), net of taxes:								
Reclassification Adjustment for Settled Contracts, net of taxes of $18,576 and $46,695, respectively				**(30,308)**				(77,541)
Changes in Fair Value of Hedge Positions, net of taxes of $(60,423) and $(30,730), respectively				**98,607**				48,784
Defined Benefit Pension and Postretirement Plans:								
Effect of Plan Termination and Amendment, net of taxes of $0 and $(752), respectively					$	1,242		
		(2,487)						

Net Loss due to Remeasurement, net of taxes of $1,614 and $0, respectively				
Settlement, net of taxes of $(930) and $(785), respectively	**1,516**		1,280	
Amortization of Net Obligation at Transition, net of taxes of $(180) and $(180), respectively	**294**		294	
Amortization of Prior Service Cost, net of taxes of $(328) and $(97), respectively	**534**		158	
Amortization of Net Loss, net of taxes of $(3,390) and $(1,818), respectively	**5,530**	**5,387**	2,966	5,940
Foreign Currency Translation Adjustment, net of taxes of $(9) and $(47), respectively		**23**		78
Total Other Comprehensive Income / (Loss)		**73,709**		(22,739)
Comprehensive Income / (Loss)		**$ 169,754**		$ 31,538

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Changes in the components of Accumulated Other Comprehensive Income/ (Loss), net of taxes, for the nine months ended September 30, 2011 were as follows:

(In thousands)	Net Gains / (Losses) on Cash Flow Hedges	Defined Benefit Pension and Postretirement Plans	Foreign Currency Translation Adjustment	Total
Balance at December 31, 2010	$ 10,494	$ (14,122)	$ (55)	$ (3,683)
Net change in unrealized gain on cash flow hedges, net of taxes of ($41,847)	68,299			68,299
Net change in defined benefit pension and postretirement plans, net of taxes of ($3,214)		5,387		5,387
Change in foreign currency translation adjustment, net of taxes of $(9)			23	23
Balance at September 30, 2011	**$ 78,793**	**$ (8,735)**	**$ (32)**	**$ 70,026**

10. PENSION AND OTHER POSTRETIREMENT BENEFITS

The components of net periodic benefit costs, included in General and Administrative Expense in the Condensed Consolidated Statement of Operations, were as follows:

(In thousands)	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Qualified and Non-Qualified Pension Plans				
Current Period Service Cost	**$**	$ 571	**$**	$ 2,365
Interest Cost	**650**	885	**2,251**	2,870
Expected Return on Plan Assets	**(945)**	(1,091)	**(3,265)**	(3,171)
Amortization of Prior Service Cost	**228**	213	**862**	255
Amortization of Net Loss	**2,373**	3,128	**8,498**	4,310
Curtailment Loss		424		424
Settlement	**2,446**	2,065	**2,446**	2,065
Net Periodic Pension Cost	**$ 4,752**	$ 6,195	**$ 10,792**	$ 9,118
Postretirement Benefits Other than Pension Plans				
Current Period Service Cost	**$ 335**	$ 316	**$ 1,004**	$ 949
Interest Cost	**467**	424	**1,402**	1,271
Amortization of Net Loss	**140**	158	**422**	474
Amortization of Net Obligation at Transition	**158**	158	**474**	474
Total Postretirement Benefit Cost	**$ 1,100**	$ 1,056	**$ 3,302**	$ 3,168

Employer Contributions

The funding levels of the pension and postretirement benefit plans are in compliance with standards set by applicable law or regulation. The Company does not have any required minimum funding obligations for its qualified pension plan in 2011. The Company previously disclosed in its financial statements for the year ended December 31, 2010 that it had not determined if any additional discretionary funding would be made in 2011. During the nine months ended September 30, 2011, the Company did not make any contributions to its qualified and non-qualified pension plans; discretionary contributions may, however, be made prior to December 31, 2011.

Termination and Amendment of Qualified and Non-Qualified Pension Plans

In July 2010, the Company notified its employees of its plan to terminate its qualified pension plan, with the plan and its related trust to be liquidated following appropriate filings with the Pension Benefit Guaranty Corporation and Internal Revenue Service, effective

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September 30, 2010. The Company then amended and restated the qualified pension plan to freeze benefit accruals, to provide for termination of the plan, to allow for an early retirement enhancement to be available to all active participants as of September 30, 2010 regardless of their age and years of service as of that date, and to make certain changes that were required or made desirable as a result of developments in the law. Because no further benefits will accrue under the qualified pension plan after September 30, 2010, the Company s related non-qualified pension plan was effectively frozen and no additional benefits will be accrued under those arrangements after September 30, 2010. For further information regarding termination and amendment of qualified and non-qualified pension plans, refer to Note 6 of the Notes to the Consolidated Financial Statements in the Form 10-K.

11. STOCK-BASED COMPENSATION

Stock-based compensation expense (including the supplemental employee incentive plan) during the first nine months of 2011 and 2010 was $29.3 million and $8.9 million, respectively, and is included in General and Administrative Expense in the Condensed Consolidated Statement of Operations. Stock-based compensation expense in the third quarter of 2011 and 2010 was $10.0 million and $3.8 million, respectively.

Restricted Stock Awards

During the first nine months of 2011, 5,300 restricted stock awards were granted with a weighted-average grant date per share value of $35.39. The fair value of restricted stock grants is based on the average of the high and low stock price on the grant date. The Company used an annual forfeiture rate assumption of 7.0% for purposes of recognizing stock-based compensation expense for restricted stock awards.

Restricted Stock Units

During the first nine months of 2011, 29,701 restricted stock units were granted to non-employee directors of the Company with a grant date per share value of $41.75. 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 will be issued when the director ceases to be a director of the Company.

Stock Appreciation Rights

During the first nine months of 2011, 95,750 stock appreciation rights (SARs) were granted to employees. These awards allow the employee to receive common stock of the Company equal to the intrinsic value over the $40.74 strike price during the contractual term of seven years. The Company calculates the fair value using a Black-Scholes model. The assumptions used in the Black-Scholes fair value calculation on the date of grant for SARs are as follows:

	$	**18.94**

Weighted-Average Value per Stock Appreciation Right Granted During the Period	
Assumptions:	
Stock Price Volatility	**52.7%**
Risk Free Rate of Return	**2.3%**
Expected Dividend Yield	**0.3%**
Expected Term (in years)	**5.0**

Performance Share Awards

During the first nine months of 2011, three types of performance share awards were granted to employees for a total of 394,757 performance shares, which included 92,696 performance share awards based on market conditions and 302,061 performance share awards based on performance conditions measured against the Company s internal performance metrics. Of the 302,061 performance-based awards 92,696 of the shares have a three-year graded performance period. For these shares, one-third of the shares are issued on each anniversary date following the date of grant, provided that the Company has $100 million or more of operating cash flow for the year preceding the vesting date. If the Company does not meet this metric for the applicable period, then the portion of the performance shares that would have been issued on that date will be forfeited. For the remaining 209,365 performance-based awards, 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. Refer to Note 12 of the Notes to the Consolidated Financial Statements in the Form 10-K for further description of the various types of performance share awards.

The performance period for the awards based on internal performance metrics commenced on January 1, 2011 and ends on December 31, 2013 and the grant date per share value for these awards was $40.74, which is based on the average of the high and low stock price on the grant date. The actual number of shares issued on each anniversary date following the grant date or at the end of the

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performance period, as applicable, will be determined based on the Company s performance against the performance criteria set by the Company s Compensation Committee. Based on the Company s probability assessment at September 30, 2011, it is considered probable that the criteria for the performance-based awards will be met. The Company used an annual forfeiture rate assumption ranging from 0% to 7% for purposes of recognizing stock-based compensation expense for all performance-based share awards.

The performance shares based on market conditions 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 performance shares based on market conditions have both an equity and liability component. The following assumptions were used for the performance shares based on market conditions using a Monte Carlo model to value the liability and equity components of the awards. The equity portion of the 2011 awards was valued on the grant date (February 17, 2011) and was not marked to market. The liability portion of the awards was valued as of September 30, 2011 on a mark-to-market basis.

	Grant Date	September 30, 2011
Value per Share	$ 31.23	$39.90 - $57.46
Assumptions:		
Stock Price Volatility	62.0%	41.94% - 60.91%
Risk Free Rate of Return	1.3%	0.02% - 0.29%
Expected Dividend Yield	0.2%	0.2%

12. ASSET RETIREMENT OBLIGATION

The following table provides a rollforward of the asset retirement obligation. Liabilities settled include settlement payments for obligations as well as obligations that were assumed by the purchasers of divested properties. Liabilities incurred include additions to obligations as well as obligations that were assumed by the Company related to acquired properties. Activity related to the Company s asset retirement obligation is as follows:

(In thousands)	
Carrying amount of asset retirement obligations at December 31, 2010	$ 72,311
Liabilities incurred	897
Liabilities settled	(1,040)
Accretion expense	2,616
Carrying amount of asset retirement obligations at September 30, 2011	**$ 74,784**

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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, 2011, and the related condensed consolidated statements of operations for the three month and nine month periods ended September 30, 2011 and 2010, and the condensed consolidated statement of cash flows for the nine month periods ended September 30, 2011 and 2010. 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 (United States), the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

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

We previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet as of December 31, 2010, and the related consolidated statements of operations, stockholders equity, comprehensive income and of cash flows for the year then ended (not presented herein), and in our report dated February 28, 2011, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying condensed consolidated balance sheet information as of December 31, 2010, 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 28, 2011

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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, 2011 and 2010 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 Corporation Annual Report on Form 10-K for the year ended December 31, 2010 (Form 10-K).

As a result of our production growth and the commencement of various transportation and gathering agreements in 2011, we began separately reporting our transportation and gathering costs as a component of operating expenses in the Condensed Consolidated Statement of Operations. Previously reported transportation and gathering costs were reflected as a component of Natural Gas Revenues and have been reclassified to conform to current year presentation. Accordingly, previously reported operating revenues and operating expenses have increased with no impact on previously reported net income.

Overview

On an equivalent basis, our production for the nine months ended September 30, 2011 increased by 42% compared to the nine months ended September 30, 2010. For the nine months ended September 30, 2011, we produced 132.7 Bcfe compared to 93.2 Bcfe for the nine months ended September 30, 2010. Natural gas production was 127.2 Bcf and crude oil/condensate/NGL production was 920 Mbbls for the first nine months of 2011. Natural gas production increased by 43% when compared to the first nine months of 2010, which had production of 89.2 Bcf. This increase was primarily a result of increased production in northeast Pennsylvania associated with our Marcellus Shale drilling program and upgrades to the Lathrop compressor station in Susquehanna County, Pennsylvania, which included the commissioning of new compression during the first nine months of 2011. Partially offsetting the production increase in northeast Pennsylvania were decreases in production primarily in east and south Texas due to normal production declines and a shift from gas to oil projects. Crude oil/condensate/NGL production increased by 39%, to 920 Mbbls, when compared to the first nine months of 2010, which had production of 660 Mbbls. This increase was primarily the result of increased production associated with our Eagle Ford Shale drilling program in south Texas.

Our average realized natural gas price for the first nine months of 2011 was $4.64 per Mcf, 21% lower than the $5.90 per Mcf price realized in the first nine months of 2010. Our average realized crude oil price for the first nine months of 2011 was $89.69 per Bbl, 8% lower than the $97.43 per Bbl price realized in the first nine months of 2010. These realized prices include realized gains and losses resulting from commodity derivatives. For information about the impact of these derivatives on realized prices, refer to Results of Operations below. Commodity prices are determined by many 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 supply and demand, which are impacted by overall economic activity, weather, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. As a result, we cannot accurately predict future natural gas, NGL and crude oil prices and, therefore, we cannot determine with any degree of certainty what effect increases or decreases will have on our future revenues, capital program or production volumes.

Operating revenues for the nine months ended September 30, 2011 increased by $71.2 million, or 11%, from the nine months ended September 30, 2010. Natural gas revenues, excluding unrealized gains/losses from the change in fair value of our derivatives not designated as hedges, increased by $63.7 million, or 12%, for the nine months ended September 30, 2011 as compared to the nine months ended September 30, 2010 as the increase in natural gas production more than offset the lower realized natural gas prices. Crude oil and condensate revenues increased by $19.4 million, or 32%, for the first nine months of 2011 as compared to the first nine months of 2010, due to increased crude oil production partially offset by lower realized crude oil prices. Brokered natural gas revenues decreased by $10.9 million, or 22%, due to a decreased sales price and decreased brokered volumes.

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. For 2011, we expect to spend approximately $825 to $875 million in capital and exploration expenditures, using proceeds from the sale of assets to supplement our cash flows from operations in order to fund incremental capital and exploration expenditures. We believe our cash on hand, operating cash flows in 2011, proceeds from asset sales and borrowings from our credit facility will be more than sufficient to fund our capital and exploration spending in 2011. We will continue to assess the natural gas and crude oil price environment and our liquidity position and may increase or decrease our capital and exploration expenditures accordingly. For the nine months ended September 30, 2011, we invested approximately $666.7 million in our exploration and development efforts.

During the first nine months of 2011, we drilled 85 gross wells (73 development, five exploratory and seven extension wells) with a success rate of 99% compared to 83 gross wells (69 development, four exploratory and 10 extension wells) with a success rate of 98% for the comparable period of the prior year. For the full year of 2011, we plan to drill approximately 140 gross (100 net) wells.

While we consider acquisitions from time to time, we continue to remain focused on our strategies of pursuing drilling opportunities that provide more predictable results on our accumulated acreage position. Additionally, we intend to maintain spending discipline

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and manage our balance sheet in an effort to ensure sufficient liquidity, including cash resources and available credit. We believe these strategies are appropriate for our portfolio of projects and 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, 2011 were funds generated from the sale of natural gas and crude oil production (including hedge realizations), borrowings under our credit facility and the sales of properties and other assets. These cash flows were primarily used to fund our development and exploration expenditures, in addition to payment of dividends and repayment of debt. See below for additional discussion and analysis of cash flow.

We generate cash from the sale of natural gas and crude oil. 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 Form 10-K and other filings with the Securities and Exchange Commission, have also influenced prices throughout the recent years. Commodity prices continue to experience increased volatility. 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 revenues.

Our working capital is also substantially influenced by 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 availability under our credit facility and liquidity available to meet our working capital requirements.

	Nine Months Ended September 30,	
(In thousands)	**2011**	**2010**
Cash Flows Provided by Operating Activities	**$ 375,366**	$ 367,492
Cash Flows Used in Investing Activities	**(586,878)**	(637,090)
Cash Flows Provided by Financing Activities	**218,491**	267,028
Net Increase / (Decrease) in Cash and Cash Equivalents	**$ 6,979**	$ (2,570)

***Operating Activities*.** Key components impacting net operating cash flows are commodity prices, production volumes and operating expenses. Net cash provided by operating activities in the first nine months of 2011 increased by $7.9 million over the first nine months of 2010. This increase was primarily due to increased operating income in 2011 as a result of higher operating revenues and an increase in the gain on sale of assets that outpaced the increase in operating expenses. This increase was offset by changes in working capital and long-term assets and liabilities which decreased operating cash flows. The increase in operating revenues was primarily due to an increase in equivalent production partially offset by lower realized natural gas and crude oil prices. Equivalent production volumes increased by 42% for the nine months ended September 30, 2011 compared to the nine months ended September 30, 2010 as a result of higher natural gas and crude oil production. Average realized natural gas prices decreased by 21% for the first nine months of 2011 compared to the first nine months of 2010. Average realized crude oil prices decreased by 8% compared to the same period. See Results of Operations for additional information relative to commodity price, production and operating expense movements. 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. Realized prices may decline in future periods.

Investing Activities. The primary use of cash in investing activities was capital spending. We established our 2011 capital budget based on our current estimate of future commodity prices and cash flows. Due to the volatility of commodity prices and new opportunities which may arise, our capital expenditures may be periodically adjusted. Cash flows used in investing activities decreased by $50.2 million for the first nine months of 2011 compared to the first nine months of 2010. The decrease was primarily due to higher proceeds from sale of assets of $61.1 million slightly offset by an increase of $10.9 million in capital and exploration expenditures.

Financing Activities. Cash flows provided by financing activities decreased by $48.5 million from the first nine months of 2010 to the first nine months of 2011. This was primarily due to an increase in repayments of debt partially offset by higher borrowings, resulting in lower net borrowings, and lower capitalized debt issuance costs in the first nine months of 2011 compared to the first nine months of 2010.

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At September 30, 2011, we had $443.0 million of borrowings outstanding under our unsecured credit facility at a weighted-average interest rate of 4.0%. The credit facility provides for an available credit line of $900 million and contains an accordion feature allowing us to increase the available credit line to $1.0 billion, if any one or more of the existing banks or new banks agree to provide such increased commitment amount. Effective April 1, 2011, the lenders under our credit facility approved an increase in the borrowing base under the facility from $1.5 billion to $1.7 billion as part of the annual redetermination under the terms of the credit facility. Our plan to sell certain oil and gas properties located in Colorado, Utah and Wyoming, triggered an interim redetermination of the Company s Borrowing Base and the $1.7 billion Borrowing Base was reaffirmed by the lenders effective September 27, 2011. As of September 30, 2011, our available credit under our credit facility was $456.8 million.

We are in compliance in all material respects with our debt covenants as of September 30, 2011.

We strive to manage our debt at a level below the available credit line in order to maintain borrowing capacity. Our revolving credit facility includes a covenant limiting our total debt. Management believes that, with operating cash flow, existing cash on hand, availability under our revolving credit facility and proceeds from the sale of assets, we have the capacity to finance our spending plans, service our debt obligations as they become due and maintain our strong financial position.

Capitalization

Information about our capitalization is as follows:

(Dollars in millions)		**September 30, 2011**		**December 31, 2010**
Debt (1)	**$**	**1,205.0**	$	975.0
Stockholders Equity		**2,043.2**		1,872.7
Total Capitalization	**$**	**3,248.2**	$	2,847.7
Debt to Capitalization		**37.1%**		34.2%
Cash and Cash Equivalents	**$**	**62.9**	$	55.9

(1) *Includes $443.0 million and $213.0 million of borrowings outstanding under our revolving credit facility at September 30, 2011 and December 31, 2010, respectively.*

During the nine months ended September 30, 2011, we paid dividends of $9.4 million ($0.09 per share) on our common stock. A regular dividend has been declared for each quarter since we became a public company in 1990.

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, borrowings under 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:

	Nine Months Ended September 30,	
(In millions)	**2011**	**2010**
Capital Expenditures		
Drilling and Facilities	$ **561.0**	$ 445.8
Leasehold Acquisitions	**60.9**	109.9
Acquisitions		0.8
Pipeline and Gathering	**7.2**	29.4
Other	**6.5**	6.6
	635.6	592.5
Exploration Expense	**31.1**	28.3
Total	$ **666.7**	$ 620.8

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For the full year of 2011, we plan to drill approximately 140 gross (100 net) wells. This 2011 drilling program is part of approximately $825 to $875 million in total planned capital and exploration expenditures. See Overview for additional information regarding the current year drilling program. We will continue to assess the natural gas and crude oil price environment and our liquidity position and may increase or decrease the capital and exploration expenditures accordingly.

Contractual Obligations

We have various contractual obligations in the normal course of our operations. For further information, please refer to Transportation Agreements and Drilling Rig Commitments under Note 6 in the Notes to the Condensed Consolidated Financial Statements and Note 8 in the Notes to Consolidated Financial Statements included in our 10-K.

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 Form 10-K for further discussion of our critical accounting policies.

Recently Issued Accounting Pronouncements

In May 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2011-04, Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs. The amendments in ASU No. 2011-04 generally represent clarifications of Topic 820, but also include some instances where a particular principle or requirement for measuring fair value or disclosing information about fair value measurements has changed. ASU No. 2011-04 results in common principles and requirements for measuring fair value and for disclosing information about fair value measurements in accordance with U.S. GAAP and IFRSs. The amendments in ASU No. 2011-04 are to be applied prospectively. For public entities, the amendments are effective for interim and annual periods beginning after December 15, 2011. Early application by public entities is not permitted. We do not expect this guidance to have a significant impact on our consolidated financial position, results of operations or cash flows.

In June 2011, the FASB issued ASU No. 2011-05, Presentation of Comprehensive Income, requiring most entities to present items of net income and other comprehensive income either in one continuous statement referred to as the statement of comprehensive income or in two separate, but consecutive, statements of net income and other comprehensive income. The new requirements are effective for public entities for fiscal years (including interim periods) beginning after December 15, 2011. We do not expect this guidance to have a significant impact on our consolidated financial position, results of operations or cash flows.

Results of Operations

Third Quarter of 2011 and 2010 Compared

We reported net income in the third quarter of 2011 of $28.5 million, or $0.27 per share, compared to net income in the third quarter of 2010 of $3.9 million, or $0.04 per share. Net income increased in the third quarter of 2011 by $24.6 million, primarily due to an increase in operating revenues and gain on sale of assets and a decrease in operating expenses partially offset by increases in interest expense and income tax expense.

Operating revenues increased by $38.1 million due to increased natural gas and crude oil and condensate revenues partially offset by decreased brokered natural gas revenues. Operating expenses decreased by $1.3 million between periods primarily due to a decrease in impairment of oil and gas properties, lower brokered natural gas cost and taxes other than income, partially offset by increases in transportation and gathering expenses, exploration expense, general and administration expense, depreciation, depletion, and amortization and direct operating expenses. In addition, net income was impacted during the third quarter by an increase in gain on sale of assets and higher income tax and interest expense.

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Revenue, Price and Volume Variances

Below is a discussion of revenue, price and volume variances.

Revenue Variances (In thousands)

	Three Months Ended September 30, 2011	2010	Variance Amount	Percent
Natural Gas (1)	$ **218,585**	$ 192,219	$ 26,366	14%
Brokered Natural Gas	**9,467**	11,675	(2,208)	(19)%
Crude Oil and Condensate	**33,158**	19,234	13,924	72%
Other	**971**	1,127	(156)	(14)%

(1) Natural Gas Revenues exclude the unrealized loss of $0.1 and $0.2 million from the change in fair value of our derivatives not designated as hedges in 2011 and 2010, respectively.

	Three Months Ended September 30, 2011	2010	Variance Amount	Percent	Increase (Decrease) (In thousands)
Price Variances					
Natural Gas (1)	$ **4.58**	$ 5.52	$ (0.94)	(17)%	$ (44,757)
Crude Oil and Condensate (2)	$ **86.89**	$ 98.26	$ (11.37)	(12)%	(4,339)
Total					$ (49,096)
Volume Variances					
Natural Gas (Mmcf)	**47,707**	34,850	12,857	37%	$ 71,123
Crude Oil and Condensate (Mbbl)	**382**	196	186	95%	18,263
Total					$ 89,386

(1) These prices include the realized impact of derivative instrument settlements, which increased the price by $0.44 per Mcf in 2011 and by $1.13 per Mcf in 2010.

(2) These prices include the realized impact of derivative instrument settlements, which increased the price by $3.62 per Bbl in 2011 and by $26.33 per Bbl in 2010.

Natural Gas Revenues

The increase in natural gas revenues of $26.4 million, excluding the impact of unrealized losses discussed above, is primarily due to increased production during the third quarter of 2011, partially offset by lower realized natural gas prices. The increased production is primarily due to our Marcellus Shale drilling program in northeast Pennsylvania and the start up of additional compressors at the Lathrop compressor station in

Susquehanna County, Pennsylvania. This increase is partially offset by decreases in production in east and south Texas due to normal production declines and a shift from gas to oil projects.

Crude Oil and Condensate Revenues

The increase in crude oil and condensate revenues of $13.9 million is primarily due to increased production due to our Eagle Ford Shale drilling program in south Texas partially offset by lower realized oil prices.

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Brokered Natural Gas Revenue and Cost

	Three Months Ended September 30, 2011		2010	Variance Amount	Percent	Price and Volume Variances (In thousands)
Brokered Natural Gas Sales						
Sales Price ($/Mcf)	**$**	**4.99**	$ 5.14	$ (0.15)	(3)%	$ (285)
Volume Brokered (Mmcf)	**x**	**1,899**	x 2,272	(373)	(16)%	(1,923)
Brokered Natural Gas Revenues (In thousands)	**$**	**9,467**	$ 11,675			$ (2,208)
Brokered Natural Gas Purchases						
Purchase Price ($/Mcf)	**$**	**4.32**	$ 4.53	$ (0.21)	(5)%	$ 398
Volume Brokered (Mmcf)	**x**	**1,899**	x 2,272	(373)	(16)%	1,679
Brokered Natural Gas Cost (In thousands)	**$**	**8,204**	$ 10,281			$ 2,077
Brokered Natural Gas Margin (In thousands)	**$**	**1,263**	$ 1,394			$ (131)

The decreased brokered natural gas margin of $0.1 million is primarily a result of a decrease in brokered volumes coupled with a decrease in purchase price that outpaced the sales price.

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,			
	2011		2010	
(In thousands)	**Realized**	**Unrealized**	**Realized**	**Unrealized**
Operating Revenues - Increase / (Decrease) to Revenue				
Cash Flow Hedges				
Natural Gas	**$ 21,170**	**$**	$ 39,461	$
Crude Oil	**1,382**		5,160	
Total Cash Flow Hedges	**22,552**		44,621	
Other Derivative Financial Instruments				
Natural Gas Basis Swaps		**(64)**		(193)
Total Other Derivative Financial Instruments		**(64)**		(193)
Total Cash Flow Hedges and Other Derivative Financial Instruments	**$ 22,552**	**$ (64)**	$ 44,621	$ (193)

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We are exposed to market risk on derivative instruments to the extent of changes in market prices of natural gas and crude 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. Although notional contract amounts are used to express the volume of natural gas price agreements, the amounts that can be subject to credit risk in the event of non-performance by third parties are substantially smaller. We do not anticipate any material impact on our financial results due to non-performance by third parties. Our derivative contract counterparties are Bank of Montreal, BNP Paribas, JPMorgan Chase, Goldman Sachs and Bank of America.

Operating and Other Expenses

	Three Months Ended September 30,		Variance	
(In thousands)	**2011**	**2010**	**Amount**	**Percent**
Operating and Other Expenses				
Brokered Natural Gas Cost	$ **8,204**	$ 10,281	$ (2,077)	(20)%
Direct Operations	**27,292**	26,466	826	3%
Transportation and Gathering	**19,768**	4,932	14,836	301%
Taxes Other Than Income	**7,042**	8,489	(1,447)	(17)%
Exploration	**20,190**	9,665	10,525	109%
Impairment of Oil and Gas Properties		35,789	(35,789)	(100)%
Depreciation, Depletion and Amortization	**90,293**	85,355	4,938	6%
General and Administrative	**27,949**	21,077	6,872	33%
Total Operating Expense	$ **200,738**	$ 202,054	$ (1,316)	(1)%
(Gain) / Loss on Sale of Assets	$ **(3,854)**	$ (265)	$ 3,589	1354%
Interest Expense and Other	**18,517**	16,758	1,759	10%
Income Tax Expense	**18,234**	1,617	16,617	1028%

Total costs and expenses from operations decreased by $1.3 million, or 1%, in the third quarter of 2011 compared to the same period of 2010. The primary reasons for this fluctuation are as follows:

- Impairment of Oil and Gas Properties decreased by $35.8 million from the third quarter of 2011 compared to the third quarter of 2010 due to the impairment of two south Texas fields recognized in the third quarter of 2010 because of continued price declines and normal production declines. There were no impairments in third quarter of 2011.

- Brokered Natural Gas Costs decreased $2.1 million. See the preceding table titled *Brokered Natural Gas Revenue and Cost* for further analysis.

- Taxes Other Than Income decreased $1.5 million primarily due to lower ad valorem and franchise tax expense partially offset by higher production tax expense due to fewer tax credits and related refunds on qualifying wells received in the third quarter of 2011 compared to 2010.

- Transportation and Gathering increased by $14.8 million primarily due to the commencement of various firm transportation and gathering arrangements in the first nine months of 2011 in Susquehanna County, Pennsylvania.

- Exploration Expense increased $10.5 million primarily due to dry hole costs related to an exploratory well in Montana partially offset by lower geophysical and geological costs.

- General and Administrative increased by $6.9 million primarily due to $6.2 million higher stock-based compensation expense primarily associated with the mark to market of the liability portion of our performance shares as a result of our higher average stock price for the month of September 2011 compared to the average stock price for the month of September 2010.

- Depreciation, Depletion and Amortization increased by $4.9 million, of which $6.7 million was due to increased depreciation and depletion from increased capital spending and higher equivalent production volumes partially offset by a lower DD&A rate of $1.62 per Mcfe for three months ended September 30, 2011 compared to $2.06 per Mcfe for three months ended September 30, 2010. The increase in depletion and depreciation was offset by a decrease in amortization of unproved properties of $2.3 million.

Gain / (Loss) on Sale of Assets

An aggregate gain of $3.9 million was recognized in the third quarter of 2011 primarily due to the sale of non-core assets as part of our ongoing asset portfolio management program.

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Income Tax Expense

Income tax expense increased by $16.6 million in the third quarter of 2011 compared to the third quarter of 2010 primarily due to increased pretax income and a higher effective tax rate. The effective tax rate for the third quarter of 2011 and 2010 was 39.0% and 29.3%, respectively. The effective tax rate was higher as a result of provision to return adjustments recorded in the third quarter 2011 having a lesser impact due to higher quarterly pretax income.

Interest Expense and Other

Interest expense and other increased by $1.8 million in the third quarter of 2011 compared to the third quarter of 2010 primarily due to an increase in weighted-average borrowings under our credit facility based on daily balances of approximately $407.7 million during the third quarter of 2011 compared to approximately $392.7 million during the third quarter of 2010. The increase in borrowings was partially offset by a lower weighted-average effective interest rate on the credit facility of approximately 3.7% during the third quarter of 2011 compared to approximately 3.8% during the third quarter of 2010. Furthermore, in December 2010 we issued $175 million aggregate principal amount of 5.58% weighted-average fixed rate notes, which increased interest expense recognized in the third quarter of 2011.

Nine Months of 2011 and 2010 Compared

We reported net income in the first nine months of 2011 of $96.0 million, or $0.92 per share, compared to net income in the first nine months of 2010 of $54.3 million, or $0.52 per share. Net income increased in the first nine months of 2011 by $41.8 million, primarily due to an increase in operating revenues and gain on sale of assets, partially offset by increases in operating expenses, interest expense and income tax expense.

Operating revenues increased by $71.2 million, largely due to increased natural gas and crude oil and condensate revenues, partially offset by decreased brokered natural gas revenues. Operating expenses increased by $28.9 million between periods primarily due to increases in transportation and gathering expenses, general and administrative expenses, depreciation, depletion and amortization and direct operations and exploration expense partially offset by a decrease in impairment of oil and gas properties and lower taxes other than income and brokered natural gas cost. In addition, net income was impacted during the first nine months by increased gain on sale of assets partially offset by higher interest expense and income tax expense.

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Revenue, Price and Volume Variances

Below is a discussion of revenue, price and volume variances.

Revenue Variances (In thousands)

	Nine Months Ended September 30, 2011	2010	Variance Amount	Percent
Natural Gas (1)	$ **589,926**	$ 526,262	$ 63,664	12%
Brokered Natural Gas	**38,947**	49,896	(10,949)	(22)%
Crude Oil and Condensate	**79,792**	60,427	19,365	32%
Other	**4,124**	3,901	223	6%

(1) Natural Gas Revenues exclude the unrealized loss of $1.0 million and the unrealized gain of $0.2 million from the change in fair value of our derivatives not designated as hedges in 2011 and 2010, respectively.

	Nine Months Ended September 30, 2011	2010	Variance Amount	Percent
Price Variances				
Natural Gas (1)	$ **4.64**	$ 5.90	$ (1.26)	(21)%
Crude Oil and Condensate (2)	$ **89.69**	$ 97.43	$ (7.74)	(8)%
Total				
Volume Variances				
Natural Gas (Mmcf)	**127,206**	89,203	38,003	43%
Crude Oil and Condensate (Mbbl)	**890**	620	270	43%
Total				

(1) These prices include the realized impact of derivative instrument settlements, which increased the price by $0.38 per Mcf in 2011 and by $1.23 per Mcf in 2010.

(2) These prices include the realized impact of derivative instrument settlements, which increased the price by $0.64 per Bbl in 2011 and by $23.42 per Bbl in 2010.

Natural Gas Revenues

The increase in Natural Gas Revenues of $63.7 million is primarily due to increased production during the first nine months of 2011, partially offset by lower realized natural gas prices. The increased production is primarily due to increased production associated with our Marcellus Shale drilling program and upgrades to the compressors at the Lathrop compressor station in Susquehanna County, Pennsylvania during the first nine months of the year, partially offset by decreases in production primarily in east and south Texas due to normal production declines and a shift from gas to oil projects.

Crude Oil and Condensate Revenues

The increase in Crude Oil and Condensate Revenues of $19.4 million is primarily due to increased production partially offset by lower realized oil prices. The increase in production is primarily due to our drilling program in the Eagle Ford Shale in south Texas, partially offset by lower production in east Texas.

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Brokered Natural Gas Revenue and Cost

		Nine Months Ended September 30, 2011		2010		Variance Amount	Variance Percent		Price and Volume Variances (In thousands)
Brokered Natural Gas Sales									
Sales Price ($/Mcf)	**$**	**5.15**	$	5.60	$	(0.45)	(8)%	$	(3,402)
Volume Brokered (Mmcf)	**x**	**7,560**	x	8,915		(1,355)	(15)%		(7,547)
Brokered Natural Gas Revenues (In thousands)	**$**	**38,947**	$	49,896				$	(10,949)
Brokered Natural Gas Purchases									
Purchase Price ($/Mcf)	**$**	**4.41**	$	4.86	$	(0.45)	(9)%	$	3,380
Volume Brokered (Mmcf)	**x**	**7,560**	x	8,915		(1,355)	(15)%		6,600
Brokered Natural Gas Cost (In thousands)	**$**	**33,362**	$	43,342				$	9,980
Brokered Natural Gas Margin (In thousands)	**$**	**5,585**	$	6,554				$	(969)

The decreased brokered natural gas margin of $1.0 million is primarily a result of a decrease in brokered volumes.

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:

(In thousands)		Nine Months Ended September 30, 2011 Realized		2011 Unrealized		2010 Realized		2010 Unrealized
Operating Revenues - Increase / (Decrease) to Revenue								
Cash Flow Hedges								
Natural Gas	**$**	**48,318**	**$**		$	109,714	$	
Crude Oil		**566**				14,522		
Total Cash Flow Hedges		**48,884**				124,236		
Other Derivative Financial Instruments								
Natural Gas Basis Swaps				**(950)**				162
Total Other Derivative Financial Instruments				**(950)**				162
Total Cash Flow Hedges and Other Derivative Financial Instruments	**$**	**48,884**	**$**	**(950)**	$	124,236	$	162

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Operating and Other Expenses

(In thousands)	Nine Months Ended September 30, 2011	2010	Variance Amount	Percent
Operating and Other Expenses				
Brokered Natural Gas Cost	$ **33,362**	$ 43,342	$ (9,980)	(23)%
Direct Operations	**76,878**	73,796	3,082	4%
Transportation and Gathering	**48,710**	13,488	35,222	261%
Taxes Other Than Income	**21,070**	31,135	(10,065)	(32)%
Exploration	**31,090**	28,324	2,766	10%
Impairment of Oil and Gas Properties		35,789	(35,789)	(100)%
Depreciation, Depletion and Amortization	**250,642**	235,579	15,063	6%
General and Administrative	**78,254**	49,675	28,579	58%
Total Operating Expense	$ **540,006**	$ 511,128	$ 28,878	6%
(Gain) / Loss on Sale of Assets	$ **(36,408)**	$ (5,411)	$ 30,997	573%
Interest Expense and Other	**53,928**	47,439	6,489	14%
Income Tax Expense	**58,268**	33,215	25,053	75%

Total costs and expenses from operations increased by $28.9 million, or 6%, in the first nine months of 2011 compared to the same period of 2010. The primary reasons for this fluctuation are as follows:

- Transportation and Gathering increased by $35.2 million primarily due to the commencement of various firm transportation and gathering arrangements in the first nine months of 2011 primarily in Susquehanna County, Pennsylvania.

- General and Administrative increased by $28.6 million primarily due to $19.2 million higher stock-based compensation expense primarily associated with the mark to market of the liability portion of our performance shares as a result of our higher average stock price for the month of September 2011 compared to the average stock price for the month of September 2010 and $5.9 million higher pension expense due to the acceleration of amortization of prior service costs and actuarial losses as a result of the plan termination and expected liquidation. Higher professional service costs also contributed to the increase.

- Depreciation, Depletion and Amortization increased by $15.1 million, of which $22.0 million was due to increased depreciation and depletion from increased capital spending and higher equivalent production volumes offset by a lower DD&A rate of $1.67 per Mcfe for nine months ended September 30, 2011 compared to $2.14 per Mcfe for nine months ended September 30, 2010 and a $1.6 million increase in amortization of asset retirement obligation costs. The increase in depletion and depreciation was offset by a decrease in amortization of unproved properties of $8.5 million primarily due to a decrease in amortization rates due to a shift in our drilling and development activities.

- Direct Operations increased $3.1 million largely due to increased operating costs primarily driven by increased production. Contributing to the increase are higher workover and environmental and regulatory costs associated with the remediation of certain wells in northeast Pennsylvania as a result of the PaDEP Global Settlement. Offsetting these increases were lower compression expenses primarily due to the sale of our gathering system in northeast Pennsylvania in the fourth quarter of 2010 and increased use of centralized compression. Lease maintenance costs were also lower in the first nine months of 2011 compared to the same period of 2010.

- Exploration Expense increased $2.8 million primarily due to higher dry hole costs incurred related to an exploratory well in Montana in 2011, partially offset by lower geophysical and geological costs primarily due to a reduction in the acquisition of seismic data.

- Impairment of Oil and Gas Properties decreased by $35.8 million for the first nine months of 2011 compared to the first nine months of 2010 due to the impairment of two south Texas fields recognized in the first nine months of 2010 as a result of continued price declines and normal production declines. There were no impairments in the first nine months of 2011.

- Taxes Other Than Income decreased $10.1 million due to decreased production taxes as a result of tax refunds and credits received in 2011 on qualifying wells and lower ad valorem and business and occupational taxes partially offset by an increase in franchise taxes expense.

- Brokered Natural Gas Costs decreased $10.0 million. See the preceding table titled *Brokered Natural Gas Revenue and Cost* for further analysis.

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Gain / (Loss) on Sale of Assets

An aggregate gain of $36.4 million was recognized in the first nine months of 2011 on the sale of oil and gas properties in east Texas and the sale of non-core assets as part of our ongoing asset portfolio management program. In the first nine months of 2010, a gain of $10.3 million was recognized on the sale of the Woodford shale prospect, offset by an impairment charge of $5.8 million on assets held for sale.

Income Tax Expense

Income tax expense increased by $25.1 million in the first nine months of 2011 compared to the first nine months of 2010 primarily due to increased pretax income partially offset by a lower effective tax rate. The effective tax rate for the first nine months of 2011 and 2010 was 37.7% and 38.0%, respectively.

Interest Expense and Other

Interest expense and other increased by $6.5 million in the first nine months of 2011 compared to the first nine months of 2010 primarily due to an increase in weighted-average borrowings under our credit facility based on daily balances of approximately $340.2 million during the first nine months of 2011 compared to approximately $304.1 million during the first nine months of 2010. The weighted-average effective interest rate on the credit facility increased to approximately 4.0% during the first nine months of 2011 compared to approximately 3.8% during the first nine months of 2010. In addition, in December 2010, we issued $175 million aggregate principal amount of 5.58% weighted-average fixed rate notes, which increased interest expense recognized in the first nine months of 2011.

Forward-Looking Information

The statements regarding future financial and operating performance and results, market prices, future hedging activities and other statements that are not historical facts contained in this report are forward-looking statements. The words expect, project, estimate, believe, anticipate, intend, budget, plan, forecast, predict, may, should, could, will and similar expressions are also intended to identify forward-lool Such statements involve risks and uncertainties, including, but not limited to, market factors, market prices (including regional basis differentials) of natural gas and crude 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

Market Risk

Our primary market risk is exposure to crude oil and natural gas prices. Realized prices are mainly driven by worldwide prices for crude oil and spot market prices for North American natural gas production. Commodity prices are volatile and unpredictable.

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 in periods of increasing 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 as well as Note 7 of the Notes to the Condensed Consolidated Financial Statements for a more detailed discussion of our hedging arrangements.

As of September 30, 2011, we had 42 derivative contracts open: 27 natural gas price swap arrangements, five natural gas collar arrangements, six natural gas basis swaps, one crude oil price collar arrangement and three crude oil price swap arrangements. During the first nine months of 2011, we entered into 31 new derivative contracts covering anticipated crude oil and natural gas production for 2011, 2012, and 2013.

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As of September 30, 2011, we had the following outstanding commodity derivatives:

Commodity and Derivative Type	Weighted-Average Contract Price		Volume		Contract Period	Net Unrealized Gain / (Loss)	
Derivatives Designated as Hedging Instruments							
Natural Gas Swaps	$6.24	per Mcf	3,254	Mmcf	Oct. 2011 - Dec. 2011	$	6,785
Natural Gas Swaps	$5.18	per Mcf	98,302	Mmcf	Oct. 2011 - Dec. 2012		86,650
Natural Gas Swaps	$5.28	per Mcf	17,854	Mmcf	Jan. 2012 - Dec. 2012		15,267
Natural Gas Collars	$6.17 Ceiling/ $5.13 Floor	per Mcf	17,805	Mmcf	Jan. 2013 - Dec. 2013		8,196
Crude Oil Collars	$93.25 Ceiling / $80.00 Floor	per Bbl	92	Mbbl	Oct. 2011- Dec. 2011		408
Crude Oil Swaps	$106.20	per Bbl	92	Mbbl	Oct. 2011 - Dec. 2011		2,466
Crude Oil Swaps	$105.00	per Bbl	366	Mbbl	Jan. 2012 - Dec. 2012		8,725
						$	**128,497**
Derivatives Not Designated as Hedging Instruments							
Natural Gas Basis Swaps	$(0.27)	per Mcf	16,123	Mmcf	Jan. 2012 - Dec. 2012		(3,073)
						$	**125,424**

The amounts set forth under the net unrealized gain / (loss) column in the table above represent our total unrealized gain position at September 30, 2011 and exclude the impact of non-performance risk of $1.5 million. Non-performance risk was primarily evaluated by reviewing credit default swap spreads for the various financial institutions in which we have derivative transactions, while non-performance risk of the Company is evaluated using a market credit spread provided by the Company s bank.

From time to time, we enter into natural gas and crude oil swap and collar agreements with counterparties to hedge price risk associated with a portion of our production. These agreements are not held for trading purposes. Under the price swaps, we receive a fixed price on a notional quantity of natural gas or crude oil in exchange for paying a variable price based on a market-based index, such as the NYMEX gas and crude oil futures. Under the collar agreements, 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.

We had natural gas price swaps covering 51.9 Bcf, or 41%, of our first nine months of 2011 natural gas production at an average price of $5.36 per Mcf.

We had one crude oil swap covering 183 Mbbl, or 21%, of our first nine months of 2011 crude oil production, at an average price of $106.20 per Bbl.

During the first nine months of 2011, crude oil collars covered 273 Mbbl, or 31% of total crude oil production, with a weighted-average floor price of $80.00 per Bbl and a weighted-average ceiling price of $93.25 per Bbl.

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.

Fair Market Value of Financial Instruments

The estimated fair value of financial instruments is the amount at which the instrument could be exchanged currently between willing parties. The carrying amounts reported in the Condensed Consolidated Balance Sheet for cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the short-term maturities of these instruments.

The fair value of long-term debt is the estimated cost to acquire the debt, including a credit spread for the difference between the issue rate and the period end market rate. The credit spread is our default or repayment risk. The credit spread (premium or discount) is determined by comparing our fixed-rate notes and credit facility to new issues (secured and unsecured) and secondary trades of similar size and credit statistics for both public and private debt. The fair value of all of the fixed-rate notes and credit facility is based on interest rates currently available to us.

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We use available marketing data and valuation methodologies to estimate the fair value of debt.

	September 30, 2011		December 31, 2010	
(In thousands)	**Carrying Amount**	**Estimated Fair Value**	**Carrying Amount**	**Estimated Fair Value**
Long-Term Debt	**$ 1,205,000**	**$ 1,339,410**	$ 975,000	$ 1,100,830

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 Rules 13a-15 and 15d-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 at a reasonable assurance level 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 third quarter of 2011 that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

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PART II. OTHER INFORMATION

ITEM 1. Legal Proceedings

The information set forth under the heading Environmental Matters in Note 6 of the Notes to Condensed Consolidated Financial Statements included in Item 1 of Part I of this quarterly report is incorporated by reference in response to this item.

We have received a number of Notices of Violation from the Pennsylvania Department of Environmental Protection (PaDEP) relating to alleged violations, primarily with respect to the Pennsylvania Clean Streams Law, the Pennsylvania Oil and Gas Act and the Pennsylvania Solid Waste Management Act and the rules and regulations promulgated thereunder. We have responded to these Notices of Violation, have remediated the areas in question and are actively cooperating with the PaDEP. While we cannot predict with certainty whether these Notices of Violation will result in fines and/or penalties, if fines and/or penalties are imposed, the aggregate of these fines and/or penalties could result in monetary sanctions in excess of $100,000.

In August 2011, the Company received a subpoena from the New York Attorney General s Office requesting documents and information regarding the Company s shale and unconventional reservoir reserves calculations. The Company is providing documents and information responsive to the request and is cooperating with the Attorney General s Office in the matter.

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, 2010.

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, 2011, 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, 2011 was 4,795,300.

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ITEM 6. **Exhibits**

Exhibit Number	Description
15.1	Awareness letter of PricewaterhouseCoopers LLP
31.1	302 Certification - Chairman, President and Chief Executive Officer
31.2	302 Certification - Vice President, Chief Financial Officer and Treasurer
32.1	906 Certification
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document

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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 28, 2011	By:	/S/ DAN O. DINGES **Dan O. Dinges** **Chairman, President and** **Chief Executive Officer** **(Principal Executive Officer)**
October 28, 2011	By:	/S/ SCOTT C. SCHROEDER **Scott C. Schroeder** **Vice President, Chief Financial Officer and** **Treasurer** **(Principal Financial Officer)**
October 28, 2011	By:	/S/ TODD M. ROEMER **Todd M. Roemer** **Controller** **(Principal Accounting Officer)**