CIMAREX ENERGY CO
Form 10-Q
November 03, 2011
Table of Contents

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

x **Quarterly Report Pursuant To Section 13 or 15(d) of the Securities Exchange Act of 1934**

o **Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the Quarterly Period ended September 30, 2011

Commission File No. 001-31446

CIMAREX ENERGY CO.

1700 Lincoln Street, Suite 1800

Denver, Colorado 80203-4518

(303) 295-3995

Incorporated in the	**Employer Identification**

State of Delaware	**No. 45-0466694**

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No 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.

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.

The number of shares of Cimarex Energy Co. common stock outstanding as of September 30, 2011 was 85,742,139.

Table of Contents

CIMAREX ENERGY CO.

Table of Contents

Table of Contents

GLOSSARY

Bbl/d Barrels (of oil or natural gas liquids) per day

Bbls Barrels (of oil or natural gas liquids)

Bcf Billion cubic feet

Bcfe Billion cubic feet equivalent

Btu British thermal unit

MBbls Thousand barrels

Mcf Thousand cubic feet (of natural gas)

Mcfe Thousand cubic feet equivalent

MMBbls Million barrels

MMBtu Million British Thermal Units

MMcf Million cubic feet

MMcf/d Million cubic feet per day

MMcfe Million cubic feet equivalent

MMcfe/d Million cubic feet equivalent per day

Net Acres Gross acreage multiplied by Cimarex s working interest percentage

Net Production Gross production multiplied by Cimarex s net revenue interest

NGL Natural gas liquids

Tcf Trillion cubic feet

Tcfe Trillion cubic feet equivalent

WTI West Texas Intermediate

One barrel of oil or NGL is the energy equivalent of six Mcf of natural gas

CAUTIONARY INFORMATION ABOUT FORWARD-LOOKING STATEMENTS

Throughout this Form 10-Q, we make statements that may be deemed forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities and Exchange Act of 1934. These forward-looking statements include, among others, statements concerning our outlook with regard to timing and amount of future production of oil and gas, price realizations, amounts, nature and timing of capital expenditures for exploration and development, plans for funding operations and capital expenditures, drilling of wells, operating costs and other expenses, marketing of oil and gas and other statements of expectations, beliefs, future plans and strategies, anticipated events or trends, and similar expressions concerning matters that are not historical facts. The forward-looking statements in this report are subject to risks and uncertainties that could cause actual results to differ materially from those expressed in or implied by the statements.

These risks and uncertainties include, but are not limited to, fluctuations in the price we receive for our oil and gas production, reductions in the quantity of oil and gas sold due to decreased industry-wide demand and/or curtailments in production from specific properties due to mechanical, marketing or other problems, operating and capital expenditures that are either significantly higher or lower than anticipated because the actual cost of identified projects varied from original estimates and/or from the number of exploration and development opportunities being greater or fewer than currently anticipated, and increased financing costs due to a significant increase in interest rates. In addition, exploration and development opportunities that we pursue may not result in productive oil and gas properties. There are also numerous uncertainties inherent in estimating quantities of proved reserves, projecting future rates of production and the timing of development expenditures. These and other risks and uncertainties affecting us are discussed in greater detail in this report and in our other filings with the Securities and Exchange Commission.

Table of Contents

PART I

ITEM 1 - Financial Statements

CIMAREX ENERGY CO.

Condensed Consolidated Balance Sheets

	September 30, 2011 (Unaudited)	December 31, 2010
	(In thousands, except share data)	
Assets		
Current assets:		
Cash and cash equivalents	$ 57,160	$ 114,126
Receivables, net	343,197	310,968
Oil and gas well equipment and supplies	82,947	81,871
Deferred income taxes	2,625	4,293
Derivative instruments	3,680	5,731
Other current assets	12,267	44,778
Total current assets	501,876	561,767
Oil and gas properties at cost, using the full cost method of accounting:		
Proved properties	9,437,102	8,421,768
Unproved properties and properties under development, not being amortized	659,947	547,609
	10,097,049	8,969,377
Less accumulated depreciation, depletion and amortization	(6,309,847)	(6,047,019)
Net oil and gas properties	3,787,202	2,922,358
Fixed assets, net	98,032	156,579
Goodwill	691,432	691,432
Other assets, net	33,010	26,111
	$ 5,111,552	$ 4,358,247
Liabilities and Stockholders Equity		
Current liabilities:		
Accounts payable	$ 61,705	$ 47,242
Accrued liabilities	379,344	320,989
Derivative instruments		9,587
Revenue payable	135,274	134,495
Total current liabilities	576,323	512,313
Long-term debt	350,000	350,000
Deferred income taxes	906,118	619,040
Other liabilities	265,704	267,062
Stockholders equity:		
Preferred stock, $0.01 par value, 15,000,000 shares authorized, no shares issued		
Common stock, $0.01 par value, 200,000,000 shares authorized, 85,742,139 and 85,234,721 shares issued, respectively	857	852
Paid-in capital	1,899,725	1,883,065
Retained earnings	1,112,978	725,651
Accumulated other comprehensive income (loss)	(153)	264
	3,013,407	2,609,832
	$ 5,111,552	$ 4,358,247

See accompanying notes to consolidated financial statements.

Table of Contents

CIMAREX ENERGY CO.

Consolidated Statements of Operations

(Unaudited)

	For the Three Months Ended September 30, 2011	For the Three Months Ended September 30, 2010	For the Nine Months Ended September 30, 2011	For the Nine Months Ended September 30, 2010
	(In thousands, except per share data)			
Revenues:				
Gas sales	$ 138,631	$ 145,396	$ 410,331	$ 522,408
Oil sales	211,928	177,834	675,239	550,058
NGL sales	69,169	43,331	200,428	91,391
Gas gathering, processing and other	13,762	11,570	40,823	41,022
Gas marketing, net	319	452	797	775
	433,809	378,583	1,327,618	1,205,654
Costs and expenses:				
Depreciation, depletion and amortization	104,681	78,705	279,554	221,561
Asset retirement obligation	3,578	1,201	8,223	5,486
Production	62,333	52,010	181,558	139,349
Transportation	15,196	13,084	45,029	35,076
Gas gathering and processing	4,821	4,577	14,002	17,182
Taxes other than income	30,533	28,094	98,625	88,862
General and administrative	9,390	11,274	34,734	36,136
Stock compensation, net	4,595	3,241	13,962	9,012
Gain on derivative instruments, net	(7,120)	(15,028)	(11,353)	(70,914)
Other operating, net	2,379	2,291	8,095	2,321
	230,386	179,449	672,429	484,071
Operating income	203,423	199,134	655,189	721,583
Other (income) and expense:				
Interest expense	9,279	9,059	27,599	27,622
Capitalized interest	(7,253)	(7,259)	(21,830)	(21,968)
Gain on early extinguishment of debt		(3,776)		(3,776)
Other, net	(3,604)	(2,711)	(7,226)	(2,790)
Income before income tax	205,001	203,821	656,646	722,495
Income tax expense	76,849	75,605	243,583	265,298
Net income	$ 128,152	$ 128,216	$ 413,063	$ 457,197
Earnings per share to common stockholders:				
Basic				
Distributed	$ 0.10	$ 0.08	$ 0.30	$ 0.24
Undistributed	1.39	1.42	4.51	5.12
	$ 1.49	$ 1.50	$ 4.81	$ 5.36
Diluted				
Distributed	$ 0.10	$ 0.08	$ 0.30	$ 0.24
Undistributed	1.39	1.42	4.49	5.09
	$ 1.49	$ 1.50	$ 4.79	$ 5.33

See accompanying notes to consolidated financial statements.

Table of Contents

CIMAREX ENERGY CO.

Condensed Consolidated Statements of Cash Flows

(Unaudited)

	For the Nine Months Ended September 30, 2011	2010
	(In thousands)	
Cash flows from operating activities:		
Net income	$ 413,063	$ 457,197
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	279,554	221,561
Asset retirement obligation	8,223	5,486
Deferred income taxes	288,986	213,678
Stock compensation, net	13,962	9,012
Derivative instruments, net	(7,536)	(39,656)
Changes in non-current assets and liabilities	3,719	10,507
Other, net	4,816	(7,904)
Changes in operating assets and liabilities:		
Increase in receivables, net	(32,229)	(4,364)
Decrease in other current assets	30,736	31
Increase (decrease) in accounts payable and accrued liabilities	(31,771)	21,120
Net cash provided by operating activities	971,523	886,668
Cash flows from investing activities:		
Oil and gas expenditures	(1,152,676)	(691,536)
Sales of oil and gas and other assets	216,000	33,646
Other expenditures	(70,050)	(38,941)
Net cash used by investing activities	(1,006,726)	(696,831)
Cash flows from financing activities:		
Net decrease in bank debt		(25,000)
Decrease in other long-term debt		(19,450)
Financing costs incurred	(7,348)	(101)
Dividends paid	(23,998)	(18,662)
Issuance of common stock and other	9,583	18,928
Net cash used by financing activities	(21,763)	(44,285)
Net change in cash and cash equivalents	(56,966)	145,552
Cash and cash equivalents at beginning of period	114,126	2,544
Cash and cash equivalents at end of period	$ 57,160	$ 148,096

See accompanying notes to consolidated financial statements.

Table of Contents

CIMAREX ENERGY GO.

Notes to Consolidated Financial Statements

September 30, 2011

(Unaudited)

1. Basis of Presentation

The accompanying unaudited financial statements have been prepared by Cimarex Energy Co. pursuant to rules and regulations of the Securities and Exchange Commission (SEC). Accordingly, certain disclosures required by accounting principles generally accepted in the United States and normally included in annual reports on Form 10-K have been omitted. Although management believes that our disclosures in these interim financial statements are adequate, they should be read in conjunction with the financial statements, summary of significant accounting policies, and footnotes included in our 2010 Annual Report on Form 10-K/A.

In the opinion of management, the accompanying financial statements reflect all adjustments necessary to present fairly our financial position, results of operations, and cash flows for the periods shown. We have evaluated subsequent events through the date of this filing.

Full Cost Accounting Method and Ceiling Limitation

We use the full cost method of accounting for our oil and gas operations. All costs associated with property acquisition, exploration, and development activities are capitalized. Exploration and development costs include dry hole costs, geological and geophysical costs, direct overhead related to exploration and development activities, and other costs incurred for the purpose of finding oil and gas reserves. Salaries and benefits paid to employees directly involved in the exploration and development of properties, as well as other internal costs that can be directly identified with acquisition, exploration, and development activities, are also capitalized. Under the full cost method of accounting, no gain or loss is recognized upon the disposition of oil and gas properties unless such disposition would significantly alter the relationship between capitalized costs and proved reserves.

Companies that follow the full cost accounting method are required to make quarterly ceiling test calculations. This test ensures that total capitalized costs for oil and gas properties (net of accumulated DD&A and deferred income taxes) do not exceed the sum of the present value discounted at 10% of estimated future net cash flows from proved reserves, the cost of properties not being amortized, the lower of cost or estimated fair value of unproven properties included in the costs being amortized, and all related tax effects. We currently do not have any unproven properties that are being amortized. Revenue calculations in the reserves are based on the unweighted average first-day-of-the-month prices for the prior twelve months. Changes in proved reserve estimates (whether based upon quantity revisions or commodity prices) will cause corresponding changes to the full cost ceiling limitation. If net capitalized costs subject to amortization exceed this limit, the excess would be charged to expense. Any recorded impairment of oil and gas properties is not reversible at a later date.

Our quarterly and annual ceiling tests are primarily impacted by commodity prices, reserve quantities added and produced, overall exploration and development costs and depletion expense. Holding all factors constant other than commodity prices, a 10% decline in prices as of September 30, 2011 would not have resulted in a ceiling test impairment. Decreases in commodity prices can also impact our goodwill impairment analyses.

Depletion of proved oil and gas properties is computed on the units-of-production method, whereby capitalized costs, as adjusted for future development costs and asset retirement obligations, are amortized over the total estimated proved reserves. The capitalized costs of unproved properties, including wells in progress, are excluded from the costs being amortized. On a quarterly basis, we evaluate excluded costs for inclusion in the costs to be amortized resulting from the determination of proved reserves or impairments. To the extent that the evaluation indicates these properties are impaired,

Table of Contents

the amount of the impairment is added to the capitalized costs to be amortized. Expenditures for maintenance and repairs are charged to production expense in the period incurred.

Goodwill

At September 30, 2011, we had $691.4 million of goodwill recorded in conjunction with past business combinations. Goodwill is subject to annual reviews for impairment, but we continuously monitor the economic environment throughout the year to determine if additional impairment assessments are necessary. These assessments are based on a two-step accounting test. The first step is to compare the estimated fair value of the Company with the recorded net book value (including goodwill), after giving effect to any period impairment of oil and gas properties resulting from the ceiling limitation calculation. If the recorded net book value is greater than zero and the estimated fair value is higher than the recorded net book value, no impairment is deemed to exist and no further testing is done.

Disruptions continue in the credit markets and global economic activity which impact stock markets and commodity prices. Management must apply judgment in determining the estimated fair value of the Company for purposes of assessing goodwill impairment. As of September 30, 2011, the market price per share of our common stock was greater than the book value by $21 per share. Due to volatility in the stock markets, management does not consider the market value of our shares to be an accurate reflection of the fair value of our net assets for goodwill impairment purposes.

To estimate the fair value of the Company, we use all available information, including the present values of expected future cash flows using discount rates commensurate with the risks involved in the assets. This estimated fair value differs significantly from the valuation used in the ceiling limitation calculation which requires that prices and costs be held constant over the life of the wells and are discounted at 10%. The ceiling calculation is not intended to be indicative of fair value. Should lower prices or quantities result in the future, or higher discount rates are necessary, the carrying value of our net assets may exceed the estimated fair value, resulting in an impairment of goodwill.

Use of Estimates

We make certain estimates and assumptions to prepare our financial statements in conformity with accounting principles generally accepted in the United States of America. Those estimates and assumptions affect the reported amounts of assets, liabilities, revenues, and expenses during the reporting period and in disclosures of commitments and contingencies. We analyze our estimates, including those related to oil and gas revenues, reserves and properties, as well as goodwill and contingencies, and base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions.

The more significant areas requiring the use of management s estimates and judgments relate to the estimation of proved oil and gas reserves, the use of these oil and gas reserves in calculating depletion, depreciation, and amortization, the use of the estimates of future net revenues in computing ceiling test limitations and estimates of future abandonment obligations used in recording asset retirement obligations, and the assessment of goodwill. Estimates and judgments are also required in determining reserves for bad debt, impairments of undeveloped properties and other assets, purchase price allocation, valuation of deferred tax assets, fair value measurements and commitments and contingencies.

Table of Contents

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

September 30, 2011

(Unaudited)

Assets Held For Sale

At June 30, 2011 we reflected certain assets as held for sale. An asset is classified as held for sale when among other requirements, management commits to a plan to sell the asset, the asset is being actively marketed at a price that is reasonable in relation to its current fair value, and completion of the sale is probable and expected to occur within one year. We sold these assets in August 2011. See Note 12 for further information on the sale of these assets.

Accounting Changes

Certain amounts in prior years financial statements have been reclassified to conform to the 2011 financial statement presentation.

Recently Issued Accounting Standards

No significant accounting standards applicable to Cimarex have been issued during the quarter ended September 30, 2011.

2. Derivative Instruments/Hedging

We periodically enter into derivative instruments to mitigate a portion of our potential exposure to a decline in commodity prices and the corresponding negative impact on cash flow available for reinvestment. While the use of these instruments limits the downside risk of adverse price changes, their use may also limit future revenues from favorable price changes.

For 2011 and 2012, management has been authorized to hedge up to 50% of our anticipated equivalent oil and gas production. Depending on changes in oil and gas futures markets and management s view of underlying supply and demand trends, we may increase or decrease our current hedging positions.

At September 30, 2011, we had the following outstanding contracts relative to our future production. We have elected not to account for these derivatives as cash flow hedges.

Natural Gas Contracts

Period	Type	Volume/Day		Index(1)	Weighted Average Price Swap	Fair Value (000 s)
Oct 11 - Dec 11	Swap	20,000	MMBtu	PEPL	$ 5.05	$ 2,511

Oil Contracts

Period	Type	Volume/Day		Index(1)	Weighted Average Price Floor	Weighted Average Price Ceiling	Fair Value (000 s)
Oct - Dec 11	Collar	12,000	Bbls	WTI	$ 65.00	$ 105.44	$ 1,169

(1) PEPL refers to Panhandle Eastern Pipe Line Company price as quoted in Platt s Inside FERC on the first business day of each month. WTI refers to West Texas Intermediate price as quoted on the New York Mercantile Exchange.

Oil contracts that expire in October through December 2011 represent approximately 45% of our anticipated fourth quarter 2011 oil production. Our gas swap contracts presently in place represent approximately 6% of expected fourth quarter 2011 gas sales volumes.

Table of Contents

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

September 30, 2011

(Unaudited)

For a swap contract, the counterparty is required to make a payment to us if the settlement price for any settlement period is less than the swap price. We are required to make a payment to the counterparty if the settlement price for the settlement period is greater than the swap price. Under a collar agreement, we receive the difference between the published index price and a floor price if the index price is below the floor. We pay the difference between the ceiling price and the index price only if the index price is above the contracted ceiling price. No amounts are paid or received if the index price is between the floor and ceiling prices.

Our derivative contracts are carried at their fair value on our balance sheet. We estimate the fair value using internal risk adjusted discounted cash flow calculations. Cash flows are based on published forward commodity price curves for the underlying commodity as of the date of the estimate. For collars, we estimate the option value of the contract floors and ceilings using an option pricing model which takes into account market volatility, market prices and contract terms. The fair value of our derivative instruments in an asset position includes a measure of counterparty credit risk, and the fair value of instruments in a liability position includes a measure of our own nonperformance risk. These credit risks are based on current published credit default swap rates. Due to the volatility of commodity prices, the estimated fair value of our derivative instruments are subject to fluctuation from period to period, which could result in significant differences between the current estimated fair value and the ultimate settlement price. The following tables present the estimated fair value of our derivative assets and liabilities as of September 30, 2011 and December 31, 2010.

September 30, 2011:	**Balance Sheet Location**		**Asset**		**Liability**	
			(In thousands)			
Natural gas contracts	Current assets	Derivative instruments	$	2,511	$	
Oil contracts	Current assets	Derivative instruments		1,169		
			$	3,680	$	

December 31, 2010:	**Balance Sheet Location**		**Asset**		**Liability**	
			(In thousands)			
Natural gas contracts	Current assets	Derivative instruments	$	5,731	$	
Oil contracts	Current liabilities	Derivative instruments				9,587
			$	5,731	$	9,587

Because we have elected not to account for our current derivative contracts as cash flow hedges, we recognize all realized and unrealized changes in fair value in earnings. Cash settlements of our derivative contracts are included in cash flows from operating activities in our statements of cash flows.

The following table summarizes the realized and unrealized gains and losses from settlements and changes in fair value of our derivative contracts as presented in our accompanying financial statements.

Table of Contents

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

September 30, 2011

(Unaudited)

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(In thousands)			
Settlements gains (losses):				
Natural gas contracts	$ 1,865	$ 14,598	$ 5,591	$ 32,596
Oil contracts	(118)	(451)	(1,774)	(1,338)
Total settlements gains (losses)	1,747	14,147	3,817	31,258
Unrealized gains (losses) on fair value change:				
Natural gas contracts	(316)	5,115	(3,221)	29,785
Oil contracts	5,689	(4,234)	10,757	9,871
Total unrealized gains (losses) on fair value change	5,373	881	7,536	39,656
Gain (loss) on derivative instruments, net	$ 7,120	$ 15,028	$ 11,353	$ 70,914

We are exposed to financial risks associated with these contracts from nonperformance by our counterparties. Counterparty risk is also a component of our estimated fair value calculations. We have mitigated our exposure to any single counterparty by contracting with a number of financial institutions, each of which has a high credit rating and is a member of our bank credit facility. Our member banks have a secured interest in our oil and gas properties, and therefore do not require us to post collateral for our hedge liability positions.

3. Fair Value Measurements

The Financial Accounting Standards Board (FASB) has established a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. This hierarchy consists of three broad levels. Level 1 inputs are the highest priority and consist of unadjusted quoted prices in active markets for identical assets and liabilities. Level 2 inputs are inputs other than quoted prices that are observable for the asset or liability, either directly or indirectly. Level 3 inputs are unobservable inputs for an asset or liability.

The following tables provide fair value measurement information for certain assets and liabilities as of September 30, 2011 and December 31, 2010.

September 30, 2011:	**Carrying Amount**	**Fair Value**

	(In thousands)			
Financial Assets (Liabilities):				
7.125% Senior Notes due 2017	$	(350,000)	$	(357,000)
Derivative instruments assets	$	3,680	$	3,680

December 31, 2010:		**Carrying Amount**		**Fair Value**
		(In thousands)		
Financial Assets (Liabilities):				
7.125% Senior Notes due 2017	$	(350,000)	$	(358,750)
Derivative instruments assets	$	5,731	$	5,731
Derivative instruments liabilities	$	(9,587)	$	(9,587)

Assessing the significance of a particular input to the fair value measurement requires judgment, considering factors specific to the asset or liability. The following methods and assumptions were used to estimate the fair value of the assets and liabilities in the table above.

Table of Contents

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

September 30, 2011

(Unaudited)

Debt

The fair value for our 7.125% fixed rate notes was based on their last traded value before period end.

Derivative Instruments (Level 2)

The fair value of our derivative instruments was estimated using internal discounted cash flow calculations. Cash flows are based on the stated contract prices and current and published forward commodity price curves, adjusted for volatility. The cash flows are risk adjusted relative to nonperformance for both our counterparties and our liability positions. Please see Note 2 for further information on the fair value of our derivative instruments.

Other Financial Instruments

The carrying amounts of our cash, cash equivalents, restricted cash, accounts receivable, accounts payable, and accrued liabilities approximate fair value because of the short-term maturities and/or liquid nature of these assets and liabilities. At September 30, 2011 and December 31, 2010, the aggregate allowance for doubtful accounts for trade, oil and gas sales, and gas gathering, processing, and marketing receivables was $6.4 million and $6.8 million, respectively.

Most of our accounts receivable balances are uncollateralized and result from transactions with other companies in the oil and gas industry. Concentration of customers may impact our overall credit risk because our customers may be similarly affected by changes in economic or other conditions within the industry.

4. Capital Stock

A summary of our common stock activity for the nine months ended September 30, 2011 follows (in thousands):

Issued and outstanding as of December 31, 2010	85,235
Restricted shares issued under compensation plans, net of cancellations	442
Option exercises, net of cancellations	65
Issued and outstanding as of September 30, 2011	85,742

Dividends and Stock Repurchases

In September 2011, the Board of Directors declared a cash dividend of $0.10 per share on our common stock. The dividend is payable on December 1, 2011 to stockholders of record on November 15, 2011. Future dividend payments will depend on the Company s level of earnings, financial requirements, and other factors considered relevant by the Board of Directors.

In December 2005, the Board of Directors authorized the repurchase of up to four million shares of our common stock. The authorization is currently set to expire on December 31, 2011. Purchases may be made in both the open market and through negotiated transactions. Through December 31, 2007, we repurchased and cancelled a total of 1,364,300 shares at an overall average price of $39.05. No shares have been repurchased since the quarter ended September 30, 2007.

Table of Contents

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

September 30, 2011

(Unaudited)

Stockholder Rights Plan

We have a stockholder rights plan. The plan is designed to improve the ability of our board to protect the interests of our stockholders in the event of an unsolicited takeover attempt. For every outstanding share of Cimarex common stock, there exists one purchase right (the Right). Each Right represents a right to purchase one one-hundredth of a share of Series A Junior Participating Preferred Stock at a purchase price of $60.00 per share subject to adjustment in certain cases to prevent dilution. The Rights will become exercisable only in the event a person or group acquires beneficial ownership of 15% or more of our common stock, or a person or group commences a tender offer or exchange offer that, if successfully consummated, would result in such person or group beneficially owning 15% or more of our common stock. In general, in either of these events, each holder of a right, other than the person or group initiating the acquisition or tender offer, will have the rights to receive Cimarex common stock with a value equal to two times the exercise price of the rights.

We generally will be entitled to redeem the Rights under certain circumstances at $0.01 per Right at any time before the close of business on the tenth business day after there has been a public announcement of the acquisition of beneficial ownership by any person or group of 15% or more of our common stock. The Rights may not be exercised until our Board s right to redeem the stock has expired. Unless redeemed earlier, the Rights expire on February 23, 2012.

5. Stock-based Compensation

Our 2011 Equity Incentive Plan (the 2011 Plan) was approved by stockholders in May 2011. The 2011 Plan replaces the 2002 Stock Incentive Plan (the 2002 Plan). No new grants will be made under the 2002 Plan. The 2011 Plan provides for the grant of stock options, restricted stock, restricted stock units, performance stock and performance stock units to officers, other eligible employees and nonemployee directors. A total of 5.3 million shares of common stock may be issued under the 2011 Plan.

The 2011 Plan is modeled after the 2002 Plan, with two major changes: we have reduced the maximum term of any option granted under the 2011 Plan from ten years to seven years, and dividends will be accrued on all shares subject to performance awards and will only be paid at the time of vesting of the award, and then only with respect to shares that are issued upon attainment of the performance goals. Service based restricted awards will continue to receive dividends on unvested shares.

We have recognized non-cash stock-based compensation cost 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
Restricted stock and units	$ 7,013	$ 4,761	$ 20,242	$ 12,991
Stock options	551	989	2,731	2,780
	7,564	5,750	22,973	15,771
Less amounts capitalized to oil and gas properties	(2,969)	(2,509)	(9,011)	(6,759)
Compensation expense	$ 4,595	$ 3,241	$ 13,962	$ 9,012

Historical amounts may not be representative of future amounts as additional awards may be granted.

Table of Contents

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

September 30, 2011

(Unaudited)

Restricted Stock and Units

The following table provides information about restricted stock and unit awards granted during 2011:

	Three Months Ended September 30, 2011		Nine Months Ended September 30, 2011	
	Number of Shares	**Weighted Average Grant-Date Fair Value**	**Number of Shares**	**Weighted Average Grant-Date Fair Value**
Performance-based stock awards		$	363,758	$ 73.01
Service-based stock awards	204,100	$ 85.32	271,053	$ 91.11
Total restricted stock awards	204,100	$ 85.32	634,811	$ 80.74
Restricted unit awards				

The performance-based awards were issued to certain executive officers and are subject to market condition-based vesting determined by our stock price performance relative to a defined peer group s stock price performance. After three years of continued service, an executive will be entitled to vest in 50% to 100% of the award. In accordance with Internal Revenue Code Section 162(m), certain of the amounts awarded may not be deductible for tax purposes. The material terms of performance goals applicable to these awards were approved by stockholders in May 2010. The other restricted shares granted in 2011 have service-based vesting schedules of three to five years.

A restricted unit represents a right to an unrestricted share of common stock upon satisfaction of defined vesting and holding conditions. Restricted units have a five-year vesting schedule and an additional three-year holding period following vesting, prior to payment in common stock.

Compensation cost for the performance-based stock awards is based on the grant date fair value of the award utilizing a Monte Carlo simulation model. Compensation cost for the service-based vesting restricted shares and units is based upon the grant-date market value of the award. Such costs are recognized ratably over the applicable vesting period.

The following table reflects the non-cash compensation cost related to our restricted stock and units (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
Performance-based stock awards	$ 4,116	$ 2,430	$ 12,185	$ 7,174
Service-based stock awards	2,897	2,294	8,023	5,807
Restricted unit awards		37	34	10
	7,013	4,761	20,242	12,991
Less amounts capitalized to oil and gas properties	(2,696)	(1,907)	(7,405)	(4,992)
Restricted stock and units compensation expense	$ 4,317	$ 2,854	$ 12,837	$ 7,999

Unamortized compensation cost related to unvested restricted shares and units at September 30, 2011 was $68 million, which we expect to recognize over a weighted average period of 2.2 years.

The following table provides information on restricted stock and unit activity as of September 30, 2011 and changes during the year:

Table of Contents

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

September 30, 2011

(Unaudited)

	Restricted Stock	Restricted Units
Outstanding as of January 1, 2011	1,899,511	94,807
Vested	(494,720)	
Converted to stock		(30,337)
Granted	634,811	
Canceled	(33,900)	
Outstanding as of September 30, 2011	2,005,702	64,470
Vested included in outstanding	N/A	64,470

Stock Options

The following tables provide information about stock options granted in 2011 and 2010:

	Three Months Ended September 30, 2011			Three Months Ended September 30, 2010		
	Options	Weighted Average Grant-Date Fair Value	Weighted Average Exercise Price	Options	Weighted Average Grant-Date Fair Value	Weighted Average Exercise Price
Granted to certain executive officers	90,000	$ 19.17	$ 55.96		$	$
Granted to other employees	91,300	$ 34.20	$ 86.01	71,500	$ 28.83	$ 69.95
	181,300			71,500		

	Nine Months Ended September 30, 2011			Nine Months Ended September 30, 2010		
	Options	Weighted Average Grant-Date Fair Value	Weighted Average Exercise Price	Options	Weighted Average Grant-Date Fair Value	Weighted Average Exercise Price
Granted to certain executive officers	90,000	$ 19.17	$ 55.96		$	$
Granted to other employees	91,300	$ 34.20	$ 86.01	93,000	$ 28.63	$ 70.30
	181,300			93,000		

Options granted under our 2011 and 2002 plans expire seven to ten years from the grant date and have service-based vesting schedules of three to five years. The plans provide that all grants have an exercise price of the average of the high and low prices of our common stock as reported by the New York Stock Exchange on the date of grant.

Compensation cost related to stock options is based on the grant date fair value of the award, recognized ratably over the applicable vesting period. We estimate the fair value using the Black-Scholes option-pricing model. Expected volatilities are based on the historical volatility of our common stock. We also use historical data to estimate the probability of option exercise, expected years until exercise and potential forfeitures. We use U.S. Treasury bond rates in effect at the grant date for our risk-free interest rates. Non-cash compensation cost related to our stock options is reflected in the following table (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	**2010**	**2011**	**2010**
Stock option awards	551	989	2,731	2,780
Less amounts capitalized to oil and gas properties	(273)	(602)	(1,606)	(1,767)
Stock option compensation expense	$ 278	$ 387	$ 1,125	$ 1,013

Table of Contents

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

September 30, 2011

(Unaudited)

As of September 30, 2011, there was $6.2 million of unrecognized compensation cost related to non-vested stock options. We expect to recognize that cost pro rata over a weighted-average period of 2.1 years.

Information about outstanding stock options is summarized below:

	Options		Weighted Average Exercise Price	Weighted Average Remaining Term		Aggregate Intrinsic Value (000 s)
Outstanding as of January 1, 2011	1,026,527	$	32.60			
Exercised	(65,325)	$	39.84			
Granted	181,300	$	71.09			
Canceled		$				
Forfeited	(15,832)	$	58.04			
Outstanding as of September 30, 2011	1,126,670	$	38.01	4.5 Years	$	24,231
Exercisable as of September 30, 2011	800,079	$	29.28	3.4 Years	$	21,854

There were 65,325 and 400,496 stock options exercised during the nine months ended September 30, 2011 and September 30, 2010, respectively. The following table provides information regarding the options exercised (in thousands):

	Nine Months Ended September 30,			
		2011		2010
Cash received from option exercises	$	2,602	$	10,135
Tax benefit from option exercises included in paid-in-capital	$	1,298	$	6,270
Intrinsic value of options exercised	$	3,558	$	17,205

The following summary reflects the status of non-vested stock options as of September 30, 2011 and changes during the year:

	Options		Weighted Average Grant-Date Fair Value		Weighted Average Exercise Price
Non-vested as of January 1, 2011	375,322	$	18.25	$	47.80

Vested	(214,199)	$	17.94	$	49.06
Granted	181,300	$	26.74	$	71.09
Forfeited	(15,832)	$	22.82	$	58.04
Non-vested as of September 30, 2011	326,591	$	22.95	$	59.41

6. Asset Retirement Obligations

We recognize the fair value of a liability for an asset retirement obligation in the period in which it is incurred, if a reasonable estimate of fair value can be made, and the associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. Oil and gas producing companies incur this liability which includes costs related to the plugging of wells, the removal of facilities and equipment, and site restorations, upon acquiring or drilling a successful well. Subsequent to initial measurement, the asset retirement liability is required to be accreted each period. If the fair value of a recorded asset retirement obligation changes, a revision is recorded to both the asset retirement obligation

Table of Contents

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

September 30, 2011

(Unaudited)

and the asset retirement capitalized cost. Capitalized costs are depleted as a component of the full cost pool.

The following table reflects the components of the change in the carrying amount of the asset retirement obligation for the nine months ended September 30, 2011 (in thousands):

Asset retirement obligation at January 1, 2011	$	138,769
Liabilities incurred		4,379
Liability settlements and disposals		(21,930)
Accretion expense		5,429
Revisions of estimated liabilities		9,473
Asset retirement obligation at September 30, 2011		136,120
Less current obligation		(29,249)
Long-term asset retirement obligation	$	106,871

7. Long-Term Debt

Debt at September 30, 2011 and December 31, 2010 consisted of the following (in thousands):

		September 30, 2011		December 31, 2010
Bank debt	$		$	
7.125% Senior Notes due 2017		350,000		350,000
Total long-term debt	$	350,000	$	350,000

Revolving Credit Facility

In July 2011, we entered into a new five-year senior unsecured revolving credit facility (Credit Facility). The Credit Facility provides for a borrowing base of $2 billion with aggregate commitments of $800 million from 14 lenders. The facility matures July 14, 2016.

The borrowing base under the Credit Facility is determined at the discretion of lenders based on the value of our proved reserves. The next regular-annual redetermination date is on April 1, 2012.

At Cimarex s option, borrowings under the Credit Facility may bear interest at either (a) LIBOR plus 1.75-2.5%, based on our leverage ratio, or (b) the higher of (i) a prime rate, (ii) the federal funds effective rate plus 0.50%, or (iii) adjusted one-month LIBOR plus 1.0% plus, in each case, an additional 0.75-1.5%, based on our leverage ratio.

The Credit Facility also has financial covenants that include the maintenance of current assets (including unused bank commitments) to current liabilities of greater than 1.0 to 1.0. We also must maintain a leverage ratio of total debt to earnings before interest expense, income taxes and noncash items (such as depreciation, depletion and amortization expense, unrealized gains and losses on commodity derivatives, ceiling test write-downs, and goodwill impairments) of not more than 3.5 to 1.0. Other covenants could limit our ability to: incur additional indebtedness, pay dividends, repurchase our common stock, or sell assets. As of September 30, 2011, we were in compliance with all of the financial and nonfinancial covenants.

As of September 30, 2011, we had letters of credit outstanding of $2.5 million leaving an unused borrowing availability of $797.5 million.

Table of Contents

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

September 30, 2011

(Unaudited)

7.125% Senior Notes due 2017

In May 2007 we issued $350 million of 7.125% senior unsecured notes that mature May 1, 2017 at par. Interest on the notes is payable May 1 and November 1 of each year. The notes are governed by an indenture containing covenants that could limit our ability to incur additional indebtedness; pay dividends or repurchase our common stock; make investments and other restricted payments; incur liens; enter into sale/leaseback transactions; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets.

The notes are redeemable at our option, in whole or in part, at any time on and after May 1, 2012 at the following redemption prices (expressed as percentages of the principal amount) plus accrued interest, if any, thereon to the date of redemption.

Year	**Percentage**
2012	103.6%
2013	102.4%
2014	101.2%
2015 and thereafter	100.0%

If a specified change of control occurs, subject to certain conditions, we must make an offer to purchase the notes at a purchase price of 101% of the principal amount of the notes, plus accrued and unpaid interest to the date of the purchase.

8. Income Taxes

The components of our provision for income taxes are as follows (in thousands):

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
	2011	**2010**	**2011**	**2010**
Current provision (benefits)	$ (44,081)	$ (12,770)	$ (45,403)	$ 51,620
Deferred taxes	120,930	88,375	288,986	213,678

	$	76,849	$	75,605	$	243,583	$	265,298

We account for uncertainty in our income tax provisions in accordance with rules promulgated by the FASB. At September 30, 2011 we have no unrecognized tax benefits that would impact our effective rate and we have made no provisions for interest or penalties related to uncertain tax positions. The tax years 2005 2010 remain open to examination by the Internal Revenue Service of the United States. We file tax returns with various state taxing authorities which remain open for tax years 2005 2010 for examination.

Our provision for income taxes differed from the U.S. statutory rate of 35% primarily due to state income taxes, nondeductible expenses, and special deductions. The effective income tax rates for the nine months ended September 30, 2011 and September 30, 2010 were 37.1% and 36.7%, respectively.

Table of Contents

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

September 30, 2011

(Unaudited)

9. Supplemental Disclosure of Cash Flow Information (in thousands):

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2011		2010		2011		2010	
Cash paid during the period for:								
Interest expense (including capitalized amounts)	$	1,345	$	1,096	$	16,153	$	16,169
Interest capitalized	$	994	$	915	$	12,777	$	12,859
Income taxes	$		$	23,730	$	1,671	$	108,587
Cash received for income taxes	$	89	$	999	$	25,094	$	3,674

10. Earnings per Share and Comprehensive Income

Earnings per Share

We calculate earnings per share based on FASB guidance which holds that unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents are participating securities and therefore should be included in computing earnings per share using the two-class earnings allocation method. The two-class method is an earnings allocation formula that determines earnings per share for each class of common stock and participating security according to dividends declared (or accumulated) and participation rights in undistributed earnings. Under this guidance, our unvested share- based payment awards, consisting of restricted stock and restricted stock units, qualify as participating securities.

Table of Contents

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

September 30, 2011

(Unaudited)

The calculations of basic and diluted net earnings per common share under the two-class method are presented below (in thousands, except per share data):

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Net income	$ 128,152	$ 128,216	$ 413,063	$ 457,197
Less distributed earnings (dividends declared during the period)	(8,581)	(6,828)	(25,709)	(20,361)
Undistributed earnings for the period	$ 119,571	$ 121,388	$ 387,354	$ 436,836
Allocation of undistributed earnings:				
Basic allocation to unrestricted common stockholders	$ 116,686	$ 117,772	$ 378,009	$ 423,822
Basic allocation to participating securities	$ 2,885	$ 3,616	$ 9,345	$ 13,014
Diluted allocation to unrestricted common stockholders	$ 116,699	$ 117,789	$ 378,054	$ 423,892
Diluted allocation to participating securities	$ 2,872	$ 3,599	$ 9,300	$ 12,944
Basic Shares Outstanding				
Unrestricted outstanding common shares	83,736	82,806	83,736	82,806
Add participating securities:				
Restricted stock outstanding	2,006	1,895	2,006	1,895
Restricted stock units outstanding	64	647	64	647
Total participating securities	2,070	2,542	2,070	2,542
Total Basic Shares Outstanding	85,806	85,348	85,806	85,348
Fully Diluted Shares				
Unrestricted outstanding common shares	83,736	82,806	83,736	82,806
Incremental shares from assumed exercise of stock options	379	411	415	459
Fully diluted common stock	84,115	83,217	84,151	83,265
Participating securities	2,070	2,542	2,070	2,542
Total Fully Diluted Shares	86,185	85,759	86,221	85,807
Basic earnings per share				
Unrestricted common stockholders:				
Distributed earnings	$ 0.10	$ 0.08	$ 0.30	$ 0.24
Undistributed earnings	1.39	1.42	4.51	5.12
	$ 1.49	$ 1.50	$ 4.81	$ 5.36
Participating securities:				
Distributed earnings	$ 0.10	$ 0.08	$ 0.30	$ 0.24
Undistributed earnings	1.39	1.42	4.51	5.12
	$ 1.49	$ 1.50	$ 4.81	$ 5.36
Fully diluted earnings per share				
Unrestricted common stockholders:				

Distributed earnings	$ 0.10	$ 0.08	$ 0.30	$ 0.24
Undistributed earnings	1.39	1.42	4.49	5.09
	$ 1.49	$ 1.50	$ 4.79	$ 5.33
Participating securities:				
Distributed earnings	$ 0.10	$ 0.08	$ 0.30	$ 0.24
Undistributed earnings	1.39	1.42	4.49	5.09
	$ 1.49	$ 1.50	$ 4.79	$ 5.33

Table of Contents

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

September 30, 2011

(Unaudited)

The following table presents the amounts of outstanding stock options, restricted stock and units as follows:

	September 30, 2011	September 30, 2010
Stock options	1,126,670	1,232,097
Restricted stock	2,005,702	1,895,111
Restricted units	64,470	647,507

Certain stock options considered to be anti-dilutive for the three months ended September 30, 2011 and 2010 were 264,767 and 106,450, respectively. For the nine months ended September 30, 2011 and 2010, certain stock options considered to be anti-dilutive were 203,676 and 143,928, respectively.

Comprehensive Income

Comprehensive income is a term used to refer to net income plus other comprehensive income. Other comprehensive income (loss) is comprised of revenues, expenses, gains and losses that under generally accepted accounting principles are reported as separate components of stockholders   equity instead of net income.

The components of comprehensive income are 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
Net income	$ 128,152	$ 128,216	$ 413,063	$ 457,197
Other comprehensive income (loss):				
Change in fair value of investments, net of tax	(585)	265	(417)	116
Total comprehensive income	$ 127,567	$ 128,481	$ 412,646	$ 457,313

11. Commitments and Contingencies

Litigation

In January 2009, the Tulsa County District Court issued a judgment totaling $119.6 million in the H.B. Krug, et al versus Helmerich & Payne, Inc. (H&P) case. This lawsuit was originally filed in 1998 and addressed H&P s conduct pertaining to a 1989 take-or-pay settlement, along with potential drainage issues and other related matters. Pursuant to the 2002 spin-off transaction to shareholders of H&P by which Cimarex became a publicly-traded entity, Cimarex assumed the assets and liabilities of H&P s exploration and production business. In 2008 we recorded litigation expense of $119.6 million for this lawsuit. During 2009 and 2010, we accrued an additional $9.4 million and $8.9 million, respectively, for post-judgment interest and fees. We have accrued an additional $6.5 million for post-judgment interest and fees during the first nine months of 2011.

On August 18, 2011, the Oklahoma Court of Appeals issued an Opinion regarding the *Krug* litigation. The Oklahoma Court of Appeals reversed and remanded the $112.7 million disgorgement of profits award, finding the trial court erred in failing to make the required findings of fact and conclusions of law. In all other respects, the Court of Appeals affirmed the judgment, including damages of $6.845 million. On October 27, 2011, Cimarex filed a petition with the Oklahoma Supreme Court requesting review of the affirmed portion of the judgment. This case is still subject to further appeal and the final outcome cannot be determined at this time.

Table of Contents

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

September 30, 2011

(Unaudited)

In the normal course of business, we have other various litigation related matters. We assess the probability of estimable amounts related to litigation matters in accordance with guidance established by the FASB and adjust our accruals accordingly. Though some of the related claims may be significant, the resolution of them we believe, individually or in the aggregate, would not have a material adverse effect on our financial condition or results of operations.

Other

We have drilling commitments of approximately $288.7 million consisting of obligations to finish drilling and completing wells in progress at September 30, 2011. We also have various commitments for drilling rigs as well as certain service contracts. The total minimum expenditure commitments under these agreements are $22.6 million to secure the use of drilling rigs and $33.6 million to secure certain dedicated services associated with completion activities.

We have projects in Oklahoma, New Mexico, and Texas where we are constructing gathering facilities and pipelines. At September 30, 2011, we had commitments of $8.3 million relating to this construction.

We have noncancelable operating leases for office and parking space in Denver, Tulsa, Dallas, Midland, and for small district and field offices. During the first quarter of 2011, we entered into a 12-year lease agreement for new office space in Tulsa, Oklahoma. The expected commencement date of this lease is December 1, 2012. Our aggregate minimum lease commitments have increased to $77 million versus $15.5 million at December 31, 2010.

At September 30, 2011, we have a purchase commitment of $10.3 million for construction of an aircraft. The total cost of the aircraft is $11.5 million with an option to trade in our existing aircraft. The aircraft is expected to be delivered to us by the end of this year.

At September 30, 2011, we had firm sales contracts to deliver approximately 17.5 Bcf of natural gas over the next 11 months. If this gas is not delivered, our financial commitment would be approximately $66.5 million. This commitment will fluctuate due to price volatility and actual volumes delivered. However, we believe no financial commitment will be due based on our current proved reserves and production levels.

In connection with gas gathering and processing agreements, we have commitments to deliver a minimum of 24.5 Bcf of gas over the next 2 to 3 years. The production from certain wells is counted toward those commitments; these wells also have individual commitments for gas deliveries. If no gas is delivered, the maximum amount that would be payable under these commitments would be approximately $17.5 million, some of which would be reimbursed by working interest owners who are selling with us under our marketing agreements. We do not expect to make significant payments relative to these commitments.

We have various other transportation and delivery commitments in the normal course of business, which approximate $3.3 million.

All of the noted commitments were routine and were made in the normal course of our business.

Table of Contents

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

September 30, 2011

(Unaudited)

12. Property Sales and Acquisitions

In order to acquire and sell oil and gas properties in a tax efficient manner, we periodically enter into like-kind exchange tax-deferred transactions. In these transactions, we utilize an exchange accommodation titleholder, a type of variable interest entity, for which we are the primary beneficiary. Accordingly, as of the acquisition date, we consolidate the oil and gas assets and reserves, as well as production, revenues and expenses attributable to properties in these like-kind exchange transactions.

Certain property acquisitions in the fourth quarter of 2010 were structured to qualify as the first step of a reverse like-kind exchange. During the first quarter of 2011, we sold various interests in oil and gas properties for approximately $11.8 million, a portion of which was included in the second step of the reverse like-kind exchange. We sold various interests in oil and gas properties for $8.5 million during the second quarter of 2011, some of which are included as part of our like-kind exchanges.

In August 2011, we sold all of our interests in assets located in Sublette County, Wyoming for $195 million (including purchase price adjustments). The assets sold principally consisted of a gas processing plant under construction and related assets ($111 million) and 210 Bcf of proved undeveloped gas reserves ($84 million). No gain or loss was recognized on the sale of proved reserves as the disposition did not significantly alter the relationship between capitalized costs and proved reserves.

At June 30, 2011 the gas processing plant and related assets and liabilities were classified as assets held for sale. We determined that the carrying amounts of the assets and liabilities were equal to their fair value, therefore no gain or loss was recognized on the sale. Because the gas plant was still under construction we had not recognized any income or expense related to plant operations in our statements of operations. The sales contract also provides for a maximum $15 million contingent payment to be made to Cimarex if certain operational and performance goals related to the start-up of the gas processing plant are met.

We had no other significant property sales during the third quarter of 2011. During the first nine months of 2010, we had $28 million of property sales of various interests in oil and gas properties.

During the first nine months of 2011, we acquired oil and gas assets for approximately $42 million of which $39 million was in our western Oklahoma Cana-Woodford shale play and $3 million was in the Permian Basin. During the first nine months of 2010, property acquisitions totaled $35.3 million.

We intend to continue to actively evaluate acquisitions and dispositions relative to our property holdings, particularly in our Cana-Woodford shale play and in the Permian Basin.

Table of Contents

ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

BUSINESS OVERVIEW

We are an independent oil and gas exploration and production company with operations entirely located in the United States. We have determined that our business is comprised of only one segment because our gathering, processing and marketing activities are ancillary to our production operations and are not separately managed.

Our operating strategy is to achieve profitable growth in proved reserves and production primarily through exploration and development. To supplement our growth and to provide for new drilling opportunities, we also consider mergers and property acquisitions. Our growth is generally funded with cash flow provided by our operating activities. In order to achieve a consistent rate of growth and mitigate risk we have historically maintained a blended portfolio of low, moderate, and higher risk exploration and development projects. To further mitigate risk, we have chosen to seek geologic and geographic diversification by operating in multiple basins. Our operations are mainly conducted in Texas, Oklahoma and New Mexico.

Our revenue, profitability and future growth are highly dependent on the oil and gas prices we receive. Large declines in commodity prices may have adverse effects on our business and financial position. Our ability to access the capital markets may also be restricted, which could have an impact on our flexibility to react to changing economic and business conditions. Further, the overall economic environment could have an impact on our lenders, business partners and customers, potentially causing them to fail to meet their obligations to us.

Our ability to find, develop and/or acquire proved oil and gas reserves will also impact our financial results. A cornerstone to our approach is a detailed evaluation of each drilling decision based on its risk-adjusted discounted cash flow rate of return on investment. Our analysis includes estimates and assessments of potential reserve size, geologic and mechanical risks, expected costs, future production profiles and future oil and gas prices. As a result we may choose to increase or decrease our capital expenditures.

Based on current market prices and service costs, we expect that 2011 Exploration and Development (E&D) expenditures to approximate $1.6 billion, up from $999 million in 2010. We anticipate approximately 46% of our E&D costs to be directed toward the Permian Basin, 47% to the Mid-Continent and 7% to the Gulf Coast and other.

During the third quarter of 2011 we invested $422.6 million on E&D expenditures, up from $295.9 during the third quarter of 2010. At September 30, 2011 we had 30 operated rigs running. At September 30, 2010 we had 25 operated rigs running.

Third quarter 2011 summary of financial and operating results:

- Third quarter sales of oil, gas and NGLs increased 15% to $419.7 million from $366.6 million in the previous year.

- Cash flow from operating activities was $332.4 million, up from $314.4 million a year earlier.

- Net income of $128.2 million ($1.49 per diluted share) stayed constant compared to net income of $128.2 million ($1.50 per diluted share) in 2010.

- Total debt of $350 million at September 30, 2011 did not change from year-end 2010.

Table of Contents

- Third quarter production volumes averaged 592 MMcfe/d, down from 600 MMcfe/d for third quarter 2010.
- The average realized oil price increased 20% to $87.64 per barrel compared to $73.20 per barrel in 2010.
- The average realized gas price increased 2% to $4.57 per Mcf versus $4.48 per Mcf in 2010.
- The average realized NGL price increased 36% to $43.11 per barrel compared to $31.73 per barrel in 2010.

Commodity Prices

While our revenues are a function of both production and prices, wide swings in commodity prices have had the greatest impact on our results of operations. Oil prices have improved during 2011, however, there is still significant volatility for oil prices as a result of concerns about sustained economic growth and geopolitical instability. Prices for natural gas have remained low primarily as a result of an oversupply.

The following table presents our average realized commodity prices for the third quarter and first nine months of 2011 versus the same periods of 2010. The realized prices do not include settlements of our commodity hedging contracts.

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Gas Prices:				
Average Henry Hub price ($/Mcf)	$ 4.20	$ 4.38	$ 4.21	$ 4.59
Average realized sales price ($/Mcf)	$ 4.57	$ 4.48	$ 4.59	$ 5.15
Oil Prices:				
Average WTI Cushing price ($/Bbl)	$ 89.76	$ 76.20	$ 95.49	$ 77.65
Average realized sales price ($/Bbl)	$ 87.64	$ 73.20	$ 93.08	$ 74.87
NGL Prices:				
Average realized sales price ($/Bbl)	$ 43.11	$ 31.73	$ 42.99	$ 33.41

On an energy equivalent basis, 56% of our aggregate 2011 production was natural gas. A $0.10 per Mcf change in our average realized gas sales price would have resulted in approximately an $8.9 million change in our gas revenues. Similarly, 44% of our production was crude oil and NGLs. A $1.00 per barrel change in our average realized sales price would have resulted in approximately an $11.9 million change in our combined oil and NGL revenues.

Hedging

In addition to supply and demand, oil and gas prices are affected by seasonal, economic and geo-political factors that we can neither control nor predict. From time to time we attempt to mitigate a portion of our price risk through the use of hedging transactions. Management has been authorized to hedge up to 50% of our anticipated 2011 and 2012 equivalent production.

During 2010 we entered into oil and gas contracts relative to our 2011 production. We had the following outstanding contracts as of September 30, 2011:

Table of Contents

Natural Gas Contracts

Period	Type	Volume/Day		Index(1)	Weighted Average Price Swap	
Oct 11 - Dec 11	Swap	20,000	MMBtu	PEPL	$	5.05

Oil Contracts

Period	Type	Volume/Day		Index(1)	Weighted Average Price Floor		Weighted Average Price Ceiling	
Oct 11 - Dec 11	Collar	12,000	Bbls	WTI	$	65.00	$	105.44

(1) PEPL refers to Panhandle Eastern Pipe Line Company price as quoted in Platt s Inside FERC on the first business day of each month. WTI refers to West Texas Intermediate price as quoted on the New York Mercantile Exchange.

Our gas swap contracts represent 6% of expected fourth quarter 2011 gas sales volumes. The oil contracts represent approximately 45% of our anticipated fourth quarter 2011 oil production.

Depending on changes in oil and gas futures markets and management s view of underlying supply and demand trends, we may increase or decrease our current hedging positions. While the use of such instruments limits the downside risk of adverse price changes, their use may also limit future revenues from favorable price changes.

We have chosen not to apply hedge accounting treatment to the derivative contracts we entered into for 2011. Therefore, settlements on these contracts do not impact our realized commodity prices during the periods they cover. Instead, any settlements on the contracts are shown as a component of operating costs and expenses as either a net gain or loss on derivative instruments. See Note 2 to the Consolidated Financial Statements and Item 3 of this report for additional information regarding our derivative instruments.

Production and Other Operating Expenses

Costs associated with finding and producing oil and gas are substantial. Some of these costs vary with commodity prices, some trend with the type and volume of production and others are a function of the number of wells we own. At the end of 2010, we owned interests in 12,425 gross wells.

Production expense generally consists of the cost of power and fuel, direct labor, third-party field services, compression, water disposal, and certain maintenance activity (workovers) necessary to produce oil and gas from existing wells.

Transportation expense is comprised of costs paid to move oil and gas from the wellhead to a specified sales point. In some cases we receive a payment from purchasers which is net of transportation costs, and in other instances we separately pay for transportation. If costs are netted in the proceeds received, both the gross revenues and gross costs are shown in sales and expenses, respectively.

Depreciation, depletion and amortization (DD&A) of our producing properties is computed using the units-of-production method. Because the economic life of each producing well depends upon the assumed price for future sales of production, fluctuations in commodity prices may impact the level of proved reserves used in the calculation. Higher prices generally have the effect of increasing reserves, which reduces depletion expense. Lower prices generally have the effect of decreasing reserves, which increases depletion expense. In addition, changes in estimates of reserve quantities and estimates of future development costs, reclassifications from unproved properties to proved properties and E&D expenditures will impact depletion expense.

Table of Contents

General and administrative expenses consist primarily of salaries and related benefits, office rent, legal fees, consultants, systems costs and other administrative costs incurred in our offices and not directly associated with exploration, development or production activities. While we expect these costs to increase with our growth, we also expect such increases to be proportionately smaller than our production growth.

Production taxes are assessed by state and local taxing authorities pertaining to production, revenues or the value of properties. These typically include production severance, ad valorem and excise taxes.

Significant Expenses that Generally Do Not Trend with Production

Stock compensation expense consists of noncash charges resulting from the issuance of restricted stock, restricted stock units and stock options. In accordance with our stock incentive plan, such grants are periodically made to nonemployee directors, officers and other eligible employees.

The net gain or loss on derivative instruments is the net realized and unrealized gain or loss on derivative contracts, to which we did not apply hedge accounting treatment. That amount will fluctuate based on changes in the fair value of the underlying commodities.

RESULTS OF OPERATIONS

Three Months and Nine Months Ended September 30, 2011 vs. September 30, 2010

Net income for the third quarter of 2011 was $128.2 million, or $1.49 per diluted share. This compares to $128.2 million, or $1.50 per diluted share, for the same period in 2010. In the third quarter of 2011 our revenues were higher than revenues in the third quarter of 2010 due to the improvement of realized commodity prices. However, our 2011 third quarter operating expenses were also higher than the same period of 2010, resulting in comparable net incomes for the two periods.

For the nine months ended September 30, 2011 net income was $413.1 million, or $4.79 per diluted share. In 2010 we had net income of $457.2 million, or $5.33 per diluted share, for the first nine months of the year. In 2011 higher revenues from higher realized commodity prices were offset by higher DD&A and production expenses compared to the same period of 2010. In addition, in the first nine months of 2011 we recorded a lower net gain on derivative contracts than in the same period of 2010. These changes are discussed further in the analysis that follows.

Commodity Sales (In thousands or as indicated)	**2011**	**2010**	**Percent Change Between 2011/2010**	**Price/Volume Analysis Price**	**Volume**	**Variance**

For the Three Months Ended September 30,					
Gas sales	$ 138,631	$ 145,396	-5%	$ 2,730	$ (9,495)	$ (6,765)
Oil sales	211,928	177,834	19%	34,916	(822)	34,094
NGL Sales	69,169	43,331	60%	18,254	7,584	25,838
	$ 419,728	$ 366,561		$ 55,900	$ (2,733)	$ 53,167
For the Nine Months Ended September 30,						
Gas sales	$ 410,331	$ 522,408	-21%	$ (50,046)	$ (62,031)	$ (112,077)
Oil sales	675,239	550,058	23%	132,095	(6,914)	125,181
NGL Sales	200,428	91,391	119%	44,662	64,375	109,037
	$ 1,285,998	$ 1,163,857		$ 126,711	$ (4,570)	$ 122,141

Table of Contents

	For the Three Months Ended September 30, 2011		For the Three Months Ended September 30, 2010		Percent Change Between 2011/2010	For the Nine Months Ended September 30, 2011		For the Nine Months Ended September 30, 2010		Percent Change Between 2011/2010
Total gas volume MMcf		30,329		32,427	-6%		89,367		101,395	-12%
Gas volume - MMcf per day		329.7		352.5			327.4		371.4	
Average gas price - per Mcf	$	4.57	$	4.48	2%	$	4.59	$	5.15	-11%
Total oil volume - thousand barrels		2,418		2,429	0%		7,254		7,347	-1%
Oil volume - barrels per day		26,284		26,407			26,572		26,912	
Average oil price - per barrel	$	87.64	$	73.20	20%	$	93.08	$	74.87	24%
Total NGL volume thousand barrels		1,604		1,366	17%		4,662		2,736	70%
NGL volume barrels per day		17,438		14,843			17,078		10,021	
Average NGL price per barrel	$	43.11	$	31.73	36%	$	42.99	$	33.41	29%

Commodity sales for the third quarter of 2011 totaled $419.7 million, compared to $366.6 million in 2010. The increase of $53.2 million between the two periods resulted from higher commodity prices, which had a positive impact of $55.9 million. Lower production volumes for oil and gas during the current quarter were only partially offset by higher NGL production volumes, resulting in a decrease of $2.7 million, compared to the third quarter of 2010.

For the first nine months of 2011 commodity sales totaled $1.286 billion. For the same period in 2010, commodity sales were $1.164 billion. The $122 million increase was attributable to higher commodity prices in 2011, partially offset by lower gas and oil production volumes compared to 2010.

Our third quarter 2011 aggregate production volumes were 592 MMcfe per day, down 1% from 600 MMcfe per day for the same period in 2010. Aggregate production volumes for the first nine months of 2011 were 589.3 MMcfe per day, down 1% from 593.0 MMcfe per day for the 2010 period. Although new production is coming online from our Permian Basin and Mid-Continent drilling programs, it is being offset by a lack of exploration success in this year s Gulf Coast drilling program and natural declines in the highly-productive Gulf Coast wells drilled over the last two years. In addition, production in the first nine months of 2011 was adversely affected by severe weather, particularly in our Permian Basin region, which resulted in production curtailments.

In the third quarter of 2011 our gas production averaged 329.7 MMcf per day, compared to 352.5 MMcf per day in 2010. This 6% decrease resulted in $9.5 million of lower revenues for the 2011 quarter. During the first nine months of 2011 our daily gas production averaged 327.4 MMcf per day, or a 12% decrease from the 2010 average of 371.4 MMcf per day. The decrease in production compared to the 2010 period resulted in $62.0 million of lower revenue in the first nine months of 2011.

Our oil production during the third quarter of 2011 averaged 26.3 thousand barrels per day. For the same period of 2010 our average daily oil production was 26.4 thousand barrels per day. The slight decrease in oil production for the quarter resulted in a decrease of $0.8 million of oil sales revenue. During the first nine months of 2011 we averaged 26.6 thousand barrels per day, down from 26.9 thousand barrels per day in 2010, or a 1% decrease. The decrease in oil production resulted in lower revenues of $6.9 million in 2011.

Our third quarter 2011 NGL volumes increased to 17.4 thousand barrels per day compared to 14.8 thousand barrels per day in 2010. This 17% increase contributed $7.6 million of revenue. NGL production for the first nine months of 2011 averaged 17.1 thousand barrels a day, compared to 10 thousand barrels a day in 2010. The 70% increase provided an additional $64.4 million of revenue in 2011.

During the first quarter of 2010 we began separately reporting NGL sales and production volumes. The determination to record and separately disclose NGL volumes is based on the location at

Table of Contents

which both title contractually transfers from Cimarex to a buyer and the associated volumes can be physically quantified. For those NGL volumes that we have recorded and disclosed separately, contractual title of the volumes has passed from Cimarex to a buyer at a point where the NGL volumes have been physically separated from the production stream. Should title contractually transfer before NGL volumes can be physically separated and quantified (typically at the wellhead), we do not report separate NGL volumes, and the value of the NGLs are included in the reported value of the disclosed gas volumes.

In the third quarter of 2011 we realized an average gas price of $4.57 per Mcf, or an increase of 2% compared to the average price received of $4.48 per Mcf for the third quarter of 2010. Our average realized gas price for the first nine months of 2011 of $4.59 per Mcf was 11% lower than the 2010 average realized price of $5.15. These price changes resulted in increased gas sales revenues of $2.7 million for the third quarter of 2011 and decreased sales revenues of $50.0 million for the first nine months of 2011.

We realized an average oil price of $87.64 per barrel for the third quarter of 2011 versus $73.20 for the same period of 2010. This 20% increase resulted in additional oil sales revenue of $34.9 million. For the first nine months of 2011 we realized an average oil price of $93.08 per barrel, which was 24% higher than the average price of $74.87 we received for the same period in 2010. This increase contributed an additional $132.1 million of oil sales revenue for the nine months ended September 30, 2011.

Our average realized price for NGLs in the third quarter of 2011 was $43.11 per barrel. This price was 36% higher than the $31.73 average price received in the third quarter of 2010, and accounted for additional NGL revenue of $18.3 million. In the first nine months of 2011 the average NGL price we received was $42.99, up from $33.41 for the same period of 2010. The 29% price increase for 2011 raised NGL sales by $44.7 million for the first nine months of 2011.

Changes in realized commodity prices were the result of overall market conditions.

Gas Gathering, Processing, Marketing and Other (In thousands):	**For the Three Months Ended September 30, 2011**	**2010**	**For the Nine Months Ended September 30, 2011**	**2010**
Gas gathering, processing and other revenues	$ 13,762	$ 11,570	$ 40,823	$ 41,022
Gas gathering and processing costs	(4,821)	(4,577)	(14,002)	(17,182)
Gas gathering, processing and other margin	$ 8,941	$ 6,993	$ 26,821	$ 23,840
Gas marketing revenues, net of related costs	$ 319	$ 452	$ 797	$ 775

We sometimes transport, process and market third-party gas that is associated with our gas. In the third quarter of 2011, third-party gas gathering, processing and other contributed $8.9 million of pre-tax cash operating margin (revenues less direct cash expenses) versus $7.0 million in 2010. For the nine months ended September 30, 2011 and 2010, such revenues less direct expenses totaled $26.8 million and $23.8 million, respectively. Our gas marketing margin (revenues less purchases) was $319 thousand for the third quarter of 2011, compared to $452 thousand in 2010. For the first nine months of 2011 our gas marketing margin was $797 thousand compared to $775 thousand in the 2010 period. Changes in net margins from gas gathering, processing, marketing and other activities are the direct result of changes in volumes and overall market conditions.

Table of Contents

Operating costs and expenses (In thousands):	For the Three Months Ended September 30, 2011	For the Three Months Ended September 30, 2010	Variance Between 2011/2010	For the Nine Months Ended September 30, 2011	For the Nine Months Ended September 30, 2010	Variance Between 2011/2010
Depreciation, depletion and amortization	$ 104,681	$ 78,705	$ 25,976	$ 279,554	$ 221,561	$ 57,993
Asset retirement obligation	3,578	1,201	2,377	8,223	5,486	2,737
Production	62,333	52,010	10,323	181,558	139,349	42,209
Transportation	15,196	13,084	2,112	45,029	35,076	9,953
Taxes other than income	30,533	28,094	2,439	98,625	88,862	9,763
General and administrative	9,390	11,274	(1,884)	34,734	36,136	(1,402)
Stock compensation	4,595	3,241	1,354	13,962	9,012	4,950
(Gain) loss on derivative instruments, net	(7,120)	(15,028)	7,908	(11,353)	(70,914)	59,561
Other operating, net	2.379	2,291	88	8,095	2,321	5,774
	$ 225,565	$ 174,872	$ 50,693	$ 658,427	$ 466,889	$ 191,538

Total operating costs and expenses (not including gas gathering, marketing and processing costs, or income tax expense) increased 29% to $225.6 million in the third quarter of 2011 compared to $174.9 million for the third quarter of 2010. For the first nine months of 2011 operating costs were $658.4 million, or an increase of 41% over the same period of 2010. Analyses of the year over year differences are discussed below.

DD&A increased from $78.7 million in the third quarter of 2010 to $104.7 million in the same period of 2011. The $26 million increase in 2011 accounts for 51% of the aggregate third quarter increase in total operating costs and expenses. On a unit of production basis, DD&A was $1.92 per Mcfe for the 2011 third quarter compared to $1.43 in the 2010 quarter. For the first nine months of 2011 DD&A was $279.6 million, compared to $221.6 million in 2010. The $58 million increase in expense is 30% of the total 2011 increase in operating costs and expenses. On a unit of production basis, the nine month rate for 2011 was $1.74 per Mcfe, up from $1.37 per Mcfe for the 2010 period. The increase in DD&A for the 2011 periods is primarily the result of increasing the cost of reserves added at a greater rate than the increase in future production.

In the third quarter of 2011 our production costs rose $10.3 million up from $52 million ($0.94 per Mcfe) in the third quarter of 2010 to $62.3 million ($1.15 per Mcfe). The $10.3 million increase in 2011 accounted for 20% of the aggregate increase for the third quarter. Production costs for the first nine months of 2011 were $181.6 million ($1.13 per Mcfe), up from $139.3 million ($0.86 per Mcfe) for the same period of 2010. The $42.2 million increase for the first nine months of 2011 was 22% of the total increase in operating costs and expenses.

Our production costs consist of lease operating expense and workover expense. Increases in our 2011 lease operating expenses accounted for approximately 94% and 78% of the quarter and nine month period over period variances, respectively. The increases resulted in part from higher water disposal costs associated with wells coming on line from our successful drilling program. Costs for equipment maintenance, rentals and labor have also contributed to the increases in lease operating expense for the 2011 periods. The remainder of the 2011 increases relate to increased workover activity in 2011.

Transportation costs rose to $15.2 million ($0.28 per Mcfe) in the third quarter of 2011 from $13.1 million ($0.24 per Mcfe) in 2010. For the first nine months of 2011 transportation costs were $45.0 million ($0.28 per Mcfe) versus $35.1 million ($0.22 per Mcfe) for 2010. Transportation costs will fluctuate based on increases or decreases in sales volumes, compression charges and fluctuation in the price of the fuel cost component. Well connection reimbursement costs resulting from a failure to meet minimum volume delivery commitments entered into in prior years will also fluctuate from period to period. Also, in the latter part of 2010 and continuing in 2011, our Mid-Continent and Permian Basin

30

Table of Contents

wells have experienced increases in transportation rates due to higher contractual rates associated with new wells coming online and contracts for existing wells being renewed.

Taxes other than income in the third quarter of 2011 were $30.5 million, or 9% higher than $28.1 million in the third quarter of 2010. For the nine months ended September 30, 2011, taxes other than income were $98.6 million, up 11% compared to $88.9 million for the 2010 period. The increased taxes between periods resulted primarily from increases in higher realized oil and NGL prices in the 2011 periods.

For the third quarter of 2011 our general and administrative (G&A) expense was $9.4 million, down $1.9 million compared to G&A expense of $11.3 million for the same period of 2010. The decrease is primarily due to lower bonus accruals in the third quarter of 2011. Our G&A expense of $34.7 million for the first nine months of 2011 declined slightly from $36.1 million for the same period of 2010.

Stock compensation expense consists of noncash charges resulting from the issuance of restricted stock, restricted stock units and stock option awards. We have recognized non-cash stock-based compensation cost as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	**2010**	**2011**	**2010**
Performance-based restricted stock awards	$ 4,116	$ 2,430	$ 12,185	$ 7,174
Service-based restricted stock awards	2,897	2,294	8,023	5,807
Restricted unit awards		37	34	10
Restricted stock and units	7,013	4,761	20,242	12,991
Stock option awards	551	989	2,731	2,780
Total stock compensation	7,564	5,750	22,973	15,771
Less amounts capitalized to oil and gas properties	(2,969)	(2,509)	(9,011)	(6,759)
Stock compensation expense	$ 4,595	$ 3,241	$ 13,962	$ 9,012

Expense associated with stock compensation will fluctuate based on the grant-date market value of the award and the number of awards granted. The increases in 2011 total stock compensation compared to the 2010 amounts result primarily from the increased price per share of our common stock on the date of grants in 2011 compared to the grant date value of previous awards. (See Note 5 to the Consolidated Financial Statements for a detailed discussion regarding our stock-based compensation).

Our net (gain) or loss on derivative instruments includes both realized gains and losses on settlements of our derivative contracts and unrealized gains and losses stemming from changes in the fair value of our outstanding derivative instruments. We estimate the fair value of these instruments based on published forward commodity price curves for the underlying commodity as of the date of the estimate. For collars, we estimate the option value of the contract floors and ceilings using an option pricing model which takes into account market volatility, market prices and contract terms. The fair value of our derivative instruments in an asset position includes a measure of counterparty credit risk. The fair value of instruments in a liability position includes a measure of our own nonperformance risk. These credit risks are based on current published credit default swap rates.

We did not elect to use hedge accounting treatment when we entered into our outstanding derivative contracts. (See Note 2 to the Consolidated Financial Statements for a complete discussion of our derivative instruments). The following table reflects the net realized and unrealized (gains) and losses on our derivative instruments:

Table of Contents

	For the Three Months Ended September 30, 2011	2010	For the Nine Months Ended September 30, 2011	2010
	(In thousands)			
Realized (gain) loss on settlement of derivative instruments	$ (1,747)	$ (14,147)	$ (3,817)	$ (31,258)
Unrealized (gain) loss from changes to the fair value of the derivative instruments	(5,373)	(881)	(7,536)	(39,656)
(Gain) loss on derivative instruments, net	$ (7,120)	$ (15,028)	$ (11,353)	$ (70,914)

The period over period decreases in the net gain on our derivative instruments is a function of fluctuations in the underlying commodity prices and the monthly settlement of the instruments. At September 30, 2010 we had outstanding contracts expiring over the following 15 months. At September 30, 2011 our outstanding contacts will expire over the next three months. The decreases in the net gains for the third quarter and first nine months of 2011 accounted for 16% and 31%, respectively, of the period over period increase in total operating costs and expenses.

Other operating, net expense consists of costs related to various legal matters most of which pertain to litigation and contract settlements and title and royalty issues. For the third quarter of 2011 these costs were $2.4 million compared to $2.3 million for 2010. Other operating, net increased from $2.3 million for the first nine months of 2010 to $8.1 million for the same period of 2011. Expenses for the first nine months of 2010 were significantly lower than the same period of 2011 due to the favorable resolution of items in the 2010 period that had been accrued in prior years.

Other Income and Expense

Interest expense for the third quarter of 2011 was $9.3 million compared to $9.1 million for 2010. For the first nine months of both 2011 and 2010 our interest expense was $27.6 million. Our interest expense includes interest on outstanding borrowings, amortization of financing costs and miscellaneous interest expense. Approximately 68% of our interest expense relates to our 7.125% senior notes due in 2017.

Components of other, net consist of miscellaneous income and expense items that will vary from period to period, including gain or loss on the sale or value of oil and gas well equipment, interest income and income and expenses associated with other non-operating activities. For the third quarter of 2011 other, net was $3.6 million of income, compared to $2.7 million of income in the third quarter of 2010. Other, net was $7.2 million of income in the first nine months of 2011, up from $2.8 million of income for the same period of 2010. In the 2010 periods, losses from sales of oil and gas well equipment were offset by net gains on asset sales. The income in the 2011 periods was mainly due to sales of oil and gas well equipment and supplies.

Income Tax Expense

In the third quarter of 2011 we recognized $76.8 million of income tax expense, which included $44.1 million of current tax benefit. This compares with third quarter 2010 income tax expense of $75.6 million, of which $12.8 million was a current tax benefit. The combined Federal and state effective income tax rates were 37.5% and 37.1% for the third quarters of 2011 and 2010, respectively. For the first nine months of

2011 we recognized net income tax expense of $243.6 million, of which $45.4 million is a current tax benefit. For the same period of 2010 we recognized net income tax expense of $265.3 million, which included $51.6 million of current tax expense. The combined Federal and state effective income tax rates for the first nine months of 2011 were 37.1% compared to 36.7% for the 2010 period. Our effective tax rates differ from the statutory rate of 35% primarily due to state income taxes, nondeductible expenses and special deductions.

Table of Contents

LIQUIDITY AND CAPITAL RESOURCES

Overview

Our liquidity is highly dependent on the commodity prices we receive. Oil and gas markets are very volatile and we cannot predict future commodity prices. Prices we receive for our production heavily influence our revenue, profitability, access to capital and future rate of growth. In 2010 and the early part of 2011 the United States and global economies had shown improvement. However, concerns about a recurrence of turmoil in the global financial system, Standard & Poor s downgrading of the United States credit rating from AAA to AA+ in August 2011 and ongoing geopolitical instability have continued to impact commodity prices, particularly the price of oil. Prices for natural gas continue to be depressed, primarily as a result of an oversupply of natural gas coupled with lower demand. Volatility in commodity prices may reduce the amount of oil and gas that we can economically produce and affect the amount of cash flow available for capital expenditures. Disruptions in economic conditions may impact third parties with whom we do business, causing them to fail to meet their obligations to us.

We intend to deal with volatility in the current economic environment by maintaining a blended portfolio of low, moderate and higher risk exploration and development projects. Our drilling activities are currently being conducted in three main areas: the Permian Basin, Mid-Continent and Gulf Coast. Our Permian activity is directed primarily to the Delaware Basin of southeast New Mexico and West Texas. A majority of our Mid-Continent drilling is in the western Oklahoma Cana-Woodford shale and Texas Panhandle Granite Wash. Our Gulf Coast operations are currently focused in southeast Texas, near Beaumont.

Historically our exploration and development expenditures have generally been funded by cash flow provided by operating activities (operating cash flow). In 2011 we have continued to fund our exploration and development expenditures primarily with operating cash flow. We also intend to continue to use debt sparingly and we may hedge a portion of our production to protect our operating cash flow for reinvestment.

From time to time we consider attractive acquisition opportunities. However, the timing and size of acquisitions are unpredictable. To stay prepared for potential acquisitions and possible declines in commodity prices, we have a revolving credit facility which provides for bank commitments of $800 million. Our credit facility is described in more detail under ***Financing*** below.

At September 30, 2011, our total debt outstanding was $350 million, which was comprised of our 7.125% Notes due in 2017.Our debt to total capitalization ratio was 10%. The reconciliation of debt to total capitalization, which is a non-GAAP measure, is: long-term debt of $350 million divided by long-term debt of $350 million plus stockholders equity of $3.013 billion. Management believes that this non-GAAP measure is useful information for investors because it is a common statistic referred to by the investment community, used to identify the amount of our leverage and to help analyze our risk exposure relative to other companies in the oil and gas exploration and production industry.

We believe that our operating cash flow and other capital resources will be adequate to continue to meet our needs for our planned capital expenditures, working capital, debt servicing and dividend payments for 2011 and beyond.

Analysis of Cash Flow Changes

Cash flow provided by operating activities for the first nine months of 2011 was $971.5 million, compared to $886.7 million for the same period of 2010. The $84.8 million increase in 2011 resulted primarily from higher revenues attributable to higher commodity prices in 2011.

Table of Contents

Cash flow used in investing activities for the first nine months of 2011 was $1.007 billion, compared to $697 million for 2010. Changes in the cash flow used in investing activities are generally the result of changes in our exploration and development programs, acquisitions and property sales. The $310 million increase for 2011 compared to 2010 was due to increased cash expenditures related to exploration, development and other expenditures partially offset by property sales. See the discussion below for further information regarding our capital expenditures and property sales.

Net cash flow used for financing activities in the first nine months of 2011 was $21.8 million, or a decrease of $22.5 million compared to $44.3 million for the same period of 2010. The decrease was due primarily to $44.5 million of net payments on our debt in 2010, versus a net of zero payments in 2011. The $44.5 million decrease in debt payments was partially offset by 2011 increases in dividend payments and financing costs and decreased proceeds from issuance of common stock in 2011.

Reconciliation of Cash Flow from Operations

	For the Three Months Ended September 30, 2011	For the Three Months Ended September 30, 2010	For the Nine Months Ended September 30, 2011	For the Nine Months Ended September 30, 2010
	(In thousands)			
Net cash provided by operating activities	$ 332,432	$ 314,408	$ 971,523	$ 886,668
Change in operating assets and liabilities	24,372	(17,628)	33,264	(16,787)
Cash flow from operations	$ 356,804	$ 296,780	$ 1,004,787	$ 869,881

Management believes that the non-GAAP measure of cash flow from operations is useful information for investors because it is used internally and is accepted by the investment community as a means of measuring the company s ability to fund its capital program. It is also used by professional research analysts in providing investment recommendations pertaining to companies in the oil and gas exploration and production industry.

Capital Expenditures

The following table sets forth certain historical information regarding our capitalized expenditures for oil and gas acquisition, exploration, and development activities (in thousands):

	For the Three Months Ended September 30, 2011	For the Three Months Ended September 30, 2010	For the Nine Months Ended September 30, 2011	For the Nine Months Ended September 30, 2010
Acquisitions:				
Proved	$ 12,439	$ 19	$ 21,604	$ 13,805
Unproved	8,380	978	20,427	21,497
	20,819	997	42,031	35,302
Exploration and development:				

Land and seismic	61,907	49,368	146,832	112,076
Exploration and development	360,733	246,501	1,032,794	613,387
	422,640	295,869	1,179,626	725,463
Sales proceeds:				
Proved*	(83,709)	807	(102,192)	(24,054)
Unproved	(150)		(1,971)	(3,917)
	(83,859)	807	(104,163)	(27,971)
	$ 359,600	$ 297,673	$ 1,117,494	$ 732,794

* The positive amount in the 2010 proved sales proceeds reflects purchase price adjustments related to a disposition in the second quarter of 2010.

Table of Contents

Capital expenditures in the table above are presented on an accrual basis. Additions to property and equipment in the Condensed Consolidated Statements of Cash Flows reflect capital expenditures on a cash basis, when payments are made.

Our exploration and development expenditures increased 63% in the first nine months of 2011 compared to the same period of 2010. At September 30, 2011 we had 30 operated rigs running. At September 30, 2010 we had 25 operated rigs running.

In the third quarter of 2011 we drilled 82 gross (48 net) wells with 77 gross (43.1 net) completed as producers. In the third quarter of 2010 we drilled 63 gross (36.4 net) wells with 59 gross (33.5 net) completed as producers.

In the first nine months of 2011 we drilled 242 gross (138.2 net) wells, with 231 gross (129.4 net) completed as producers. At September 30, 2011 we also had 32 gross (16 net) wells that were in the process of being completed or were awaiting completion. During the same period of 2010 we drilled 152 gross (91.9 net) wells, completing 143 gross (85.7 net) as producers. At September 30, 2010 we had 42 gross (22.1 net) wells that were in the process of being completed or were awaiting completion.

Our exploration and development program for 2011 is expected to be principally funded from cash flow, including non-core property sales. Based on current market prices and service costs, our 2011 capital expenditures are expected to approximate $1.6 billion. Although our capital budget is generally set at a level that we believe corresponds with our anticipated 2011 cash flows, the timing of capital expenditures and the receipt of cash flows do not necessarily match. For example, our planned capital expenditures are front-end loaded and we may outspend cash flows for a period of time. Therefore, we may borrow and repay funds under our credit facility throughout the year. Should we start to see a significant change in commodity prices or production volumes from our current forecasts, we have the operational flexibility to increase or decrease our capital expenditures for changes in our expected cash flows from operations.

In August 2011, we sold all of our interests in assets located in Sublette County, Wyoming for $195 million (including purchase price adjustments). The assets sold principally consisted of a gas processing plant under construction and related assets ($111 million) and 210 Bcf of proved undeveloped gas reserves ($84 million). No gain or loss was recognized on the sale of proved reserves as the disposition did not significantly alter the relationship between capitalized costs and proved reserves.

At June 30, 2011 the gas processing plant and related assets and liabilities were classified as assets held for sale. We determined that the carrying amounts of the assets and liabilities were equal to their fair value, therefore no gain or loss was recognized on the sale. Because the gas plant was still under construction we had not recognized any income or expense related to plant operations in our statements of operations. The sales contract also provides for a maximum $15 million contingent payment to be made to Cimarex if certain operational and performance goals related to the start-up of the gas processing plant are met.

During the first nine months of 2011, we had property acquisitions of approximately $42 million, of which $39 million was in our western Oklahoma Cana-Woodford shale play and $3 million was in the Permian Basin. During the first nine months of 2010 we had property acquisitions of $35.3 million, most of which were additional interests in our western Oklahoma Cana-Woodford shale play. In the first nine months of 2011 we sold other non-core property interests (not including our Wyoming properties) for $20.6 million. For the same period in 2010 we had $28 million of non-core property sales. We continue to actively evaluate acquisitions and dispositions relative to our property holdings, particularly in our core areas of operation. See Note 12 to the Consolidated Financial Statements of this report for additional information regarding property acquisitions and sales.

Table of Contents

We have made, and will continue to make, expenditures to comply with environmental and safety regulations and requirements. These costs are considered a normal recurring cost of our ongoing operations and not an extraordinary cost of compliance. At this time we do not anticipate that we will be required to expend amounts that will have a material adverse effect on our financial position or operations, nor are we aware of any pending regulatory changes that would have a material impact.

Financial Condition

Future cash flows and the availability of financing will be subject to a number of variables, such as our success in locating and producing new reserves, the level of production from existing wells and realized commodity prices. To meet our capital and liquidity requirements, we rely on certain resources, including cash flows from operating activities, access to capital markets, and bank borrowings. While we attempt to operate within forecasted cash flows from operations, we do periodically access our credit facility to finance our working capital needs and growth. See our discussion on *Financing* below.

During the first nine months of 2011 our total assets increased by $753.3 million to $5.1 billion, up from $4.4 billion at December 31, 2010. The change is primarily made up of increased net oil and gas assets of $864.8 million partially offset by a decrease of $57.0 million in our cash and cash equivalents and a decrease of $58.5 in our net fixed assets. The decrease in our net fixed assets was mainly due to our previously discussed sale of our gas processing plant in Wyoming.

At September 30, 2011, our total liabilities were $2.1 billion, up $349.7 million from $1.75 billion at December 31, 2010. The increase resulted primarily from a net increase in current liabilities of $64.0 million, mostly related to increased accrued E&D expenditures, and a $287.1 million increase in noncurrent deferred income taxes. Stockholders equity rose $403.6 million to $3.0 billion at the end of the third quarter of 2011 compared to $2.6 billion at December 31, 2010. The increase is mainly due to our net income of $413.1 million for the first nine months of 2011.

Dividends

On February 24, 2011 the Board of Directors increased our regular cash dividend on our common stock from $0.08 to $0.10 per common share. Future dividend payments will depend on the Company s level of earnings, financial requirements, and other factors considered relevant by our Board of Directors.

Common Stock Repurchase Program

In December 2005, the Board of Directors authorized the repurchase of up to four million shares of common stock. During 2007 we repurchased a total of 1,114,200 shares at an average purchase price of $37.93. Cumulative purchases through December 31, 2007 total 1,364,300 shares at an average price of $39.05. There were no shares repurchased since the quarter ended September 30, 2007.

Working Capital Analysis

Our working capital balance fluctuates primarily as a result of our exploration and development activities, our realized commodity prices and our production operating activities. Working capital is also impacted by our current tax provisions, accrued G&A and changes in the fair value of our outstanding derivative instruments.

Our working capital decreased $123.9 million from $49.5 million at year-end 2010 to a deficit of $74.4 million at September 30, 2011. Although we anticipate that our 2011 capital spending (excluding possible acquisitions) will correspond with our 2011 cash flow including non-core property sales, we may

Table of Contents

borrow and repay funds under our credit facility throughout the year because the timing of expenditures and the receipt of cash flows from operations do not necessarily match.

Working capital decreased primarily because of the following:

- Cash and cash equivalents decreased by $57 million as cash was used primarily to fund our E&D activity.
- Our operations related accounts receivable decreased by $20.9 million.
- We received $25 million related to a tax refund that was outstanding at December 31, 2010, which was used to fund E&D activities.
- Other current assets decreased by $6.8 million
- Accrued liabilities related to our E&D expenditures increased by $60 million
- Our operations related accounts payable and accrued liabilities increased by $13.6 million.

These working capital decreases were partially offset by the following:

- Our income tax receivable increased by $53.1 million.
- The net fair value of our derivative instruments increased by $7.5 million.

Our receivables are a major component of our working capital and are made up of a diverse group of companies including major energy companies, pipeline companies, local distribution companies and end-users in various industries. The collection of receivables during the period presented has been timely. Historically, losses associated with uncollectible receivables have not been significant.

Financing

At September 30, 2011 and December 31, 2010 our only outstanding debt was our $350 million 7.125% senior unsecured notes.

Revolving Credit Facility

In July 2011, we entered into a new five-year senior unsecured revolving credit facility (Credit Facility). The Credit Facility provides for a borrowing base of $2 billion with aggregate commitments of $800 million from 14 lenders. The facility matures July 14, 2016.

The borrowing base under the Credit Facility is determined at the discretion of lenders based on the value of our proved reserves. The next regular-annual redetermination date is on April 1, 2012.

At Cimarex s option, borrowings under the Credit Facility may bear interest at either (a) LIBOR plus 1.75-2.5%, based on our leverage ratio, or (b) the higher of (i) a prime rate, (ii) the federal funds effective rate plus 0.50%, or (iii) adjusted one-month LIBOR plus 1.0% plus, in each case, an additional 0.75-1.5%, based on our leverage ratio.

The Credit Facility also has financial covenants that include the maintenance of current assets (including unused bank commitments) to current liabilities of greater than 1.0 to 1.0. We also must maintain a leverage ratio of total debt to earnings before interest expense, income taxes and noncash items (such as depreciation, depletion and amortization expense, unrealized gains and losses on commodity derivatives, ceiling test write-downs, and goodwill impairments) of not more than 3.5 to 1.0. Other covenants could limit our ability to: incur additional indebtedness, pay dividends, repurchase our common stock, or sell assets. As of September 30, 2011, we were in compliance with all of the financial and nonfinancial covenants.

Table of Contents

At September 30, 2011, there were no outstanding borrowings under the Credit Facility. We had letters of credit outstanding of $2.5 million leaving an unused borrowing availability of $797.5 million. During the first nine months of 2011 we had an average daily bank debt outstanding of $12.3 million, compared to $6.0 million for the same period of 2010. Our largest amount of bank borrowings outstanding during the first nine months of 2011 was $149 million occurring in mid July. During the first nine months of 2010 our largest amount of outstanding bank borrowings was $69.0 million in mid January.

7.125% Senior Notes due 2017

In May 2007 we issued $350 million of 7.125% senior unsecured notes that mature May 1, 2017 at par. Interest on the notes is payable May 1 and November 1 of each year. The notes are governed by an indenture containing covenants that could limit our ability to incur additional indebtedness; pay dividends or repurchase our common stock; make investments and other restricted payments; incur liens; enter into sale/leaseback transactions; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets.

The notes are redeemable at our option, in whole or in part, at any time on and after May 1, 2012 at the following redemption prices (expressed as percentages of the principal amount) plus accrued interest, if any, thereon to the date of redemption.

Year	**Percentage**
2012	103.6%
2013	102.4%
2014	101.2%
2015 and thereafter	100.0%

If a specified change of control occurs, subject to certain conditions, we must make an offer to purchase the notes at a purchase price of 101% of the principal amount of the notes, plus accrued and unpaid interest to the date of the purchase.

Contractual Obligations and Material Commitments

At September 30, 2011, we had contractual obligations and material commitments as follows:

	Payments Due by Period				
Contractual obligations:	**Total**	**Less than 1 Year**	**1-3 Years**	**4-5 Years**	**More than 5 Years**
			(In thousands)		
Long-term debt(1)	$ 350,000	$	$	$	$ 350,000
Fixed-Rate interest payments(1)	149,625	24,938	49,875	49,875	24,937
Operating leases(2)	77,010	4,986	15,672	11,768	44,584
Drilling commitments(3)	344,891	334,368	10,523		

Purchase commitments(4)	10,305	10,305			
Gathering facilities and pipelines(5)	8,271	8,271			
Asset retirement obligation(6)	136,120	29,249	(6)	(6)	(6)
Other liabilities(7)	73,077	12,641	24,656	24,016	11,764
Firm Transportation	3,081	1,817	1,094	170	

(1) See item 3: Interest Rate Risk for more information regarding fixed and variable rate debt.

Table of Contents

(2) In the first quarter of 2011 we entered into a 12-year lease agreement for new office space in Tulsa, Oklahoma, which increased our aggregate minimum lease commitments beginning December 2012 by approximately $63 million over the term of this lease.

(3) We have drilling commitments of approximately $288.7 million consisting of obligations to finish drilling and completing wells in progress at September 30, 2011. We also have various commitments for drilling rigs as well as certain service contracts. The total minimum expenditure commitments under these agreements are $22.6 million to secure the use of drilling rigs and $33.6 million to secure certain dedicated services associated with completion activities.

(4) At September 30, 2011, we have a purchase commitment of $10.3 million for construction of an aircraft. The total cost of the aircraft is $11.5 million with an option to trade in our existing aircraft. The aircraft is expected to be delivered to us by the end of 2011.

(5) We have projects in Oklahoma, New Mexico, and Texas where we are constructing gathering facilities and pipelines. At September 30, 2011, we had commitments of $8.3 million relating to this construction.

(6) We have not included the long term asset retirement obligations because we are not able to precisely predict the timing of these amounts.

(7) Other liabilities include the fair value of our liabilities associated with our benefit obligations and other miscellaneous commitments.

At September 30, 2011, we had firm sales contracts to deliver approximately 17.5 Bcf of natural gas over the next 11 months. If this gas is not delivered, our financial commitment would be approximately $66.5 million. This commitment will fluctuate due to price volatility and actual volumes delivered. However, we believe no financial commitment will be due based on our current proved reserves and production levels.

In connection with gas gathering and processing agreements, we have commitments to deliver a minimum of 24.5 Bcf of gas over the next 2-3 years. The production from certain wells is counted toward those commitments; these wells also have individual commitments for gas deliveries. If no gas is delivered, the maximum amount that would be payable under these commitments would be approximately $17.5 million, some of which would be reimbursed by working interest owners who are selling with us under our marketing agreements. We do not expect to make significant payments relative to these commitments.

We have various other delivery commitments in the normal course of business, which are individually and in aggregate not material.

All of the noted commitments were routine and were made in the normal course of our business.

Based on current commodity prices and anticipated levels of production, we believe that the estimated net cash generated from operations, coupled with the cash on hand and amounts available under our existing bank credit facility will be adequate to meet future liquidity needs, including satisfying our financial obligations and funding our operations and planned exploration and development activities.

2011 Outlook

We expect our 2011 E&D capital expenditures to be principally funded from cash flow, including non-core property sales. Based on current market prices and service costs, we expect 2011 E&D expenditures to be approximately $1.6 billion. We remain focused on profitable growth and maximizing our return on investment. We currently have a large inventory of drilling opportunities and limited lease expirations.

As has been our historical practice, we regularly review our capital expenditures throughout the year and will adjust our investments based on changes in commodity prices, service cost and drilling success. Operationally we have the flexibility to adjust our capital expenditures based upon market conditions. Our future growth will continue to depend upon our ability to economically add reserves in excess of production.

Table of Contents

Though there are a variety of factors that could curtail, delay or even cancel some of our planned operations, we believe our projected program is likely to occur. The majority of projects are in hand, drilling rigs are being scheduled, and the historical results of our drilling efforts warrant pursuit of the projects.

Production for 2011 is projected to be in the range of 589 to 595 MMcfe per day, or relatively flat compared to 2010. Revenues from production will be dependent not only on the level of oil and gas actually produced, but also the prices that will be realized. During 2010, our realized prices averaged $4.92 per Mcf of gas, $76.76 per barrel of oil, and $34.91 per barrel of NGL. For the first nine months of 2011 our realized prices averaged $4.59 per Mcf of gas, $93.08 per barrel of oil, and $42.99 per barrel of NGL. Commodity prices can be very volatile and the possibility of full year realized 2011 prices varying from prices received in the first nine months of 2011 is high.

Certain expenses for 2011 on a per Mcfe basis are currently estimated as follows:

		2011	
Production expense	$1.02	-	$1.22
Transportation expense	0.28	-	0.33
DD&A and asset retirement obligation	1.90	-	2.05
General and administrative	0.20	-	0.25
Production taxes (% of oil and gas revenue)	7.5%	-	8.5%

ITEM 3. QUALITATIVE AND QUANTITATIVE DISCLOSURES ABOUT MARKET RISK

The term   market risk   refers to the risk of loss arising from adverse changes in commodity prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses.

Price Fluctuations

Our major market risk is pricing applicable to our oil and gas production. The prices we receive for our production are based on prevailing market conditions and are influenced by many factors that are beyond our control. Pricing for oil and gas production has been volatile and unpredictable.

We periodically hedge a portion of our price risk associated with our future oil and gas production.

The following table details the contracts we have in place as of September 30, 2011:

Natural Gas Contracts

Period	Type	Volume/Day	Index(1)	Weighted Average Price Swap	Fair Value (000 s)
Oct 11 - Dec 11	Swap	20,000 MMBtu	PEPL	$ 5.05	$ 2,511

Oil Contracts

Period	Type	Volume/Day	Index(1)	Weighted Average Price Floor	Weighted Average Price Ceiling	Fair Value (000 s)
Oct 11 - Dec 11	Collar	12,000 Bbls	WTI	$ 65.00	$ 105.44	$ 1,169

---

(1) PEPL refers to Panhandle Eastern Pipe Line Company price as quoted in Platt s Inside FERC on the first business day of each month. WTI refers to West Texas Intermediate price as quoted on the New York Mercantile Exchange.

Table of Contents

While these contracts limit the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. For the 2011 gas contracts listed above, a hypothetical $0.10 change in the price below or above the contracted price applied to the notional amounts would cause a change in our gain (loss) on mark-to-market derivatives in 2011 of $184 thousand. For the 2011 oil contracts listed above, a hypothetical $1.00 change in the price below or above the contracted price applied to the notional amounts would cause a change in our gain (loss) on mark-to-market derivatives in 2011 of $1.1 million.

In spite of the recent turmoil in the financial markets, counterparty credit risk did not have a significant effect on our cash flow calculations and commodity derivative valuations. This is primarily the result of two factors. First, we have mitigated our exposure to any single counterparty by contracting with numerous counterparties. Second, our derivative contracts are held with investment grade counterparties that are a part of our credit facility. See Note 2 to the Consolidated Financial Statements of this report for additional information regarding our derivative instruments.

Interest Rate Risk

At September 30, 2011 our debt was our senior unsecured notes that bear interest at a fixed rate of 7.125% and will mature on May 1, 2017.

At September 30, 2011, we consider our interest rate exposure to be minimal because all of our long-term debt obligations were at fixed rates. This assessment excludes accounts receivable, accounts payable and accrued liabilities because of the short-term maturity of such instruments. See Note 3 and Note 7 to the Consolidated Financial Statements in this report for additional information regarding debt.

Table of Contents

ITEM 4. CONTROLS AND PROCEDURES

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

Our management, with the participation of our Chief Executive Officer (CEO) and Chief Financial Officer (CFO), have evaluated the effectiveness of our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e)) as of September 30, 2011 and concluded that the disclosure controls and procedures are effective in providing reasonable assurance that the information required to be disclosed in reports filed with the SEC is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms. The disclosure controls and procedures are also designed to provide reasonable assurance that such information is accumulated and communicated to our management, including the CEO and CFO, as appropriate to allow such persons to make timely decisions regarding required disclosures.

Our management does not expect that our disclosure controls and procedures will prevent all errors and all fraud. The design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Based on the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple errors or mistakes. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the controls. The design of any system of controls is also based upon certain assumptions about the likelihood of future events. Therefore, a control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Our disclosure controls and procedures are designed to provide such reasonable assurances of achieving our desired control objectives, and our CEO and CFO have concluded, as of September 30, 2011, that our disclosure controls and procedures are effective in achieving that level of reasonable assurance.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There have been no changes in our internal controls over financial reporting or in other factors that occurred during the fiscal quarter ended September 30, 2011, that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

Table of Contents

PART II

ITEM 6 EXHIBITS

10.1	Credit Agreement dated as of July 14, 2011, among Cimarex, the Administrative Agent, the Co-Syndication Agents, the Documentation Agents and the Lenders (filed as Exhibit 10.1 to the Registrant s Form 8-K on July 18, 2011 [file no. 001-31446] and incorporated herein by reference.
10.2	Form of Restricted Stock Award Agreement under the Cimarex Energy Co. 2011 Equity Incentive Plan.
10.3	Form of Non-Qualified Stock Option Agreement (executive officer 2011 grants) under the Cimarex Energy Co. 2011 Equity Incentive Plan.
10.4	Form of Non-Qualified Stock Option Agreement under the Cimarex Energy Co. 2011 Equity Incentive Plan.
31.1	Certification of Thomas E. Jorden, Chief Executive Officer of Cimarex Energy Co. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Paul Korus, Chief Financial Officer of Cimarex Energy Co. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Thomas E. Jorden, Chief Executive Officer of Cimarex Energy Co. pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350.
32.2	Certification of Paul Korus, Chief Financial Officer of Cimarex Energy Co. pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350.
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document

Table of Contents

SIGNATURE

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.

November 3, 2011

CIMAREX ENERGY CO.

/s/ Paul Korus
Paul Korus
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/ James H. Shonsey
James H. Shonsey
Vice President, Chief Accounting Officer and Controller
(Principal Accounting Officer)