CIMAREX ENERGY CO
Form 10-Q
May 07, 2010
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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 March 31, 2010

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 March 31, 2010 was 83,883,540.

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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

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 working interest percentage

Net Production Gross production multiplied by net revenue interest

NGL Natural gas liquids

Tcf Trillion cubic feet

Tcfe Trillion cubic feet equivalent

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.

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PART I

ITEM 1 - Financial Statements

CIMAREX ENERGY CO.

Consolidated Balance Sheets

	March 31, 2010 (Unaudited)	December 31, 2009
	(In thousands, except share data)	
Assets		
Current assets:		
Cash and cash equivalents	$ 62,542	$ 2,544
Restricted cash	593	593
Receivables, net	267,366	227,896
Oil and gas well equipment and supplies	128,207	145,153
Deferred income taxes		15,837
Derivative instruments	47,497	1,238
Other current assets	12,890	13,997
Total current assets	519,095	407,258
Oil and gas properties at cost, using the full cost method of accounting:		
Proved properties	7,730,333	7,549,861
Unproved properties and properties under development, not being amortized	435,379	399,724
	8,165,712	7,949,585
Less accumulated depreciation, depletion and amortization	(5,828,786)	(5,764,669)
Net oil and gas properties	2,336,926	2,184,916
Fixed assets, net	129,395	127,237
Goodwill	691,432	691,432
Other assets, net	31,272	33,694
	$ 3,708,120	$ 3,444,537
Liabilities and Stockholders Equity		
Current liabilities:		
Accounts payable	$ 44,471	$ 30,214
Accrued liabilities	232,622	235,815
Derivative instruments	7,171	13,902
Revenue payable	132,910	108,832
Total current liabilities	417,174	388,763
Long-term debt	367,832	392,793
Deferred income taxes	407,166	348,897
Other liabilities	277,886	275,978
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, 83,883,540 and 83,541,995 shares issued, respectively	839	835
Paid-in capital	1,861,417	1,859,255
Retained earnings	375,726	178,035
Accumulated other comprehensive income (loss)	80	(19)

		2,238,062		2,038,106
	$	3,708,120	$	3,444,537

See accompanying notes to consolidated financial statements.

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CIMAREX ENERGY CO.

Consolidated Statements of Operations

(Unaudited)

	For the Three Months Ended March 31, 2010	2009
	(In thousands, except per share data)	
Revenues:		
Gas sales	$ 225,637	$ 116,624
Oil sales	191,560	79,337
NGL sales	15,209	1,268
Gas gathering, processing and other	15,850	11,070
Gas marketing, net	314	880
	448,570	209,179
Costs and expenses:		
Impairment of oil and gas properties		791,137
Depreciation, depletion and amortization	69,710	89,666
Asset retirement obligation	2,644	2,545
Production	41,983	50,414
Transportation	11,167	8,709
Gas gathering and processing	6,505	5,106
Taxes other than income	32,358	15,545
General and administrative	13,045	7,762
Stock compensation, net	2,778	2,257
Gain on derivative instruments, net	(52,597)	(102)
Other operating, net	(1,846)	10,092
	125,747	983,131
Operating income (loss)	322,823	(773,952)
Other (income) and expense:		
Interest expense	9,462	8,267
Capitalized interest	(7,424)	(5,513)
Other, net	(1,930)	2,355
Income (loss) before income tax	322,715	(779,061)
Income tax expense (benefit)	118,354	(284,961)
Net income (loss)	$ 204,361	$ (494,100)
Earnings (loss) per share to common stockholders:		
Basic		
Distributed	$ 0.08	$ 0.06
Undistributed	2.34	(6.11)
	$ 2.42	$ (6.05)
Diluted		
Distributed	$ 0.08	$ 0.06
Undistributed	2.31	(6.11)
	$ 2.39	$ (6.05)

See accompanying notes to consolidated financial statements.

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CIMAREX ENERGY CO.

Condensed Consolidated Statements of Cash Flows

(Unaudited)

	For the Three Months Ended March 31, 2010	2009
	(In thousands)	
Cash flows from operating activities:		
Net income (loss)	$ 204,361	$ (494,100)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Impairments and other valuation losses		795,562
Depreciation, depletion and amortization	69,710	89,666
Asset retirement obligation	2,644	2,545
Deferred income taxes	84,990	(269,752)
Stock compensation, net	2,778	2,257
Derivative instruments, net	(52,056)	(102)
Changes in non-current assets and liabilities	3,101	4,426
Other, net	(2,321)	7,144
Changes in operating assets and liabilities:		
(Increase) decrease in receivables, net	(39,495)	87,231
(Increase) decrease in other current assets	18,495	(23,744)
Increase (decrease) in accounts payable and accrued liabilities	6,900	(118,577)
Net cash provided by operating activities	299,107	82,556
Cash flows from investing activities:		
Oil and gas expenditures	(203,682)	(197,549)
Sales of oil and gas and other assets	55	3,824
Sales of short-term investments		923
Other expenditures	(7,822)	(7,967)
Net cash used by investing activities	(211,449)	(200,769)
Cash flows from financing activities:		
Net increase (decrease) in bank debt	(25,000)	125,000
Financing costs incurred		(2)
Dividends paid	(5,069)	(5,040)
Issuance of common stock and other	2,409	
Net cash (used in) provided by financing activities	(27,660)	119,958
Net change in cash and cash equivalents	59,998	1,745
Cash and cash equivalents at beginning of period	2,544	1,213
Cash and cash equivalents at end of period	$ 62,542	$ 2,958

See accompanying notes to consolidated financial statements.

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CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements

March 31, 2010

(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 2009 Annual Report on Form 10-K.

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 after the balance sheet date of March 31, 2010, through the filing of this report.

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.

At the end of each quarter, we make a full cost ceiling limitation calculation, whereby net capitalized costs related to proved properties less associated deferred income taxes may not exceed the amount of the present value discounted at ten percent of estimated future net revenues from proved reserves less estimated future production and development costs and related income tax expense. Future net revenues used in the calculation of the full cost ceiling limitation have previously been determined based on current commodity prices and are adjusted for designated cash flow hedges. For year-end 2009, new SEC rules were implemented requiring reserve calculations to be 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. In periods prior to year-end 2009 we used prices in effect at period end.

Due to decreases in period end commodity prices at March 31, 2009, our ceiling limitation calculation resulted in excess capitalized costs of $791 million ($502 million, net of tax), for which we recorded a non-cash impairment of oil and gas properties. No further impairments have been recorded since the first quarter of 2009. 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 March 31, 2010 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 costs of wells in progress and certain unevaluated properties are not being amortized. On a quarterly basis, we evaluate such costs for inclusion in the costs to be amortized resulting from the determination of proved reserves, impairments, or reductions in value. To the extent that the evaluation indicates these properties are impaired, the amount

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

March 31, 2010

(Unaudited)

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 March 31, 2010, 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. At March 31, 2010, the estimated fair value was higher than the recorded net book value. Therefore, no further testing was required.

There continues to be disruptions in the credit markets and global economic activity which continues to 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 March 31, 2010, the market price per share of our common stock was greater than the book value by $33 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 our net assets for 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 percent. 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 be 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 investments, purchase price allocation, valuation of deferred tax assets, fair value measurements and commitments and contingencies.

Accounting Changes

Certain amounts in prior years financial statements have been reclassified to conform to the 2010 financial statement presentation.

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CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

March 31, 2010

(Unaudited)

Recently Issued Accounting Standards

There have been no significant accounting standards applicable to Cimarex issued during the quarter ended March 31, 2010.

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.

At March 31, 2010, 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

				Weighted Average Price			Fair Value
Period	**Type**	**Volume/Day**	**Index(1)**	**Floor**	**Ceiling**	**Swap**	**(000 s)**
Apr 10 - Dec 10	Collar	100,000MMBtu	PEPL	$ 5.00	$ 6.62		$ 29,505
Apr 10 - Dec 10	Swap	40,000MMBtu	PEPL			$ 5.18	$ 12,783
Apr 10 - Dec 10	Collar	20,000MMBtu	HSC	$ 5.00	$ 6.85		$ 5,209

Oil Contracts

				Weighted Average Price		Fair Value
Period	**Type**	**Volume/Day**	**Index(1)**	**Floor**	**Ceiling**	**(000 s)**
Apr 10 - Dec 10	Collar	10,000 Bbls	WTI	$ 60.03	$ 92.07	$ (7,205)
Apr 10 - Dec 10	Put/Floor	1,000 Bbls	WTI	$ 60.00		$ 141

Jan 11 - Dec 11	Collar	5,000 Bbls	WTI	$	65.00	$	105.64	$	(1,483)

(1) PEPL refers to Panhandle Eastern Pipe Line Company price and HSC refers to Houston Ship Channel price, both 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.

The combined gas and oil contracts that expire in 2010 represent approximately 40% of our equivalent oil and gas production for the remainder of 2010. In March 2010, we entered into additional oil contracts relative to our 2011 production, as noted in the table above. Management has been authorized to hedge up to 50% of our anticipated equivalent oil and gas production for 2011. Subsequent to March 31, 2010, we entered into additional derivative contracts relative to our 2011 oil production.

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. Under a floor contract, if the settlement price for a settlement period is below the floor price, we receive the difference between the settlement price and the floor price. We are not required to make any payments in connection with the settlement of a floor contract. 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.

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Notes to Consolidated Financial Statements (Continued)

March 31, 2010

(Unaudited)

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 the stated contract prices and current and projected published forward commodity price curves, adjusted for volatility. Due to the volatility of commodity prices, the estimated fair values 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 values of our derivative assets and liabilities as of March 31, 2010 and December 31, 2009.

	Balance Sheet Location		Asset	Liability
			(In thousands)	
March 31, 2010:				
Natural gas contracts	Current assets	Derivative instruments	$ 47,497	$
Oil contracts	Current liabilities	Derivative instruments	$	$ 7,171
Oil contracts	Noncurrent liabilities	Other liabilities	$	$ 1,376

	Balance Sheet Location		Asset	Liability
			(In thousands)	
December 31, 2009:				
Natural gas contracts	Current assets	Derivative instruments	$ 1,238	$
Natural gas contracts	Current liabilities	Derivative instruments	$	$ 4,308
Oil contracts	Current liabilities	Derivative instruments	$	$ 9,594

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 cash settlements and changes in fair value of our derivative contracts as presented in our accompanying financial statements.

	Three Months Ended March 31, 2010	2009
Cash settlements gains (losses):		
Natural gas contracts	$ 982	$
Oil contracts	(441)	
Total cash settlements gains (losses)	541	
Unrealized gains (losses) on fair value change:		

Natural gas contracts		50,568	102
Oil contracts		1,488	
Total net unrealized gains (losses) on fair value change		52,056	102
Gain (loss) on derivative instruments, net	$	52,597	102

We are exposed to financial risks associated with these contracts from non-performance 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 eight 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.

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Notes to Consolidated Financial Statements (Continued)

March 31, 2010

(Unaudited)

3. Fair Value Measurements

The 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 March 31, 2010 and December 31, 2009.

	Carrying Amount	Fair Value
	(In thousands)	
March 31, 2010:		
Financial Assets (Liabilities):		
Derivative instruments assets	$ 47,497	$ 47,497
Derivative instruments liabilities	$ (8,547)	$ (8,547)
7.125% Notes due 2017	$ (350,000)	$ (357,438)
Floating rate convertible notes due 2023	$ (17,832)	$ (40,397)

	Carrying Amount	Fair Value
	(In thousands)	
December 31, 2009:		
Financial Assets (Liabilities):		
Derivative instruments assets	$ 1,238	$ 1,238
Derivative instruments liabilities	$ (13,902)	$ (13,902)
Bank debt	$ (25,000)	$ (25,000)
7.125% Notes due 2017	$ (350,000)	$ (354,375)
Floating rate convertible notes due 2023	$ (17,793)	$ (36,036)

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 values of the assets and liabilities in the table above.

Bank Debt and Notes

Debt

We had no bank debt at March 31, 2010. The fair value of our bank debt at December 31, 2009 was estimated to approximate the carrying amount because the floating rate interest rate paid on such debt was set for periods of three months or less.

Notes

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

There is not an observable market for our convertible notes. At March 31, 2010 and December 31, 2009, the closing price of our common stock (as defined by the indenture) exceeded the conversion rate of $28.59 attributable to the conversion feature; therefore, the fair value of the convertible notes at March 31, 2010 and December 31, 2009 included value attributable to both the face amount of the notes and the conversion feature. The fair value of the face amount of the notes was estimated to approximate the face value of the notes because the notes bear interest at the London Interbank Offered Rate, and reset quarterly. The fair value of the conversion feature was calculated using the conversion formula for the notes, based on the closing price per share for our common stock at March 31, 2010 and December 31, 2009.

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

March 31, 2010

(Unaudited)

Derivative Instruments (Level 2)

The fair values of our derivative instruments were 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 non-performance for both our counterparties and our liability positions. Please see Note 2 for further information on the fair values 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 of these assets and liabilities. At March 31, 2010 and December 31, 2009, the aggregate allowance for doubtful accounts for trade, oil and gas sales, and gas gathering, processing, and marketing receivables was $6.9 million.

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 three months ended March 31, 2010 follows:

		Number of Shares (in thousands)	
	Issued	**Treasury**	**Outstanding**
December 31, 2009	83,542		83,542
Restricted shares issued under compensation plans, net of cancellations	264		264
Option exercises, net of cancellations	78		78
March 31, 2010	83,884		83,884

Stock-based Compensation

Our 2002 Stock Incentive Plan was approved by stockholders in May 2003 and is effective until October 1, 2012. The plan provides for grants of stock options, restricted stock and restricted stock units to non-employee directors, officers and other eligible employees. A total of 12.7 million shares of common stock may be issued under the Plan.

Restricted Stock and Units

During the three months ended March 31, 2010, we issued a total of 401,000 restricted shares to non-employee directors, officers, and other employees. Included in that amount are 396,000 shares issued to certain executives that 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. The material terms of performance goals applicable to these awards were approved by stockholders in May 2006. The other shares granted in 2010 have service-based vesting schedules of five years.

The following table presents restricted stock activity as of March 31, 2010, and changes during the year:

Outstanding as of January 1, 2010	1,727,250
Vested	(218,880)
Granted	401,000
Canceled	(49,220)
Outstanding as of March 31, 2010	1,860,150

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CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

March 31, 2010

(Unaudited)

The following table presents restricted unit activity as of March 31, 2010 and changes during the year:

Outstanding as of January 1, 2010	649,843
Converted to Stock	(2,336)
Granted	
Canceled	
Outstanding as of March 31, 2010	647,507
Vested included in outstanding	643,223

Vesting of restricted stock and units granted in years before 2006 is exclusively related to continued service of the grantee for one to five years. In certain cases, a three-year required holding period following vesting is also required. A restricted unit represents a right to an unrestricted share of common stock upon completion of defined vesting and holding periods. The restricted stock and stock unit agreements provide that grantees are entitled to receive dividends on unvested shares.

Compensation expense for service-based vesting restricted shares or units is based upon amortization of the grant-date market value of the award. The fair value of the market condition-based restricted stock awards is based on the grant-date market value of the award utilizing a Monte Carlo simulation model to estimate the percentage of awards that will vest at the end of a three-year period. Compensation expense related to the restricted stock and unit awards is recognized ratably over the applicable vesting period. For the three months ended March 31, 2010 and 2009, total compensation expense (including capitalized amounts) equaled $3.8 million and $2.3 million, respectively.

Unamortized compensation costs related to unvested restricted shares and units at March 31, 2010 and 2009 was $40.4 million and $34.3 million, respectively.

Stock Options

Options granted under our plan expire ten years from the grant date and have service-based vesting schedules of three to five years. The plan provides 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.

There were 5,000 stock options granted to employees during the three months ended March 31, 2010. There were no stock options granted to employees during the three months ended March 31, 2009.

Information about outstanding stock options is summarized below:

	Shares		Weighted Average Exercise Price	Weighted Average Remaining Term		Aggregate Intrinsic Value (000)
Outstanding as of January 1, 2010	1,573,974	$	29.93			
Exercised	(78,213)	$	19.84			
Granted	5,000	$	62.07			
Canceled	(1,699)	$	56.74			
Forfeited	(14,503)	$	45.74			
Outstanding as of March 31, 2010	1,484,559	$	30.38	5.2 Years	$	42,825
Exercisable as of March 31, 2010	949,717	$	23.22	3.3 Years	$	34,188

There were 78,213 stock options exercised during the three months ended March 31, 2010. There were no stock options exercised during the three months ended March 31, 2009. Cash received from option exercises during the three months ended March 31, 2010 was $1.6 million. The related tax

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Notes to Consolidated Financial Statements (Continued)

March 31, 2010

(Unaudited)

benefits realized from option exercises totaled $857 thousand and were recorded to paid-in capital. The total intrinsic value of stock options exercised during the three months ended March 31, 2010 was $3.2 million.

We estimate the fair value of options as of the date of grant 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. The risk-free interest rate we use is the five-year U.S. Treasury bond in effect at the date of the grant.

The following summary reflects the status of non-vested stock options as of March 31, 2010 and changes during the year:

	Shares		Weighted Average Grant Date Fair Value		Weighted Average Exercise Price
Non-vested as of January 1, 2010	544,345	$	15.66	$	42.99
Vested					
Granted	5,000	$	24.61	$	62.07
Forfeited	(14,503)	$	16.27	$	45.74
Non-vested as of March 31, 2010	534,842	$	15.73	$	43.10

We recognize compensation cost related to stock options ratably over the vesting period. Historical amounts may not be representative of future amounts as additional options may be granted. Compensation cost (including capitalized amounts) for the three months ended March 31, 2010 and 2009 were $824 thousand and $664 thousand, respectively.

As of March 31, 2010, there was $5.9 million of unrecognized compensation cost related to non-vested stock options granted under our stock incentive plan. We expect to recognize that cost pro rata over a weighted-average period of 1.8 years.

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 right to receive Cimarex common stock with a value equal to two times the exercise price of the right.

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.

Dividends and Stock Repurchases

In February 2010, the Board of Directors increased our quarterly cash dividend to $0.08 per share from $0.06 per share. The dividend is payable June 1, 2010 to stockholders of record on May 14, 2010. Future dividend payments will depend on the

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Notes to Consolidated Financial Statements (Continued)

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(Unaudited)

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. Through December 31, 2007, we had repurchased and cancelled a total of 1,364,300 shares at an overall average price of $39.05. Purchases may be made in both the open market and through negotiated transactions, and purchases may be increased, decreased or discontinued at any time without prior notice. There were no shares repurchased in the first quarter of 2010, or since the quarter ended September 30, 2007.

Issuer Purchases of Equity Securities for the Quarter Ended March 31, 2010

	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of shares that may yet be Purchased Under the Plans or Programs
January, 2010	None	NA	None	2,635,700
February, 2010	None	NA	None	2,635,700
March, 2010	None	NA	None	2,635,700

5. 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 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 three months ended March 31, 2010 (in thousands):

Asset retirement obligation at January 1, 2010	$	149,310
Liabilities incurred		538
Liability settlements and disposals		(2,116)
Accretion expense		1,973
Revisions of estimated liabilities		
Asset retirement obligation at March 31, 2010		149,705
Less current obligation		(21,821)
Long-term asset retirement obligation	$	127,884

6. Long-Term Debt

Debt at March 31, 2010 and December 31, 2009 consisted of the following (in thousands):

		March 31, 2010		December 31, 2009
Bank debt	$		$	25,000
7.125% Notes due 2017		350,000		350,000
Floating rate convertible notes due 2023 (face value $19,450)		17,832		17,793
Total long-term debt	$	367,832	$	392,793

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(Unaudited)

Bank Debt

We have a three-year senior secured revolving credit facility (credit facility). The credit facility provides for bank commitments of $800 million, with a borrowing base of $1 billion. The credit facility is provided by a syndicate of banks led by JP Morgan Chase Bank, N.A., matures on April 14, 2012 and is secured by mortgages on certain of our oil and gas properties and the stock of certain wholly-owned operating subsidiaries.

The borrowing base under the credit agreement is determined at the discretion of the lenders, based on the collateral value of our proved reserves, and is subject to potential special and regular semi-annual redeterminations. The borrowing base of $1 billion and bank commitments of $800 million were reaffirmed in April 2010.

The credit facility contains covenants and restrictive provisions which may limit our ability to incur additional indebtedness, make investments or loans and create liens. The credit agreement requires us to maintain a current ratio (defined to include undrawn borrowings) greater than 1 to 1 and a leverage ratio not to exceed 3.5 to 1. As of March 31, 2010, we were in compliance with all of the financial and non-financial covenants.

At Cimarex s option, borrowings under the credit facility may bear interest at either (a) a London Interbank Offered Rate (LIBOR) plus 2 to 3 percent, based on borrowing base usage, or (b) the higher of (i) a prime rate, (ii) the federal funds effective rate plus 0.50 percent, or (iii) adjusted LIBOR, in each case plus an additional 1.125 to 2.125 percent based on borrowing base usage.

At March 31, 2010, there were no outstanding borrowings under the credit facility. We had letters of credit outstanding of $14.4 million leaving an unused borrowing availability of $785.6 million.

7.125% 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%

At any time prior to May 1, 2010, we may redeem up to 35% of the original principal amount of the notes with the proceeds of certain equity offerings of our shares of common stock at a redemption price of 107.125% of the principal amount of the notes, together with accrued and unpaid interest, if any, to the date of redemption. At any time prior to May 1, 2012, we may also redeem all, but not part, of the notes at a price of 100% of the principal amount of the notes plus accrued and unpaid interest plus a make-whole premium.

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.

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Floating rate convertible notes due 2023

The floating rate convertible senior notes mature on December 15, 2023. The notes are senior unsecured obligations and bear interest at the three month LIBOR, reset quarterly. On March 31, 2010, the interest rate was approximately 0.26%.

We previously repurchased $105.5 million of these borrowings at the option of the holders. Holders of the remaining $19.5 million of notes have optional repurchase dates as of December 15, 2013, and 2018.

In addition to the repurchase rights, holders of the convertible notes may surrender their notes for conversion into a combination of cash and shares of our common stock upon the occurrence of certain circumstances, including if the price of our common stock has been trading above 110% of the conversion price of $28.59 per share for a defined period of time. Based upon the price of our common stock, the notes were not convertible for the first nine months of 2009. The notes became convertible effective October 1, 2009 and continue to be convertible through the first and second quarters of 2010.

At our option, we may offer to redeem the notes at any time at par. In addition, if a 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.

The debt and equity components of the instruments are accounted for separately. The value assigned to the debt component is the estimated value of similar debt without a conversion feature as of the issuance date, with the remaining proceeds allocated to the equity component and recorded as additional paid-in capital. The debt component is recorded at a discount and is subsequently accreted to its par value, thereby reflecting an overall market rate of interest in the income statement. The effective interest rate for the quarters ended March 31, 2010 and 2009 was 1.2% and 3.0%, respectively.

7. Income Taxes

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

	Three Months Ended March 31, 2010		2009
Current provision (benefit)	$ 33,364		$ (15,209)
Deferred tax (benefit)	84,990		(269,752)
	$ 118,354		$ (284,961)

We account for uncertainty in our income tax provisions in accordance with rules promulgated by the FASB. At March 31, 2010 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 2008 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 2008 for examination.

Our provision for income taxes differed from the U.S. statutory rate of 35% primarily due to state income taxes, non-deductible expenses, and special deductions. The effective income tax rate for the three months ended March 31, 2010 was 36.7%.

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Notes to Consolidated Financial Statements (Continued)

March 31, 2010

(Unaudited)

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

	Three Months Ended March 31, 2010		Three Months Ended March 31, 2009	
Cash paid during the period for:				
Interest expense	$	1,371	$	1,837
Interest capitalized		7,424		5,513
Income taxes		22,945		20
Cash received for income taxes		1,866		41,982

9. Earnings (Loss) per Share and Comprehensive Income

Earnings (Loss) per Share

We calculate earnings (loss) per share based on FASB guidance which holds that unvested share-based payment awards that contain non-forfeitable 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. We adopted this guidance in the first quarter of 2009.

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(Unaudited)

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

	Three Months Ended March 31,			
		2010		2009
Net income (loss)	$	204,361	$	(494,100)
Less distributed earnings (dividends declared during the period)		(6,759)		(5,038)
Undistributed earnings (loss) for the period	$	197,602	$	(499,138)
Allocation of undistributed earnings(loss):				
Basic allocation to unrestricted common stockholders	$	191,740	$	(499,138)
Basic allocation to participating securities	$	5,862	$	(2)
Diluted allocation to unrestricted common stockholders	$	191,799	$	(499,138)
Diluted allocation to participating securities	$	5,803	$	(2)
Basic Shares Outstanding				
Unrestricted outstanding common shares		82,023		81,684
Add Participating securities:				
Restricted stock outstanding		1,860		1,613
Restricted stock units outstanding		648		651
Total participating securities		2,508		2,264(2)
Total basic shares outstanding		84,531		83,948
Fully Diluted Shares				
Unrestricted outstanding common shares		82,023		81,684
Incremental shares from assumed exercise of stock options		477		(1)
Incremental shares from assumed conversion of the convertible senior notes		370		(1)
Fully diluted common stock		82,870		81,684
Participating securities		2,508		2,264(2)
Total Fully Diluted Shares		85,378		83,948
Basic earnings (loss) per share				
Unrestricted common stockholders:				
Distributed earnings	$	0.08	$	0.06
Undistributed earnings (loss)		2.34		(6.11)
	$	2.42	$	(6.05)
Participating securities:				
Distributed earnings	$	0.08	$	0.06
Undistributed earnings		2.34		0.00
	$	2.42	$	0.06
Fully diluted earnings (loss) per share				
Unrestricted common stockholders:				

Distributed earnings	$	0.08	$	0.06
Undistributed earnings (loss)		2.31		(6.11)
	$	2.39	$	(6.05)
Participating securities:				
Distributed earnings	$	0.08	$	0.06
Undistributed earnings		2.31		0.00
	$	2.39	$	0.06

(1) No potential common shares or securities are included in the diluted share computation when a loss from continuing operations exists.

(2) Participating securities are included in distributed earnings and not in undistributed earnings when a loss from continuing operations exists.

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March 31, 2010

(Unaudited)

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

	March 31, 2010	March 31, 2009
Stock options	1,484,559	1,493,116
Restricted stock	1,860,150	1,612,745
Restricted units	647,507	651,672

Certain stock options and restricted units and shares were considered to be anti-dilutive as follows:

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
Stock options	413,265	1,493,116
Restricted stock		1,612,745
Restricted units		651,672
	413,265	3,757,533

Comprehensive Income (Loss)

Comprehensive income is a term used to refer to net income (loss) plus other comprehensive income (loss). 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 (loss).

The components of comprehensive income (loss) are as follows (in thousands):

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009

Net Income (loss)	$	204,361	$	(494,100)
Other comprehensive income (loss):				
Change in fair value of investments, net of tax		99		235
Total comprehensive income (loss)	$	204,460	$	(493,865)

10. 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. Only $6.9 million of the judgment pertained to damages, with the remainder being disgorgement of H&P s estimated potential compounded profit since 1989 resulting from the noted damages. 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 had accrued litigation expense of $119.6 million for this lawsuit. During 2009 and the first quarter of 2010, we have accrued an additional $9.4 million and $2.2 million, respectively. We have appealed the District Court s judgments.

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(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 a large development project in Sublette County, Wyoming where we are developing the deep Madison gas formation and constructing a gas processing plant. At March 31, 2010, we had commitments of $141.6 million relating to construction of the gas processing plant of which $86.7 million is subject to a construction contract. The total cost of the project will approximate $347 million. Pursuant to the terms of our operating agreement with our partners in this project, we will be reimbursed by them for 42.5% of the costs. The gas processing plant is subject to a delivery commitment agreement over a 20 year period, commencing December, 2011. If no deliveries were made, the maximum amount that would be payable under the agreement would be approximately $43 million.

We have drilling commitments of approximately $77.2 million consisting of obligations to complete drilling wells in progress at March 31, 2010. We also have minimum expenditure contractual commitments of $47.0 million to secure the use of drilling rigs.

At March 31, 2010, we have a purchase commitment of $11.1 million for construction of an aircraft. The total cost of the aircraft is $12.3 million with an option to trade in our existing aircraft. The completion of the aircraft is expected to be no later than October 30, 2010.

At March 31, 2010, we had firm sales contracts to deliver approximately 9.5 Bcf of natural gas over the next twelve months. If this gas is not delivered, our financial commitment would be approximately $35.7 million. This commitment will fluctuate due to price volatility and actual volumes delivered. However, we believe no significant financial commitment will be due based on our reserves and current production levels.

In connection with a gas gathering and processing agreement, we have commitments to deliver 49.7 Bcf of gas over the next four years. If no gas was delivered, the maximum amount that would be payable under these commitments would be approximately $37.1 million, some of which would be reimbursed by working interest owners who are selling with us under our marketing agreement. We do not expect to make significant payments relative to these commitments.

We have other various delivery commitments in the normal course of business, none of which are individually material. In aggregate these commitments have a maximum amount that would be payable, if no gas is delivered, of approximately $3.2 million, some of which would be reimbursed by working interest owners who are selling with us under our marketing agreements.

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

11. Property Sales and Acquisitions

During the first quarter of 2010 we had property acquisitions of $23.2 million, primarily for additional interests in our Anadarko Basin, Cana-Woodford shale play. 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. This first quarter acquisition was structured to qualify as the first step of a reverse like-kind exchange. We utilized an exchange accommodation titleholder, a type of variable interest entity, for which we are the primary beneficiary. Accordingly, as of the acquisition date, we have consolidated the oil and gas assets and reserves, as well as production, revenues and expenses attributable to these properties. Subsequent to March 31, 2010 we agreed to acquire additional interests in our Cana-Woodford shale play for approximately $9.4 million.

We had no significant property sales during the first quarter of 2010.

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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. 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 located in Texas, Oklahoma, New Mexico, Kansas and Wyoming.

Our revenue, profitability and future growth are highly dependent on the commodity prices we receive. Our ability to find, develop and/or acquire proved oil and gas reserves will also impact our financial results. Continued volatility in commodity prices, and turmoil in the global financial system may have adverse effects on our business and financial position. Our ability to access the capital markets may be restricted, which could have an impact on our flexibility to react to changing economic and business conditions. Further, the global economic situation could have an impact on our lenders, business partners and customers, potentially causing them to fail to meet their obligations to us.

Due to lower commodity prices we sharply reduced our capital investments during 2009. In 2009, investments in oil and gas exploration, development and acquisition activities totaled $528 million. Our exploration and development capital investment is expected to increase to $700-$900 million in 2010, depending on commodity prices and corresponding cash flow. At March 31, 2009 we had four operated rigs running. At March 31, 2010 we had 16 operated rigs running.

First quarter 2010 summary financial and operating results:

- First quarter production volumes averaged 584.5 MMcfe/d, up from 489.0 MMcfe/d for first quarter 2009.
- First quarter sales of oil, gas and NGLs increased 119% to $432 million, from $197 million a year earlier.
- The average realized oil price increased 112% to $76.11 per barrel compared to $35.86 per barrel in 2009.

- The average realized gas price increased 67% to $6.41 per Mcf versus $3.83 per Mcf in 2009.

- The average realized NGL price increased 40% to $39.18 per barrel compared to $27.96 per barrel in 2009.

- First quarter cash flow from operating activities was $299.1 million, up from $82.6 million a year earlier.

- Net income of $204.4 million ($2.39 per diluted share) increased from a net loss of $494.1 million ($6.05 per share) in 2009.

- Debt totaled $368 million at March 31, 2010, down from $393 million at year-end 2009.

- First quarter 2010 drilling included 37 gross (23.1 net) wells with 34 gross, (21.1 net), completed as producers, compared to 25 gross (15.2 net) wells with 23 gross (13.7 net) completed as producers for first quarter 2009.

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Commodity Prices

While our revenues are a function of both production and prices, wide swings in prices have had the greatest impact on our results of operations. The following table presents our average realized prices for each commodity, during the first quarter of 2010 versus 2009.

	Three Months Ended March 31, 2010	2009
Gas Prices:		
Average Henry Hub price ($/Mcf)	$ 5.30	$ 4.91
Average realized sales price ($/Mcf)	$ 6.41	$ 3.83
Oil Prices:		
Average WTI Cushing price ($/Bbl)	$ 78.72	$ 43.08
Average realized sales price ($/Bbl)	$ 76.11	$ 35.86
NGL Prices:		
Average realized sales price ($/Bbl)	$ 39.18	$ 27.96

On an energy equivalent basis, 67% of our first quarter 2010 aggregate production was natural gas. A $0.10 per Mcf change in our average realized gas sales price would have resulted in approximately a $3.5 million change in our gas revenues. Similarly, 33% 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 a $2.9 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.

In March, 2009 we entered into derivative gas contracts covering the period April 2009 through December 2009. During the second and third quarters of 2009 we entered into derivative contracts for a portion of our 2010 oil and gas production. As of March 31, 2010, the remaining 2010 contracts cover approximately 40% of our anticipated remaining 2010 oil and gas production volumes.

In March, 2010, we entered into derivative contracts for a portion of our 2011 oil production. Management has been authorized to hedge up to 50% of our anticipated 2011 equivalent oil and gas production. Subsequent to March 31, 2010, we entered into additional derivative contracts relative to our 2011 oil production.

We had the following outstanding contracts as of March 31, 2010:

Natural Gas Contracts

				Weighted Average Price		
Period	**Type**	**Volume/Day**	**Index(1)**	**Floor**	**Ceiling**	**Swap**
Apr 10 - Dec 10	Collar	100,000 MMBtu	PEPL	$ 5.00	$ 6.62	
Apr 10 - Dec 10	Swap	40,000 MMBtu	PEPL			$ 5.18
Apr 10 - Dec 10	Collar	20,000 MMBtu	HSC	$ 5.00	$ 6.85	

Oil Contracts

				Weighted Average Price	
Period	**Type**	**Volume/Day**	**Index(1)**	**Floor**	**Ceiling**
Apr 10 - Dec 10	Collar	10,000 Bbls	WTI	$ 60.03	$ 92.07
Apr 10 - Dec 10	Put/Floor	1,000 Bbls	WTI	$ 60.00	
Jan 11 - Dec 11	Collar	5,000 Bbls	WTI	$ 65.00	$ 105.64

(1) PEPL refers to Panhandle Eastern Pipe Line Company price and HSC refers to Houston Ship Channel price, both 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.

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We have chosen not to apply hedge accounting treatment to any of our derivative contracts entered into in 2009 and 2010. 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

The costs associated with finding and producing oil and gas are substantial. Some of these costs vary with commodity prices, some trend with production volume and some are a function of the number of wells we own. At the end of 2009, we owned interests in 12,320 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 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, while 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 or reclassifications from unproved properties to proved properties will impact depletion expense.

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 non-cash charges resulting from the issuance of restricted stock and restricted stock units to certain employees and the expensing of stock options. Net stock compensation expense in the first three months of 2010 was $2.8 million compared to $2.3 million in the first three months of 2009.

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. The amount will fluctuate, based on changes in the fair value of the underlying commodities. We had a net (gain) of $52.6 million and $0.1 million in the first quarter of 2010 and 2009, respectively.

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RESULTS OF OPERATIONS

Quarter ended March 31, 2010 vs. March 31, 2009

Net income for the first quarter of 2010 was $204.4 million, or $2.39 per diluted share. This compares to a net loss of $494.1 million, or $6.05 per share for the same period in 2009. The change in net income is primarily the result of a non-cash full cost ceiling write-down recorded in the first quarter of 2009 and the improvement of realized commodity prices in the first quarter of 2010 compared to 2009. These changes are discussed further in the analysis that follows.

Commodity Sales (In thousands or as indicated)	**For the Three Months Ended March 31, 2010**	**2009**	**Percent Change Between 2010/2009**	**Price/Volume Analysis Price**	**Volume**	**Variance**
Gas sales	$ 225,637	$ 116,624	93%	$ 90,752	$ 18,261	$ 109,013
Oil sales	191,560	79,337	141%	101,309	10,914	112,223
NGL Sales	15,209	1,268	1099%	4,353	9,588	13,941
Total sales	$ 432,406	$ 197,229		$ 196,414	$ 38,763	$ 235,177
Total gas volume MMcf	35,175	30,465	15%			
Gas volume MMcf per day	390.8	338.5				
Average gas price per Mcf	$ 6.41	$ 3.83	67%			
Total oil volume thousand barrels	2,517	2,212	14%			
Oil volume barrels per day	27,967	24,582				
Average oil price per barrel	$ 76.11	$ 35.86	112%			
Total NGL volume thousand barrels	388	45	762%			
NGL volume barrels per day	4,313	504				
Average NGL price per barrel	$ 39.18	$ 27.96	40%			

Commodity sales for the first quarter of 2010 totaled $432.4 million, compared to $197.2 million in 2009. The increase of $235.2 million between the two periods was mostly the result of higher commodity prices which had a positive impact of $196.4 million. Higher production volumes during the current quarter contributed an increase of $38.8 million, compared to the prior year.

Compared to the first quarter of 2009, our first quarter 2010 oil production increased by 14% to an average of 27,967 barrels per day. This increase resulted in $10.9 million of incremental revenues. Gas volumes averaged 390.8 MMcf per day in 2010 compared to 338.5 MMcf per day in the first quarter of 2009, resulting in an increase in revenues of $18.3 million. Our NGL volumes for the first quarter of 2010 increased to 4,313 barrels per day, compared to 504 barrels per day for the same period of 2009. This increase added $9.6 million of incremental revenue. First quarter 2010 production volumes totaled 584.5 MMcfe per day, up 95.5 MMcfe per day from the same period in 2009.

The increase in our first quarter 2010 production compared to the first quarter of 2009 is due to our successful exploration wells on our properties in the Gulf Coast and positive results from our drilling in the Anadarko Basin, Cana-Woodford area. Our increase in NGL production also comes from our wells in the Anadarko Basin, Cana-Woodford area. Most of our gas wells produce from reservoirs characterized by high initial production which decline rapidly and stabilize within three to five years.

Our average realized gas price increased by 67% to $6.41 per Mcf, for the three months ended March 31, 2010, compared to $3.83 per Mcf for the first quarter of 2009. This price increase raised gas sales by $90.8 million between the two periods. Our realized oil price averaged $76.11 per barrel during the first quarter of 2010,or an increase of 112%, compared to $35.86 per barrel for the same period in 2009. This resulted in increased oil sales of $101.3 million. The average NGL price we received in the first quarter of 2010 was $39.18 per barrel, up from $27.96 per barrel in 2009. The increase in the average NGL price increased NGL sales by $4.4 million.

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

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	For the Three Months Ended March 31, 2010	2009
Gas Gathering, Processing, Marketing and Other (in thousands):		
Gas gathering, processing and other revenues	$ 15,850	$ 11,070
Gas gathering and processing costs	(6,505)	(5,106)
Gas gathering, processing and other margin	$ 9,345	$ 5,964
Gas marketing revenues, net of related costs	$ 314	$ 880

We sometimes transport, process and market third-party gas that is associated with our gas. In the first quarter of 2010, third-party gas gathering, processing and other contributed $9 million of pre-tax cash operating margin (revenues less direct cash expenses) versus $6 million in 2009. Our gas marketing margin (revenues less purchases) decreased to $0.3 million in the first quarter of 2010 from $0.9 million in the first quarter of 2009. Changes in net margins from gas gathering, processing, marketing and other activities are the direct result of changes in volumes and overall market conditions.

	For the Three Months Ended March 31, 2010	2009	Variance Between 2010/2009
Operating costs and expenses (in thousands):			
Impairment of oil and gas properties	$	$ 791,137	$ (791,137)
Depreciation, depletion and amortization	69,710	89,666	(19,956)
Asset retirement obligation	2,644	2,545	99
Production	41,983	50,414	(8,431)
Transportation	11,167	8,709	2,458
Taxes other than income	32,358	15,545	16,813
General and administrative	13,045	7,762	5,283
Stock compensation	2,778	2,257	521
Gain on derivative instruments, net	(52,597)	(102)	(52,495)
Other operating, net	(1,846)	10,092	(11,938)
	$ 119,242	$ 978,025	$ (858,783)

Total operating costs and expenses (not including gas gathering, marketing and processing costs, or income tax expense) decreased $859 million to $119 million for the first quarter of 2010 compared to $978 million in the first quarter of 2009.

The largest component of the decrease between periods is the non-cash impairment of oil and gas properties of $791 million ($502 million net of tax) recorded in the first quarter of 2009. The impairment resulted from a ceiling test write-down as a result of declines in natural gas prices during the first quarter of 2009. Volatility of commodity prices could require us to record a ceiling test write-down in future periods. The full cost method of accounting is discussed in detail under Note 1 to the Consolidated Financial Statements.

DD&A decreased from $89.7 million in the first quarter of 2009 to $69.7 million in the same period of 2010. On a unit of production basis, DD&A was $1.33 per Mcfe in 2010 compared to $2.04 per Mcfe for 2009. The significant decrease in DD&A is due to the $791 million reduction to the carrying value of oil and gas properties recorded during the first quarter of 2009.

Production costs decreased $8.4 million from $50.4 million ($1.15 per Mcfe) in the first quarter of 2009 to $42 million ($0.80 per Mcfe) in the first quarter of 2010. Our production costs consist of workover expense and lease operating expenses. We have seen a decrease in costs in both of these areas. Lower lease operating expenses are a result of decreases in service costs and a continuing focus on efficiencies in production operations.

Transportation costs rose to $11.2 million in the first quarter of 2010 from $8.7 million in 2009. Transportation costs will fluctuate based on increases or decreases in sales volumes and fluctuation in the

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price of the fuel cost component. We also recorded $1.1 million of well connection reimbursement costs in the first quarter of 2010. These costs resulted from a failure to meet minimum volume delivery commitments entered into in prior years.

Taxes other than income were $16.8 million higher, increasing from $15.5 million in 2009 to $32.4 million in 2010. The increase between periods resulted from increases in oil and gas sales stemming from significantly higher commodity prices.

General and administrative (G&A) expenses increased $5.3 million from $7.8 million in the first quarter of 2009 to $13.0 million in the first quarter of 2010. The increase between periods is due to higher employee benefits related to increases in bonus and profit sharing expenses. Due to the low commodity prices in the first quarter of 2009, no bonus or profit sharing expenses were accrued.

A significant component of our operating costs and expense for the first quarter of 2010 is the $52.6 million net (gain) on derivative instruments. This includes both realized gains and losses on settlements of our derivative contracts and changes in the fair value of our outstanding derivative instruments. We estimate the fair values of our derivative financial instruments by using internal discounted cash flow calculations. The most significant variable to our cash flow calculations is our estimate of future commodity prices. We base our estimate of future prices upon published forward commodity price curves. We did not elect hedge accounting treatment for derivative contracts that we entered into in 2009 and 2010. In the first quarter of 2010 we recorded a net unrealized gain of $52.1 million and a net realized gain of $0.5 million. In the first quarter of 2009 we recorded an unrealized gain of $0.1 million on outstanding derivative instruments.

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. The change from an expense of $10.1 million in the first quarter of 2009 to a gain of $1.8 million for the first quarter of 2010 is due to fewer litigation accruals and the resolution of certain legal matters in the first quarter of 2010.

Other income and expense

Interest expense changed from $8.3 million in the first quarter of 2009 to $9.5 million for the same period of 2010. The $1.2 million increase is due to additional deferred financing costs associated with the new credit facility we entered into in April 2009.

Other, net changed from $2.4 million of expense in the first quarter of 2009 to $1.9 million of income in the first quarter of 2010. Components consist of miscellaneous income and expense items that will vary from period to period, including income and loss from equity investees, gain or loss on the sale or value of oil and gas well equipment and interest income. The change is primarily the result of losses in the first quarter of 2009 related to oil and gas well equipment. Due to the significant slowing of drilling activity across the industry, the value of drill pipe decreased.

Income tax expense

In the first quarter of 2010 we recognized $118.4 million of income tax expense, of which $33.4 million is current. This compares with first quarter 2009 current tax benefit of $15.2 million and a total income tax benefit of $285.0 million. The combined Federal and state effective income tax rates were 36.7% and 36.6% for the first quarters of 2010 and 2009, respectively. The effective tax rate of 36.7% for the first quarter of 2010 differs from the statutory rate of 35% primarily due to state income taxes, non-deductible expenses and special deductions.

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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. The ongoing turmoil in our economy and the global financial system may negatively impact realized commodity prices. Volatility in prices may reduce the amount of oil and gas that we can economically produce. Commodity prices also affect the amount of cash flow available for capital expenditures as well as our ability to borrow and raise additional capital. These conditions could 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 portfolio of exploration and development opportunities including our Anadarko Basin, Cana-Woodford shale gas development, our Permian Basin horizontal oil plays and our higher-risk geophysically driven Gulf Coast drilling program.

Historically our exploration and development expenditures have generally been funded by cash flow provided by operating activities (operating cash flow). In 2010 we intend to continue to fund our exploration and development expenditures primarily with operating cash flow. We will also continue to use debt sparingly and hedge a portion of our production, to protect our operating cash flow for reinvestment.

In addition, we will consider attractive acquisition opportunities. However, the timing and size of acquisitions are unpredictable. To ready ourselves for potential acquisitions and further declines in commodity prices, we have a three-year senior secured revolving credit facility. The credit facility provides for bank commitments of $800 million with a borrowing base of $1 billion.

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 2010 and beyond.

Analysis of Cash Flow Changes

Cash flow provided by operating activities for the first three months of 2010 was $299.1 million, compared to $82.6 million for the three months ended March 31, 2009. The $216.5 million increase in 2010 resulted primarily from higher revenues attributable to higher commodity prices and production volumes.

Cash flow used in investing activities for the first three months of 2010 was $211.4 million, compared to $200.8 million for the three months ended March 31, 2009. 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 increase from first quarter 2009 to 2010 was due to increased cash expenditures related to property acquisitions in 2010.

Net cash flow used for financing activities in the first three months of 2010 was $27.7 million versus net cash flow provided by financing activities of $120.0 million for the same period of 2009. In 2009 we had net borrowings under our credit facility of $125.0 million. In the first quarter of 2010 we had net payments to our credit facility of $25 million, resulting in zero bank debt outstanding at March 31, 2010.

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Reconciliation of Cash Flow From Operations

	For the Three Months Ended March 31, 2010	2009
	(In thousands)	
Net cash provided by operating activities	$ 299,107	$ 82,556
Change in operating assets and liabilities	14,100	55,090
Cash flow from operations	$ 313,207	$ 137,646

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 capitalized expenditures by us in our oil and gas acquisition, exploration, and development activities (in thousands):

	For the Three Months Ended March 31, 2010	2009
Acquisitions:		
Proved	$ 7,156	$ 75
Unproved	16,044	
	23,200	75
Exploration and development:		
Land and seismic	24,903	16,279
Exploration and development	167,686	125,752
	192,589	142,031
Property sales		(3,764)
	$ 215,789	$ 138,342

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 36 percent in the first quarter of 2010 compared to the first of quarter 2009. Due to significantly lower commodity prices, in 2009 we sharply reduced our development and exploration activities, especially in the first half of 2009. At March 31, 2009 we had four operated rigs running. At March 31, 2010 we had 16 operated rigs running.

In the first quarter of 2010 we drilled 37 gross (23.1 net) wells, with 34 gross (21.1 net) completed as producers. At quarter-end we also had 29 gross (18.5 net) wells that were in the process of being completed or were awaiting completion. During the first quarter of 2009 we drilled and completed 25 gross (15.2 net) wells, of which two gross (one net), were unsuccessful. At March 31, 2009 we had 16 gross (8.4 net) wells in the process of being completed.

Our planned exploration and development program for 2010 is expected to range from $700 to $900 million, depending on commodity prices and corresponding cash flow. Although our capital budget is set at a level that we believe corresponds with our anticipated cash flows, the timing of capital expenditures and the receipt of cash flows do not necessarily match. We anticipate borrowing and repaying funds under our credit arrangements throughout the year. For example, our planned capital expenditures are front-end loaded and we may outspend cash flows in the first half of the year. If we start to see a significant change in commodity prices from our current forecasts, we have the operational flexibility to react quickly with our capital expenditures to changes in our cash flows from operations.

During the first quarter of 2010 we had property acquisitions of $23 million, primarily for additional interests in our Anadarko Basin, Cana-Woodford shale play. Subsequent to March 31, 2010 we agreed to acquire additional interests in our Cana-Woodford shale play for approximately $9.4 million.

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We have a large development project in Sublette County, Wyoming where we are developing the deep Madison gas formation and constructing a gas processing plant. The total cost of the project will approximate $347 million. Pursuant to the terms of our operating agreement with our partners in this project, we are reimbursed by them for 42.5% of the costs. Through March 31, 2010 our cumulative investment in this project is $78 million, of which $61 million is included in our fixed assets. At present we expect to initiate gas sales from this project in 2011. Our share of the total investment, including planned expansion, will approximate $200 million.

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. 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

During the first quarter of 2010 our total assets increased by $264 million to $3.7 billion, up from $3.4 billion at December 31, 2009. The increase was primarily due to a $112 million increase in our current assets (mainly from increases in our cash and cash equivalents and derivative instruments) and an increase of $152 million in our net oil and gas assets. As of March 31, 2010, stockholders equity totaled $2.2 billion, up from $2.0 billion at December 31, 2009. The increase is a result of our first quarter 2010 net income of $204 million.

Dividends

On February 25, 2010 the Board of Directors increased our regular cash dividend on our common stock from $0.06 to $0.08 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 in the first quarter of 2010, or since the quarter ended September 30, 2007.

Working Capital

Working capital increased $83 million from year-end 2009 to $102 million at March 31, 2010. Working capital increased primarily because of the following:

- Cash and cash equivalents increased by $60 million primarily due to increases in commodity prices and production volumes.

- Our trade and commodity sales receivables increased by $40 million.

- The aggregate fair value of our derivative instruments increased by $53 million.

These working capital increases were partially offset by:

- Oil and gas well equipment and supplies decreased by $17 million, as supplies were used in the first quarter s drilling activities.

- A decrease of $16 million related to our deferred tax asset in the first quarter of 2010.

- An aggregate increase of $35 million of operations related accounts payable and accrued liabilities, resulting from increases in commodity prices, production volumes and increased drilling activity.

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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

Debt at March 31, 2010 and December 31, 2009 consisted of the following (in thousands):

	March 31, 2010	December 31, 2009
Bank debt	$	$ 25,000
7.125% Notes due 2017	350,000	350,000
Floating rate convertible notes due 2023 (face value $19,450)	17,832	17,793
Total long-term debt	$ 367,832	$ 392,793

Bank Debt

We have a three-year senior secured revolving credit facility (credit facility). The credit facility provides for bank commitments of $800 million, with a borrowing base of $1 billion. The credit facility is provided by a syndicate of banks led by JP Morgan Chase Bank, N.A., matures on April 14, 2012 and is secured by mortgages on certain of our oil and gas properties and the stock of certain wholly-owned operating subsidiaries.

The borrowing base under the credit agreement is determined at the discretion of the lenders, based on the collateral value of our proved reserves, and is subject to potential special and regular semi-annual redeterminations. The borrowing base of $1 billion and bank commitments of $800 million were reaffirmed in April 2010.

The credit facility contains covenants and restrictive provisions which may limit our ability to incur additional indebtedness, make investments or loans and create liens. The credit agreement requires us to maintain a current ratio (defined to include undrawn borrowings) greater than 1 to 1 and a leverage ratio not to exceed 3.5 to 1. As of March 31, 2010, we were in compliance with all of the financial and non-financial covenants.

At Cimarex s option, borrowings under the credit facility may bear interest at either (a) a London Interbank Offered Rate (LIBOR) plus 2 to 3 percent, based on borrowing base usage, or (b) the higher of (i) a prime rate, (ii) the federal funds effective rate plus 0.50 percent, or (iii) adjusted LIBOR, in each case plus an additional 1.125 to 2.125 percent based on borrowing base usage.

At March 31, 2010, there were no outstanding borrowings under the credit facility. We had letters of credit outstanding of $14.4 million leaving an unused borrowing availability of $785.6 million.

7.125% 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%

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At any time prior to May 1, 2010, we may redeem up to 35% of the original principal amount of the notes with the proceeds of certain equity offerings of our shares of common stock at a redemption price of 107.125% of the principal amount of the notes, together with accrued and unpaid interest, if any, to the date of redemption. At any time prior to May 1, 2012, we may also redeem all, but not part, of the notes at a price of 100% of the principal amount of the notes plus accrued and unpaid interest plus a make-whole premium.

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.

Floating rate convertible notes due 2023

The floating rate convertible senior notes mature on December 15, 2023. The notes are senior unsecured obligations and bear interest at the three month LIBOR, reset quarterly. On March 31, 2010, the interest rate was approximately 0.26%.

We previously repurchased $105.5 million of these borrowings at the option of the holders. Holders of the remaining $19.5 million of notes have optional repurchase dates as of December 15, 2013, and 2018.

In addition to the repurchase rights, holders of the convertible notes may surrender their notes for conversion into a combination of cash and shares of our common stock upon the occurrence of certain circumstances, including if the price of our common stock has been trading above 110% of the conversion price of $28.59 per share for a defined period of time. Based upon the price of our common stock, the notes were not convertible for the first nine months of 2009. The notes became convertible effective October 1, 2009 and continue to be convertible through the first and second quarters of 2010.

At our option, we may offer to redeem the notes at any time at par. In addition, if a 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.

The debt and equity components of the instruments are accounted for separately. The value assigned to the debt component is the estimated value of similar debt without a conversion feature as of the issuance date, with the remaining proceeds allocated to the equity component and recorded as additional paid-in capital. The debt component is recorded at a discount and is subsequently accreted to its par value, thereby reflecting an overall market rate of interest in the income statement. The effective interest rate for the quarters ended March 31, 2010 and 2009 was 1.2% and 3.0%, respectively.

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Contractual Obligations and Material Commitments

At March 31, 2010, we had contractual obligations and material commitments as follows:

		Payments Due by Period (In thousands)			
Contractual obligations	**Total**	**Less than 1 Year**	**1-3 Years**	**4-5 Years**	**More than 5 Years**
Long-term debt(1)	$ 369,450	$	$	$	$ 369,450
Fixed-Rate interest payments(1)	187,031	24,938	49,875	49,875	62,343
Operating leases	19,603	4,924	9,488	5,078	113
Drilling commitments(2)	124,175	98,070	26,105		
Purchase commitments(3)	11,051	11,051			
Gas processing facility(4)	86,709	40,056	21,957	24,696	
Asset retirement obligation	149,705	21,821	(5)	(5)	(5)
Other liabilities(6)	58,073	17,186	21,407	10,031	9,449

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

(2) We have drilling commitments of approximately $77.2 million consisting of obligations to complete drilling wells in progress at March 31, 2010. We also have minimum expenditure commitments of $47.0 million to secure the use of drilling rigs.

(3) At March 31, 2010, we have a purchase commitment of $11.1 million for construction of an aircraft. The total cost of the aircraft is $12.3 million with an option to trade in our existing aircraft. The completion of the aircraft is expected to be no later than October 30, 2010.

(4) We have a large development project in Sublette County, Wyoming where we are developing the deep Madison gas formation and constructing a gas processing plant. At March 31, 2010, we had commitments of $141.6 million relating to construction of the gas processing plant of which $86.7 million is subject to a construction contract. The total cost of the project will approximate $347 million. Pursuant to the terms of our operating agreement with our partners in this project, we will be reimbursed by them for 42.5% of the costs. The gas processing plant is subject to a delivery commitment agreement over a 20 year period, commencing December, 2011. If no deliveries were made, the maximum amount that would be payable under the agreement would be approximately $43 million.

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

(6) Other liabilities include the fair value of our liabilities associated with our derivative contracts, benefit obligations and other miscellaneous commitments.

At March 31, 2010, we had firm sales contracts to deliver approximately 9.5 Bcf of natural gas over the next twelve months. If this gas is not delivered, our financial commitment would be approximately $35.7 million. This commitment will fluctuate due to price volatility and actual volumes delivered. However, we believe no significant financial commitment will be due based on our reserves and current production levels.

In connection with a gas gathering and processing agreement, we have commitments to deliver 49.7 Bcf of gas over the next four years. If no gas was delivered, the maximum amount that would be payable under these commitments would be approximately $37.1 million, some of which would be reimbursed by working interest owners who are selling with us under our marketing agreement. We do not expect to make significant payments relative to these commitments.

We have other various delivery commitments in the normal course of business, none of which are individually material. In aggregate these commitments have a maximum amount that would be payable, if no gas is delivered, of approximately $3.2 million, some of which would be reimbursed by working interest owners who are selling with us under our marketing agreements.

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

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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.

2010 Outlook

Our exploration and development expenditures program for 2010 is projected to range from $700 million to $900 million. 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. It is also possible that we may increase our level of planned capital investment if our commodity prices exceed our current expectation or if attractive new opportunities arise. A majority of the expenditures will be in the Mid-Continent area, primarily in our Anadarko Basin, Cana-Woodford play. In addition we plan to continue to drill in our Permian Basin and Gulf Coast areas.

Production estimates for 2010 range from 570 to 595 MMcfe per day. 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 2009, our realized prices averaged $4.12 per Mcf of gas, $56.63 per barrel of oil and $37.11 per NGL. Prices can be very volatile and the possibility of 2010 realized prices being different than they were in 2009 is high.

Certain expenses for 2010 on a per Mcfe basis are currently estimated as follows:

		2010	
Production expense	$0.80	-	$1.00
Transportation expense	0.19	-	0.24
DD&A and Asset retirement obligation	1.40	-	1.70
General and Administrative	0.24	-	0.30
Production taxes (% of oil and gas revenue)	7.5%	-	8.5%

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

We consider accounting policies related to oil and gas reserves, full cost accounting, goodwill, derivatives, contingencies and asset retirement obligations to be critical policies and estimates. These critical policies and estimates are summarized in Management s Discussion and Analysis of Financial Condition and Results of Operations in our annual report on Form 10-K for the year ended December 31, 2009.

Recent Accounting Developments

There have been no significant accounting standards applicable to Cimarex issued during the quarter ended March 31, 2010.

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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 March 31, 2010:

Natural Gas Contracts

Period	Type	Volume/Day	Index(1)	Weighted Average Price Floor	Weighted Average Price Ceiling	Weighted Average Price Swap	Fair Value (000 s)
Apr 10 - Dec 10	Collar	100,000 MMBtu	PEPL	$ 5.00	$ 6.62		$ 29,505
Apr 10 - Dec 10	Swap	40,000 MMBtu	PEPL			$ 5.18	$ 12,783
Apr 10 - Dec 10	Collar	20,000 MMBtu	HSC	$ 5.00	$ 6.85		$ 5,209

Oil Contracts

Period	Type	Volume/Day	Index(1)	Weighted Average Price Floor	Weighted Average Price Ceiling	Fair Value (000 s)
Apr 10 - Dec 10	Collar	10,000 Bbls	WTI	$ 60.03	$ 92.07	$ (7,205)
Apr 10 - Dec 10	Put/Floor	1,000 Bbls	WTI	$ 60.00		$ 141
Jan 11 - Dec 11	Collar	5,000 Bbls	WTI	$ 65.00	$ 105.64	$ (1,483)

(1) PEPL refers to Panhandle Eastern Pipe Line Company price and HSC refers to Houston Ship Channel price, both 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.

While these contracts limit the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. For the 2010 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 2010 of $4.4 million. For the 2010 and 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 2010 of $4.9 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. Our commodity derivative contracts are held with eight separate 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.

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Interest Rate Risk

At March 31, 2010 our debt was comprised of the following (in thousands):

	Fixed Rate Debt	Variable Rate Debt
7.125% Notes due 2017	$ 350,000	$
Floating rate convertible notes due 2023 (face value $19,450)		17,832
Total long-term debt	$ 350,000	$ 17,832

Our senior unsecured notes bear interest at a fixed rate of 7.125% and will mature on May 1, 2017, and our unsecured convertible senior notes bear interest at an annual rate of three-month LIBOR, reset quarterly.

We consider our interest rate exposure to be minimal because approximately 95% of our long-term debt obligations were at fixed rates. An increase of 100 basis points in the three-month LIBOR rate would increase our annual interest expense by $195 thousand. This sensitivity analysis for interest rate risk excludes accounts receivable, accounts payable and accrued liabilities because of the short-term maturity of such instruments. See Note 3 and Note 6 to the Consolidated Financial Statements in this report for additional information regarding debt.

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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 March 31, 2010 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 March 31, 2010, 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 March 31, 2010, that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

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PART II

ITEM 6 EXHIBITS

31.1 Certification of F. H. Merelli, 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 F. H. Merelli, 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 The following materials from the Cimarex Energy Co. Quarterly Report on Form 10-Q for the quarter ended March 31, 2010, formatted in XBRL (eXtensible Business Reporting Language) includes (i) the Consolidated Statements of Operations, (ii) the Consolidated Balance Sheets, (iii) the Consolidated Statements of Cash Flows, and (iv) Notes to the Consolidated Financial Statements, tagged as blocks of text.*

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* Users of this data are advised pursuant to Rule 401 of Regulation S-T that the financial information contained in the XBRL-Related Documents is unaudited. Furthermore, users of this data are advised in accordance with Rule 406T of Regulation S-T promulgated by the Securities and Exchange Commission that this Interactive Data File is deemed not filed or part of a registration statement or prospectus for purposes of sections 11 or 12 of the Securities Act of 1933, as amended, is deemed not filed for purposes of section 18 of the Securities Exchange Act of 1934, as amended, and otherwise is not subject to liability under these sections.

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SIGNATURES

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

May 7, 2010

CIMAREX ENERGY CO.

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

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