CIMAREX ENERGY CO
Form 10-Q
May 06, 2009
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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, 2009

Commission File No. 001-31446

CIMAREX ENERGY CO.

1700 Lincoln Street, Suite 1800

Denver, Colorado 80203-4518

(303) 295-3995

Incorporated in the State of Delaware	**Employer Identification 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 o 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, 2009 was 83,296,484.

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In this report, we use terms to discuss oil and gas producing activities as defined in Rule 4-10(a) of Regulation S-X. We express quantities of natural gas in terms of thousand cubic feet (Mcf), million cubic feet (MMcf) or billion cubic feet (Bcf). MMBtu is one million British Thermal Units, a common energy measurement. Oil is quantified in terms of barrels (Bbls), thousands of barrels (MBbls) and millions of barrels (MMBbls). Oil is compared to natural gas in terms of equivalent thousand cubic feet (Mcfe) or equivalent million cubic feet (MMcfe). One barrel of oil is the energy equivalent of six Mcf of natural gas. Information relating to our working interest in wells or acreage, net oil and gas wells or acreage is determined by multiplying gross wells or acreage by our working interest therein. Unless otherwise specified, all references to wells and acres are gross.

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PART I

ITEM 1 - Financial Statements

CIMAREX ENERGY CO.

Consolidated Balance Sheets

(Unaudited)

	March 31, 2009	December 31, 2008
	(In thousands, except share data)	
Assets		
Current assets:		
Cash and cash equivalents	$ 2,958	$ 1,213
Restricted cash	502	502
Short-term investments	1,610	2,502
Receivables, net	171,851	259,082
Inventories	208,027	186,062
Deferred income taxes	6,282	2,435
Derivative instruments	6,736	
Other current assets	53,868	63,148
Total current assets	451,834	514,944
Oil and gas properties at cost, using the full cost method of accounting:		
Proved properties	7,240,166	7,052,464
Unproved properties and properties under development, not being amortized	416,646	465,638
	7,656,812	7,518,102
Less accumulated depreciation, depletion and amortization	(5,591,584)	(4,709,597)
Net oil and gas properties	2,065,228	2,808,505
Fixed assets, net	122,837	119,616
Goodwill	691,432	691,432
Other assets, net	29,229	30,436
	$ 3,360,560	$ 4,164,933
Liabilities and Stockholders Equity		
Current liabilities:		
Accounts payable	$ 35,579	$ 101,157
Accrued liabilities	178,230	263,994
Revenue payable	84,359	104,438
Total current liabilities	298,168	469,589
Long-term debt	712,672	587,630

Deferred income taxes		235,147		500,945
Other liabilities		260,540		255,122
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, 84,181,876 and 84,144,024 shares issued, respectively		842		841
Treasury stock, at cost, 885,392 and 885,392 shares held, respectively		(33,344)		(33,344)
Paid-in capital		1,876,127		1,874,834
Retained earnings		11,128		510,271
Accumulated other comprehensive loss		(720)		(955)
		1,854,033		2,351,647
	$	3,360,560	$	4,164,933

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, 2009		For the Three Months Ended March 31, 2008	
	(In thousands, except per share data)			
Revenues:				
Gas sales	$	116,624	$	258,955
Oil sales		80,605		195,450
Gas gathering, processing and other		11,070		21,838
Gas marketing, net		880		967
		209,179		477,210
Costs and expenses:				
Impairment of oil and gas properties		791,137		
Depreciation, depletion and amortization		89,666		125,556
Asset retirement obligation		2,545		1,594
Production		50,414		52,052
Transportation		8,709		8,309
Gas gathering and processing		5,106		10,175
Taxes other than income		15,545		30,607
General and administrative		7,762		11,584
Stock compensation, net		2,257		2,275
Unrealized gain on derivative instruments		(102)		
Other operating, net		10,092		1,036
		983,131		243,188
Operating income (loss)		(773,952)		234,022
Other (income) and expense:				
Interest expense		8,267		8,697
Capitalized interest		(5,513)		(4,606)
Other, net		2,355		(3,017)
Income (loss) before income tax		(779,061)		232,948
Income tax expense (benefit)		(284,961)		83,410
Net income (loss)	$	(494,100)	$	149,538
Earnings (loss) per share to common stockholders:				
Basic				
Distributed	$	0.06	$	0.06
Undistributed		(6.11)		1.73
	$	(6.05)	$	1.79
Diluted				
Distributed	$	0.06	$	0.06
Undistributed		(6.11)		1.67
	$	(6.05)	$	1.73

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, 2009 (In thousands)	2008
Cash flows from operating activities:		
Net income (loss)	$ (494,100)	$ 149,538
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Impairment of oil and gas properties	791,137	
Depreciation, depletion and amortization	89,666	125,556
Asset retirement obligation	2,545	1,594
Deferred income taxes	(269,752)	55,492
Stock compensation, net	2,257	2,275
Unrealized gain on derivative instruments	(102)	
Changes in non-current assets and liabilities	4,426	62
Other	7,144	245
Changes in operating assets and liabilities:		
(Increase) decrease in receivables, net	87,231	(40,649)
Increase in other current assets	(19,319)	(6,437)
Increase (decrease) in accounts payable and accrued liabilities	(118,577)	27,569
Net cash provided by operating activities	82,556	315,245
Cash flows from investing activities:		
Oil and gas expenditures	(197,549)	(284,281)
Proceeds from sale of assets	3,824	104
Sales of short-term investments	923	5,000
Other expenditures	(7,967)	(8,994)
Net cash used by investing activities	(200,769)	(288,171)
Cash flows from financing activities:		
Net increase (decrease) in bank debt	125,000	
Financing costs incurred	(2)	
Dividends paid	(5,040)	(4,953)
Issuance of common stock and other		2,116
Net cash provided by (used in) financing activities	119,958	(2,837)
Net change in cash and cash equivalents	1,745	24,237
Cash and cash equivalents at beginning of period	1,213	123,050
Cash and cash equivalents at end of period	$ 2,958	$ 147,287

See accompanying notes to consolidated financial statements.

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements

March 31, 2009

(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 2008 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.

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 are determined based on current oil and gas prices and are adjusted for designated cash flow hedges, if any. Changes in proved reserve estimates (whether based upon quantity revisions or oil and gas 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. However, if commodity prices increase after period end and before issuance of the financial statements, these higher commodity prices may be used to determine if the capital costs are in fact impaired as of the end of the period. Any recorded impairment of oil and gas properties is not reversible at a later date.

Due to the significant decrease in natural gas prices since December 31, 2008, 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. Our quarterly and annual ceiling tests are primarily impacted by period end 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, 2009 would have resulted in an additional ceiling test impairment of approximately 14% of our full cost pool. Also, goodwill could potentially be impaired. Changes in actual reserve quantities added and produced along with our actual overall exploration and development costs will determine the Company s actual ceiling test calculation and impairment analyses.

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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 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, 2009, 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, 2009, the estimated fair value was higher than the recorded net book value. Therefore, no impairment was deemed to exist and no further testing was required.

If the estimated fair value is below the recorded net book value, a second step must be performed to determine the goodwill impairment required, if any. In this second step, the estimated fair value from the first step is used as the purchase price in a hypothetical acquisition of the Company. Purchase business combination accounting rules are followed to determine a hypothetical purchase price allocation to the Company s assets and liabilities. The residual amount of goodwill that results from this hypothetical purchase price allocation is compared to the recorded amount of goodwill and the recorded amount is written down to the hypothetical amount, if lower.

There have recently been severe disruptions in the credit markets and reductions in global economic activity which had significant adverse impacts on stock markets and oil-and-gas-related commodity prices. Management must apply judgment in determining the estimated fair value of the Company for purposes of performing the goodwill impairment test. As of March 31, 2009, the book value per share of our common stock exceeded the market price by less than $4 per share. 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 used all available information to make these fair value determinations, including the present values of expected future cash flows using discount rates commensurate with the risks involved in the assets.

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,

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(Unaudited)

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 2009 financial statement presentation. We adopted FSP APB 14-1 and FSP EITF 03-6-1 (see Notes 5 and 9, respectively) in the first quarter of 2009. Accordingly, prior periods have been adjusted retrospectively to conform to the applicable accounting pronouncements.

2. Derivative Instruments/Hedging

We have periodically entered into derivative instruments to mitigate a portion of our potential exposure to a decline in natural gas prices and the corresponding negative impact on cash flow available for reinvestment. While we could also hedge our exposure to oil prices and interest rates, we have not chosen to do so.

In March 2009, we entered into collar agreements that commence in April 2009 to hedge an average of approximately 148,000 MMBtu per day through December of our anticipated Mid-Continent gas production. These contracts are indexed to Mid-Continent pricing and have floors of $3.00 and ceilings of $5.00 and will expire monthly through the end of 2009. In order to obtain the floor and ceiling we wanted, we paid $6.6 million. These contracts represent approximately 50% of our total anticipated gas production for the remainder of 2009.

2009 Mid-Continent Gas price Collar Contracts

Period	**Type**	**Volume/Day**	**Duration**	**Mid-Continent Price**			**Fair Value (000 s)**	
Second quarter	Collar	150,000 MMBTU	Apr 09 - Jun 09	$3.00	-	$5.00	$	5,618
Third quarter	Collar	150,000 MMBTU	July 09 - Sept 09	$3.00	-	$5.00		2,189
Fourth quarter	Collar	143,370 MMBTU	Oct 09 - Dec 09	$3.00	-	$5.00		(1,071)

$	6,736

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.

At March 31, 2009, the fair value of these contracts was $6.7 million and was recorded as a current asset. We have elected not to account for these derivatives as cash flow hedges. Therefore, we will recognize all unrealized changes in fair value in earnings, rather than deferring such amounts in accumulated other comprehensive income (which is included in shareholders equity). The realized gains or losses upon settlement of the contracts will be reflected in operating income or expense, instead of being recorded as an adjustment to the realized gas sales price.

We are exposed to financial risks associated with these contracts if the index exceeds the ceiling and from non-performance by the counterparties to these contracts. Our counterparties are five large financial institutions, each of which has a high credit rating and is a member of our bank credit facility.

During 2008, we had zero-cost collars covering 40,000 MMBtu/d with Mid-Continent weighted average floor and ceiling prices of $7.00 to $9.90 for 2008. These contracts were designated as cash flow hedges for accounting purposes. At March 31, 2008, the remaining contracts outstanding represented approximately 13% of our remaining 2008 gas production.

We received $1.0 million of settlements during the first quarter of 2008. The settlements were recorded in gas sales and increased the average realized price for the period by $0.03 per Mcf. We also recognized an unrealized loss of $354 thousand related to the ineffective portion of the derivative contracts.

At March 31, 2008, the fair value calculation of the remaining contracts was a current liability of approximately $6.8 million. An unrealized loss (net of deferred income taxes) of $4.1 million was recorded in other comprehensive income. These contracts expired during the remaining nine months of 2008.

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3. Fair Value Measurements

Our short-term investments are reported at fair value in the accompanying balance sheets. SFAS No. 157, *Fair Value Measurements* 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, 2009 and December 31, 2008.

March 31, 2009:		**Carrying Amount**		**Fair Value**
		(In thousands)		
Financial Assets (Liabilities):				
Short-term investments	$	1,610	$	1,610
Derivative instruments	$	6,736	$	6,736
7.125% Notes due 2017	$	(350,000)	$	(280,000)
Bank debt	$	(345,000)	$	(345,000)
Floating rate convertible notes due 2023	$	(17,672)	$	(19,450)

December 31, 2008:		**Carrying Amount**		**Fair Value**
		(In thousands)		
Financial Assets (Liabilities):				
Short-term investments	$	2,502	$	2,502
7.125% Notes due 2017	$	(350,000)	$	(267,750)
Bank debt	$	(220,000)	$	(220,000)
Floating rate convertible notes due 2023	$	(21,223)	$	(19,450)

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.

Short-term Investments (Level 2)

In the fourth quarter of 2007, we invested $16 million in an asset-backed securities fund, which we expect to be liquidated in 2009. The investments are classified as available-for-sale, and at the end of each period, changes in the fair value of the investments are recorded in other comprehensive income. The fair values of these investments are based on a net asset valuation provided by the fund manager. During 2009, we liquidated $907 thousand of the investments, with a realized loss of $189 thousand which was included in earnings for the period. We also reflected an unrealized gain of $204 thousand in other comprehensive income as of March 31, 2009. During 2008, we liquidated $10.4 million of the investments, with a realized loss of $395 thousand and an impairment charge of $801 thousand, both of which were included in earnings for the period. We also reflected an unrealized loss of $664 thousand in other comprehensive income as of December 31, 2008.

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Bank Debt and Notes

Debt

The fair value of our bank debt is estimated to approximate the carrying amount as the interest is a floating rate based on either the London Interbank Offered Rate (LIBOR) or the JP Morgan Chase Bank prime rate and resets periodically.

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. The fair value of the notes is estimated to approximate the face value of the notes, because the notes bear interest at LIBOR, and reset quarterly. The conversion rate of $28.59 attributable to the conversion feature at March 31, 2009 and December 31, 2008 exceeded the closing price of our common stock; therefore, no value was attributed to the conversion feature at either date.

Derivative Instruments (Level 2)

The fair value of our derivative instruments at March 31, 2009 was estimated using internal risk adjusted discounted cash flow calculations based on the stated contract prices and current and projected market prices at March 31, 2009. At December 31, 2008, we had no derivative instruments outstanding.

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, 2009 and December 31, 2008, the aggregate allowance for doubtful accounts for trade, oil and gas sales, and gas gathering, processing, and marketing receivables was $5.8 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

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, 2009, we issued a total of 228,000 restricted shares 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.

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(Unaudited)

The following table presents restricted stock activity as of March 31, 2009, and changes during the year:

Outstanding as of January 1, 2009	1,672,245
Vested	(155,040)
Granted	228,000
Canceled	(132,460)
Outstanding as of March 31, 2009	1,612,745

The following table presents restricted unit activity as of March 31, 2009 and changes during the year:

Outstanding as of January 1, 2009	655,205
Converted to Stock	(3,533)
Granted	
Canceled	
Outstanding as of March 31, 2009	651,672
Vested included in outstanding	592,714

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 also applies. 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, 2009 and 2008, total compensation expense (including capitalized amounts) equaled $2.3 million and $3.6 million, respectively.

Unamortized compensation costs related to unvested restricted shares and units at March 31, 2009 and 2008 was $34.3 million and $34.5 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 no stock options granted to employees during the three months ended March 31, 2009 and 2008.

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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, 2009	1,532,016	$ 29.95		
Exercised				
Granted				
Canceled	(38,900)	56.74		
Outstanding as of March 31, 2009	1,493,116	$ 29.26	5.2 Years	$ 2,257
Exercisable as of March 31, 2009	1,002,396	$ 17.17	3.3 Years	$ 2,257

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, 2008 was $958 thousand. The related tax benefits realized from option exercises totaled $1.2 million and were recorded to paid-in capital. The total intrinsic value of stock options exercised during the three months ended March 31, 2008 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, 2009 and changes during the year:

	Shares	Weighted Average Grant Date Fair Value	Weighted Average Exercise Price
Non-vested as of January 1, 2009	529,620	$ 18.96	$ 54.15
Vested			
Granted			
Forfeited	(38,900)	19.43	56.74
Non-vested as of March 31, 2009	490,720	$ 18.92	$ 53.94

Compensation cost for stock options is determined pursuant to SFAS No. 123R. Historical amounts may not be representative of future amounts as additional options may be granted. We recognize compensation cost related to stock options ratably over the vesting period. For the three months ended March 31, 2009 and 2008, compensation cost (including capitalized amounts) equaled $664 thousand and $82 thousand, respectively.

As of March 31, 2009, there was $7.3 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 2.4 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

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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 December 2008, the Board of Directors declared a cash dividend of $0.06 per share on our common stock. The dividend was paid on March 2, 2009 to stockholders of record on February 13, 2009. The Board of Directors declared our first quarterly cash dividend of $0.04 per share in December 2005. A dividend has been declared in every quarter since then. Future dividend payments will depend on the Company s level of earnings, financial requirements, and other factors considered relevant by the Board of Directors.

In December 2005, the Board of Directors authorized the repurchase of up to four million shares of our common stock. The authorization is currently set to expire on December 31, 2009. 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 2009, or since the quarter ended September 30, 2007.

Issuer Purchases of Equity Securities for the Quarter Ended March 31, 2009

	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, 2009	None	NA	None	2,635,700
February, 2009	None	NA	None	2,635,700
March, 2009	None	NA	None	2,635,700

A summary of our common stock activity for the three months ended March 31, 2009, follows:

		Number of Shares (in thousands)	
	Issued	Treasury	Outstanding
December 31, 2008	84,144	(885)	83,259
Restricted shares issued under compensation plans, net of cancellations	38		38
Option exercises, net of cancellations			
March 31, 2009	84,182	(885)	83,297

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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, 2009 (in thousands):

Asset retirement obligation at January 1, 2009	$	139,948
Liabilities incurred		1,218
Liability settlements and disposals		(750)
Accretion expense		1,961
Revisions of estimated liabilities		8
Asset retirement obligation at March 31, 2009		142,385
Less current obligation		(16,701)
Long-term asset retirement obligation	$	125,684

6. Long-Term Debt

Debt at March 31, 2009 and December 31, 2008 consisted of the following (in thousands):

	March 31, 2009	December 31, 2008
Bank debt	$ 345,000	$ 220,000
7.125% Notes due 2017	350,000	350,000
Floating rate convertible notes due 2023 (face value $19,450)	17,672	17,630
Total long-term debt	$ 712,672	$ 587,630

Bank Debt

In April 2009, we entered into a new three-year senior secured revolving credit facility (credit facility). The new credit facility increases bank commitments from $500 million to $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.

Like our previous credit facility, the borrowing base 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 new credit facility also contains similar covenants and restrictive provisions as were contained in the previous credit facility, which may limit our ability to incur additional indebtedness, make investments or loans and create liens. The new credit agreement requires us to maintain a current ratio greater than 1 to 1 (unchanged) and a leverage ratio not to exceed 3.5 to 1 (increased from 3.0 to 1).

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.

Our previous credit facility, which was outstanding at March 31, 2009, had a borrowing base of $1.0 billion. At March 31, 2009, there was $345 million of borrowings outstanding under the credit facility at a weighted average interest rate of approximately 3.25%. We also had letters of credit outstanding of $2.8 million leaving an unused borrowing availability of $152.2 million. The credit facility contained various covenants, restrictive provisions and ratios. As of March 31, 2009, we were in compliance with all of the financial and non-financial covenants.

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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.

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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 were assumed in the Magnum Hunter merger and mature on December 15, 2023. The notes are senior unsecured obligations and bear interest at the three month LIBOR, reset quarterly. On March 31, 2009, the interest rate was 1.3%.

The holders as of December 15, 2008, had the right to require us to repurchase all or a portion of the notes at a price of 100% of the principal amount (plus accrued interest). As of December 15, 2008, holders with principal of $105.550 million submitted their notes for repurchase leaving $19.450 million still outstanding. We repurchased the $105.550 million in notes with borrowings under our credit facility. The remaining notes have future repurchase dates as of December 15, 2013, and 2018. We have the right at any time to redeem some or all of the notes still outstanding at a redemption price of 100% of the principal amount (plus accrued interest).

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 the conversion price of $28.59 per share. On March 31, 2009, the closing price of our common stock traded on the New York Stock Exchange was $18.38.

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.

In May, 2008, the Financial Accounting Standards Board (FASB) issued a new Staff Position (No. APB 14-1), *Accounting for Convertible Debt Instrument That May Be Settled in Cash upon Conversion (Including Partial Cash Settlement)*, that impacts the accounting for the components of convertible debt that can be settled wholly or partly in cash upon conversion. The new requirements apply not only to new instruments, but are to be applied retrospectively to previously issued convertible instruments. The debt and equity components of the instruments are to be 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. This Staff Position is effective for both new and previously issued instruments for current and comparative periods in fiscal years beginning after December 15, 2008, and interim periods within those years. We adopted the staff position in the first quarter of 2009. Upon adoption, without considering tax effects, we retrospectively recorded a decrease in the book value of our Floating Rate Convertible Notes of approximately $30 million as of June 7, 2005, and a corresponding increase in additional paid-in capital. We also recorded additional non-cash interest expense of approximately $1.9 million per year for 2006 through 2008. Prior to the adoption of the staff position, we recorded a gain of $9.6 million on the early extinguishment of the notes in December 2008. After adoption, the gain was restated to a loss of $10.1 million.

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7. Income Taxes

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

	Three Months Ended March 31,	
	2009	2008
Current provision (benefit)	$ (15,209)	$ 27,918
Deferred tax (benefit)	(269,752)	55,492
	$ (284,961)	$ 83,410

We adopted the provisions of Financial Accounting Standards Board Interpretation No. 48 Accounting for Uncertainty in Income Taxes (FIN 48) an interpretation of FASB Statement No. 109 Accounting for Income Taxes , on January 1, 2007. The adoption of FIN 48 resulted in no impact to our consolidated financial statements and we have no unrecognized tax benefits that would impact our effective rate.

As of March 31, 2009, we 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 2004-2008 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, 2009 was 36.6%.

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

	Three Months Ended March 31,	
	2009	2008
Cash paid during the period for:		
Interest expense	$ 1,837	$ 2,211
Interest capitalized	5,513	4,606
Income taxes	20	26,423
Cash received for income taxes	41,982	179

9. Earnings (Loss) per Share and Comprehensive Income

Earnings (Loss) per Share

In 2008, the FASB issued a new Staff Position (EITF 03-6-1), *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities,* which holds that unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents are participating securities (as defined by EITF 03-6 as securities that may participate in undistributed earnings with common stock, whether that participation is conditioned upon the occurrence of a specified event or not, regardless of the form of participation), 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. This Staff Position is effective for financial statements issued in fiscal years beginning after December 15, 2008, and interim periods within those

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years. The requirements of this Staff Position are to be applied by restating previously reported earnings per share data. Under this staff position, our unvested share based payment awards, consisting of restricted stock and restricted stock units, qualify as participating securities. We adopted this in the first quarter of 2009.

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, 2009		Three Months Ended March 31, 2008	
Net income (loss)	$	(494,100)	$	149,538
Less distributed earnings (dividends declared during the period)		(5,038)		(5,013)
Undistributed earnings (loss) for the period	$	(499,138)	$	144,525
Allocation of undistributed earnings(loss):				
Basic allocation to unrestricted common stockholders	$	(499,138)	$	140,685
Basic allocation to participating securities	$	(2)	$	3,840
Diluted allocation to unrestricted common stockholders	$	(499,138)	$	140,807
Diluted allocation to participating securities	$	(2)	$	3,718
Basic Shares Outstanding				
Unrestricted outstanding common shares		81,684		81,333
Add Participating securities:				
Restricted stock outstanding		1,613		1,518
Restricted stock units outstanding		651		702
Total participating securities		2,264		2,220
Total basic shares outstanding		83,948		83,553
Fully Diluted Shares				
Unrestricted outstanding common shares		81,684		81,333
Incremental shares from assumed exercise of stock options		(1)		629
Incremental shares from assumed conversion of the convertible senior notes		(1)		2,125
Fully diluted common stock		81,684		84,087
Participating securities		2,264(2)		2,220
Total Fully Diluted Shares		83,948		86,307
Basic earnings (loss) per share				
Unrestricted common stockholders:				
Distributed earnings	$	0.06	$	0.06
Undistributed earnings (loss)		(6.11)		1.73
	$	(6.05)	$	1.79

Participating securities:				
Distributed earnings	$	0.06	$	0.06
Undistributed earnings (loss)		0.00		1.73
	$	0.06	$	1.79
Fully diluted earnings (loss) per share				
Unrestricted common stockholders:				
Distributed earnings	$	0.06	$	0.06
Undistributed earnings (loss)		(6.11)		1.67
	$	(6.05)	$	1.73
Participating securities:				
Distributed earnings	$	0.06	$	0.06
Undistributed earnings (loss)		0.00		1.67
	$	0.06	$	1.73

(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.

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

	March 31,	
	2009	**2008**
Stock options	1,493,116	1,378,500
Restricted stock	1,612,745	1,518,095
Restricted units	651,672	701,915

All stock options and restricted units and shares were considered potentially dilutive securities for each of the periods presented except for those determined to be anti-dilutive as follows (in thousands):

	Three Months Ended March 31,	
	2009	**2008**
Stock options	1,493,116	30,300
Restricted stock	1,612,745	
Restricted units	651,672	
	3,757,533	30,300

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):

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	Three Months Ended March 31,	
	2009	**2008**
Net Income (loss)	$ (494,100)	$ 149,538
Other comprehensive income (loss):		
Cash flow hedges		
Decrease in fair value		(17,550)
Settlements reflected in gas sales		(992)
Sub-total		(18,542)
Related income tax effect		6,791
Total cash flow hedges		(11,751)
Change in fair value of short-term investments and other, net of tax	235	(203)
Total comprehensive income (loss)	$ (493,865)	$ 137,584

10. Commitments and Contingencies

Litigation

In January 2009, the Tulsa County District Court issued a judgment 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. Damages of $6.9 million plus $119.5 million for disgorgement of H&P s estimated potential compounded profit since 1989, resulting from the noted damages, were awarded to plaintiff royalty owners, for a total of $126.4 million. This amount was subsequently adjusted by the court to a total of $119.6 million. 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. We periodically assess the probability of estimable amounts related to litigation matters, as required by Financial Accounting Standard No. 5 (*Accounting for Contingencies)* and adjust our accruals accordingly. We have appealed the District Court s judgments.

In the normal course of business, we have other various litigation related matters and associated accruals. For the quarter ended March 31, 2009, we had approximately $10.3 million of such accruals. 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, 2009, we had commitments of $167.2 million relating to construction of the gas processing plant of which $105.1 million is subject to a construction contract. The total cost of the project will approximate $358 million. Pursuant to the terms of our operating agreement with our partners in this project, we will be reimbursed by them for 421/2% 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 $39.2 million consisting of obligations to complete drilling wells in progress at March 31, 2009. We also have minimum expenditure contractual commitments of $76.1 million to secure the use of drilling rigs.

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At March 31, 2009, we had outstanding purchase order commitments of $16.3 million for tubular inventory.

At March 31, 2009, we had firm sales contracts to deliver approximately 10.8 Bcf of natural gas over the next twelve months. If this gas is not delivered, our financial commitment would be approximately $28.9 million. This commitment will fluctuate due to price volatility and actual volumes delivered. However, we believe no financial commitment will be due based on our reserves and current production levels.

In connection with a gas gathering and processing agreement, we have commitments to deliver 60.0 Bcf of gas over the next five years. If no gas was delivered, the maximum amount that would be payable under these commitments would be approximately $45.6 million.

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 $5.4 million.

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

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

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.

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.

We seek to achieve profitable growth in proved reserves and production primarily through exploration and development. We generally fund our growth with cash flow provided by our operating activities. To achieve a consistent rate of growth and mitigate risk, we maintain 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 oil and gas reserves and operations are mainly located in Texas, Oklahoma, New Mexico, Kansas, Louisiana and Wyoming.

To supplement our growth and to provide for new drilling opportunities, we also consider mergers and acquisitions. In 2005 we acquired Magnum Hunter Resources, Inc, in a stock-for-stock merger with a total transaction value of approximately $2.1 billion. Magnum Hunter was a Dallas-based independent oil and gas exploration and production company with operations concentrated in the Permian Basin of West Texas and New Mexico and in the Gulf of Mexico. During 2007 we purchased $40.9 million of assets, with the largest acquisition being in the Texas Panhandle area. In October 2008 we acquired 38,000 net acres in our western Oklahoma, Anadarko Basin Woodford shale play, at a total cost of $180.9 million. We have increased our position in the play to approximately 98,000 net acres. In first quarter 2009 we had $0.1 million of asset purchases.

From time to time we also consider selling certain assets. In 2007, we sold $177.0 million of non-core properties. The two largest sales were $87.5 million for our West Texas Spraberry oil properties and

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$53.5 million for our Gulf of Mexico Main Pass area operated properties. During 2008, we sold 17 Bcfe of proved reserves for $38.1 million. During first quarter 2009 we had $3.8 million of asset sales.

Market Conditions

As of March 31, 2009 we continue to see the credit crisis and related turmoil in the global financial system that existed at December 31, 2008. These factors have led to a continued decline in natural gas prices and instability in oil prices. An extended decline in oil and gas prices could have a material adverse effect on our financial position, results of operations, cash flows and access to capital.

Please see the discussion of Risk Factors in Item 1 of our annual report on Form 10-K for the year ended December 31, 2008 for a discussion of risk factors that affect our business, financial condition and results of operations. This report should be read together with those discussions.

First quarter 2009 financial and operating results:

- First quarter oil and gas production volumes averaged 489.0 million cubic feet equivalent per day (MMcfe/d), up from 476.2 MMcfe/d for first quarter 2008.
- First quarter oil and gas sales totaled $197.2 million.
- First quarter cash flow from operating activities was $96.0 million.
- A continued decline in gas prices led to a $501.8 million after-tax, non-cash full-cost ceiling test write-down of oil and gas properties.
- First quarter drilling totaled 41 gross (24 net) wells, completing 95% as producers.
- We currently have four operated rigs running.

Oil and Gas 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. Our average realized gas price decreased from $8.38 per Mcf in first quarter 2008 to $3.83 per Mcf in 2009; realized oil prices decreased from $94.38 per barrel in first quarter 2008 to $35.70 per barrel in 2009. 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. However, we have made limited use of hedging transactions to somewhat reduce price risk as discussed further below.

	Three Months Ended March 31, 2009		Three Months Ended March 31, 2008	
Gas Prices:				
Average Henry Hub price ($/Mcf)	$	4.07	$	8.03
Average realized sales price including hedge effect ($/Mcf)	$	3.83	$	8.38
Effect of hedges ($/Mcf)	$		$	0.03
Oil Prices:				
Average WTI Cushing price ($/Bbl)	$	48.06	$	97.90
Average realized sales price ($/Bbl)	$	35.70	$	94.38

On an energy equivalent basis, 69% of our 2009 aggregate production was natural gas. A $0.10 per Mcf change in our average realized gas sales price would have resulted in approximately a $3.0 million change in our gas revenues. Similarly 31% of our production was crude oil. A $1.00 per barrel change in our average realized crude oil sales price would have resulted in approximately a $2.3 million change in our oil revenues.

To mitigate a portion of our exposure to potentially adverse gas market changes we consider the use of financial derivatives. During the first quarter of 2008 we had 40,000 MMBtu per day of Mid-Continent gas production hedged through the use of collars. As of December 31, 2008 all of our cash flow effective hedge contracts had expired.

In March 2009 we entered into new derivative financial instruments covering the period of April 2009 through December 2009. The price collars set a floor and ceiling price of $3.00 and $5.00 and cover an average of approximately 148,000 MMBtu per day of our Mid-Continent gas production during the contract period. We did not choose to apply hedge accounting treatment so these contracts will not impact our realized gas prices during the year. Instead, any settlements on these contracts will be shown as a component of operating costs and expenses as a realized (gain) loss on derivative instruments. These contracts will cover approximately 38% of our overall 2009 estimated gas production and about 53% of our estimated April through December 2009 gas volumes. 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 oil and gas prices, some trend with production volume and some are a function of the number of wells we own. At the end of 2008, we owned interests in 12,980 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 oil and gas 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.

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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 resulting from the adoption of SFAS No. 123R, *Share Based Payment*. Net stock compensation expense in the first three months of 2009 was $2.3 million compared to $2.3 million in the first three months of 2008.

The derivative fair value (gain) loss is the net realized and unrealized gain or loss on derivative financial instruments to which we did not apply hedge accounting treatment and fluctuates based on changes in the fair value of underlying commodities. The net derivative fair value gain was $0.1 million in the first quarter of 2009.

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RESULTS OF OPERATIONS

Quarter ended March 31, 2009 vs. March 31, 2008

We recognized a net loss for the first quarter of 2009 of $494.1 million, or $6.05 per share. This compares to net income of $149.5 million, or $1.73 per diluted share for the same period in 2008. The net loss is primarily the result of a non-cash full cost ceiling write-down recorded in the first quarter of 2009. The full cost ceiling impairment is discussed further in the operating costs and expenses section below.

Oil and Gas Sales	**For the Three Months Ended March 31,**		**Percent Change Between**	**Price/Volume Analysis**		
(In thousands or as indicated)	**2009**	**2008**	**2009/2008**	**Price**	**Volume**	**Variance**
Gas sales	$ 116,624	$ 258,955	(55)%	$ (138,616)	$ (3,715)	$ (142,331)
Oil sales	80,605	195,450	(59)%	(132,499)	17,654	(114,845)
Total oil and gas sales	$ 197,229	$ 454,405		$ (271,115)	$ 13,939	$ (257,176)
Total gas volume MMcf	30,465	30,910	(1)%			
Gas volume MMcf per day	338.5	339.7				
Average gas price per Mcf	$ 3.83	$ 8.38	(54)%			
Effect of hedges per Mcf	$	$ 0.03				
Total oil volume thousand barrels	2,258	2,071	9%			
Oil volume barrels per day	25,086	22,757				
Average oil price per barrel	$ 35.70	$ 94.38	(62)%			

Oil and gas sales for the first quarter of 2009 totaled $197.2 million, compared to $454.4 million in 2008. The decrease of $257.2 million in sales between the two periods was the result of lower commodity prices which had a negative impact of $271.1 million. These lower prices were slightly offset by an increase in sales of $13.9 million due to higher production volumes during the current quarter.

Compared to the first quarter of 2008, our first quarter 2009 oil production increased by 9% to an average of 25,086 barrels per day in 2009. This increase resulted in $17.6 million of incremental revenues. Gas volumes averaged 338.5 MMcf per day in 2009 compared to 339.7 MMcf per day in the first quarter of 2008, resulting in a decrease in revenues of $3.7 million. Total first quarter 2009 oil and gas production volumes were 489.0 MMcfe per day, up 12.8 MMcfe per day from the same period in 2008.

Average realized gas prices decreased by 54% to $3.83 per Mcf for the three months ended March 31, 2009, compared to $8.38 per Mcf for the first quarter of 2008. This price decrease lowered gas sales by $138.6 million between the two periods. Included in our 2008 realized gas price is $1.0 million of cash receipts (a positive $0.03 per Mcf effect) from settlement of cash flow hedges on 40,000 MMBtu per day of Mid-Continent gas production.

Realized oil prices averaged $35.70 per barrel during the first quarter of 2009, compared to $94.38 per barrel for the same period in 2008. The decrease in oil sales resulting from this 62% decline in oil prices totaled $132.5 million.

Changes in realized gas and oil prices were the result of overall market conditions.

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	For the Three Months Ended March 31, 2009	2008
Gas Gathering, Processing, Marketing and Other (in thousands):		
Gas gathering, processing and other revenues	$ 11,070	$ 21,838
Gas gathering and processing costs	(5,106)	(10,175)
Gas gathering, processing and other margin	$ 5,964	$ 11,663
Gas marketing revenues, net of related costs	$ 880	$ 967

We sometimes transport, process and market third-party gas that is associated with our gas. In the first quarter of 2009, third-party gas gathering, processing and other contributed $6.0 million of pre-tax cash operating margin (revenues less direct cash expenses) versus $11.7 million in 2008. Our gas marketing margin (revenues less purchases) decreased to $0.9 million in the first quarter of 2009 from $1.0 million in the first quarter of 2008. Decreases in net margins from gas gathering, processing, marketing and other activities are the direct result of decreased commodity prices and overall market conditions.

	For the Three Months Ended March 31, 2009	2008	Variance Between 2009/2008
Operating costs and expenses (in thousands):			
Impairment of oil and gas properties	$ 791,137	$	$ 791,137
Depreciation, depletion and amortization	89,666	125,556	(35,890)
Asset retirement obligation	2,545	1,594	951
Production	50,414	52,052	(1,638)
Transportation	8,709	8,309	400
Taxes other than income	15,545	30,607	(15,062)
General and administrative	7,762	11,584	(3,822)
Stock compensation	2,257	2,275	(18)
Unrealized (Gain) Loss on derivative instruments	(102)		(102)
Other operating, net	10,092	1,036	9,056
	$ 978,025	$ 233,013	$ 745,012

Total operating costs and expenses (not including gas gathering, marketing and processing costs, or income tax expense) increased to $978.0 million in the first quarter of 2009 compared to $233.0 million in the first quarter of 2008.

The largest component of the increase between periods is the non-cash impairment of oil and gas properties in the amount of $791.1 million ($501.8 million, net of tax) that was recorded as a result of declines in natural gas prices during the first quarter of 2009. Due to the volatility of oil and gas prices and because the ceiling calculation requires that prices in effect as of the last day of the period be held constant in valuing proved reserves, we may be required 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 $125.6 million in the first quarter of 2008 to $89.7 million in the same period of 2009. On a unit of production basis, DD&A was $2.04 per Mcfe in 2009 compared to $2.90 per Mcfe for 2008. The significant decrease in DD&A is due to the $2.2 billion reduction to the carrying value of oil and gas properties recorded during the last half of 2008. With the recording of an additional impairment in the first quarter of 2009 we expect the DD&A rate to be lower in the second quarter of 2009 in comparison to the first quarter of the current year.

Production costs decreased $1.6 million from $52.0 million ($1.20 per Mcfe) in the first quarter of 2008 to $50.4 million ($1.15 per Mcfe) in the first quarter of 2009. A component of the decrease between

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periods is the result of the sale of producing properties in the fourth quarter of 2008 leading to a decrease in production expense in the first quarter of 2009. The remaining change between periods is primarily attributable to a decline in lease operating expenses and insurance premiums related to our offshore properties. Overall, we have started to see a decrease in service costs in comparison to their peak in mid 2008 and expect to see this trend continue through the remainder of the year.

Taxes other than income were $15.1 million lower, decreasing from $30.6 million in 2008 to $15.5 million in 2009. The decrease between periods resulted from decreases in oil and gas sales stemming from significantly lower commodity prices.

General and administrative (G&A) expenses decreased $3.8 million from $11.6 million in the first quarter of 2008 to $7.8 million in the first quarter of 2009. The decrease between periods is due to lower employee-benefit costs due to a decrease in bonus and profit sharing expenses resulting from significant decreases in commodity prices from prior year.

A component of our operating costs and expense for the first quarter of 2009 is unrealized loss (gain) on changes in the fair value of our derivative instruments. We estimate the fair values of our natural gas 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 on the derivative contracts that we entered into in March 2009. As a result, we recorded an unrealized gain of $0.1 million during the first quarter. In order to receive the contract pricing terms of a $3.00 floor and $5.00 ceiling, we paid a total premium of $6.6 million (or an average of $0.16 per MMBtu) for these contacts. The derivative asset at March 31, 2009, relating to these contracts, equaled $6.7 million.

The increase in Other operating, net in the first quarter of 2009 to $10.1 million from $1.0 million in the first quarter of 2008 is related to the resolution of and accruals related to various legal matters most of which pertain to title and royalty issues.

Other income and expense

Interest expense decreased from $8.7 million in the first quarter of 2008 to $8.3 million for the same period of 2009. This change resulted from a $1.6 million decrease in interest expense on our convertible notes due to the December 2008 repurchase of $105.6 million of the outstanding $125 million (face value). This decrease was mostly offset by a $1.2 million increase in interest expense on bank debt. We had no borrowings on our credit facility during the first quarter of 2008 and an outstanding balance of $345 million at March 31, 2009.

Other, net decreased from $3.0 million of income in the first quarter of 2008 to $2.4 million of expense in the first quarter of 2009. Components consist of miscellaneous income and expense items that will vary from period to period, including income and loss in equity investees, gain or loss on sale of inventory and interest income. The decrease is primarily the result of an inventory impairment due to a decreased value of drill pipe resulting from the significant slowing of drilling activity across the industry.

Income tax expense

In the first quarter of 2009 total income tax benefit of $285.0 million was recognized, of which $15.2 million is current. This compares with first quarter 2008 current taxes of $27.9 million and total income tax expense of $83.4 million. The combined Federal and state effective income tax rates were 36.6% and 35.8% in the first quarters of 2009 and 2008, respectively. The effective tax rate of 36.6% for the first quarter of 2009 differs from the statutory rate primarily due to state income taxes and non-deductible expenses.

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LIQUIDITY AND CAPITAL RESOURCES

Overview

The ongoing economic downturn, credit crisis and slowing demand have continued to negatively impact commodity prices. Sustained low oil and gas prices may reduce the amount of oil and gas that we can economically produce, and can also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital. These conditions may also impact third parties with whom we do business which could lead to losses associated with uncollectible receivables.

We have and will continue to focus on maintaining liquidity, promoting operational efficiency, and expanding long-term reserves through focused drilling projects and potential acquisitions. Historically our exploration and development expenditures have generally been funded by cash flow provided by operating activities (operating cash flow). With our intent to continue to operate within operating cash flows, we have significantly scaled back our planned 2009 drilling program in comparison to 2008. We are focusing on our highest rate of return projects which are primarily in our Woodford shale position in the Anadarko Basin of Western Oklahoma and our south Texas Yegua and Cook Mountain play.

We continue to search for attractive acquisition opportunities; however, the timing and size of acquisitions are unpredictable. In order to ready ourselves for such an opportunity and to prepare ourselves for the potential of further declines in commodity prices, in April 2009, we entered into a new three-year senior secured revolving credit facility. The new facility increases bank commitments from $500 million to a fully-subscribed $800 million. The borrowing base remains unchanged at $1 billion. In addition to our increased credit facility, we may consider a high-yield bond offering in the future to raise additional capital, if appropriate.

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 2009 and beyond.

Analysis of Cash Flow Changes

Cash flow provided by operating activities for the three months of 2009 was $82.6 million, compared to $315.2 million for the three months ended March 31, 2008. The decrease in first quarter 2009 resulted primarily from lower revenues resulting from lower oil and gas prices.

Cash flow used in investing activities for the three months of 2009 was $200.8 million, compared to $288.2 million for the three months ended March 31, 2008. 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 decrease from first quarter 2008 to 2009 was mostly caused by decreased oil and gas expenditures resulting from decreased activity in our drilling and exploitation programs.

Net cash flow provided by financing activities in the first three months of 2009 was $120.0 million versus $2.8 million used in the first three months of 2008. In 2009 we had borrowings under our credit facility of $125.0 million while we had no borrowings in the first quarter of 2008.

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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 Three Months Ended March 31,	
	2009	**2008**
Acquisitions:		
Proved	$ 75	$ 1,045
Unproved		
	75	1,045
Exploration and development:		
Land and seismic	16,279	23,171
Exploration and development	125,752	283,784
	142,031	306,955
Property sales	(3,764)	
	$ 138,342	$ 308,000

Our exploration and development expenditures decreased 54 percent in first quarter 2009 compared to first quarter 2008. The decrease in 2009 resulted from a planned decrease in our exploration activity in response to current economic environment and our continued efforts to operate within our cash flow provided by operating activities. Overall, we drilled a total of 41 gross (24 net) wells during the first three months of 2009 versus 126 gross (76 net) wells in the same period of 2008.

Our planned capital program for 2009 is approximately $500 million with the expectation of continued low oil and gas prices. Although our 2009 capital budget is set at a level that we believe corresponds with our anticipated 2009 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 expect to 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.

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 our total assets, net oil and gas assets, net income and stockholders equity were reduced by a non-cash impairment of oil and gas properties in the amount of $791.1 million ($501.8 million after tax). Total assets decreased by $0.8 billion in first quarter 2009 from

$4.2 billion at the beginning of the year to $3.4 billion by March 31, 2009. Our net oil and gas assets decreased by $743.3 million and our cash position increased by $1.7 million for the same period. As of March 31, 2009, stockholders equity totaled $1.9 billion, down from $2.4 billion at December 31, 2008. The decrease resulted primarily from a first quarter 2009 net loss of $494.1 million.

Dividends

In December 2005, the Board of Directors declared the Company s first quarterly cash dividend of $.04 per share payable to shareholders. A dividend has been authorized in every quarter since then. On

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December 12, 2007 the Board of Directors increased the regular cash dividend on our common stock from $0.04 to $0.06 per common share.

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. No purchases have been made in the first quarter of 2009.

Working Capital

Working capital increased $108.3 million from year-end 2008 to $153.7 million at quarter-end 2009. Working capital increased primarily because of the following:

- Revenue payable decreased by $20.0 million due to a decrease in commodity prices during the first quarter.
- Accrued liabilities decreased by $85.8 million due to a significant decrease in exploration and development activities.
- Accounts payable decreased by $65.6 million due to timing of payments.

These working capital increases were partially offset by:

- Revenue receivable decreased by $30.5 million due to a decrease in commodity prices during the first quarter.
- Other receivables decreased by $26.7 million due to receipt of an income tax refund receivable during first quarter.

- Other current assets decreased by $9.2 million primarily due to the timing of payment of advances and prepaid expenses.

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.

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Financing

Debt at March 31, 2009 and December 31, 2008 consisted of the following (in thousands):

	March 31, 2009	December 31, 2008
Bank debt	$ 345,000	$ 220,000
7.125% Notes due 2017	350,000	350,000
Floating rate convertible notes due 2023 (face value $19,450)	17,672	17,630
Total long-term debt	$ 712,672	$ 587,630

Bank Debt

In April 2009, we entered into a new three-year senior secured revolving credit facility (credit facility). The new credit facility increases bank commitments from $500 million to $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.

Like our previous credit facility, the borrowing base 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 new credit facility also contains similar covenants and restrictive provisions as were contained in the previous credit facility, which may limit our ability to incur additional indebtedness, make investments or loans and create liens. The new credit agreement requires us to maintain a current ratio greater than 1 to 1 (unchanged) and a leverage ratio not to exceed 3.5 to 1 (increased from 3.0 to 1).

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.

Our previous credit facility, which was outstanding at March 31, 2009, had a borrowing base of $1.0 billion. At March 31, 2009, there was $345 million of borrowings outstanding under the credit facility at a weighted average interest rate of approximately 3.25%. We also had letters of credit outstanding of $2.8 million leaving an unused borrowing availability of $152.2 million. The credit facility contained various covenants, restrictive provisions and ratios. As of March 31, 2009, we were in compliance with all of the financial and non-financial covenants.

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.

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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.

Floating rate convertible notes due 2023

The floating rate convertible senior notes were assumed in the Magnum Hunter merger and mature on December 15, 2023. The notes are senior unsecured obligations and bear interest at the three month LIBOR, reset quarterly. On March 31, 2009, the interest rate was 1.3%.

The holders as of December 15, 2008, had the right to require us to repurchase all or a portion of the notes at a price of 100% of the principal amount (plus accrued interest). As of December 15, 2008, holders with principal of $105.550 million submitted their notes for repurchase leaving $19.450 million still outstanding. We repurchased the $105.550 million in notes with borrowings under our credit facility. The remaining notes have future repurchase dates as of December 15, 2013, and 2018. We have the right at any time to redeem some or all of the notes still outstanding at a redemption price of 100% of the principal amount (plus accrued interest).

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 the conversion price of $28.59 per share. On March 31, 2009, the closing price of our common stock traded on the New York Stock Exchange was $18.38.

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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Contractual Obligations and Material Commitments

At March 31, 2009, we had contractual obligations and material commitments as follows:

	Payments Due by Period				
Contractual obligations	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
	(In thousands)				
Long-term debt(1)	$ 714,450	$ 345,000	$	$	$ 369,450
Fixed-Rate interest payments(1)	211,969	24,938	49,875	49,875	87,281
Operating leases	26,921	5,815	10,719	9,049	1,338
Drilling commitments(2)	115,274	115,274			
Inventory commitments(3)	16,287	16,287			
Gas processing facility(4)	105,130	45,500	32,254	27,376	
Asset retirement obligation	142,385	16,701	(5)	(5)	(5)
Other liabilities(6)	43,059	8,859	17,628	8,827	7,745

(1) These amounts do not include interest on the $345 million of bank debt outstanding at March 31, 2009. The weighted average interest rate at March 31, 2009 was approximately 3.25%. See item 3: Interest Rate Risk for more information regarding fixed and variable rate debt.

(2) We have drilling commitments of approximately $39.2 million consisting of obligations to complete drilling wells in progress at March 31, 2009. We also have minimum expenditure commitments of $76.1 million to secure the use of drilling rigs. Hurricanes Gustav and Ike occurred during the third quarter of 2008.

(3) At March 31, 2009, we had outstanding purchase order commitments of $16.3 million for tubular inventory.

(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, 2009, we had commitments of $167.2 million relating to construction of the gas processing plant of which $105.1 million is subject to a construction contract. The total cost of the project will approximate $358 million. Pursuant to the terms of our operating agreement with our partners in this project, we will be reimbursed by them for 42 1/2% 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 benefit obligations and other miscellaneous commitments.

At March 31, 2009, we had firm sales contracts to deliver approximately 10.8 Bcf of natural gas over the next twelve months. If this gas is not delivered, our financial commitment would be approximately $28.9 million. This commitment may fluctuate due to either price volatility or volumes delivered. However, we do not anticipate that a financial commitment will be due.

In connection with a gas gathering and processing agreement, we have commitments to deliver 60.0 Bcf of gas over the next five years. If no gas was delivered, the maximum amount that would be payable under these commitments would be approximately $45.6 million.

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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 $5.4 million.

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

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

2009 Outlook

Our exploration and development expenditures program for 2009 is projected to range from $400 million to $600 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. A majority of the expenditures will be in the Mid-Continent area, primarily in our Western Oklahoma Anadarko-Woodford shale Cana play. In addition we plan to continue to drill in our Permian Basin and Gulf Coast areas.

Production estimates for 2009 range from 440 to 460 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 2008, our realized prices averaged $8.43 per Mcf of gas and $96.03 per barrel of oil. Prices can be very volatile and the possibility of 2009 realized prices being different than they were in 2008 is high.

Costs of operations on a per Mcfe basis for 2009 are currently estimated as follows:

	2009		
Production expense	$ 1.20	-	$1.30
Transportation expense	0.17	-	0.22
DD&A and Asset retirement obligation	1.40	-	1.70
General and Administrative	0.22	-	0.28
Production taxes (% of oil and gas revenue)	7.0%	-	8.0%

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, 2008.

Recent Accounting Developments

In May, 2008, the Financial Accounting Standards Board (FASB) issued a new Staff Position (No. APB 14-1), *Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion (Including Partial Cash Settlement),* that will impact the accounting for the components of convertible debt that can be settled wholly or partly in cash upon conversion. The new requirements apply not only to new instruments, but also would be applied retrospectively to previously issued convertible instruments. The debt and equity components of the instruments are to be accounted for separately. The value assigned to the debt component is the estimated value of similar debt without a conversion feature as

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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. This Staff Position is effective for both new and previously issued instruments for current and comparative periods in fiscal years beginning after December 15, 2008, and interim periods within those years. We adopted the staff position in the first quarter of 2009. Upon adoption, without considering tax effects, we retrospectively recorded a decrease in the book value of our Floating Rate Convertible Notes of approximately $30 million as of June 7, 2005, and a corresponding increase in additional paid-in capital. We also recorded additional non-cash interest expense of approximately $1.9 million per year for 2006 through 2008. Prior to adoption of the staff position, we recorded a gain of $9.6 million on the early extinguishment of the notes in December 2008. After adoption, the gain was restated to a loss of $10.1 million.

In June, 2008, the FASB issued a new Staff Position (EITF 03-6-1), *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities,* which holds that unvested share-based payment awards that contain non forfeitable rights to dividends or dividend equivalents are participating securities (as defined by EITF 03-6 as securities that may participate in undistributed earnings with common stock, whether that participation is conditioned upon the occurrence of a specified event or not, regardless of the form of participation), 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. This Staff Position is effective for financial statements issued in fiscal years beginning after December 15, 2008, and interim periods within those years. We adopted this in the first quarter of 2009 and have restated previously reported earnings per share data.

In December 2008, the SEC adopted revisions to its required oil and gas reporting disclosures. The revisions are intended to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves. In the three decades that have passed since adoption of these disclosure items, there have been significant changes in the oil and gas industry. The amendments are designed to modernize and update the oil and gas disclosure requirements to align them with current practices and changes in technology. In addition, the amendments concurrently align the SEC s full cost accounting rules with the revised disclosures. The revised disclosure requirements must be incorporated in registration statements filed on or after January 1, 2010, and annual reports on Form 10-K for fiscal years ending on or after December 31, 2009. A company may not apply the new rules to disclosures in quarterly reports prior to the first annual report in which the revised disclosures are required.

The following amendments have the greatest likelihood of affecting our reserve disclosures:

- *Pricing mechanism for oil and gas reserves estimation* The SEC s current rules require proved reserve estimates to be calculated using prices as of the end of the period and held constant over the life of the reserves. Price changes can be made only to the extent provided by contractual arrangements. The revised rules require reserve estimates to be calculated using a 12-month average price. The 12-month average price will also be used for purposes of calculating the full cost ceiling limitations. Price changes can still be incorporated to the extent defined by contractual arrangements. The use of a 12-month average price rather than a single-day price is expected to reduce the impact on reserve estimates and the full cost ceiling limitations due to short-term volatility and seasonality of prices.

- *Reasonable certainty* The SEC s current definition of proved oil and gas reserves incorporate certain specific concepts such as lowest known hydrocarbons, which limits the ability to claim proved reserves in the absence of information on fluid contacts in a well penetration, notwithstanding the existence of other engineering and geoscientific evidence. The revised rules amend the definition to permit the use of new reliable technologies to establish the reasonable certainty of proved reserves. This revision also includes provisions for establishing levels of lowest

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known hydrocarbons and highest known oil through reliable technology other than well penetrations.

The revised rules also amend the definition of proved oil and gas reserves to include reserves located beyond development spacing areas that are immediately adjacent to developed spacing areas if economic producibility can be established with reasonable certainty. These revisions are designed to permit the use of alternative technologies to establish proved reserves in lieu of requiring companies to use specific tests. In addition, they establish a uniform standard of reasonable certainty that applies to all proved reserves, regardless of location or distance from producing wells.

Because the revised rules generally expand the definition of proved reserves, proved reserve estimates could increase upon adoption of the revised rules. However, we are not able to estimate the magnitude of the potential change at this time.

- *Unproved reserves* The SEC s current rules prohibit disclosure of reserve estimates other than proved in documents filed with the SEC. The revised rules permit disclosure of probable and possible reserves and provide definitions of probable reserves and possible reserves. Disclosure of probable and possible reserves is optional. However, such disclosures must meet specific requirements. Disclosures of probable or possible reserves must provide the same level of geographic detail as proved reserves. Probable and possible reserve disclosures must also provide the relative uncertainty associated with these classifications of reserves estimations. We have not yet determined whether we will disclose our probable and possible reserves in documents filed with the SEC.

ITEM 3. QUALITATIVE AND QUANTITATIVE DISCLOSURES ABOUT MARKET RISK

The term market risk refers to the risk of loss arising from adverse changes in oil and gas prices, interest rates and value of our short-term investments. 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.

Currently, we are largely accepting the volatility risk that the change in prices presents. None of our future oil production is subject to hedging. With regard to our future natural gas production, based on contracts currently in place, the following table details the remaining contracts:

2009 Mid-Continent Gas price Collar Contracts

Period	Type	Volume/Day	Duration	Mid-Continent Price		Fair Value (000 s)
Second quarter	Collar	150,000 MMBTU	Apr 09 - Jun 09	$3.00 - $5.00	$	5,618
Third quarter	Collar	150,000 MMBTU	July 09 - Sept 09	$3.00 - $5.00		2,189
Fourth quarter	Collar	143,370 MMBTU	Oct 09 - Dec 09	$3.00 - $5.00		(1,071)
					$	6,736

While these contracts limit the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. Mid-Continent gas would have to be above the $5.00 ceiling for us to have any negative impact with respect to these collars. At March 31, 2009, the weighted average Mid-Continent prices for the 2009 contracts approximated $3.36.

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 five 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.

Interest Rate Risk

At March 31, 2009 our debt was comprised of the following (in thousands):

		Fixed Rate Debt		Variable Rate Debt
Bank debt	$		$	345,000
7.125% Notes due 2017		350,000		
Floating rate convertible notes due 2023				17,672
Total long-term debt	$	350,000	$	362,672

As of March 31, 2009, the amounts outstanding under our senior secured revolving credit facility bear interest at our election at either a floating LIBOR rate plus 1%-1.75% or the prime rate plus 0%-0.5%. 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.

In April 2009, we entered into a new credit facility that bears interest at either (a) a 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.

We consider our interest rate exposure to be minimal because approximately 49% 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 $3.6 million. 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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Market Value of Investments

We currently have $1.6 million invested in a securities fund. We expect to liquidate our investment in this fund within the next 12 months. A five percent change in these investments market value would have an $81 thousand impact on our investments.

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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, 2009 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, 2009, 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, 2009, 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

10.1 Credit Agreement dated as of April 14, 2009, among Cimarex, the Lenders, the Administrative Agent, the Co-Syndication Agents, the Co-Documentation Agents and the Lead Arranger (filed as Exhibit 10.1 to the Registration s Form 8-K on April 20, 2009 [file no. 001-31446] and incorporated herein by reference).

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.

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SIGNATURE

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

May 6, 2009

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)