CIMAREX ENERGY CO
Form 10-Q
May 09, 2007

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, 2007

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 is a large accelerated filer, an accelerated filer, or a non-accelerated filer (as defined in Rule 12b-2 of the Exchange Act). (Check One)

Large accelerated filer x Accelerated Filer o Non-accelerated filer 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, 2007 was 83,286,560.

CIMAREX ENERGY CO.

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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.

PART I

ITEM 1 - Financial Statements

CIMAREX ENERGY CO.

Consolidated Balance Sheets

(Unaudited)

	March 31, 2007	**December 31, 2006**
	(In thousands, except share data)	
Assets		
Current assets:		
Cash and cash equivalents	$ 7,351	$ 5,048
Receivables, net	300,147	306,458
Inventories	42,001	39,397
Deferred income taxes	4,477	1,498
Derivative instruments, net	10,093	41,945
Other current assets	18,692	22,411
Total current assets	382,761	416,757
Oil and gas properties at cost, using the full cost method of accounting:		
Proved properties	4,954,773	4,656,854
Unproved properties and properties under development, not being amortized	373,555	425,173
	5,328,328	5,082,027
Less accumulated depreciation, depletion and amortization	(1,598,955)	(1,494,317)
Net oil and gas properties	3,729,373	3,587,710
Fixed assets, net	86,882	88,924
Goodwill	691,432	691,432
Derivative instruments	2,823	7,051
Other assets, net	38,404	37,876
	$ 4,931,675	$ 4,829,750
Liabilities and Stockholders Equity		
Current liabilities:		
Accounts payable	$ 49,436	$ 56,241
Accrued liabilities	176,343	202,163
Revenue payable	95,670	96,184
Total current liabilities	321,449	354,588
Long-term debt	508,720	443,667
Deferred income taxes	945,411	921,665
Other liabilities	136,622	133,687
Stockholders equity:		
Preferred stock, $0.01 par value, 15,000,000 shares authorized, no shares issued		
Common stock, $0.01 par value, 200,000,000 shares authorized, 83,286,560 and 83,962,132 shares issued, respectively	844	840
Treasury stock, at cost, 1,078,822 and 1,078,822 shares held, respectively	(40,628)	(40,628)
Paid-in capital	1,872,286	1,867,448
Retained earnings	1,178,635	1,117,402
Accumulated other comprehensive income	8,336	31,081

	3,019,473	2,976,143
	$ 4,931,675	$ 4,829,750

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, 2007	2006
	(In thousands, except per share data)	
Revenues:		
Gas sales	$ 196,290	$ 233,723
Oil sales	97,164	88,272
Gas gathering and processing	12,639	11,302
Gas marketing, net	782	1,953
	306,875	335,250
Costs and expenses:		
Depreciation, depletion and amortization	108,884	90,628
Asset retirement obligation accretion	2,591	1,448
Production	45,005	41,772
Transportation	5,934	4,308
Gas gathering and processing	7,311	6,553
Taxes other than income	20,627	23,546
General and administrative	12,651	10,885
Stock compensation, net	2,670	1,968
Gain on derivative instruments		(15,567)
Other operating, net	(271)	31
	205,402	165,572
Operating income	101,473	169,678
Other (income) and expense:		
Interest expense net of capitalized interest of $5,091 and $6,219 respectively	4,074	271
Amortization of fair value of debt	(947)	(945)
Other, net	(3,449)	(3,342)
Income before income tax expense	101,795	173,694
Income tax expense	37,167	63,543
Net income	$ 64,628	$ 110,151
Earnings per share:		
Basic	$ 0.79	$ 1.33
Diluted	$ 0.77	$ 1.29
Weighted average shares outstanding:		
Basic	82,222	82,633
Diluted	84,393	85,242

See accompanying notes to consolidated financial statements.

CIMAREX ENERGY CO.

Condensed Consolidated Statements of Cash Flows

(Unaudited)

	For the Three Months Ended March 31, 2007	2006
	(In thousands)	
Cash flows from operating activities:		
Net income	$ 64,628	$ 110,151
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	108,884	90,628
Asset retirement obligation accretion	2,591	1,448
Deferred income taxes	37,167	46,681
Stock compensation, net	2,670	1,968
Derivative instruments		(22,919)
Other	(542)	(840)
Changes in operating assets and liabilities		
Decrease in receivables, net	6,311	28,525
(Increase) decrease in other current assets	1,115	(14,448)
(Decrease) in accounts payable and accrued liabilities	(35,245)	(13,541)
Increase (decrease) in other non-current liabilities	(1,110)	362
Net cash provided by operating activities	186,469	228,015
Cash flows from investing activities:		
Oil and gas expenditures	(252,348)	(218,963)
Acquisition of proved oil and gas properties	(23)	(2,862)
Merger costs		(469)
Proceeds from sale of assets	349	60
Other expenditures	(2,303)	(5,729)
Net cash used by investing activities	(254,325)	(227,963)
Cash flows from financing activities:		
Borrowings (payments) on long-term debt, net	66,000	
Treasury Stock acquired		(10,281)
Dividends paid	(3,365)	(3,327)
Proceeds from issuance of common stock and other	7,524	2,584
Net cash (used in) provided by financing activities	70,159	(11,024)
Net change in cash and cash equivalents	2,303	(10,972)
Cash and cash equivalents at beginning of period	5,048	61,647
Cash and cash equivalents at end of period	$ 7,351	$ 50,675

See accompanying notes to consolidated financial statements.

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CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements

March 31, 2007

(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 2006 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.

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 an amount equal to 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 we determine that net capitalized costs exceed the full cost ceiling limit. 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 will be used to determine if the capital costs are in fact impaired as of the end of the period.

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. Abandonments of unproved properties are accounted for as an adjustment to capitalized costs related to proved oil and gas properties, with no losses recognized.

Proceeds from the sale of oil and gas properties are credited against capitalized costs, unless such proceeds would significantly alter the amortization base. Expenditures for maintenance and repairs are charged to production expense in the period incurred.

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 and liabilities and the reported amounts of revenues and expenses during the reporting period and in disclosures of commitments and contingencies. We analyze our estimates, including those related to oil and gas revenues, reserves and properties, as well as goodwill and contingencies, and base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions.

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

Certain amounts in prior years financial statements have been reclassified to conform to the 2007 financial statement presentation.

2. Derivative Instruments

SFAS No.133, *Accounting for Derivative Instruments and Hedging Activities,* requires that all derivatives be recorded on the balance sheet at fair value. We determine the fair value of derivative contracts based on the stated contract prices and current and projected market prices at the determination date discounted to reflect the time value of money until settlement. The accounting treatment for the changes in fair value depends upon whether or not a derivative instrument is designated as a hedge for accounting treatment purposes. Realized and unrealized gains and losses on derivatives that are not designated as hedges are recognized currently in costs and expenses associated with operating income in our consolidated statements of operations. For derivatives designated as cash flow hedges, changes in the fair value, to the extent the hedge is effective, are recognized in other comprehensive income until the hedged item is settled. Changes in the fair value of the hedge resulting from ineffectiveness are recognized currently as unrealized gains or losses in other income and expense in the consolidated statements of operations. Gains and losses upon settlement of the cash flow hedges are recognized in gas revenues in the period the contracts are settled.

In connection with the Magnum Hunter merger, Magnum Hunter s existing commodity derivatives were not designated for hedge accounting treatment. As a result, Cimarex recognized a net gain for the quarter ended March 31, 2006 of $15.6 million. Activity included both non-cash mark-to-market derivative gains and losses as well as cash settlements. Cash payments related to those contracts that settled in the quarter ended March 31, 2006 equaled $7.4 million. The derivative liability at March 31, 2006, relating to those contracts, equaled $19.0 million. As of December 31, 2006, all derivative contracts assumed with the Magnum Hunter merger had matured.

To mitigate a portion of our potential exposure to adverse market changes in an environment of volatile gas prices, we entered into additional derivative contracts in July 2006. Using zero-cost collars, we hedged 29.2 million MMBtu and 14.6 million MMBtu of our anticipated Mid-Continent gas production for 2007 and 2008, respectively. At March 31, 2007, this represented approximately 55% and 30% of our current anticipated Mid-Continent gas production for 2007 and 2008, respectively.

Under the collar agreements, we will receive the difference between an agreed upon Mid-Continent index price and a floor price if the index price is below the floor price. We will pay the difference between the agreed upon contracted 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 contracted floor and ceiling prices. We have designated these derivatives for hedge accounting treatment as cash flow hedges.

During the quarter ended March 31, 2007, we recognized an unrealized loss of $78 thousand related to the ineffective portion of the derivative contracts. The following table sets forth the terms of the related derivative contracts at March 31, 2007:

Commodity	Type	Volume/Day	Duration		Mid-Continent Weighted Average Price	Fair Value (000 s)	
Natural Gas	Collars	80,000 MMBTU	Apr 07	Dec 07	$7.00 - $10.17	$	11,760
Natural Gas	Collars	40,000 MMBTU	Jan 08	Dec 08	$7.00 - $9.90	1,156	
						$	12,916

At March 31, 2007, the $12.9 million fair value of the derivative contracts was recorded as a current asset of $10.1 million and a long term asset of $2.8 million on our consolidated balance sheet. A cumulative unrealized gain (net of deferred income taxes) of $8.2 million was recorded in other comprehensive income. Based on the estimated fair values of the derivative contracts at March 31, 2007, the amount of unrealized gain (net of deferred income taxes) to be reclassified from accumulated other comprehensive income to gas revenue in the next twelve months would be approximately $6.4 million; however, actual gains and losses recognized may differ significantly. At March 31, 2007, the weighted average Mid-Continent prices for the 2007 and 2008 contracts approximated $7.26 and $7.66, respectively. We believe that we have sufficient production volumes such that the hedge contract transactions will occur as expected. Settlements received during the quarter ended March 31, 2007 totaled $5.1 million, which were recorded in gas sales and increased the realized gas price for the quarter by $0.18 per Mcf.

Depending on changes in oil and gas futures markets and management s view of underlying oil and natural gas supply and demand trends, we may increase or decrease our current hedging positions.

3. 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, 2007 we issued a total of 237,000 restricted shares to non-employee directors, officers, and other employees. Included in that amount are 228,000 shares issued to certain executives that are subject to market condition-based vesting determined by our stock price performance relative to a defined peer group s stock price performance. After three years of continued service, the executive will be entitled to vest in 50% to 100% of the award. The material terms of performance goals applicable to these awards were approved by stockholders in May 2006. The remaining shares and units granted in 2007 have service-based vesting schedules ranging from one to five years.

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The following table presents restricted stock activity as of March 31, 2007, and changes during the year:

Outstanding as of January 1, 2007	792,779
Vested	
Granted	237,000
Canceled	(24,000)
Outstanding as of March 31, 2007	1,005,779

The following table presents restricted unit activity as of March 31, 2007 and changes during the year:

Outstanding as of January 1, 2007	696,641
Vested	
Granted	
Canceled	
Outstanding as of March 31, 2007	696,641
Vested included in outstanding	172,617

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, net of an estimated forfeiture rate. The fair value of the market condition-based restricted stock 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 the three-year period. For the quarters ended March 31, 2007, and 2006, we recorded compensation expense of $2.7 million and $1.5 million, respectively. We also capitalized to oil and gas properties associated costs of $0.7 million and $0.7 million, respectively. Unamortized compensation expense related to unvested restricted shares and units at March 31, 2007 was $26.9 million and $3.4 million, respectively. Compensation expense related to the restricted stock and unit awards is recognized ratably over the applicable vesting period.

Stock Options

Options granted under our plan expire ten years from the grant date and vest in one-fifth increments on each of the first five anniversaries of the grant date. The plan provides that all grants have an exercise price equal to 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. Upon the exercise of stock options granted after October 1, 2002, grantees are required to hold at least 50 percent of the profit shares, as defined in the plan, until the eighth anniversary of the grant date.

There were no stock options granted to employees during the three months ended March 31, 2007 and 2006.

Information about outstanding stock options is summarized below:

	Shares	Weighted Average Exercised	Weighted Average Remaining Term	Aggregate Intrinsic Value (000)
Outstanding as of January 1, 2007	1,913,529	$ 16.23		
Exercised	(358,078)	12.33		
Granted				
Canceled				
Outstanding as of March 31, 2007	1,555,451	$ 17.12	5.2 Years	$ 31,375
Exercisable as of March 31, 2007(1)	1,249,171	$ 15.67	4.8 Years	$ 26,840

(1) Does not include 6,060 vested options that have an exercise price exceeding our March 31, 2007 stock price.

The total intrinsic value of stock options exercised during the three months ended March 31, 2007 and 2006 was $8.6 million and $2.9 million, respectively.

For the quarter ended March 31, 2007, compensation expense related to stock options was approximately $496 thousand, or $315 thousand after tax. In the same period for 2006, compensation expense was $468 thousand, or $299 thousand after tax. Compensation expense 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 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.

Cash received from option exercises during the three months ended March 31, 2007 and 2006 was $4.4 million and $1.5 million, respectively. The related tax benefits realized from option exercises totaled $3.2 million and $1.1 million, respectively, and were recorded to paid-in capital.

The following summary reflects the status of non-vested stock options granted to employees and directors as of March 31, 2007 and changes during the year:

	Shares	Weighted Average Grant Date Fair Value
Non-vested as of January 1, 2007	300,220	$ 10.41
Vested		
Granted		
Forfeited		
Non-vested as of March 31, 2007	300,220	$ 10.41

As of March 31, 2007 there was $2.4 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 3.8 years. The weighted average exercise price of the non-vested stock options is $22.62.

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Stockholder Rights Plan

We have a stockholder rights plan. The plan is designed to improve the ability of our board to protect the interests of our stockholders in the event of an unsolicited takeover attempt. For every outstanding share of Cimarex common stock, there exists one purchase right (the Right). Each Right represents a right to purchase one one-hundredth of a share of Series A Junior Participating Preferred Stock. The Rights will become exercisable only in the event a person or group acquires beneficial ownership of 15 percent 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 percent or more of our common stock. The purchase price for each one one-hundredth of a share of Preferred Stock pursuant to the exercise of a Right is $60.00, subject to adjustment in certain cases to prevent dilution.

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 percent 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 2005, the Board of Directors declared our first quarterly cash dividend of $0.04 per share. A $0.04 per share cash dividend was also declared to stockholders in every quarter of 2006 and the first quarter of 2007. Future dividend payments will depend on our 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 common stock. Through December 31, 2005, 68,000 shares had been repurchased at an average price of $43.03. In 2006, an additional 182,100 shares were repurchased at an average price of $44.43 per share. There were no shares purchased in the first quarter of 2007. All repurchased shares have been cancelled.

A summary of our common stock activity follows:

	Number of Shares (in thousands)		
	Issued	**Treasury**	**Outstanding**
December 31, 2006	83,962	(1,079)	82,883
Restricted shares issued under compensation plans, net of cancellations	213		213
Option exercises, net of cancellations	190		190
March 31, 2007	84,365	(1,079)	83,286

4. **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. 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.

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, 2007 (in thousands):

Balance as of January 1, 2007	$	129,141
Liabilities incurred in the current period		1,060
Liabilities settled in the current period		(1,092)
Accretion expense		1,761
Revision of estimated liabilities		381
Balance as of March 31, 2007		131,251
Less: Current asset retirement obligation		(4,320)
Long-term asset retirement obligation	$	126,931

5. Long-Term Debt

At December 31, 2006, debt consisted of the following (in thousands):

Bank debt	$ 95,000	
9.6% Notes due 2012 (face value $195,000)	210,746	(1)
Floating rate convertible notes due 2023 (face value $125,000)	137,921	(2)
Total long-term debt	$ 443,667	

Debt at March 31, 2007 consisted of the following (in thousands):

Bank debt	$ 161,000	
9.6% Notes due 2012 (face value $195,000)	209,990	(1)
Floating rate convertible notes due 2023, 5.36% at March 31, 2007 (face value $125,000)	137,730	(2)
Total long-term debt	$ 508,720	

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(1) Fair market value at June 7, 2005 (date of acquisition of Magnum Hunter) equaled $215.5 million. The subsequent noted balances represent the fair market value at date of acquisition less amortization of the premium of fair market value over face value.

(2) Fair market value at June 7, 2005 equaled $144.75 million. The subsequent noted balances represent the fair market value at date of acquisition less amortization of the premium of fair market value over face value.

Our revolving credit facility provides for $500 million of long-term committed credit. The facility is scheduled to mature on July 1, 2010 and is secured by mortgages on certain oil and gas properties and the stock of certain wholly-owned operating subsidiaries. At March 31, 2007, there were outstanding borrowings of $161 million under the revolving credit facility at a weighted average interest rate of approximately 6.52%. We also had letters of credit for approximately $5 million posted against the borrowing base, leaving an unused borrowing amount of approximately $334 million at March 31, 2007.

The credit facility agreement contains both financial and non-financial covenants. We continue to comply with these covenants and do not view them as materially restrictive.

The 9.6% notes assumed in the Magnum Hunter merger have a face value of $195 million and are due March 15, 2012. The notes are unsecured and are redeemable, as a whole or in part, at our option, on and after March 15, 2007 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	
2007	104.8	%
2008	103.2	%
2009	101.6	%
2010 and thereafter	100.0	%

In May 2007, we sold $350 million of 7.125% notes that will mature May 1, 2017. The notes were sold to the public at par. Net proceeds from the sale approximate $344 million, after deducting underwriting discounts and commissions and estimated expenses of the offering. We plan to use the net proceeds to redeem the 9.6% notes and reduce outstanding borrowings under our credit facility.

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 an annual rate equal to three-month LIBOR, reset quarterly. On March 31, 2007, the interest rate equaled 5.36%.

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 fixed conversion price of $28.99 per share. On March 30, 2007, the closing price of our common stock on the New York Stock Exchange was $37.02. There is not an observable market for the notes. Based on an average common stock price of $37.02, management estimates the fair value of the notes at March 31, 2007 was approximately $159.6 million (or $1,277 per bond).

In addition to the holders right to redeem the notes if our common stock price is above the conversion price, the holders also have the right to require us to repurchase all or a portion of the notes at a repurchase price equal to 100% of the principal amount (plus accrued interest) on December 15, 2008, 2013, and 2018. The indenture agreement also provides us with an option to redeem some or all of the notes at a redemption price equal to 100% of the principal amount and shares for the value of the convertible feature (plus accrued interest) anytime after December 22, 2008.

6. Income Taxes

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

	Three Months Ended March 31, 2007	2006
Current (benefits) taxes	$ (15,354)	$ 16,862
Deferred taxes	52,521	46,681
	$ 37,167	$ 63,543

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.

We recognize interest and penalties related to uncertain tax positions in Other, net. As of March 31, 2007, we made no provisions for interest or penalties related to uncertain tax positions. The tax years 2003 2006

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remain open to examination by both the Internal Revenue Service of the United States and by the various state taxing authorities in which we file.

Our provision for income taxes differed from the U.S. statutory rate of 35% primarily due to state income taxes and non-deductible expenses. The income tax rate for the three months ended March 31, 2007 was 36.5%.

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

	Three Months Ended March 31, 2007	2006
Cash paid during the period for:		
Interest (net of amounts capitalized)	$ 8,744	$ 5,301
Income taxes (net of refunds received)	$ (690)	$ 20,415

8. Earnings per Share and Comprehensive Income

Earnings per Share

The calculations of basic and diluted net earnings per common share are presented below (in thousands, except per share data):

	Three Months Ended March 31, 2007	2006
Net Income available to common stockholders for basic diluted shares	$ 64,628	$ 110,151
Basic weighted-average shares outstanding	82,222	82,633
Incremental shares from assumed exercise of stock options, vesting of restricted stock units and conversion of convertible senior notes	2,171	2,609
Diluted weighted-average shares outstanding	84,393	85,242
Earnings per share:		
Basic	$ 0.79	$ 1.33
Diluted	$ 0.77	$ 1.29

There were stock options outstanding for 1,555,451 and 1,924,578 shares of our common stock at March 31, 2007 and 2006, respectively. All stock options and restricted units and shares were considered potentially dilutive securities for each of the periods presented.

Comprehensive Income

Comprehensive income is a term used to refer to net income plus other comprehensive income. Other comprehensive income 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.

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The components of comprehensive income are as follows (in 000 s):

	Three Months Ended March 31, 2007	2006
Net Income	$ 64,628	$ 110,151
Other comprehensive income:		
Cash flow hedges		
Decrease in fair value	(30,894)	
Settlements reflected in gas sales	(5,108)	
Sub-total	(36,002)	
Related income tax effect	13,287	
Total cash flow hedges	(22,715)	
Change in fair value of marketable securities available for sale, net of tax	(30)	
Total comprehensive income	$ 41,883	$ 110,151

9. Commitments and Contingencies

Litigation

As of March 31, 2007, we have accrued $7.2 million for a mediated litigation settlement pertaining to post-production deductions on properties operated by us. We have also accrued an additional $1.5 million for a mediated litigation settlement pertaining to oil and gas property title issues. We anticipate payment of both settlements during 2007. We have other various litigation related matters in the normal course of business, none of which can be estimated or are deemed to be material, individually or in aggregate.

Other

At March 31, 2007, we had firm sales contracts to deliver approximately 765 Mcf of natural gas over the next five months. If this gas is not delivered, our financial commitment would be approximately $5.2 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.

We have other various delivery commitments in the normal course of business, none of which are individually material. In aggregate these commitments have a maximum amount that would be payable, if no gas is delivered, of approximately $3.3 million.

We have contractual commitments for drilling rigs and on oil and gas wells approved for drilling or in the process of being drilled at March 31, 2007 of approximately $56.3 million.

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

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.

INTRODUCTION

Cimarex Energy Co. is an independent oil and gas exploration and production company. Our operations are presently focused primarily in Oklahoma, Texas, New Mexico, Kansas, Louisiana, and the Gulf of Mexico.

Our primary focus is to explore for and discover new reserves. To supplement our growth, we also consider mergers and acquisitions. On June 7, 2005, we completed the acquisition of Magnum Hunter Resources, Inc., an 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. Overall, about 39 percent of our proved reserves are in the Permian Basin and 41 percent are in our Mid-Continent region. Our onshore Gulf Coast and Gulf of Mexico operations collectively make up ten percent of our proved reserves.

Industry and Economic Factors

In managing our business we must deal with many factors inherent in our industry. First and foremost is wide fluctuation of oil and gas prices. Historically, oil and gas markets have been cyclical and volatile, with future price movements difficult to predict. While our revenues are a function of both production and prices, wide swings in prices often have the greatest impact on our results of operations.

Our operations entail significant complexities. Advanced technologies requiring highly trained personnel are utilized in both exploration and production. Even when the technology is properly

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used, the interpreter still may not know conclusively if hydrocarbons will be present or the rate at which they will be produced. Exploration is a high-risk activity, often times resulting in no commercially productive reservoirs being discovered. Moreover, costs associated with operating within the industry are substantial and usually move up and down together with commodity prices.

The oil and gas industry is highly competitive. We compete with major and diversified energy companies, independent oil and gas companies, and individual operators. In addition, the industry as a whole competes with other businesses that supply energy to industrial, commercial, and residential end users.

Extensive federal, state, and local regulation of the industry significantly affects our operations. In particular, our activities are subject to comprehensive environmental regulations. Compliance with these regulations increases the cost of planning, designing, drilling, installing, operating, and abandoning oil and gas wells and related facilities. These regulations may become more demanding in the future.

Approach to the Business

Profitable growth of our assets will largely depend upon our ability to successfully find and develop new proved reserves. To achieve an overall acceptable rate of growth, we maintain a blended portfolio of low, moderate, and higher risk exploration and development projects. We believe that this approach allows for consistent increases in our oil and gas reserves, while minimizing the chance of failure. To further mitigate risk, we have chosen to seek geologic and geographic diversification by operating in multiple basins. We may also consider the use of transaction-specific hedging of oil and gas prices to reduce price risk. In connection with the acquisition of Magnum Hunter, we acquired existing commodity derivatives. Also, in July 2006, we entered into additional derivative contracts as discussed more fully below.

Implementation of our business approach relies on our ability to fund ongoing exploration and development projects with cash flow provided by operating activities, periodic sales of non-core properties, and external sources of capital.

We project that 2007 exploration and development expenditures will approximately range from $800 million to $1 billion. Approximately 37 percent of the expenditures will be in the Mid-Continent area, 28 percent in the Permian Basin, 24 percent in the Gulf Coast area and eight percent in the Gulf of Mexico.

Exploration and development expenditures during the first quarter of 2007 totaled $245.5 million, down from $273.2 million for the first quarter of 2006. In the three months of 2007, we participated in drilling 110 gross (62 net) wells, with an overall completion rate of 94 percent.

Cash flow from operating activities for the three months ended March 31, 2007 totaled $186.5 million, helping to fund our drilling program.

Based on expected cash provided by operating activities and monies available under our senior secured revolving credit facility, we believe we are well positioned to fund the projects identified for the remainder of 2007 and beyond.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Our discussion and analysis of our financial condition and results of operation are based upon our Consolidated Financial Statements, which have been prepared in accordance with accounting principles generally accepted in the United States of America, or GAAP. The preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues, and expenses. Our significant accounting policies are described in Note 4 to our Consolidated Financial Statements included in our Annual Report on Form 10-K filed for the year ended December 31, 2006. In response to SEC Release No. 33-8040, Cautionary Advice Regarding Disclosure about Critical Accounting Policies, we have identified certain of these policies which are particularly important to the portrayal of our financial position and results of operations and which require the application of significant judgment by our management. 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. We believe the following critical accounting policies affect our more significant judgments and estimates used in the preparation of our Consolidated Financial Statements.

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.

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 an amount equal to 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 is adjusted for designated cash flow hedges if it is determined that net capitalized costs exceed the full cost ceiling limit. 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 will be used to determine if the capital costs are in fact impaired as of the end of the period.

Revenue Recognition

Revenues from oil and gas sales are recognized based on the sales method, with revenue recognized on actual volumes sold to purchasers. There is a ready market for oil and gas, with sales occurring soon after production. We market and sell natural gas for working interest partners under short term sales and supply agreements and earn a fee for such services. Revenues are recognized as gas is delivered and are reflected net of gas purchases on the consolidated statement of operations.

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Oil and Gas Reserves

The process of estimating quantities of oil and gas reserves is complex, requiring significant decisions in the evaluation of all available geological, geophysical, engineering, and economic data. The data for a given field may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history, and continual reassessment of the viability of production under varying economic conditions. As a result, material revisions to existing reserve estimates may occur from time to time. Although we make every reasonable effort to ensure that reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various fields make these estimates generally less precise than other estimates included in the financial statement disclosures, especially during interim quarters.

We use the units-of-production method to amortize our oil and gas properties. Changes in reserve quantities will cause corresponding changes in depletion expense in periods subsequent to the quantity revision or, in some cases, a full cost ceiling limitation charge in the period of the revision. To date, changes in expense resulting from changes in previous estimates of reserves have not been material.

Goodwill

We account for goodwill in accordance with Statement of Financial Accounting Standards (SFAS) No. 142, *Goodwill and Other Intangible Assets*. SFAS No. 142 requires an annual impairment assessment, which we perform in the fourth quarter. A more frequent assessment is required if certain events occur that reasonably indicate an impairment may have occurred. The volatility of oil and gas prices may cause more frequent assessments. The impairment assessment requires us to make estimates regarding the fair value of goodwill. The estimated fair value is based on numerous factors, including future net cash flows of our estimates of proved reserves as well as the success of future exploration for and development of unproved reserves. If the estimated fair value exceeds its carrying amount, goodwill is considered not impaired. If the carrying amount exceeds the estimated fair value, then a measurement of the loss must be performed, with any deficiency recorded as an impairment. To date, no related impairment has been recorded.

Derivative Instruments

SFAS No.133, *Accounting for Derivative Instruments and Hedging Activities,* requires that all derivatives be recorded on the balance sheet at fair value. We determine the fair value of derivative contracts based on the stated contract prices and current and projected market prices at the determination date discounted to reflect the time value of money until settlement. The accounting treatment for the changes in fair value is dependent upon whether or not a derivative instrument is designated as a hedge for accounting treatment purposes. Realized and unrealized gains and losses on derivatives that are not designated as hedges are recognized currently in costs and expenses associated with operating income in our consolidated statements of operations. For derivatives designated as cash flow hedges, changes in the fair value, to the extent the hedge is effective, are recognized in other comprehensive income until the hedged item is settled. Changes in the fair value of the hedge resulting from ineffectiveness are recognized currently as unrealized gains or losses in other income and expense in the consolidated statements of operations. Gains and losses upon settlement of the cash flow hedges will be recognized in gas revenues in the period the contracts are settled.

In connection with the Magnum Hunter merger, Magnum Hunter s existing commodity derivatives were not designated for hedge accounting treatment. As a result, we recognized a net gain for the quarter ended March 31, 2006 of $15.6 million. Activity included both non-cash mark-to-market derivative gains and losses as well as cash settlements. Cash payments related to those contracts that settled in the first quarter ended March 31, 2006 equaled $7.4 million. The derivative liability at March 31, 2006, relating to those contracts, equaled $19.0 million. As of December 31, 2006, all derivative contracts assumed with the Magnum Hunter merger had matured.

To mitigate a portion of our potential exposure to adverse market changes in an environment of volatile gas prices, we entered into additional derivative contracts in July 2006. Using zero-cost collars, we hedged 29.2 million MMBtu and 14.6 million MMBtu of our anticipated Mid-Continent gas production for 2007 and 2008, respectively. At March 31, 2007, this represented approximately 55% and 30% of our current anticipated Mid-Continent gas production for 2007 and 2008, respectively.

Under the collar agreements, we will receive the difference between an agreed upon Mid-Continent index price and a floor price if the index price is below the floor price. We will pay the difference between the agreed upon contracted 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 contracted floor and ceiling prices. These derivatives have been designated for hedge accounting treatment as cash flow hedges.

Settlements received during the quarter ended March 31, 2007 totaled $5.1 million, which were recorded in gas sales and increased the realized gas price for the quarter by $0.18 per Mcf. Also during the quarter, we recorded an unrealized loss of $78 thousand related to the ineffective portion of the hedges. At March 31, 2007, $10.1 million and $2.8 million of the hedges were recorded as current and long-term assets, respectively, and a cumulative unrealized gain (net of deferred income taxes) of $8.2 million was recorded in other comprehensive income. See Note 2 to the Consolidated Financial Statements and Item 3 of this report for additional information regarding our derivative instruments.

Depending on changes in oil and gas futures markets and management s view of underlying oil and natural gas supply and demand trends, we may increase or decrease our current hedging positions.

Contingencies

A provision for contingencies is charged to expense when the loss is probable and the cost can be reasonably estimated. Determining when expenses should be recorded for these contingencies and the appropriate amounts for accrual is a complex estimation process that includes subjective judgment. In many cases, this judgment is based on interpretation of laws and regulations, which can be interpreted differently by regulators and/or courts of law. We closely monitor known and potential legal, environmental and other contingencies and periodically determine when we should record losses for these items based on information available to us. As of March 31, 2007, we have accrued for a mediated $7.2 million litigation settlement pertaining to post-production deductions on properties operated by us. We have also accrued an additional $1.5 million for a mediated litigation settlement pertaining to oil and gas property title issues. We anticipate payment of both settlements during 2007. We have other various litigation related matters in the normal course of business, none of which can be estimated or are deemed to be material, individually or in aggregate. See Note 9 to the Consolidated Financial Statements.

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. After initial measurement, the asset retirement liability must be accreted each period. Capitalized costs are depleted as a component of the full cost pool.

Stock Options

Effective January 1, 2005, we adopted the provisions of SFAS No. 123R, *Share Based Payment* on a prospective basis. SFAS No. 123R requires companies to recognize in the income statement the grant-date fair value of stock options and other equity-based compensation to employees.

We estimate the fair value of each option award 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 option exercise, expected years until exercise, and employee termination within the valuation model. The risk free interest rate is based on U.S. Treasury Securities at a constant five year fixed maturity in effect at the date of the grant.

Segment Information

We have one reportable segment (exploration and production).

Recent Accounting Developments

In May 2007, the FASB issued a Staff Position changing the criteria for determining whether a tax position has been settled with the taxing authority for purposes of applying Interpretation 48, *Accounting for Uncertainty in Income Taxes*. A company s tax position will be considered settled if the taxing authority has completed its examination, the company does not plan to appeal, and it is *remote* that the taxing authority would reexamine the tax position in the future. Effective January 1, 2007, we adopted the provisions of Interpretation 48, *Accounting for Uncertainty in Income Taxes.* We have evaluated the effects of implementing this interpretation and the adoption of this interpretation does not have a material impact on our financial statements.

Overview

Our results of operations are primarily impacted by changes in oil and gas prices and changes in our production volumes. Realized oil prices decreased from $59.57 per barrel in the first quarter of 2006 to $55.22 per barrel in the first quarter of 2007. Realized gas prices decreased from $7.19 per Mcf in the first quarter of 2006 to $6.73 per Mcf in the first quarter of 2007.

Gas marketing revenues, net of related costs, pertain to sales of gas on behalf of third parties that are incidental to sales of our own production. Sales and costs associated with our production are reflected in gas sales and transportation expense.

We also own interests in gas gathering systems and gas processing plants that are connected to our production operations. We transport and process third party gas that is associated with our gas.

Transportation expenses are comprised of costs paid to carry and deliver oil and gas to a specified delivery 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.

Production costs are composed of lease operating expenses, which generally consist of pumpers salaries, utilities, water disposal, maintenance and other costs necessary to operate our producing properties.

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

Depreciation, depletion and amortization 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, 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. While we expect such costs to increase with our growth, we expect such increases to be proportionately smaller than our production growth.

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.

Basis of Presentation

Certain amounts in prior years financial statements have been reclassified to conform to the 2007 financial statement presentation.

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RESULTS OF OPERATIONS

Periods Ended March 31, 2007 Compared with Periods Ended March 31, 2006:

SUMMARY DATA: **(in thousands or as indicated)**	**For the Three Months Ended March 31,** **2007**	**2006**
Net income	$ 64,628	$ 110,151
Per share-basic	0.79	1.33
Per share-diluted	0.77	1.29
Gas sales	$ 196,290	$ 233,723
Oil sales	97,164	88,272
Total oil and gas sales	$ 293,454	$ 321,995
Total gas volume-MMcf	29,177	32,515
Gas volume-MMcf per day	324.2	361.3
Average gas price-per Mcf (before hedge effect)	$ 6.55	$ 7.19
Effect of hedges per Mcf	0.18	
Total oil volume-thousand barrels	1,760	1,482
Oil volume-barrels per day	19,552	16,464
Average oil price-per barrel	$ 55.22	$ 59.57
Gas gathering and processing revenues	$ 12,639	$ 11,302
Gas gathering and processing costs	(7,311)	(6,553)
Gas gathering and processing margin	$ 5,328	$ 4,749
Gas marketing revenues, net	$ 782	$ 1,953
Costs and expenses:		
Depreciation, depletion and amortization	$ 108,884	$ 90,628
Production	45,005	41,772
Transportation	5,934	4,308
Taxes other than income	20,627	23,546
General and administrative	12,651	10,885
Stock compensation	2,670	1,968
Other operating, net	(271)	31
Loss (gain) on derivative instruments		(15,567)
Interest expense, net of capitalized interest	4,074	271
Amortization of fair value of debt	(947)	(945)
Asset retirement obligation accretion	2,591	1,448
Other, net	(3,449)	(3,342)

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Net income for the first quarter of 2007 was $64.6 million, or $0.77 per diluted share, compared to net income of $110.2 million, or $1.29 per diluted share for the same period in 2006. The change in net income results from the effect of changes in revenues and costs, as discussed further.

Oil and gas sales for the first quarter of 2007 totaled $293.5 million, compared to $322.0 million for the first quarter of 2006. The $28.5 million decrease in sales between the two periods results from $21.1 million related to lower commodity prices, and $24.0 million due to lower gas production volumes offset by $16.6 million due to higher oil production volumes.

Realized gas prices averaged $6.73 per Mcf (including an $0.18 per Mcf effect from hedges) for the three months ended March 31, 2007, compared to $7.19 per Mcf for the first quarter of 2006. This 6.4 percent change decreased sales by $13.4 million between the two periods. Realized oil prices averaged $55.22 per barrel for the first quarter of 2007, compared to $59.57 per barrel for the same period in 2006. The decrease in sales between periods resulting from this 7.3 percent reduction in oil prices totaled $7.7 million.

Average gas volumes declined 37.1 MMcf per day in the first quarter of 2007 to 324.2 MMcf per day from 361.3 MMcf per day in the first quarter of 2006, resulting in $24.0 million of lower revenues. Oil volumes averaged 19,552 barrels per day for the first quarter of 2007, compared to 16,464 barrels per day in the same period of 2006, resulting in increased revenues of $16.6 million. The lower gas volumes are attributable primarily to natural reservoir declines in the Gulf Coast area, which were only partially offset by new exploration success in the area. Daily gas production volumes in the area averaged 52.5 MMcf in 2007 versus 86.0 MMcf in 2006. The increase in oil sales volumes between the periods of 2007 and 2006 is due to positive drilling results during 2006 and 2007.

Gas gathering and processing revenues, net of related costs, equaled $5.3 million in the first quarter of 2007, compared to $4.7 million in the first quarter of 2006. We own interests in gas gathering systems and gas processing plants that are connected to our production operations. We transport and process third party gas that is associated with our gas.

Gas marketing net revenues equaled $0.8 million in 2007 compared to $2.0 million, net of related costs of $29.9 million and $57.2 million for the first quarters of 2007 and 2006, respectively. Gas marketing revenues, net of related costs, pertain to sales of gas on behalf of third parties that is incidental to sales of our own production.

Costs and Expenses

Net costs and expenses (not including gas gathering, marketing and processing costs) were $197.8 million in the first quarter of 2007 compared to $155.0 million in the first quarter of 2006. Depreciation, depletion and amortization (DD&A) was a large component of these changes between periods. DD&A equaled $108.9 million in the first quarter of 2007 compared to $90.6 million in the same period of 2006. On a unit of production basis, DD&A was $2.74 per Mcfe in 2007 compared to $2.19 per Mcfe in 2006. The increase largely stems from higher costs for reserves added during 2006 and 2007. Certain high cost wells that were determined not to be productive have influenced our per unit rates, even though overall drilling success rates have remained high.

Production costs rose $3.2 million from $41.8 million ($1.01 per Mcfe) in the first quarter of 2006 to 45.0 million ($1.13 per Mcfe) in the first quarter of 2007. The higher costs in 2007 resulted primarily from the inclusion of costs associated with higher field operating expenses from an expanded number of properties, and higher maintenance costs.

Transportation costs increased from $4.3 million, or $0.10 per Mcfe, in the first quarter of 2006 to $5.9 million, or $0.15 per Mcfe, in the first quarter of 2007. The increase is the result of expiring contracts being renewed with increased current market rates.

Taxes, other than income, were $2.9 million lower, dropping from $23.5 million in the first quarter of 2006 to $20.6 million in the same period of 2007. The decrease between periods resulted from decreases in oil and gas sales stemming from lower commodity prices and lower gas production volumes.

General and administrative (G&A) expenses increased $1.8 million from $10.9 million in the first quarter of 2006 to $12.7 million in the first quarter of 2007. The increase between periods is due to an expansion of staff and higher employee-benefit costs.

Stock compensation expense consists of non-cash charges resulting from the issuance of restricted stock, restricted stock units, and stock option awards net of amounts capitalized. Stock compensation increased from $2.0 million in the three months of 2006 to $2.7 million in the three months of 2007.

A component of net costs and expenses for 2006 was a gain on derivative instruments. In connection with the Magnum Hunter merger, Magnum Hunter s existing commodity derivatives were not designated for hedge accounting treatment. As a result, we recognized a net gain for the quarter ended March 31, 2006 of $15.6 million. Activity included both non-cash mark-to-market derivative gains and losses as well as cash settlements. Cash payments related to these contracts that settled in the first quarter ended March 31, 2006 equaled $7.4 million. As of December 31, 2006, all derivative contracts assumed with the Magnum Hunter merger had matured.

To mitigate a portion of our potential exposure to adverse market changes in an environment of volatile gas prices, we entered into additional derivative contracts in July 2006. These derivatives have been designated for hedge accounting treatment as cash flow hedges.

Settlements received during the quarter ended March 31, 2007 totaled $5.1 million, which were recorded in gas sales and increased the realized gas price for the quarter by $0.18 per Mcf. Also during the quarter, we recorded an unrealized loss of $78 thousand related to the ineffective portion of the hedges. See Note 2 to the Consolidated Financial Statements and Item 3 of this report for additional information regarding our derivative instruments.

Net interest expense in the first quarter of 2007 of $4.1 million is comprised of $9.2 million of interest expense, offset by $5.1 million of capitalized interest resulting from interest recognized on borrowings associated with costs incurred to bring properties under development, not being amortized, to their intended use. Net interest expense in the first quarter of 2006 of $271 thousand is comprised of $6.5 million of interest expense, offset by $6.2 million of capitalized interest. The increase in the 2007 net interest amount from 2006 results from higher interest expense due to larger debt levels (long-term debt at March 31, 2007 equaled $508.7 million versus $351.5 million at March 31, 2006) and lower associated costs incurred to bring properties under development, not being amortized, to their intended use.

Asset retirement obligation accretion increased $1.2 million from $1.4 million in the first quarter of 2006 to $2.6 million in the same period of 2007. 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. The liability at March 31, 2007 equaled $131.3 million versus $103.5 million at March 31, 2006.

Other net income for the first quarter of 2007 equaled $3.4 million, compared to $3.3 million for the first quarter of 2006. The components of other income and expense consist of miscellaneous items that will vary from period to period, including income and loss in equity investees.

Income tax expense

Income tax expense totaled $37.2 million for the first quarter of 2007 versus $63.5 million for the first quarter of 2006. Tax expense equaled a combined Federal and state effective income tax rate of 36.5 percent and 36.6 percent in the first quarters of 2007 and 2006, respectively. We estimate that of our three-month 2007 income tax expense, $15.4 million is a current benefit.

LIQUIDITY AND CAPITAL RESOURCES

Cash Flows

Our primary source of capital is cash flow generated from operating activities. Prices we receive for oil and gas sales and our level of production will impact these future cash flows. No prediction can be made as to the prices we will receive. Production volumes will, in large part, depend upon the amount and results of future capital expenditures. In turn, actual levels of capital expenditures may vary due to many factors, including drilling results, oil and gas prices, industry conditions, prices and availability of goods and services, and the extent to which proved properties are acquired.

Cash flow provided by operating activities for the three months of 2007 was $186.5 million, compared to $228.0 million for the three months ended March 31, 2006. The decrease in 2007 from the earlier period resulted primarily from lower oil and gas prices and lower gas production and the change in accounts payable and accrued liabilities.

Revenues from oil and gas sales facilitated the funding of our exploration and development expenditure program for the three months of 2007.

Cash flow used in investing activities for the three months of 2007 was $254.3 million, compared to $228.0 million for the three months ended March 31, 2006. The increase in 2007 stemmed from a larger exploration and development program.

Cash flow provided by financing activities for the three months of 2007 was $70.2 million versus $11.0 million used in the three months of 2006. The cash provided in financing activities in 2007 resulted primarily from the borrowing of $66.0 million on our credit facility.

Financial Condition

As of March 31, 2007, stockholders equity totaled $3.02 billion, up from $2.98 billion at December 31, 2006. The increase resulted primarily from first quarter net income of $64.6 million, offset by a reduction in other comprehensive income of $22.7 million, arising from unrealized losses recorded during the quarter related to derivative contracts qualifying for hedge accounting treatment. At March 31, 2007 our cash balance equaled $7.4 million.

In December 2005, the Board of Directors declared our first quarterly dividend of $0.04 per share payable to stockholders. A $0.04 per share dividend has been authorized and paid in every quarter since December 2005.

In December 2005, the Board of Directors authorized the repurchase of up to four million shares of common stock. Through December 31, 2006, 182,100 shares had been repurchased at an average price of $44.43. No repurchases of common stock occurred in the first quarter of 2007.

Working Capital

Working capital at March 31, 2007 was $61.3 million, compared to $62.2 million at December 31, 2006. Our receivables are from a diverse group of companies including major energy companies, pipeline companies, local distribution companies and end-users in various industries. The collection of receivables during the period presented has been timely. Historically, losses associated with uncollectible receivables have not been significant.

Financing

Debt at December 31, 2006 consisted of the following (in thousands):

Bank debt	$	95,000	
9.6% Notes due 2012 (face value $195,000)	210,746		(1)
Floating rate convertible notes due 2023 (face value $125,000)	137,921		(2)
Total long-term debt	$	443,667	

Debt at March 31, 2007 consisted of the following (in thousands):

Bank debt	$	161,000	
9.6% Notes due 2012 (face value $195,000)	209,990		(1)
Floating rate convertible notes due 2023, 5.36% at March 31, 2007 (face value $125,000)	137,730		(2)
Total long-term debt	$	508,720	

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(1) Fair market value at June 7, 2005 (date of acquisition of Magnum Hunter) equaled $215.5 million. The subsequent noted balances represent the fair market value at date of acquisition less amortization of the premium of fair market value over face value.

(2) Fair market value at June 7, 2005 equaled $144.75 million. The subsequent noted balances represent the fair market value at date of acquisition less amortization of the premium of fair market value over face value.

Our revolving credit facility provides for $500 million of long-term committed credit. The facility is scheduled to mature on July 1, 2010 and is secured by mortgages on certain oil and gas properties and the stock of certain wholly-owned operating subsidiaries. At March 31, 2007, there were outstanding borrowings of $161 million under the revolving credit facility at a weighted average interest rate of approximately 6.52%. We also had letters of credit for approximately $5 million posted against the borrowing base, leaving an unused borrowing amount of approximately $334 million at March 31, 2007.

The credit facility agreement contains both financial and non-financial covenants. We continue to comply with these covenants and do not view them as materially restrictive.

The 9.6% notes assumed in the Magnum Hunter merger have a face value of $195 million and are due March 15, 2012. The notes are unsecured and are redeemable, as a whole or in part, at our option, on and after March 15, 2007 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	
2007	104.8	%
2008	103.2	%
2009	101.6	%
2010 and thereafter	100.0	%

In May 2007, we sold $350 million of 7.125% notes that will mature May 1, 2017. The notes were sold to the public at par. Net proceeds from the sale approximate $344 million, after deducting underwriting discounts and commissions and estimated expenses of the offering. We plan to use the net proceeds to redeem the 9.6% notes and reduce outstanding borrowings under our credit facility.

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 an annual rate equal to three-month LIBOR, reset quarterly. On March 31, 2007, the interest rate equaled 5.36%.

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 fixed conversion price of $28.99 per share. On March 31, 2007, the closing price of our common stock on the New York Stock Exchange was $37.02. There is not an observable market for the notes. Based on an average common stock price of $37.02, management estimates the fair value of the notes at March 31, 2007 was approximately $159.6 million (or $1,277 per bond).

In addition to the holders right to redeem the notes if our common stock price is above the conversion price, the holders also have the right to require us to repurchase all or a portion of the notes at a repurchase price equal to 100% of the principal amount (plus accrued interest) on December 15, 2008, 2013, and 2018. The indenture agreement also provides us with an option to redeem some or all of the notes at a redemption price equal to 100% of the principal amount (plus accrued interest) anytime after December 22, 2008.

Contractual Obligations and Material Commitments

At March 31, 2007, we had contractual obligations and material commitments as follows:

	Payments Due by Period (In thousands)				
Contractual Obligations	**Total**	**Less than 1 Year**	**1-3 Years**	**3-5 Years**	**More than 5 Years**
Long-term debt (1)	$ 481,000	$	$	$ 356,000	$ 125,000
Fixed-Rate interest payments(1)	93,600	18,720	37,440	37,440	
Operating leases	30,027	5,240	9,922	7,640	7,225
Drilling commitments	56,251	56,251			
Asset retirement obligation	131,251	4,320	(2)	(2)	(2)
Other liabilities	6,701	206	70	53	6,372

(1) These amounts do not include interest on the $161 million of bank debt outstanding at March 31, 2007. The weighted average interest rate at March 31, 2007 on the bank debt was approximately 6.52%. These amounts have not been adjusted to reflect the subsequent redemption of our 9.6% notes and issuance of new notes. See Item 3: Interest Rate Risk for more information regarding fixed and variable rate debt.

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

At March 31, 2007, we had firm sales contracts to deliver approximately 765 Mcf of natural gas over the next 5 months. If this gas is not delivered, our financial commitment would be approximately $5.2 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.

Cimarex has other various delivery commitments in the normal course of business, none of which are individually material. In aggregate these commitments have a maximum amount that would be payable, if no gas is delivered, of approximately $3.3 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 line of credit will be adequate to meet future liquidity needs, including satisfying our financial obligations and funding our operations and exploration and development activities.

2007 Outlook

Our projected 2007 exploration and development expenditure program, ranging from $800 million to $1 billion, will require a great deal of coordination and effort. Though a variety of factors could curtail, delay or even cancel some of our drilling operations, we believe our projected program has a high probability of occurrence. The majority of projects are in hand, drilling rigs are being scheduled, and the historical results of our drilling efforts in these areas warrant pursuit of the projects.

Costs of operations on a per Mcfe basis for 2007 are estimated to approximate levels realized in late 2006. Should factors beyond our control change, our program and realized costs will vary from current projections. These factors could include volatility in commodity prices, changes in the supply of and demand for oil and gas, weather conditions, governmental regulations and more.

Production estimates for 2007 range from 450 to 470 MMcfe per day. Revenues will depend not only on the level of oil and gas actually produced, but also the prices that will be realized. During 2006, our realized prices averaged $6.50 per Mcf of gas and $61.96 per barrel of oil. Prices can be very volatile and the probability of 2007 realized prices being different than they were in 2006 is high.

ITEM 3. QUALITATIVE AND QUANTITATIVE DISCLOSURES ABOUT MARKET RISK

Price Fluctuations

Our results of operations are highly dependent upon the prices we receive for oil and gas production, and those prices constantly change in response to market forces. Nearly all of our revenue is from the sale of oil and gas, so these fluctuations, positive and negative, can have a significant impact on our results of operations and cash flows.

Monthly gas price realizations during the first quarter of 2007 ranged from \$6.04 per Mcf to \$7.15 per Mcf. Oil prices ranged from \$51.38 per barrel to \$57.60 per barrel. It is impossible to predict future oil and gas prices with any degree of certainty.

In July 2006, we entered into derivative contracts to mitigate a portion of our potential exposure to adverse market changes in the Mid-Continent region, in an environment of volatile gas prices. These arrangements, which were based on prices available in the financial markets at the time the contracts were entered into, will be settled in cash and will not require physical delivery of hydrocarbons. These hedges have been designated for hedge accounting treatment as cash flow hedges under SFAS No. 133 and therefore, gains and losses upon settlement of the hedges will be recognized in gas revenue in the period the contracts are settled. We believe that we have sufficient production volumes such that the hedge contract transactions will occur as expected.

The following tables reflect the volumes, weighted average contract prices and fair values of the contracts we have in place as of March 31, 2007. We are exposed to risks associated with these contracts arising from volatility in commodity prices and the unlikely event of non-performance by the counterparties to the agreements. See Note 2 to the Consolidated Financial Statements and *Derivative Instruments* in Item 2 of this report for additional information regarding our derivative instruments.

Commodity	**Type**	**Volume/Day**	**Duration**		**Mid-Continent Weighted Average Price**	**Fair Value (000 s)**
Natural Gas	Collars	80,000 MMBTU	Apr 07	Dec 07	\$7.00 - \$10.17	\$ 11,760
Natural Gas	Collars	40,000 MMBTU	Jan 08	Dec 08	\$7.00 - \$9.90	1,156
						\$ 12,916

At March 31, 2007, the weighted average Mid-Continent prices for the 2007 and 2008 contracts approximated \$7.26 and \$7.66, respectively.

Interest Rate Risk

Fixed and Variable Rate Debt. We assumed fixed and variable rate debt as part of the acquisition of Magnum Hunter. These agreements expose us to market risk related to changes in interest rates. We have a credit facility that bears interest at either a Base rate or a Eurodollar rate at our option.

The following table presents the carrying and fair value of our debt along with average interest rates as of March 31, 2007. The fair value for the convertible notes was based on an average price per share of $37.02 for our common stock. The fair value for the fixed rate senior notes was based on their last traded value before March 31, 2007.

Expected Maturity Dates (in thousands of dollars)	**2010**		**2012**		**2023**		**Total**		**Book Value**		**Fair Value**	
Variable Rate Debt:												
Bank debt (a)	$	161,000	$		$		$	161,000	$	161,000	$	161,000
Convertible Notes (b)	$		$		$	125,000	$	125,000	$	137,730	$	159,635
Fixed Rate Debt:												
Senior Notes (c)	$		$	195,000	$		$	195,000	$	209,990	$	204,263

(a) At March 31, 2007, the weighted average interest rate on outstanding borrowings under the credit facility was approximately 6.52%.

(b) The interest rate on the convertible notes is 5.36%. The rate on these notes is equal to the three month LIBOR, reset quarterly. A holder of these notes has the right to require us to repurchase all or a portion of these notes on December 15, 2008, 2013, and 2018. The repurchase will be equal to the face value of the notes plus accrued and unpaid interest up to the date of repurchase.

(c) The interest rate on the senior notes due 2012 is a fixed 9.6%. In May, 2007 these notes were redeemed with proceeds from the issuance of $350 million of 7.125% notes that will mature May 1, 2017.

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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, 2007 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, 2007, 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, 2007, that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

PART II

ITEM 6 EXHIBITS

(a)

1.1	Underwriting Agreement dated as of April 17, 2007, by and among Cimarex Energy Co., the Subsidiary Guarantors listed on Schedule 2 thereto and J.P. Morgan Securities Inc., as representative of the several underwriters listed in Schedule 1 thereto, filed on April 20, 2007 as Exhibit 1.1 to the Registrant s Current Report on Form 8-K and incorporated herein by reference.
4.4	Senior Indenture dated as of May 1, 2007, by and among Cimarex Energy Co., the Subsidiary Guarantors party thereto and U.S. Bank National Association, as trustee, filed on May 2, 2007 as Exhibit 4.1 to the Registrant s Current Report on Form 8-K, and incorporated herein by reference.
4.5	Form of Senior Notes due 2017 included in Exhibit 4.1 to the Registrant s Current Report on Form 8-K filed on May 2, 2007 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.

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 9, 2007

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)