CIMAREX ENERGY CO
Form 10-Q
November 07, 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 September 30, 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 September 30, 2007 was 82,489,091.

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)

	September 30, 2007	December 31, 2006
	(In thousands, except share data)	
Assets		
Current assets:		
Cash and cash equivalents	$ 23	$ 5,048
Restricted cash	7,373	
Receivables, net	292,218	306,458
Inventories	36,750	39,397
Deferred income taxes	7,937	1,498
Derivative instruments	19,626	41,945
Other current assets	29,509	22,411
Total current assets	393,436	416,757
Oil and gas properties at cost, using the full cost method of accounting:		
Proved properties	5,393,449	4,656,854
Unproved properties and properties under development, not being amortized	423,013	425,173
	5,816,462	5,082,027
Less accumulated depreciation, depletion and amortization	(1,820,727)	(1,494,317)
Net oil and gas properties	3,995,735	3,587,710
Fixed assets, net	86,370	88,924
Goodwill	691,432	691,432
Derivative instruments	1,928	7,051
Other assets, net	45,060	37,876
	$ 5,213,961	$ 4,829,750
Liabilities and Stockholders Equity		
Current liabilities:		
Accounts payable	$ 42,027	$ 56,241
Accrued liabilities	227,293	202,163
Revenue payable	103,029	96,184
Total current liabilities	372,349	354,588
Long-term debt	526,349	443,667
Deferred income taxes	1,045,351	921,665
Other liabilities	134,228	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, 83,567,913 and 83,962,132 shares issued, respectively	836	840
Treasury stock, at cost, 1,078,822 and 1,078,822 shares held, respectively	(40,628)	(40,628)
Paid-in capital	1,837,812	1,867,448
Retained earnings	1,323,815	1,117,402
Accumulated other comprehensive income	13,849	31,081

		3,135,684		2,976,143
	$	5,213,961	$	4,829,750

See accompanying notes to consolidated financial statements.

CIMAREX ENERGY CO.

Consolidated Statements of Operations

(Unaudited)

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2007	2006	2007	2006
	(In thousands, except per share data)			
Revenues:				
Gas sales	$ 192,423	$ 197,460	$ 603,650	$ 622,841
Oil sales	135,335	111,801	343,329	308,911
Gas gathering and processing	14,773	13,126	42,425	36,520
Gas marketing, net	1,222	495	3,308	3,241
	343,753	322,882	992,712	971,513
Costs and expenses:				
Depreciation, depletion and amortization	117,634	104,904	339,315	290,305
Asset retirement obligation	2,124	1,977	7,114	4,918
Production	55,945	42,624	151,866	128,200
Transportation	6,882	5,845	19,110	15,636
Gas gathering and processing	6,859	7,325	21,995	20,264
Taxes other than income	22,397	22,912	66,826	68,392
General and administrative	10,922	10,804	35,531	31,679
Stock compensation, net	2,800	2,265	8,068	6,329
Gain on derivative instruments		(4,782)		(23,598)
Other operating, net	3,867		6,182	(61)
	229,430	193,874	656,007	542,064
Operating income	114,323	129,008	336,705	429,449
Other (income) and expense:				
Interest expense net of capitalized interest of $4,990, $6,726, $14,979 and $18,555 respectively	4,284	1,388	13,757	3,446
Amortization of fair value of debt	(191)	(947)	(1,718)	(2,838)
Gain on early extinguishment of debt			(5,099)	
Other, net	(5,316)	(20,137)	(12,222)	(25,515)
Income before income tax expense	115,546	148,704	341,987	454,356
Income tax expense	42,390	54,747	125,496	167,382
Net income	$ 73,156	$ 93,957	$ 216,491	$ 286,974
Earnings per share:				
Basic	$ 0.90	$ 1.15	$ 2.64	$ 3.50
Diluted	$ 0.87	$ 1.11	$ 2.56	$ 3.41
Weighted average shares outstanding:				
Basic	81,568	82,052	82,022	82,062
Diluted	84,025	84,311	84,418	84,275

See accompanying notes to consolidated financial statements.

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CIMAREX ENERGY CO.

Condensed Consolidated Statements of Cash Flows

(Unaudited)

	For the Nine Months Ended September 30,	
	2007	2006
	(In thousands)	
Cash flows from operating activities:		
Net income	$ 216,491	$ 286,974
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	339,315	290,305
Asset retirement obligation	7,114	4,918
Deferred income taxes	125,496	174,602
Stock compensation, net	8,068	6,329
Derivative instruments		(39,200)
Gain on liquidation of equity investees	(3,015)	(18,322)
Other	(6,512)	(947)
Changes in operating assets and liabilities		
Decrease in receivables, net	19,643	51,067
(Increase) in other current assets	(4,451)	(9,454)
(Decrease) in accounts payable and accrued liabilities	(1,255)	(69,336)
Increase (decrease) in other non-current liabilities	(7,725)	200
Net cash provided by operating activities	693,169	677,136
Cash flows from investing activities:		
Oil and gas expenditures	(735,937)	(802,155)
Acquisition of proved oil and gas properties	(17,554)	(5,530)
Proceeds from sale of assets	23,196	10,659
Distributions received from equity investees	3,015	58,285
Other expenditures	(10,991)	(23,651)
Net cash used by investing activities	(738,271)	(762,392)
Cash flows from financing activities:		
Net increase (decrease) in bank debt	(56,000)	50,000
Borrowings on other long-term debt	350,000	
Payments on other long-term debt	(204,360)	
Financing costs incurred	(6,099)	(74)
Treasury Stock acquired	(42,266)	(11,016)
Dividends paid	(10,095)	(10,006)
Proceeds from issuance of common stock and other	8,897	2,789
Net cash provided by financing activities	40,077	31,693
Net change in cash and cash equivalents	(5,025)	(53,563)
Cash and cash equivalents at beginning of period	5,048	61,647
Cash and cash equivalents at end of period	$ 23	$ 8,084

See accompanying notes to consolidated financial statements.

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements

September 30, 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 net gains for the quarter and nine months ended September 30, 2006 of $4.8 million and $23.6 million, respectively. 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 and nine months ended September 30, 2006 equaled $4.2 million and $15.7 million, respectively. The derivative liability at September 30, 2006, relating to those contracts, equaled $2.7 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. Of the original 2007 volumes hedged, there were 7.4 million MMBtu remaining as of September 30, 2007, which represented approximately 48% of our current anticipated Mid-Continent gas production for 2007. The 2008 hedged volumes represented 26% of our current anticipated Mid-Continent gas production for 2008.

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.

The following table sets forth the terms of the related derivative contracts at September 30, 2007:

Commodity	Type	Volume/Day	Duration		Mid-Continent Weighted Average Price		Fair Value (000 s)
Natural Gas	Collars	80,000 MMBTU	Oct 07	Dec 07	$7.00 - $10.17	$	9,179
Natural Gas	Collars	40,000 MMBTU	Jan 08	Dec 08	$7.00 - $9.90		12,375
						$	21,554

At September 30, 2007, the $21.6 million fair value of the derivative contracts was recorded as a current asset of $19.7 million and a long term asset of $1.9 million on our consolidated balance sheet. A cumulative unrealized gain (net of deferred income taxes) of $13.6 million was recorded in other comprehensive income. Based on the estimated fair values of the derivative contracts at September 30, 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 $12.4 million; however, actual gains and losses recognized may differ significantly. At September 30, 2007, the weighted average Mid-Continent prices for the 2007 and 2008 contracts approximated $6.07 and $6.82, respectively. We believe that we have sufficient production volumes such that the hedge contract transactions will occur as expected. Settlements received during the quarter and nine months ended September 30, 2007 equaled $11.5 million and $20 million which were recorded in gas sales and increased the realized gas price for the quarter and nine months ended by $0.39 and $0.23 per Mcf, respectively. Also during the quarter and nine months ended September 30, 2007, we recognized an unrealized loss of $4 thousand and an unrealized gain of $13 thousand related to the ineffective portion of the derivative contracts, respectively.

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 nine months ended September 30, 2007 we issued a total of 545,309 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.

The following table presents restricted stock activity as of September 30, 2007, and changes during the year:

Outstanding as of January 1, 2007	792,779
Vested	(13,416)
Granted	545,309
Canceled	(46,150)
Outstanding as of September 30, 2007	1,278,522

The following table presents restricted unit activity as of September 30, 2007 and changes during the year:

Outstanding as of January 1, 2007	696,641
Converted to stock	
Granted	5,274
Canceled	
Outstanding as of September 30, 2007	701,915
Vested included in outstanding	176,099

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 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. We recorded compensation costs related to the restricted stock and units as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Compensation costs:				
Recorded as expense	$ 2,293	$ 1,797	$ 6,563	$ 4,925
Capitalized to oil and gas properties	$ 1,057	$ 901	$ 2,678	$ 2,339

Unamortized compensation expense related to unvested restricted shares and units at September 30, 2007 and 2006 was $34.7 million and $33.0 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 nine months ended September 30, 2007 and 2006.

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, 2007	1,913,529	$ 16.23		
Exercised	(413,146)	12.76		
Granted				
Canceled	(1)	7.91		
Outstanding as of September 30, 2007	1,500,382	$ 17.18	4.7 Years	$ 30,317
Exercisable as of September 30, 2007	1,211,022	$ 15.98	4.4 Years	$ 25,838

The total intrinsic value of stock options exercised during the three months ended September 30, 2007 and 2006 was $714 thousand and $65 thousand, respectively. The total intrinsic value of options exercised during the nine months ended September 30, 2007 and 2006 was $9.9 million and $3.1 million, respectively.

Compensation expense related to stock options was approximately $0.5 million for both the quarters ended September 30, 2007 and 2006. For the nine months ended September 30, 2007 and 2006, compensation expense related to stock options was approximately $1.5 million and $1.4 million, respectively. 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 nine months ended September 30, 2007 and 2006 was $5.3 million and $1.6 million, respectively. The related tax benefits realized from option exercises totaled $3.6 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 September 30, 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	(10,860)	12.98
Granted		
Forfeited		
Non-vested as of September 30, 2007	289,360	$ 10.32

As of September 30, 2007 there was $1.4 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 3.7 years. The weighted average exercise price of the non-vested stock options is $22.20.

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

A $0.04 per share cash dividend has been declared to stockholders in every quarter since December 2005. 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 September 30, 2007 we have repurchased and cancelled a total of 1,364,300 shares at an overall average price of $39.05. The shares were acquired as follows:

	Shares Repurchased		Average Price
Year ended December 31, 2005	68,000	$	43.03
Year ended December 31, 2006	182,100	$	44.43
Quarter ended June 30, 2007	197,300	$	40.50
Quarter ended September 30, 2007	916,900	$	37.38
	1,364,300	$	39.05

In 2006 we cancelled all of the shares repurchased in 2005 and 2006. During the second quarter of 2007 we cancelled 25,000 shares, and during the third quarter of 2007 we cancelled the remaining shares.

A summary of our common stock activity for the nine months ended September 30, 2007 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	499		499
Option exercises, net of cancellations	221		221
Treasury shares purchased		(1,114)	(1,114)
Treasury shares cancelled	(1,114)	1,114	
September 30, 2007	83,568	(1,079)	82,489

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 nine months ended September 30, 2007 (in thousands):

Balance as of January 1, 2007	$	129,141
Liabilities incurred in the current period		3,229
Liabilities settled in the current period		(5,149)
Accretion expense		5,202
Revision of estimated liabilities		(1,192)
Balance as of September 30, 2007		131,231
Less: Current asset retirement obligation		(7,270)
Long-term asset retirement obligation	$	123,961

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 September 30, 2007 consisted of the following (in thousands):

Bank debt	$	39,000
9.6% Notes due 2012 (face value $195,000)		
7.125% Notes due 2017		350,000
Floating rate convertible notes due 2023, 5.69% at September 30, 2007 (face value $125,000)		137,349(2)
Total long-term debt	$	526,349

(1) Fair market value at June 7, 2005 (date of acquisition of Magnum Hunter) was $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 was $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 September 30, 2007, there were outstanding borrowings of $39.0 million under the revolving credit facility at a weighted average interest rate of approximately 7.75%. We also had letters of credit for approximately $2.7 million posted against the borrowing base, leaving an unused borrowing amount of approximately $458.3 million at September 30, 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 were redeemed on May 18, 2007 at a redemption price of 104.8% of the principal amount plus accrued interest of $3.3 million through the redemption date for a total of $207.6 million. We recognized a gain on the early extinguishment of this debt of $5.1 million which is reflected on the income statement under Other income and expense.

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 were used to redeem the 9.6% notes and reduce outstanding borrowings under our credit facility. Interest is payable May 1 and November 1 of each year. The first interest payment will be made on November 1, 2007. The notes are unsecured and 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	103.563%
2013	102.375%
2014	101.188%
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 equal to 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.

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 September 30, 2007, the interest rate equaled 5.69%.

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 September 28, 2007, the closing price of our common stock on the New York Stock Exchange was $37.25. There is not an observable market for the notes. Based on an average common stock price of $37.25, management estimates the fair value of the notes at September 30, 2007 was approximately $160.6 million (or $1,285 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 September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Current (benefits) taxes	$	$ (11,537)	$	$ (7,219)
Deferred taxes	42,390	66,284	125,496	174,601
	$ 42,390	$ 54,747	$ 125,496	$ 167,382

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 September 30, 2007, we made no provisions for interest or penalties related to uncertain tax positions. The tax years 2004 2006 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 2003-2006 for examination.

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 nine months ended September 30, 2007 was 36.7%.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Cash paid during the period for:				
Interest	$ 2,820	$ 11,968	$ 23,435	$ 26,085
Capitalized interest	4,990	6,726	14,979	18,555
Income taxes (net of refunds received)	$ 134	$ 183	$ (370)	$ 36,268

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 September 30,		Nine Month Ended September, 30,	
	2007	2006	2007	2006
Net Income available to common stockholders for basic diluted shares	$ 73,156	$ 93,957	$ 216,491	$ 286,974
Basic weighted-average shares outstanding	81,568	82,052	82,022	82,062
Incremental shares from assumed exercise of stock options, vesting of restricted stock units and conversion of convertible senior notes	2,457	2,259	2,396	2,213
Diluted weighted-average shares outstanding	84,025	84,311	84,418	84,275
Earnings per share:				
Basic	$ 0.90	$ 1.15	$ 2.64	$ 3.50
Diluted	$ 0.87	$ 1.11	$ 2.56	$ 3.41

There were stock options outstanding for 1,500,382 and 1,917,448 shares of our common stock at September 30, 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.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Net Income	$ 73,156	$ 93,957	$ 216,491	$ 286,974
Other comprehensive income:				
Cash flow hedges				
Increase (decrease) in fair value	11,432	32,158	(7,457)	32,158
Settlements reflected in gas sales	(11,522)		(19,999)	
Sub-total	(90)	32,158	(27,456)	32,158
Related income tax effect	(8)	(11,850)	10,145	(11,850)
Total cash flow hedges	(98)	20,308	(17,311)	20,308
Change in fair value of marketable securities available for sale, net of tax	33	(13)	79	20
Total comprehensive income	$ 73,091	$ 114,252	$ 199,259	$ 307,302

9. Commitments and Contingencies

Litigation

In the normal course of business we have various litigation related matters and associated accruals, the resolution of which we believe, individually or in aggregate, would not have a material adverse effect on the financial condition of the Company. One of such matters is restricted cash of $7.4 million held for a mediated settlement pertaining to post-production deductions on properties operated by us. We anticipate payment of this settlement during 2007.

Other

At September 30, 2007, we had commitments of approximately $117.8 million relating to construction of a plant processing facility adjacent to a field of producing gas wells in which we have a significant interest. In July 2007, we entered into an agreement with a third party who will reimburse us for approximately 42.5 percent of the construction costs and thereby effectively reduce our net cash commitment to approximately $67.8 million.

We have approximately $128.7 million of contractual commitments related to our drilling obligations at September 30, 2007.

At September 30, 2007, we had firm sales contracts to deliver approximately 1.2 Bcf of natural gas over the next six months. If this gas is not delivered, our financial commitment would be approximately $6.7 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 $2.6 million.

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

10. Property Sales

Various interests in oil and gas properties and related assets were sold during the first nine months of 2007 for $23.0 million which was recorded as a reduction to oil and gas properties.

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.

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 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. Various interests in oil and gas properties were sold during the first nine months of 2007 for $22.7 million. In October 2007 we closed on an $11.0 million property sale. Additionally, we have agreed to sell a portion of our non-core West Texas Spraberry oil properties for $90.0 million with an expected closing in December of 2007.

We project 2007 exploration and development expenditures to be approximately $1 billion. Approximately 39 percent of the expenditures will be in the Mid-Continent area, 38 percent in the Permian Basin, 18 percent in the Gulf Coast area and five percent in the Gulf of Mexico.

Exploration and development expenditures during the third quarter of 2007 totaled $234.2 million, down from $249.7 million for the third quarter of 2006. Capital expenditures for exploration and development during the first nine months of 2007 were $716.6 million, down from $804.6 million during the first nine months of 2006. In the nine months of 2007, we participated in drilling 345 gross (199 net) wells, with an overall completion rate of 92 percent.

Cash flow from operating activities for the nine months ended September 30, 2007 totaled $693.2 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. The increase in 2007 commodity prices has significantly increased our 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 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.

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 of $23.6 million during the first nine months of 2006. 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 nine months of September 30, 2006 equaled $15.7 million. The derivative liability at September 30, 2006, relating to those contracts, equaled $2.7 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. Of the original 2007 volumes hedged there were 7.4

million MMBtu remaining as of September 30, 2007, which represented approximately 48% of our current anticipated Mid-Continent gas production for 2007. The 2008 hedged volumes represented 26% of our current anticipated Mid-Continent gas production for 2008.

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 and nine months ended September 30, 2007 equaled $11.5 million and $20 million which were recorded in gas sales and increased the realized gas price for the quarter and nine months ended by $0.39 per Mcf and $0.23 per Mcf, respectively. Also during the quarter and nine months ended September 30, 2007, we recognized an unrealized loss of $4 thousand and an unrealized gain of $13 thousand related to the ineffective portion of the derivative contracts, respectively. At September 30, 2007, $19.7 million and $1.9 million of the hedges were recorded as current and long-term assets, respectively, and a cumulative unrealized gain (net of deferred income taxes) of $13.6 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. One of such accruals was for a mediated $7.5 million litigation settlement pertaining to post-production deductions on properties operated by us. We anticipate payment of this settlement during 2007. In the normal course of business we have various other litigation related matters and associated accruals, the resolution of which we believe, individually or in aggregate, would not have a material adverse effect on our company.

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 Securities and Exchange Commission (SEC) approved interpretive guidance to help public companies strengthen their internal control over financial reporting while reducing unnecessary costs. The guidance should reduce uncertainty about what constitutes a reasonable approach to management s evaluation while maintaining flexibility. The SEC also amended its rules to define the term material weakness as a deficiency, or combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the company s annual or interim financial statements will not be prevented or detected on a timely basis. The SEC also voted to revise the requirements regarding the auditor s attestation report on the effectiveness of internal control over financial reporting to more clearly convey that the auditor is not evaluating management s evaluation process, but is opining directly on internal control over financial reporting.

Also in May 2007, the Public Company Accounting Oversight Board (PCAOB) adopted Auditing Standard No. 5, An Audit of Internal Control over Financial Reporting That is Integrated with An Audit of Financial Statements. This new standard supersedes the PCAOB s existing standard for these audits. The new standard is designed to focus the audit of internal control on the most important matters, include only requirements necessary for an effective audit, make the audit scalable to fit the size and the complexity of any company, and simplify the requirements. The auditors report required by the new standard expresses only one opinion, an opinion of the effectiveness of the company s internal control over financial reporting. No opinion will be expressed by the auditor on whether management s assessment is fairly stated. The new standard will be effective for audits of fiscal years ending on or after November 15, 2007. Earlier adoption is permitted.

Overview

Our results of operations are primarily impacted by changes in oil and gas prices and changes in our production volumes. Realized oil prices increased from $66.57 per barrel in the third quarter of 2006 to $71.63 per barrel in the third quarter of 2007. Realized gas prices increased from $6.35 per Mcf in the third quarter of 2006 to $6.43 per Mcf in the third 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.

RESULTS OF OPERATIONS

Periods Ended September 30, 2007 Compared with Periods Ended September 30, 2006:

SUMMARY DATA: (in thousands or as indicated)	For the Three Months Ended September 30, 2007	2006	For the Nine Months Ended September 30, 2007	2006
Net income	$ 73,156	$ 93,957	$ 216,491	$ 286,974
Per share-basic	0.90	1.15	2.64	3.50
Per share-diluted	0.87	1.11	2.56	3.41
Gas sales	$ 192,423	$ 197,460	$ 603,650	$ 622,841
Oil sales	135,335	111,801	343,329	308,911
Total oil and gas sales	$ 327,758	$ 309,261	$ 946,979	$ 931,752
Total gas volume-MMcf	29,921	31,096	88,560	94,429
Gas volume-MMcf per day	325.2	338.0	324.4	345.9
Average gas price-per Mcf (before hedge effect)	$ 6.04	$ 6.35	$ 6.59	$ 6.60
Effect of hedges per Mcf	0.39		0.23	
Total oil volume-thousand barrels	1,889	1,679	5,451	4,819
Oil volume-barrels per day	20,537	18,255	19,967	17,651
Average oil price-per barrel	$ 71.63	$ 66.57	$ 62.99	$ 64.11
Gas gathering and processing revenues	$ 14,773	$ 13,126	$ 42,425	$ 36,520
Gas gathering and processing costs	(6,859)	(7,325)	(21,995)	(20,264)
Gas gathering and processing margin	$ 7,914	$ 5,801	$ 20,430	$ 16,256
Gas marketing revenues, net	$ 1,222	$ 495	$ 3,308	$ 3,241
Costs and expenses:				
Depreciation, depletion and amortization	$ 117,634	$ 104,904	$ 339,315	$ 290,305
Production	55,945	42,624	151,866	128,200
Transportation	6,882	5,845	19,110	15,636
Taxes other than income	22,397	22,912	66,826	68,392
General and administrative	10,922	10,804	35,531	31,679
Stock compensation, net	2,800	2,265	8,068	6,329
Other operating, net	3,867		6,182	(61)
Gain on derivative instruments		(4,782)		(23,598)
Interest expense, net of capitalized interest	4,284	1,388	13,757	3,446
Amortization of fair value of debt	(191)	(947)	(1,718)	(2,838)
Gain on early extinguishment of debt			(5,099)	
Asset retirement obligation	2,124	1,977	7,114	4,918
Other, net	(5,316)	(20,137)	(12,222)	(25,515)

Net income for the third quarter of 2007 was $73.2 million, or $0.87 per diluted share, compared to net income of $94.0 million, or $1.11 per diluted share for the same period in 2006. For the nine months ended September 30, 2007, net income was $216.5 million, or $2.56 per diluted share, compared to net income of $287.0 million, or $3.41 per diluted share, for the nine months of 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 third quarter of 2007 totaled $327.8 million, compared to $309.3 million for the third quarter of 2006. The $18.5 million increase in sales between the two periods results from $12.0 million related to higher commodity prices, and $14.0 million due to higher oil production volumes offset by $7.5 million due to lower gas production volumes. For the nine months ended September 30, 2007, oil and gas sales increased by $15.2 million, to $947.0 million from $931.8 million during the nine months of 2006. This increase resulted from a $13.4 million increase in oil and gas sales related to higher commodity prices. The remaining $1.8 million increase was due to higher oil production volumes offset by lower gas production volumes between the two nine-month periods.

Realized gas prices averaged $6.43 per Mcf (including a positive $0.39 per Mcf effect from hedges) for the three months ended September 30, 2007, compared to $6.35 per Mcf for the third quarter of 2006. This change increased sales by $2.4 million between the two periods. Realized oil prices averaged $71.63 per barrel for the third quarter of 2007, compared to $66.57 per barrel for the same period in 2006. The increase in sales between periods resulting from this eight percent change in oil prices totaled $9.6 million.

For the nine months ended September 30, 2007, realized gas prices increased to $6.82 per Mcf (including a positive $0.23 per Mcf effect from hedges) from $6.60 per Mcf realized in the nine months of 2006. This price change increased sales by $19.5 million between the two nine-month periods. Realized oil prices averaged $62.99 per barrel for the nine months of 2007, compared to $64.11 per barrel for the same period in 2006, resulting in a $6.1 million decrease in sales between periods. Changes in realized prices were the direct result of overall market conditions.

Average gas volumes declined 12.8 MMcf per day in the third quarter of 2007 to 325.2 MMcf per day from 338.0 MMcf per day in the third quarter of 2006, resulting in $7.5 million of lower revenues. Oil volumes averaged 20,537 barrels per day for the third quarter of 2007, compared to 18,255 barrels per day in the same period of 2006, resulting in increased revenues of $14.0 million. For the nine months of 2007, gas volumes averaged 324.4 MMcf per day and oil volumes equaled 19,967 barrels per day, compared to nine months 2006 volumes of 345.9 MMcf per day and 17,651 barrels per day. The lower gas volumes decreased sales between the two periods by $38.7 million, and higher oil volumes resulted in $40.5 million of additional revenues. The lower gas volumes are attributable primarily to natural reservoir declines in our Gulf Coast and Gulf of Mexico areas, which were only partially offset by new exploration success in the area. Daily gas production volumes in these areas averaged 75.7 MMcf in 2007 versus 102.2 MMcf in 2006. The increase in oil sales volumes between the periods of 2007 and 2006 is due to positive drilling results primarily from our successful horizontal drilling programs in the Permian region.

Gas gathering and processing revenues, net of related costs, equaled $7.9 million in the third quarter of 2007, compared to $5.8 million in the third quarter of 2006. For the nine months ended September 30, 2007 and 2006, such revenues net of related costs totaled $20.4 million and $16.3 million, respectively. 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 $1.2 million in 2007 compared to $0.5 million, net of related costs of $20.7 million and $31.2 million for the third quarters of 2007 and 2006,

respectively. Gas marketing net revenues increased to $3.3 million from $3.2 million, net of related costs of $82.5 million and $118.2 million for the nine months 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 $221.3 million in the third quarter of 2007 compared to $166.9 million in the third quarter of 2006. For the nine months of 2007 and 2006, these costs and expenses equaled $628.7 million and $496.9 million, respectively. Depreciation, depletion, and amortization (DD&A) was a large component of these changes between periods. DD&A equaled $117.6 million in the third quarter of 2007 compared to $104.9 million in the same period of 2006. For the nine months of 2007 and 2006, DD&A totaled $339.3 million and $290.3 million, respectively. On a unit of production basis, DD&A was $2.85 per Mcfe in the third quarter of 2007 compared to $2.55 per Mcfe for the third quarter of 2006. For the nine months of 2007 and 2006, DD&A on a unit of production basis equaled $2.80 per Mcfe and $2.35 per Mcfe, respectively. The increases largely stem 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 $13.3 million from $42.6 million ($1.04 per Mcfe) in the third quarter of 2006 to $55.9 million ($1.36 per Mcfe) in the third quarter of 2007. For the nine months of 2007 and 2006, production costs equaled $151.9 million ($1.25 per Mcfe) and $128.2 million ($1.04 per Mcfe), respectively. The higher costs in 2007 resulted 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 $5.8 million, or $0.14 per Mcfe, in the third quarter of 2006 to $6.9 million, or $0.17 per Mcfe, in the third quarter of 2007. Transportation costs for the nine months of 2007 equaled $19.1 million compared to $15.6 million for the same period in 2006. The increase is the result of expiring contracts being renewed with increased current market rates.

Taxes, other than income, decreased from $22.9 million in the third quarter of 2006 to $22.4 million in the third quarter of 2007. For the first nine months these costs were $1.6 million lower, decreasing from $68.4 million in 2006 to $66.8 million in the same period of 2007. The decrease during the period resulted from various severance tax credits received during the year.

General and administrative (G&A) expenses increased from $10.8 million in the third quarter of 2006 to $10.9 million in the third quarter of 2007. G&A expenses for the nine months of 2007 increased $3.8 million from $31.7 million in 2006 compared to $35.5 million for the same period of 2007. The increase between periods is due to higher employee-benefit costs and an increase in legal fees.

Stock compensation, net 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, net increased from $6.3 million in the nine months of 2006 to $8.1 million in the nine months of 2007.

Other Operating, net, equaled $6.2 million of expense for the nine months of 2007 compared to income of $61 thousand in the same period of 2006. The decrease between periods resulted from various litigation settlements and accruals pertaining primarily to resolution of oil and gas

property title and royalty issues.

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 of $23.6 million during the nine months of 2006. 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 nine months of September 30, 2006 equaled $15.7 million. The derivative liability at September 30, 2006, relating to those contracts, equaled $2.7 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 on derivative contracts during the quarter and nine months ended September 30, 2007 equaled $11.5 million and $20.0 million which were recorded in gas sales and increased the realized gas price for the quarter and nine months by $0.39 per Mcf and $0.23 per Mcf, respectively. Also during the quarter and nine months ended September 30 2007, we recognized an unrealized loss of $4 thousand and an unrealized gain of $13 thousand related to the ineffective portion of the derivative contracts, respectively. At September 30, 2007, $19.7 million and $1.9 million of the hedges were recorded as current and long-term assets, respectively, and a cumulative unrealized gain (net of deferred income taxes) of $13.6 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.

Net interest expense in the third quarter of 2007 of $4.1 million is comprised of $9.1 million of interest expense, offset by $5.0 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 third quarter of 2006 of $0.4 million is comprised of $7.1 million of interest expense, offset by $6.7 million of capitalized interest. Net interest expense for the nine months of 2007 equaled $12.0 million ($27.0 million of interest expense less $15.0 million of capitalized interest) compared to $0.6 million ($19.2 million of interest expense less $18.6 million of capitalized interest) for the same period of 2006. The increase in the 2007 net interest amounts compared to 2006 results from increased interest expense due to higher debt levels (long-term debt at September 30, 2007 equaled $526.3 million versus $399.6 million at September 30, 2006) and lower associated costs incurred to bring properties under development, not being amortized, to their intended use.

A gain on early extinguishment of debt of $5.1 million was recognized in the second quarter of 2007. On May 18, 2007 the $195.0 million (face value) 9.6% notes assumed in the Magnum Hunter merger were redeemed at a redemption price of 104.8% of the principal amount, for a total of $204.4 million. The gain recognized is the difference between the $204.4 million redemption amount plus related miscellaneous costs of $0.1 million and $209.6 million of net carrying amount of the debt consisting of $195.0 million of principal plus $14.6 million of premium resulting from the recording of the debt under purchase accounting when we first assumed the 9.6% notes.

Asset retirement obligation expense was $2.1 million in the third quarter of 2007 compared to $2.0 million for 2006. The asset retirement obligation expense increased from $4.9 million for the first nine months of 2006 to $7.1 million for the same period in 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 September 30, 2007 equaled $131.2 million versus $118.5 million at September 30, 2006.

Other, net for the third quarter of 2007 equaled $5.3 million of income compared to $20.1 million of income for the third quarter of 2006. Other, net for the nine months ended September 30, 2007 and 2006 equaled $12.2 million and $25.5 million of income, respectively. The components of Other, net consist of miscellaneous income and expense items that will vary from period to period, including income and loss in equity investees and gain or loss on sale of inventory. The large decrease is due to the 2006 liquidation of the Company s investment in the Company s limited partnership affiliates, Teal Hunter L.P. and Mallard Hunter L.P. Excess distributions of $18.3 million from this liquidation were recorded in Other, net in the third quarter of 2006.

Income Tax Expense

Income tax expense totaled $42.4 million for the third quarter of 2007 versus $54.7 million for the third quarter of 2006. Tax expense equaled a combined Federal and state effective income tax rate of 36.7 percent and 36.8 percent in the third quarters of 2007 and 2006, respectively. Income tax expense for the nine months of 2007 equaled $125.5 million compared to $167.4 million for the same period of 2006, equating to combined Federal and state effective income tax rates of 36.7 percent and 36.8 percent, respectively.

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 commodity 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 nine months of 2007 was $693.2 million, compared to $677.1 million for the nine months ended September 30, 2006. The increase in 2007 from the earlier period resulted from the change in receivables and accounts payable, primarily due to the relative changes in commodity prices for the two reporting periods.

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

Cash flow used in investing activities for the nine months of 2007 was $738.3 million, compared to $762.4 million for the nine months ended September 30, 2006. The decrease in 2007 resulted from the change in the timing of our exploration and development activity.

Cash flow provided by financing activities for the nine months of 2007 was $40.1 million versus $31.7 million for the nine months of 2006. The cash provided by financing activities in 2007 resulted primarily from the net proceeds from the sale of $350.0 million of 7.125% notes after the redemption of the outstanding $195.0 million 9.6% notes and the payment of outstanding borrowings under our credit facility.

Financial Condition

As of September 30, 2007, stockholders equity totaled $3.14 billion, up from $2.98 billion at December 31, 2006. The increase resulted primarily from current year net income of $216.5 million, offset by a reduction in other comprehensive income of $17.2 million, arising from the settlement of derivative contracts qualifying for hedge accounting treatment during the period. At September 30, 2007, our cash balance equaled $23 thousand.

A $0.04 per share cash dividend has been declared to stockholders 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 September 30, 2007 a total of 1,364,300 shares have been repurchased at an overall average price of $39.05.

Working Capital

Working capital at September 30, 2007 was $21.1 million, compared to $62.2 million at December 31, 2006. The change in working capital is primarily due to the decrease in the asset associated with derivative contracts outstanding at December 31, 2006. This decrease is the result of the settlement of derivative contracts qualifying for hedge accounting treatment during the first nine months of 2007 and an increase in accrued liabilities due mainly to the timing of payments.

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

Financing

Debt at 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 September 30, 2007 consisted of the following (in thousands):

Bank debt	$	39,000
9.6% Notes due 2012 (face value $195,000)		
7.125% Notes due 2017		350,000
Floating rate convertible notes due 2023, 5.69% at September 30, 2007 (face value $125,000)		137,349(2)
Total long-term debt	$	526,349

(1) Fair market value at June 7, 2005 (date of acquisition of Magnum Hunter) was $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 was $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 September 30, 2007, there were outstanding borrowings of $39.0 million under the revolving credit facility at a weighted average interest rate of approximately 7.75%. We also had letters of credit for approximately $2.7 million posted against the borrowing base, leaving an unused borrowing amount of approximately $458.3 million at September 30, 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 were redeemed on May 18, 2007 at a redemption price of 104.8% of the principal amount plus accrued interest of $3.3 million through the redemption date for a total of $207.6 million. We recognized a gain on the early extinguishment of this debt of $5.1 million which is reflected on the income statement under Other income and expense.

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 were used to redeem the 9.6% notes and reduce outstanding borrowings under our credit facility. Interest is payable May 1 and November 1 of each year. The first interest payment will be made on November 1, 2007. The notes are unsecured and 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	103.563%
2013	102.375%
2014	101.188%
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 equal to 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.

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 September 30, 2007, the interest rate equaled 5.69%.

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 September 28, 2007, the closing price of our common stock on the New York Stock Exchange was $37.25. There is not an observable market for the notes. Based on an average common stock price of $37.25, management estimates the fair value of the notes at September 30, 2007 was approximately $160.6 million (or $1,285 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 September 30, 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)	$ 514,000	$	$ 39,000	$	$ 475,000
Fixed-Rate interest payments(1)	249,375	24,938	49,875	49,875	124,687
Operating leases	28,778	5,470	9,775	8,178	5,355
Drilling commitments	128,678	120,339	8,339		
Plant facility	117,758	97,604	20,154		
Asset retirement obligation	131,231	7,270	(2)	(2)	(2)
Other liabilities	15,453	8,197	67	59	7,130

(1) These amounts do not include interest on the $39 million of bank debt outstanding at September 30, 2007. The weighted average interest rate at September 30, 2007 on the bank debt was approximately 7.75%. 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 September 30, 2007, we had commitments of approximately $117.8 million relating to construction of a plant processing facility adjacent to a field of producing gas wells in which we have a significant interest. In July 2007, we entered into an agreement with a third party who will reimburse us for approximately 42.5 percent of the construction costs and thereby effectively reduce our net cash commitment to approximately $67.8 million.

At September 30, 2007, we had firm sales contracts to deliver approximately 1.2 Bcf of natural gas over the next six months. If this gas is not delivered, our financial commitment would be approximately $6.7 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 $2.6 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, expected to be approximately $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 448 to 451 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 third quarter of 2007 ranged from $6.18 per Mcf to $6.81 per Mcf. Oil prices ranged from $69.51 per barrel to $75.77 per barrel. Monthly gas price realizations during the nine months of 2007 ranged from $6.04 per Mcf to $7.66 per Mcf. Oil prices for the nine months of 2007 ranged from $51.38 per barrel to $75.77 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 September 30, 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	Oct 07	Dec 07	$7.00 - $10.17	$	9,179
Natural Gas	Collars	40,000 MMBTU	Jan 08	Dec 08	$7.00 - $9.90		12,375
						$	21,554

At September 30, 2007, the weighted average Mid-Continent prices for the 2007 and 2008 contracts approximated $6.07 and $6.82, respectively.

Interest Rate Risk

Fixed and Variable Rate Debt. We assumed fixed and variable rate debt as part of the acquisition of Magnum Hunter. In May 2007, we sold $350 million of 7.125% notes that will mature May 1, 2017. A portion of these net proceeds was used to redeem the 9.6% notes assumed 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 September 30, 2007. The fair value for the convertible notes was based on an average price per share of $37.25 for our common stock. The fair value for the fixed rate senior notes was based on their last traded value before September 30, 2007.

Expected Maturity Dates (in thousands of dollars)	**2010**	**2017**	**2023**	**Total**	**Book Value**	**Fair Value**
Variable Rate Debt:						
Bank Debt (a)	$ 39,000	$	$	$ 39,000	$ 39,000	$ 39,000
Convertible Notes (b)	$	$	$ 125,000	$ 125,000	$ 137,349	$ 160,627
Fixed Rate Debt:						
Senior Notes (c)	$	$ 350,000	$	$ 350,000	$ 350,000	$ 348,250

(a) At September 30, 2007, the weighted average interest rate on outstanding borrowings under the credit facility was approximately 7.75%.

(b) The interest rate on the convertible notes is 5.69%. 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 2017 is a fixed 7.125%.

ITEM 4. CONTROLS AND PROCEDURES

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

Our management, with the participation of our Chief Executive Officer (CEO) and Chief Financial Officer (CFO), have evaluated the effectiveness of our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e)) as of September 30, 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 September 30, 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 September 30, 2007, that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

PART II

ITEM 6 EXHIBITS

3(ii)	Amended and Restated Bylaws of Cimarex Energy Co. (filed as Exhibit 3.1 to Current Report on Form 8-K dated September 20, 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.

November 7, 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)