CIMAREX ENERGY CO
Form 10-Q
May 06, 2011
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

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

For the Quarterly Period ended March 31, 2011

Commission File No. 001-31446

CIMAREX ENERGY CO.

1700 Lincoln Street, Suite 1800

Denver, Colorado 80203-4518

(303) 295-3995

Incorporated in the State of Delaware	**Employer Identification No. 45-0466694**

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No o.

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer, and smaller reporting company in Rule 12b-2 of the Exchange Act.

Large accelerated filer x	Accelerated filer o
Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No x.

The number of shares of Cimarex Energy Co. common stock outstanding as of March 31, 2011 was 85,539,995.

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GLOSSARY

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

Bbls Barrels (of oil or natural gas liquids)

Bcf Billion cubic feet

Bcfe Billion cubic feet equivalent

Btu British thermal unit

MBbls Thousand barrels

Mcf Thousand cubic feet (of natural gas)

Mcfe Thousand cubic feet equivalent

MMBbls Million barrels

MMBtu Million British Thermal Units

MMcf Million cubic feet

MMcf/d Million cubic feet per day

MMcfe Million cubic feet equivalent

MMcfe/d Million cubic feet equivalent per day

Net Acres Gross acreage multiplied by Cimarex s working interest percentage

Net Production Gross production multiplied by Cimarex s net revenue interest

NGL Natural gas liquids

Tcf Trillion cubic feet

Tcfe Trillion cubic feet equivalent

WTI West Texas Intermediate

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

CAUTIONARY INFORMATION ABOUT FORWARD-LOOKING STATEMENTS

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

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

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PART I

ITEM 1 - Financial Statements

CIMAREX ENERGY CO.

Condensed Consolidated Balance Sheets

	March 31, 2011 (Unaudited)	December 31, 2010
	(In thousands, except share data)	
Assets		
Current assets:		
Cash and cash equivalents	$ 54,146	$ 114,126
Receivables, net	308,946	310,968
Oil and gas well equipment and supplies	79,599	81,871
Deferred income taxes	9,848	4,293
Derivative instruments	3,975	5,731
Other current assets	49,356	44,778
Total current assets	505,870	561,767
Oil and gas properties at cost, using the full cost method of accounting:		
Proved properties	8,698,442	8,421,768
Unproved properties and properties under development, not being amortized	598,656	547,609
	9,297,098	8,969,377
Less accumulated depreciation, depletion and amortization	(6,126,581)	(6,047,019)
Net oil and gas properties	3,170,517	2,922,358
Fixed assets, net	167,546	156,579
Goodwill	691,432	691,432
Other assets, net	34,406	26,111
	$ 4,569,771	$ 4,358,247
Liabilities and Stockholders Equity		
Current liabilities:		
Accounts payable	$ 47,322	$ 47,242
Accrued liabilities	328,271	320,989
Derivative instruments	28,109	9,587
Revenue payable	136,000	134,495
Total current liabilities	539,702	512,313
Long-term debt	350,000	350,000
Deferred income taxes	694,384	619,040
Other liabilities	264,138	267,062
Stockholders equity:		
Preferred stock, $0.01 par value, 15,000,000 shares authorized, no shares issued		
Common stock, $0.01 par value, 200,000,000 shares authorized, 85,539,995 and 85,234,721 shares issued, respectively	855	852
Paid-in capital	1,885,036	1,883,065

Retained earnings		835,233		725,651
Accumulated other comprehensive income		423		264
		2,721,547		2,609,832
	$	4,569,771	$	4,358,247

See accompanying notes to consolidated financial statements.

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CIMAREX ENERGY CO.

Consolidated Statements of Operations

(Unaudited)

	For the Three Months Ended March 31, 2011	2010
	(In thousands, except per share data)	
Revenues:		
Gas sales	$ 131,323	$ 225,637
Oil sales	220,499	191,560
NGL sales	62,190	15,209
Gas gathering, processing and other	12,517	15,850
Gas marketing, net	67	314
	426,596	448,570
Costs and expenses:		
Depreciation, depletion and amortization	85,026	69,710
Asset retirement obligation	1,938	2,644
Production	58,480	41,983
Transportation	13,446	11,167
Gas gathering and processing	4,551	6,505
Taxes other than income	33,597	32,358
General and administrative	14,727	13,045
Stock compensation, net	4,750	2,778
(Gain) loss on derivative instruments, net	18,244	(52,597)
Other operating, net	3,374	(1,846)
	238,133	125,747
Operating income	188,463	322,823
Other (income) and expense:		
Interest expense	8,980	9,462
Capitalized interest	(7,225)	(7,424)
Other, net	(604)	(1,930)
Income before income tax	187,312	322,715
Income tax expense	69,150	118,354
Net income	$ 118,162	$ 204,361
Earnings per share to common stockholders:		
Basic		
Distributed	$ 0.10	$ 0.08
Undistributed	1.28	2.34
	$ 1.38	$ 2.42
Diluted		
Distributed	$ 0.10	$ 0.08
Undistributed	1.27	2.31
	$ 1.37	$ 2.39

See accompanying notes to consolidated financial statements.

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CIMAREX ENERGY CO.

Condensed Consolidated Statements of Cash Flows

(Unaudited)

	For the Three Months Ended March 31, 2011	2010
	(In thousands)	
Cash flows from operating activities:		
Net income	$ 118,162	$ 204,361
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	85,026	69,710
Asset retirement obligation	1,938	2,644
Deferred income taxes	69,698	84,990
Stock compensation, net	4,750	2,778
Derivative instruments, net	20,278	(52,056)
Changes in non-current assets and liabilities	2,738	3,101
Other, net	2,030	(2,321)
Changes in operating assets and liabilities:		
(Increase) decrease in receivables, net	2,022	(39,495)
(Increase) decrease in other current assets	(3,005)	18,495
Increase (decrease) in accounts payable and accrued liabilities	(38,360)	6,900
Net cash provided by operating activities	265,277	299,107
Cash flows from investing activities:		
Oil and gas expenditures	(310,182)	(203,682)
Sales of oil and gas and other assets	12,037	55
Other expenditures	(24,506)	(7,822)
Net cash used by investing activities	(322,651)	(211,449)
Cash flows from financing activities:		
Net decrease in bank debt		(25,000)
Dividends paid	(6,849)	(5,069)
Issuance of common stock and other	4,243	2,409
Net cash used by financing activities	(2,606)	(27,660)
Net change in cash and cash equivalents	(59,980)	59,998
Cash and cash equivalents at beginning of period	114,126	2,544
Cash and cash equivalents at end of period	$ 54,146	$ 62,542

See accompanying notes to consolidated financial statements.

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CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements

March 31, 2011

(Unaudited)

1. Basis of Presentation

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

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

Full Cost Accounting Method and Ceiling Limitation

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

At the end of each quarter, we make a full cost ceiling limitation calculation, whereby net capitalized costs related to proved properties less associated deferred income taxes may not exceed the amount of the present value discounted at 10% of estimated future net revenues from proved reserves less estimated future production and development costs and related income tax expense. Revenue calculations in the reserves are based on the unweighted average first-day-of-the-month prices for the prior twelve months. Changes in proved reserve estimates (whether based upon quantity revisions or commodity prices) will cause corresponding changes to the full cost ceiling limitation. If net capitalized costs subject to amortization exceed this limit, the excess would be charged to expense. Any recorded impairment of oil and gas properties is not reversible at a later date.

Our quarterly and annual ceiling tests are primarily impacted by commodity prices, reserve quantities added and produced, overall exploration and development costs and depletion expense. Holding all factors constant other than commodity prices, a 10% decline in prices as of March 31, 2011

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Notes to Consolidated Financial Statements (Continued)

March 31, 2011

(Unaudited)

would not have resulted in a ceiling test impairment. Decreases in commodity prices can also impact our goodwill impairment analyses.

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

Goodwill

At March 31, 2011, we had $691.4 million of goodwill recorded in conjunction with past business combinations. Goodwill is subject to annual reviews for impairment, but we continuously monitor the economic environment throughout the year to determine if additional impairment assessments are necessary. These assessments are based on a two-step accounting test. The first step is to compare the estimated fair value of the Company with the recorded net book value (including goodwill), after giving effect to any period impairment of oil and gas properties resulting from the ceiling limitation calculation. If the recorded net book value is greater than zero and the estimated fair value is higher than the recorded net book value, no impairment is deemed to exist and no further testing is done.

Disruptions continue in the credit markets and global economic activity which impact stock markets and commodity prices. Management must apply judgment in determining the estimated fair value of the Company for purposes of assessing goodwill impairment. As of March 31, 2011, the market price per share of our common stock was greater than the book value by $83 per share. Due to volatility in the stock markets, management does not consider the market value of our shares to be an accurate reflection of our net assets for impairment purposes.

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

Use of Estimates

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

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Notes to Consolidated Financial Statements (Continued)

March 31, 2011

(Unaudited)

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

Accounting Changes

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

Recently Issued Accounting Standards

No significant accounting standards applicable to Cimarex have been issued during the quarter ended March 31, 2011.

2. Derivative Instruments/Hedging

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

At March 31, 2011, we had the following outstanding contracts relative to our future production. We have elected not to account for these derivatives as cash flow hedges.

Natural Gas Contracts

Period	Type	Volume/Day	Index(1)	Weighted Average Price Swap	Fair Value (000 s)
Apr 11 - Dec 11	Swap	20,000 MMBtu	PEPL	$ 5.05	$ 3,975

Oil Contracts

Period	Type	Volume/Day	Index(1)	Weighted Average Price Floor	Weighted Average Price Ceiling	Fair Value (000 s)
Apr 11 - Dec 11	Collar	12,000 Bbls	WTI	$ 65.00	$ 105.44	$ (28,109)

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

Oil contracts that expire in 2011 represent approximately 40-45% of our anticipated oil production for 2011. Our gas swap contracts presently in place represent approximately 5-6% of expected gas sales volumes.

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

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

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Notes to Consolidated Financial Statements (Continued)

March 31, 2011

(Unaudited)

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

	Balance Sheet Location		Asset	Liability
			(In thousands)	
March 31, 2011:				
Natural gas contracts	Current assets	Derivative instruments	$ 3,975	$
Oil contracts	Current liabilities	Derivative instruments		28,109
			$ 3,975	$ 28,109

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

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

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

	Three Months Ended March 31, 2011	2010
Settlements gains (losses):		
Natural gas contracts	$ 2,034	$ 982
Oil contracts		(441)
Total settlements gains (losses)	2,034	541
Unrealized gains (losses) on fair value change:		
Natural gas contracts	(1,756)	50,568
Oil contracts	(18,522)	1,488
Total net unrealized gains (losses) on fair value change	(20,278)	52,056
Gain (loss) on derivative instruments, net	$ (18,244)	$ 52,597

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

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Notes to Consolidated Financial Statements (Continued)

March 31, 2011

(Unaudited)

3. Fair Value Measurements

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

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

	Carrying Amount	Fair Value
	(In thousands)	
March 31, 2011:		
Financial Assets (Liabilities):		
7.125% Notes due 2017	$ (350,000)	$ (371,000)
Derivative instruments assets	$ 3,975	$ 3,975
Derivative instruments liabilities	$ (28,109)	$ (28,109)

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

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

Debt

Notes

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

Derivative Instruments (Level 2)

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

Other Financial Instruments

The carrying amounts of our cash, cash equivalents, restricted cash, accounts receivable, accounts payable, and accrued liabilities approximate fair value because of the short-term maturities and/or liquid nature of these assets and liabilities. At both March 31, 2011 and December 31, 2010, the aggregate

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Notes to Consolidated Financial Statements (Continued)

March 31, 2011

(Unaudited)

allowance for doubtful accounts for trade, oil and gas sales, and gas gathering, processing, and marketing receivables was $6.8 million.

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

4. Capital Stock

A summary of our common stock activity for the three months ended March 31, 2011 follows:

		Number of Shares (in thousands)	
	Issued	**Treasury**	**Outstanding**
December 31, 2010	85,235		85,235
Restricted shares issued under compensation plans, net of cancellations	269		269
Option exercises, net of cancellations	36		36
March 31, 2011	85,540		85,540

Stock-based Compensation

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

Restricted Stock and Units

During the three months ended March 31, 2011, we issued a total of 378,258 restricted shares to non-employee directors, officers, and other employees. Included in that amount are 363,758 shares issued to certain executives that are subject to market condition-based vesting determined by our stock price performance relative to a defined peer group s stock price performance. After three years of continued service, an executive will be entitled to vest in 50% to 100% of the award. The material terms of performance goals applicable to these awards were approved by stockholders in May 2006 and May 2010. The other shares granted in 2011 have service-based vesting schedules of five years.

The following table presents restricted stock activity as of March 31, 2011, and changes during the year:

Outstanding as of January 1, 2011	1,899,511
Vested	(276,488)
Granted	378,258
Canceled	(7,500)
Outstanding as of March 31, 2011	1,993,781

The following table presents restricted unit activity as of March 31, 2011 and changes during the year:

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Notes to Consolidated Financial Statements (Continued)

March 31, 2011

(Unaudited)

Outstanding as of January 1, 2011	94,807
Converted to Stock	(8,337)
Granted	
Canceled	
Outstanding as of March 31, 2011	86,470
Vested included in outstanding	85,206

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

Compensation cost for service-based vesting restricted shares or units is based upon amortization of the grant-date market value of the award. The fair value of the market condition-based restricted stock awards is calculated based on the grant-date market value of the award utilizing a Monte Carlo simulation model. Compensation cost related to the restricted stock and unit awards is recognized ratably over the applicable vesting period. For the three months ended March 31, 2011 and 2010, total compensation costs (including capitalized amounts) were $6.5 million and $3.8 million, respectively. This increase is due to higher grant-date market value of awards granted during the current quarter.

Unamortized compensation costs related to unvested restricted shares and units at March 31, 2011 and 2010 was $61.1 million and $40.4 million, respectively.

Stock Options

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

There were no stock options granted to employees during the three months ended March 31, 2011. There were 5,000 stock options granted to employees during the three months ended March 31, 2010.

Information about outstanding stock options is summarized below:

	Options		Weighted Average Exercise Price	Weighted Average Remaining Term		Aggregate Intrinsic Value (000 s)
Outstanding as of January 1, 2011	1,026,527	$	32.60			
Exercised	(36,193)	$	39.56			
Granted		$				
Canceled		$				
Forfeited	(7,835)	$	55.63			
Outstanding as of March 31, 2011	982,499	$	32.16	4.7 Years	$	81,763
Exercisable as of March 31, 2011	615,012	$	22.91	2.7 Years	$	56,868

There were 36,193 stock options exercised during the three months ended March 31, 2011. There were 78,213 stock options exercised during the three months ended March 31, 2010. Cash received from option exercises during the three months ended March 31, 2011 and March 31, 2010, was $1.4 million

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CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

March 31, 2011

(Unaudited)

and $1.6 million, respectively. The related tax benefits realized from option exercises totaled $797 thousand and $857 thousand, respectively, and were recorded to paid-in capital. The total intrinsic value of stock options exercised during the three months ended March 31, 2011 and March 31, 2010 was $2.2 million and $3.2 million, respectively.

We estimate the fair value of options as of the date of grant using the Black-Scholes option-pricing model. Expected volatilities are based on the historical volatility of our common stock. We also use historical data to estimate the probability of option exercise, expected years until exercise and potential forfeitures. The risk-free interest rate we use is the five-year U.S. Treasury bond in effect at the date of the grant.

The following summary reflects the status of non-vested stock options as of March 31, 2011 and changes during the year:

	Options		Weighted Average Grant Date Fair Value		Weighted Average Exercise Price
Non-vested as of January 1, 2011	375,322	$	18.25	$	47.80
Vested		$		$	
Granted		$		$	
Forfeited	(7,835)	$	21.26	$	55.63
Non-vested as of March 31, 2011	367,487	$	18.19	$	47.63

We recognize compensation cost ratably over the vesting period. Historical amounts may not be representative of future amounts as additional options may be granted. Compensation costs (including capitalized amounts) for the three months ended March 31, 2011 and 2010 were $1.1 million and $824 thousand, respectively.

As of March 31, 2011, there was $3.9 million of unrecognized compensation cost related to non-vested stock options granted under our stock incentive plan. We expect to recognize that cost on a pro rata basis over a weighted-average period of 1.2 years.

Stockholder Rights Plan

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

We generally will be entitled to redeem the Rights under certain circumstances at $0.01 per Right at any time before the close of business on the tenth business day after there has been a public announcement of the acquisition of beneficial ownership by any person or group of 15% or more of our

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common stock. The Rights may not be exercised until our Board s right to redeem the stock has expired. Unless redeemed earlier, the Rights expire on February 23, 2012.

Dividends and Stock Repurchases

In February 2011, the Board of Directors increased our quarterly cash dividend to $0.10 per share from $0.08 per share. The dividend is payable June 1, 2011 to stockholders of record on May 13, 2011. Future dividend payments will depend on the Company s level of earnings, financial requirements, and other factors considered relevant by the Board of Directors.

In December 2005, the Board of Directors authorized the repurchase of up to four million shares of our common stock. The authorization is currently set to expire on December 31, 2011. Purchases may be made in both the open market and through negotiated transactions, and purchases may be increased, decreased or discontinued at any time without prior notice. Through December 31, 2007, we repurchased and cancelled a total of 1,364,300 shares at an overall average price of $39.05. There were no shares repurchased in the first quarter of 2011, or since the quarter ended September 30, 2007.

Issuer Purchases of Equity Securities for the Quarter Ended March 31, 2011

	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of shares that may yet be Purchased Under the Plans or Programs
January, 2011	None	NA	None	2,635,700
February, 2011	None	NA	None	2,635,700
March, 2011	None	NA	None	2,635,700

5. Asset Retirement Obligations

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

The following table reflects the components of the change in the carrying amount of the asset retirement obligation for the three months ended March 31, 2011 (in thousands):

Asset retirement obligation at January 1, 2011	$	138,769
Liabilities incurred		425
Liability settlements and disposals		(7,055)
Accretion expense		1,846
Revisions of estimated liabilities		2,569
Asset retirement obligation at March 31, 2011		136,554
Less current obligation		(27,467)
Long-term asset retirement obligation	$	109,087

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6. Long-Term Debt

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

Bank Debt

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

At March 31, 2011, there were no outstanding borrowings under the credit facility. We had letters of credit outstanding of $7.5 million leaving an unused borrowing availability of $792.5 million.

The borrowing base under the credit agreement is determined at the discretion of the lenders, based on the collateral value of our proved reserves, and is subject to potential special and regular semi-annual redeterminations. The borrowing base of $1 billion and bank commitments of $800 million were reaffirmed in April 2011.

The credit facility contains covenants and restrictive provisions which may limit our ability to incur additional indebtedness, make investments or loans and create liens. The credit agreement requires us to maintain a current ratio (defined to include undrawn borrowings) greater than 1 to 1 and a leverage ratio not to exceed 3.5 to 1. As of March 31, 2011, we were in compliance with all of the financial and non-financial covenants.

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

7.125% Notes due 2017

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

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

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

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At any time prior to May 1, 2012, we may also redeem all, but not part, of the notes at a price of 100% of the principal amount of the notes plus accrued and unpaid interest plus a make-whole premium.

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

Floating rate convertible notes due 2023

In July 2010, all remaining holders of our floating rate convertible notes converted their notes for cash and shares. The effective interest rate for the quarter ended March 31, 2010 was 1.2%.

7. Income Taxes

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

	Three Months Ended March 31,	
	2011	**2010**
Current provision (benefit)	$ (548)	$ 33,364
Deferred tax (benefit)	69,698	84,990
	$ 69,150	$ 118,354

We account for uncertainty in our income tax provisions in accordance with rules promulgated by the FASB. At March 31, 2011 we have no unrecognized tax benefits that would impact our effective rate and we have made no provisions for interest or penalties related to uncertain tax positions. The tax years 2005 - 2009 remain open to examination by the Internal Revenue Service of the United States. We file tax returns with various state taxing authorities which remain open for tax years 2005 - 2009 for examination.

Our provision for income taxes differed from the U.S. statutory rate of 35% primarily due to state income taxes, non-deductible expenses, and special deductions. The effective income tax rate for the three months ended March 31, 2011 and March 31, 2010 was 36.9% and 36.7%, respectively.

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

	Three Months Ended March 31, 2011	2010
Cash paid during the period for:		
Interest expense (including capitalized amounts)	$ 1,062	$ 1,371
Interest capitalized	854	1,076
Income taxes	171	22,945
Cash received for income taxes	25,004	1,866

9. Earnings per Share and Comprehensive Income

Earnings per Share

We calculate earnings per share based on FASB guidance which holds that unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents are participating

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(Unaudited)

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

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March 31, 2011

(Unaudited)

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

	Three Months Ended March 31, 2011		Three Months Ended March 31, 2010	
Net income	$	118,162	$	204,361
Less distributed earnings (dividends declared during the period)		(8,561)		(6,759)
Undistributed earnings for the period	$	109,601	$	197,602
Allocation of undistributed earnings				
Basic allocation to unrestricted common stockholders	$	106,938	$	191,740
Basic allocation to participating securities	$	2,663	$	5,862
Diluted allocation to unrestricted common stockholders	$	106,952	$	191,799
Diluted allocation to participating securities	$	2,649	$	5,803
Basic Shares Outstanding				
Unrestricted outstanding common shares		83,546		82,023
Add Participating securities:				
Restricted stock outstanding		1,994		1,860
Restricted stock units outstanding		86		648
Total participating securities		2,080		2,508
Total Basic Shares Outstanding		85,626		84,531
Fully Diluted Shares				
Unrestricted outstanding common shares		83,546		82,023
Incremental shares from assumed exercise of stock options		438		477
Incremental shares from assumed conversion of the convertible senior notes				370
Fully diluted common stock		83,984		82,870
Participating securities		2,080		2,508
Total Fully Diluted Shares		86,064		85,378
Basic earnings per share				
Unrestricted common stockholders:				
Distributed earnings	$	0.10	$	0.08
Undistributed earnings		1.28		2.34
	$	1.38	$	2.42
Participating securities:				
Distributed earnings	$	0.10	$	0.08
Undistributed earnings		1.28		2.34
	$	1.38	$	2.42
Fully diluted earnings per share				
Unrestricted common stockholders:				

Distributed earnings	$	0.10	$	0.08
Undistributed earnings		1.27		2.31
	$	1.37	$	2.39
Participating securities:				
Distributed earnings	$	0.10	$	0.08
Undistributed earnings		1.27		2.31
	$	1.37	$	2.39

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Notes to Consolidated Financial Statements (Continued)

March 31, 2011

(Unaudited)

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

	March 31,	
	2011	**2010**
Stock options	982,499	1,484,559
Restricted stock	1,993,781	1,860,150
Restricted units	86,470	647,507

Certain stock options considered to be anti-dilutive for the three months ended March 31, 2011 and 2010 were 9,228 and 413,265, respectively.

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 thousands):

	Three Months Ended March 31,	
	2011	**2010**
Net Income	$ 118,162	$ 204,361
Other comprehensive income:		
Change in fair value of investments, net of tax	159	99
Total comprehensive income	$ 118,321	$ 204,460

10. Commitments and Contingencies

Litigation

In January 2009, the Tulsa County District Court issued a judgment totaling $119.6 million in the H.B. Krug, et al versus Helmerich & Payne, Inc. (H&P) case. This lawsuit was originally filed in 1998 and addressed H&P s conduct pertaining to a 1989 take-or-pay settlement, along with potential drainage issues and other related matters. Pursuant to the 2002 spin-off transaction to shareholders of H&P by which Cimarex became a publicly-traded entity, Cimarex assumed the assets and liabilities of H&P s exploration and production business. In 2008 we had accrued litigation expense of $119.6 million for this lawsuit. During 2009 and 2010, we have accrued an additional $9.4 million and $8.9 million, respectively. We have accrued an additional $2.2 million during the first quarter of 2011. We have appealed the District Court s judgments.

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

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Notes to Consolidated Financial Statements (Continued)

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Other

We have a large development project in Sublette County, Wyoming where we are developing the deep Madison gas formation and constructing a gas processing plant. At March 31, 2011, we had commitments of $89.3 million relating to construction of the gas processing plant of which $67.6 million is subject to construction contracts. The total cost of the project will approximate $358 million. Pursuant to the terms of our operating agreement with our partner in this project, we will be reimbursed by them for 42.5% of the costs. The gas processing plant is subject to a delivery commitment agreement over a 20 year period, commencing December, 2011. If no deliveries were made, the maximum amount that would be payable under the agreement would be approximately $43 million.

We have drilling commitments of approximately $157.6 million consisting of obligations to complete drilling wells in progress at March 31, 2011. We also have various commitments for drilling rigs as well as certain service contracts. The total minimum expenditure commitments under these agreements are $26.5 million to secure the use of drilling rigs and $46.2 million to secure certain dedicated services associated with drilling activities.

We have non-cancelable operating leases for office and parking space in Denver, Tulsa, Dallas, Midland, and for small district and field offices. During the first quarter of 2011, we entered into a new 12-year lease agreement for additional office space. The expected commencement date is December 1, 2012. Our aggregate minimum lease payments increased to $75 million versus $15.5 million at December 31, 2010.

At March 31, 2011, we have a purchase commitment of $10.3 million for construction of an aircraft. The total cost of the aircraft is $11.5 million with an option to trade in our existing aircraft. The completion of the aircraft is expected to be by the end of this year.

At March 31, 2011, we had firm sales contracts to deliver approximately 13.7 Bcf of natural gas over the next 12 months. If this gas is not delivered, our financial commitment would be approximately $50.3 million. This commitment will fluctuate due to price volatility and actual volumes delivered. However, we believe no financial commitment will be due based on our current reserves and production levels.

In connection with a gas gathering and processing agreement, we have commitments to deliver a minimum of 24 Bcf of gas over the next three years. The production from certain wells is counted toward that commitment; these wells also have individual commitments for gas deliveries. If no gas is delivered, the maximum amount that would be payable under these commitments would be approximately $22.2 million, some of which would be reimbursed by working interest owners who are selling with us under our marketing agreements. We do not expect to make significant payments relative to these commitments.

We have 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 $1.4 million, some of which would be reimbursed by working interest owners who are selling with us under our marketing agreements.

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

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11. Property Sales and Acquisitions

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

Certain property acquisitions in the fourth quarter of 2010 were structured to qualify as the first step of a reverse like-kind exchange. During the first quarter of 2011, we sold various interests in oil and gas properties for approximately $11.8 million, a portion of which is included in the second step of the reverse like-kind exchange. At March 31, 2011 our non-current other assets, net included $7.8 million of cash held in trust to be used in completing our like-kind exchange. There were no significant property sales during the first quarter of 2010.

We had no significant property acquisitions during the first quarter of 2011. Subsequent to March 31, 2011, we completed a property acquisition for approximately $18 million. During the first quarter of 2010 we had property acquisitions of $23.7 million. This first quarter acquisition was structured to qualify as the first step of a reverse like-kind exchange.

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

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

BUSINESS OVERVIEW

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

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

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

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

Based on current market prices and service costs, we expect that 2011 Exploration and Development (E&D) expenditures may range from $1.3 to $1.4 billion, up from $999 million in 2010. We anticipate approximately 55% of our E&D costs to be directed toward the Permian Basin, 38% to the Mid-Continent and 7% to the Gulf Coast and other. At March 31, 2011 we had 23 operated rigs running. At March 31, 2010 we had 16 operated rigs running.

First quarter 2011 summary operating and financial results:

- First quarter production volumes averaged 590.0 MMcfe/d, up from 584.5 MMcfe/d for first quarter 2010.

- Our average realized oil price increased 20% to $91.46 per barrel compared to $76.11 per barrel in 2010.

- Our average realized gas price decreased 31% to $4.45 per Mcf versus $6.41 per Mcf in 2010.

- Our average realized NGL price increased 4% to $40.77 per barrel compared to $39.18 per barrel in 2010.

- First quarter commodity sales were $414 million, down 4% from $432 million a year earlier, primarily due to the decrease in our average realized gas price in the first quarter of 2011.

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- Our first quarter cash flow from operating activities was $265.3 million, down from $299.1 million a year earlier.

- Net income of $118.2 million ($1.37 per diluted share) declined from net income of $204.4 million ($2.39 per diluted share) in 2010.

- Total debt of $350 million at March 31, 2011 did not change from year-end 2010.

- Our first quarter 2011 drilling included 67 gross (36.7 net) wells with 65 gross (34.7 net) completed as producers, compared to 37 gross (23.1 net) wells with 34 gross (21.1 net) completed as producers for first quarter 2010.

Commodity Prices

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

The following table presents our average realized prices during the first quarter of 2011 versus the same period of 2010. The realized prices do not include settlements of our commodity contracts.

	Three Months Ended March 31, 2011	2010
Gas Prices:		
Average Henry Hub price ($/Mcf)	$ 4.11	$ 5.30
Average realized sales price ($/Mcf)	$ 4.45	$ 6.41
Oil Prices:		
Average WTI Cushing price ($/Bbl)	$ 94.15	$ 78.72
Average realized sales price ($/Bbl)	$ 91.46	$ 76.11
NGL Prices:		
Average realized sales price ($/Bbl)	$ 40.77	$ 39.18

On an energy equivalent basis, 56% of our first quarter 2011 aggregate production was natural gas. A $0.10 per Mcf change in our average realized gas sales price would have resulted in a $2.9 million change in our gas revenues. Similarly, 44% of our production was crude oil and NGL. A $1.00 per barrel change in our average realized sales price would have resulted in a $3.9 million change in our combined oil and NGL revenues.

Hedging

In addition to supply and demand, oil and gas prices are affected by seasonal, economic and geo-political factors that we can neither control nor predict. From time to time, we attempt to mitigate a portion of our price risk through the use of hedging transactions.

During 2010 we entered into oil and gas contracts relative to our 2011 production. Management has been authorized to hedge up to 50% of our anticipated 2011 equivalent production. Oil contracts that expire in 2011 represent approximately 40-45% of our anticipated remaining oil production for 2011. Our gas swap contracts presently in place represent 5-6% of expected remaining 2011 gas sales volumes.

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The following contracts were outstanding as of March 31, 2011:

Natural Gas Contracts

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

Oil Contracts

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

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

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

We have chosen not to apply hedge accounting treatment to the derivative contracts we entered into in 2010. Therefore, settlements on these contracts do not impact our realized commodity prices during the periods they cover. Instead, any settlements on the contracts are shown as a component of operating costs and expenses as either a net gain or loss on derivative instruments. See Note 2 to the Consolidated Financial Statements and Item 3 of this report for additional information regarding our derivative instruments.

Production and other operating expenses

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

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

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

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

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

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increase with our growth, we also expect such increases to be proportionately smaller than our production growth.

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

Significant expenses that generally do not trend with production

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

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

RESULTS OF OPERATIONS

Quarter ended March 31, 2011 vs. March 31, 2010

Net income for the first quarter of 2011 was $118.2 million, or $1.37 per diluted share. This compares to $204.4 million, or $2.39 per diluted share, for the same period in 2010. The decrease in net income results from lower gas sales, which were partially offset by higher oil and NGL sales. Also contributing to the decrease in net income was a net non-cash unrealized loss on derivative contracts during the first quarter of 2011 versus a net non-cash unrealized gain for the same period of 2010. These changes are discussed further in the analysis that follows.

	Month Ended March 31,		Percentage Change Between	Price / Volume Analysis		
(In thousands or as indicated)	**2011**	**2010**	**2011/2010**	**Price**	**Volume**	**Variance**
Gas sales	$ 131,323	$ 225,637	-42%	$ (57,793)	$ (36,521)	$ (94,314)
Oil sales	220,499	191,560	15%	37,009	(8,070)	28,939
NGL Sales	62,190	15,209	309%	2,425	44,556	46,981
Total sales	$ 414,012	$ 432,406	-4%	$ (18,359)	$ (35)	$ (18,394)
Total gas volume MMcf	29,486	35,175	-16%			
Gas volume MMcf per day	327.6	390.8				
Average gas price per Mcf	$ 4.45	$ 6.41	-31%			
Total oil volume thousand barrels	2,411	2,517	-4%			
Oil volume barrels per day	26,788	27,967				

Average oil price per barrel	$	91.46	$	76.11	20%
Total NGL volume thousand barrels		1,525		388	293%
NGL volume barrels per day		16,947		4,313	
Average NGL price per barrel	$	40.77	$	39.18	4%

Commodity sales for the first quarter of 2011 totaled $414.0 million, compared to $432.4 million in 2010. The decrease in the first quarter of 2011 was mostly a result of lower realized sales prices and production for natural gas, which had a negative impact of $94.3 million. Higher oil sales of $28.9 million combined with higher NGL sales of $47.0 million partially offset the decrease in gas sales, resulting in a net decrease for the 2011 period of $18.4 million.

Compared to the first quarter of 2010, our first quarter 2011 gas production decreased by 16% to an average of 327.6 MMcf per day. The lower gas production resulted in decreased revenues of

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$36.5 million. Oil production volumes averaged 26,788 per day in 2011 compared to 27,967 per day in the first quarter of 2010 resulting in decreased revenues of $8.1 million. Our NGL volumes for the first quarter of 2011 increased to 16,947 barrels per day compared to 4,313 barrels per day for the same period of 2010. The increase in NGL volume added $44.6 million of revenue.

First quarter 2011 aggregate production volumes were 590.0 MMcfe per day, up slightly from 584.5 MMcfe per day for the same period in 2010. First quarter 2011 production was adversely affected by severe weather, particularly in the Permian Basin region, which resulted in production curtailments.

During the first quarter of 2010 we began separately reporting NGL sales and production volumes. The determination of whether to record and separately disclose NGL volumes is based on where title transfer occurs during processing of the well stream. New gas processing contracts related to new drilling activity and ongoing contractual amendments have resulted in title of NGL volumes being conveyed to the Company. As a consequence, reported gas and NGL volumes and prices between periods may not be comparable.

Our average realized gas price decreased by 31% to $4.45 per Mcf for the three months ended March 31, 2011 compared to $6.41 per Mcf for the same period of 2010. This price decrease resulted in $57.8 million of lower gas sales in 2011. Our realized oil price averaged $91.46 per barrel during the first quarter of 2011, or an increase of 20%, compared to $76.11 per barrel for the same period in 2010. This price increase contributed an additional $37.0 million in oil revenue for 2011. The average NGL price we received in the first quarter of 2011 was $40.77 per barrel, up from $39.18 per barrel in 2010. The increase in the NGL price resulted in additional NGL sales of $2.4 million.

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

	For the Three Months Ended March 31, 2011	For the Three Months Ended March 31, 2010
Gas Gathering, Processing, Marketing and Other (in thousands):		
Gas gathering, processing and other revenues	$ 12,517	$ 15,850
Gas gathering and processing costs	(4,551)	(6,505)
Gas gathering, processing and other margin	$ 7,966	$ 9,345
Gas marketing revenues, net of related costs	$ 67	$ 314

We sometimes transport, process and market third-party gas that is associated with our gas. In the first quarter of 2011, third-party gas gathering, processing and other contributed $8.0 million of pre-tax cash operating margin (revenues less direct cash expenses) versus $9.3 million in 2010. Our gas marketing margin (revenues less purchases) decreased to $67 thousand in the first quarter of 2011 from $314 thousand in the first quarter of 2010. Changes in net margins from gas gathering, processing, marketing and other activities are the direct result of changes in volumes and overall market conditions.

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	For the Three Months Ended March 31, 2011	2010	Variance Between 2011/2010
Operating Costs and Expenses:			
(In thousands)			
Depreciation, depletion and amortization	$ 85,026	$ 69,710	$ 15,316
Asset retirement obligation	1,938	2,644	(706)
Production	58,480	41,983	16,497
Transportation	13,446	11,167	2,279
Taxes other than income	33,597	32,358	1,239
General and administrative	14,727	13,045	1,682
Stock compensation, net	4,750	2,778	1,972
(Gain) loss on derivative instruments, net	18,244	(52,597)	70,841
Other operating, net	3,374	(1,846)	5,220
	$ 233,582	$ 119,242	$ 114,340

Total operating costs and expenses (not including gas gathering, marketing, and processing costs or income tax expense) increased $114.3 million to $233.6 million for the first quarter of 2011 compared to $119.2 million in the first quarter of 2010. Analysis of the year over year differences are discussed below.

DD&A increased from $69.7 million in the first quarter of 2010 to $85.0 million in the same period of 2011. The $15.3 million increase in 2011 accounts for 13% of the total 2011 increase in operating costs and expenses. On a unit of production basis, DD&A was $1.60 per Mcfe in 2011 compared to $1.33 per Mcfe for 2010. The increase in DD&A results from increasing the cost of reserves added at a greater rate than the increase in future production.

Production costs rose $16.5 million from $42.0 million ($0.80 per Mcfe) in the first quarter of 2010 to $58.5 million ($1.10 per Mcfe) in the first quarter of 2011. Our production costs consist of lease operating expense and workover expense. In 2011, lease operating expenses increased $12.7 million due in part to higher water disposal costs associated with wells coming on line from our successful drilling program. Costs for fuel, equipment maintenance and rentals have also contributed to the increase in the 2011 period.

The workover component of production costs was $8.5 million in the first quarter of 2011 compared to $4.7 million for the same period of 2010. In 2011, we had increased workover activity in our Permian Basin and Mid-Continent regions.

Transportation costs increased from $11.2 million ($0.21 per Mcfe) in the first quarter of 2010 to $13.4 million ($0.25 per Mcfe) in 2011. Transportation costs will fluctuate regionally, based on increases or decreases in sales volumes and fluctuation in the price of the fuel cost component. We have experienced increases in transportation rates due to higher contractual rates associated with new wells coming online and contracts for existing wells being renewed, particularly for our Mid-Continent wells.

Taxes other than income increased modestly from $32.4 million for the first quarter of 2010 to $33.6 million in 2011. Generally, taxes other than income will vary based on increases or decreases in production volumes and changes in commodity prices.

General and administrative (G&A) expenses for the first quarter of 2011 were $14.7 million ($0.28 per Mcfe) compared to $13.0 million ($0.25 per Mcfe) in the first quarter of 2010. The increase between periods is the net effect of lower employee benefit costs being capitalized (resulting in higher G&A expense), partially offset by lower corporate expenses.

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Stock compensation expense consists of non-cash charges resulting from the issuance of restricted stock, restricted stock units and stock option awards. Stock compensation expense in the first quarter of 2011 was $4.8 million, up from $2.8 million in the first quarter of 2010. Expense associated with stock compensation will fluctuate based on the grant date market value of the award and the number of awards granted. (See Note 4 to the Consolidated Financial Statements for a detailed discussion regarding our stock-based compensation).

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

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

	For the Three Months Ended March 31,			
	2011		2010	
	(In thousands)			
Realized (gain) on settlement of derivative instruments	$	(2,034)	$	(541)
Unrealized (gain) loss from changes to the fair value of the derivative instruments		20,278		(52,056)
(Gain) loss on derivative instruments, net	$	18,244	$	(52,597)

Other operating, net expense consists of costs related to various legal matters most of which pertain to litigation and contract settlements and title and royalty issues. The change from income of $1.8 million in the first quarter of 2010 to an expense of $3.4 million for the first quarter of 2011 relates primarily to the favorable resolution of items in the 2010 period that had been accrued for in prior years.

Other income and expense

Interest expense for the first quarter of 2011 was $9.0 million compared to $9.5 million for the same period of 2010. The 5% decrease results from lower outstanding debt and lower miscellaneous interest expense.

Components of other, net consist of miscellaneous income and expense items that will vary from period to period, including gain or loss on the sale or value of oil and gas well equipment, interest income and income and expenses associated with other non-operating activities. Other, net decreased from $1.9 million of income in the first quarter of 2010 to $0.6 million of income in the first quarter of 2011. The $1.3 million decrease is due to an increase of $1.9 million of non-operating expenses, partially offset by an increase in interest income.

Income tax expense

In the first quarter of 2011 we recognized $69.2 million of income tax expense, which included $0.5 million of current tax benefit. This compares with 2010 first quarter income tax expense of $118.4 million, of which $33.4 million was current tax expense. The combined Federal and state

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effective income tax rates was 36.9% for the first quarter of 2011 compared to 36.7% for the first quarter of 2010. The effective tax rate of 36.9% for the first quarter of 2011 differs from the statutory rate of 35% primarily due to state income taxes, non-deductible expenses and special deductions.

LIQUIDITY AND CAPITAL RESOURCES

Overview

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

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

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

From time to time we consider attractive acquisition opportunities. However, the timing and size of acquisitions are unpredictable. To prepare ourselves for potential acquisitions and possible declines in commodity prices, we have a senior secured revolving credit facility. The credit facility provides for bank commitments of $800 million with a borrowing base of $1 billion.

At March 31, 2011, our total debt outstanding was $350 million, which is comprised of our 7.125% Notes due in 2017. Our debt to total capitalization ratio at March 31, 2011 was 11%. The reconciliation of debt to total capitalization, which is a non-GAAP measure, is: long-term debt of $350 million divided by long-term debt of $350 million plus stockholders equity of $2.722 billion. Management believes that this non-GAAP measure is useful information for investors because it is a common statistic referred to by the investment community, used to identify the amount of our leverage and to help analyze our risk exposure relative to other companies in the oil and gas exploration and production industry.

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

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Analysis of Cash Flow Changes

Cash flow provided by operating activities for the first quarter of 2011 was $265.3 million, compared to $299.1 million for the same period of 2010. The $33.8 million decrease resulted primarily from lower realized prices for gas and increased production operating expense in the first quarter of 2011.

Cash flow used in investing activities for the first three months of 2011 was $322.7 million, compared to $211.4 million for the three months ended March 31, 2010. Changes in the cash flow used in investing activities are generally the result of changes in our exploration and development programs, acquisitions and property sales. The increase from first quarter 2010 to 2011 was due to increased E&D and other capital expenditures.

Net cash flow used for financing activities in the first three months of 2011 was $2.6 million versus $27.7 million for the same period of 2010. The $25.1 million decrease was mainly a result of net payments of $25 million on our credit facility during the first three months of 2010.

Reconciliation of Cash Flow from Operations

	For the Three Months Ended March 31,			
	2011		2010	
	(In thousands)			
Net cash provided by operating activities	$	265,277	$	299,107
Change in operating assets and liabilities		39,343		14,100
Cash flow from operations	$	304,620	$	313,207

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

Capital Expenditures

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

For the Three Months Ended March 31,

	2011	2010
Acquisitions:		
Proved	$	$ 7,156
Unproved	441	16,497
	441	23,653
Exploration and development:		
Land and seismic	32,426	24,450
Exploration and development	304,575	167,628
	337,001	192,078
Sales proceeds:		
Proved*	(11,354)	58
Unproved	(494)	
	(11,848)	58
	$ 325,594	$ 215,789

*The positive amount in the first quarter 2010 proved sales proceeds reflects purchase price adjustments related to dispositions in 2009.

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

Our exploration and development expenditures increased 75% from $192.1 million in the first quarter of 2010 to $337.0 million in the first of quarter 2011. As of March 31, 2011 we had 23 operated rigs running. At March 31, 2010 we had 16 operated rigs running.

During the first quarter of 2011 we drilled 67 gross (36.7 net) wells, with 65 gross (34.7 net) completed as producers. As of March 31, 2011 we also had 82 gross wells in progress. During the first quarter of 2010 we drilled and completed 37 gross (23.1 net) wells, of which 3 gross (2 net), were unsuccessful. At March 31, 2010 we had 49 gross wells in process.

Our planned exploration and development program for 2011 is expected to be principally funded from cash flow. Based on current market prices and service costs, our 2011 capital expenditures are expected to range from $1.3 to $1.4 billion. Although our capital budget is set at a level that we believe corresponds with our anticipated 2011 cash flows, the timing of capital expenditures and the receipt of cash flows do not necessarily match. For example, our planned capital expenditures are front-end loaded and we may outspend cash flows for a period of time. Therefore, we may borrow and repay funds under our credit facility throughout the year. Should we start to see a significant change in commodity prices from our current forecasts, we have the operational flexibility to increase or decrease our capital expenditures for changes in our expected cash flows from operations.

We had no significant acquisitions in the first quarter of 2011. Subsequent to March 31, 2011 we purchased additional interests in our western Oklahoma Cana-Woodford shale play for approximately $18 million. During the first quarter of 2010 we had property acquisitions of $23.7 million, most of which was additional interests in our western Oklahoma Cana-Woodford shale play. In the first quarter of 2011 we sold non-core property interests for $11.8 million. We did not have any property sales in the first quarter of 2010. We continue to actively evaluate acquisitions and dispositions relative to our property holdings, particularly in our core areas of operation.

We have a large development project in Sublette County, Wyoming where we are developing the deep Madison gas formation and constructing a gas processing plant. The total cost of the project will approximate $358 million. Pursuant to the terms of our operating agreement with our partner in this project, we are reimbursed for 42.5% of the costs. Through March 31, 2011 our cumulative investment in this project is $121 million, of which $100.9 million is included in our fixed assets. At present we expect to initiate gas sales from this project in the fourth quarter of 2011.

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

Financial Condition

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

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During the first quarter of 2011 our total assets increased by $211.5 million to $4.6 billion, up from $4.4 billion at December 31, 2010. The change is primarily made up of increases in our net oil and gas assets and fixed assets of $259.2 million partially offset by a decrease of $60 million in our cash and cash equivalents.

At March 31, 2011, our total liabilities had increased to $1.8 billion, up $99.8 million from $1.7 billion at December 31, 2010. The increase resulted primarily from a net increase in current liabilities of $27.4 million, mostly related to increased accrued E&D expenditures, and a $75.3 million increase in non-current deferred income taxes. Stockholders equity rose $111.7 million to $2.7 billion at the end of the first quarter of 2011 compared to $2.6 billion at December 31, 2010. The increase is mainly due to our net income of $118 million for the first quarter of 2011.

Dividends

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

Common Stock Repurchase Program

In December 2005, the Board of Directors authorized the repurchase of up to four million shares of common stock. During 2007 we repurchased a total of 1,114,200 shares at an average purchase price of $37.93. Cumulative purchases through December 31, 2007 total 1,364,300 shares at an average price of $39.05. There were no shares repurchased in the first quarter of 2011, or since the quarter ended September 30, 2007.

Working Capital Analysis

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

Our working capital decreased $83.3 million from $49.5 million at year-end 2010 to a deficit of $33.8 million at March 31, 2011. Although we anticipate that our 2011 capital spending (excluding possible acquisitions) will correspond with our anticipated 2011 operating cash flow, we may borrow and repay funds under our credit facility throughout the year, because the timing of expenditures and the receipt of cash flows from operations do not necessarily match.

Working capital decreased primarily because of the following:

- Cash and cash equivalents decreased by $60 million as cash was used primarily to fund our E&D activity.

- We received $25 million related to a tax refund that was outstanding at December 31, 2010, which was used to fund E&D activity.

- Accrued liabilities related to our E&D expenditures increased by $24.4 million.

- The aggregate fair value of our derivative instruments decreased by $20.3 million.

These working capital decreases were partially offset by the following:

- Our operations related accounts receivable increased by $23.0 million.

- Our operations related accounts payable decreased by $15.6 million.

- Our deferred tax asset increased by $5.6 million.

- Other current assets increased by $4.6 million.

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

Financing

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

Bank Debt

We have a three-year senior secured revolving credit facility (credit facility). The credit facility provides for bank commitments of $800 million, with a borrowing base of $1 billion. The credit facility is provided by a syndicate of banks led by JP Morgan Chase Bank, N.A., matures on April 14, 2012 and is secured by mortgages on certain of our oil and gas properties and the stock of certain wholly-owned operating subsidiaries. We are currently in discussions with our existing syndicate of banks to extend our existing facility, or obtain a replacement credit facility, before our current credit facility matures in 2012. We intend to have a new credit facility in place during the second half of 2011.

At March 31, 2011, there were no outstanding borrowings under the credit facility. We had letters of credit outstanding of $7.5 million leaving an unused borrowing availability of $792.5 million. During the first quarter of 2011 we had an average daily bank debt outstanding of $44.4 thousand, compared to $18.1 million for the same period of 2010. Our largest amount of bank borrowings outstanding during the first quarter of 2011 was $2 million in late March. During the first quarter of 2010 our largest amount of outstanding borrowing was $69 million in mid January.

The borrowing base under the credit agreement is determined at the discretion of the lenders, based on the collateral value of our proved reserves, and is subject to potential special and regular semi-annual redeterminations. The borrowing base of $1 billion and bank commitments of $800 million were reaffirmed in April 2011.

The credit facility contains covenants and restrictive provisions which may limit our ability to incur additional indebtedness, make investments or loans and create liens. The credit agreement requires us to maintain a current ratio (defined to include undrawn borrowings) greater than 1 to 1 and a leverage ratio not to exceed 3.5 to 1. As of March 31, 2011, we were in compliance with all of the financial and non-financial covenants.

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

7.125% Notes due 2017

In May, 2007, we issued $350 million of 7.125% senior unsecured notes that mature May 1, 2017 at par. Interest on the notes is payable May 1 and November 1 of each year. The notes are governed by an indenture containing covenants that could limit our ability to incur additional indebtedness; pay

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dividends or repurchase our common stock; make investments and other restricted payments; incur liens; enter into sale/leaseback transactions; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets.

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

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

At any time prior to May 1, 2012, we may also redeem all, but not part, of the notes at a price of 100% of the principal amount of the notes plus accrued and unpaid interest plus a make-whole premium.

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

Contractual Obligations and Material Commitments

At March 31, 2011, we had contractual obligations and material commitments as follows:

	Payments Due by Period				
	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
			(In thousands)		
Contractual obligations:					
Long-term debt(1)	$ 350,000	$	$	$	$ 350,000
Fixed-Rate interest payments(1)	162,094	24,938	49,875	49,875	37,406
Operating leases(2)	75,112	5,095	13,874	10,953	45,190
Drilling commitments(3)	230,293	199,752	30,541		
Purchase commitments(4)	10,305	10,305			
Gas processing facility(5)	67,550	42,074	25,476		
Asset retirement obligation(6)	136,554	27,467	(6)	(6)	(6)
Derivative instruments	28,109	28,109			
Other liabilities(7)	50,052	13,267	24,659	34	12,092

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

(2) In the first quarter of 2011 we entered into a new 12-year lease agreement for additional office space, which increased our aggregate minimum lease payments by approximately $60 million.

(3) We have drilling commitments of approximately $157.6 million consisting of obligations to complete drilling wells in progress at March 31, 2011. We also have various commitments for drilling rigs as well as certain service contracts. The total minimum expenditure commitments under these agreements are $26.5 million to secure the use of drilling rigs and $46.2 million to secure certain dedicated services associated with drilling activities.

(4) At March 31, 2011, we have a purchase commitment of $10.3 million for construction of an aircraft. The total cost of the aircraft is $11.5 million with an option to trade in our existing aircraft. Construction of the aircraft is expected to be completed by the end of 2011.

(5) We have a large development project in Sublette County, Wyoming where we are developing the deep Madison gas formation and constructing a gas processing plant. At March 31, 2011, we had commitments of $89.3 million relating to construction of the gas processing plant of which $67.6 million is subject to a construction contract. The total cost of the project will approximate $358 million. Pursuant to the terms of our operating agreement with our partner in this project, we

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are reimbursed for 42.5% of the costs. The gas processing plant is subject to a delivery commitment agreement over a 20 year period, commencing December, 2011. If no deliveries were made, the maximum amount that would be payable under the agreement would be approximately $43 million.

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

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

At March 31, 2011, we had firm sales contracts to deliver approximately 13.7 Bcf of natural gas over the next 12 months. If this gas is not delivered, our financial commitment would be approximately $50.3 million. This commitment will fluctuate due to price volatility and actual volumes delivered. However, we believe no financial commitment will be due based on our current reserves and production levels.

In connection with a gas gathering and processing agreement, we have commitments to deliver a minimum of 24 Bcf of gas over the next three years. The production from certain wells is counted toward that commitment; these wells also have individual commitments for gas deliveries. If no gas is delivered, the maximum amount that would be payable under these commitments would be approximately $22.2 million, some of which would be reimbursed by working interest owners who are selling with us under our marketing agreements. We do not expect to make significant payments relative to these commitments.

We have 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 $1.4 million, some of which would be reimbursed by working interest owners who are selling with us under our marketing agreements.

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

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

2011 Outlook

We expect our 2011 E&D capital expenditures to be principally funded from cash flow. Based on current market prices and service costs, we expect 2011 E&D expenditures to range from $1.3 to $1.4 billion. We remain focused on profitable growth and maximizing our return on investment. We currently have a large inventory of drilling opportunities and limited lease expirations.

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

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

Production for 2011 is projected to be in the range of 605 to 635 MMcfe per day, or a 2-7% increase over 2010. Revenues from production will be dependent not only on the level of oil and gas

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actually produced, but also the prices that will be realized. During 2010, our realized prices averaged $4.92 per Mcf of gas, $76.76 per barrel of oil, and $34.91 per barrel of NGL. Commodity prices can be very volatile and the possibility of realized 2011 prices varying from prices received in 2010 is high.

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

	2011
Production expense	$1.02 - $1.22
Transportation expense	0.22 - 0.27
DD&A and asset retirement obligation	1.65 - 1.80
General and administrative	0.22 - 0.28
Production taxes (% of oil and gas revenue)	7.5% - 8.5%

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

We consider accounting policies related to oil and gas reserves, full cost accounting, goodwill, derivatives, contingencies and asset retirement obligations to be critical policies and estimates. These critical policies and estimates are summarized in Management s Discussion and Analysis of Financial Condition and Results of Operations in our annual report on Form 10-K for the year ended December 31, 2010.

Recent Accounting Developments

No significant accounting standards applicable to Cimarex have been issued during the quarter ended March 31, 2011.

ITEM 3. QUALITATIVE AND QUANTITATIVE DISCLOSURES ABOUT MARKET RISK

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

Price Fluctuations

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

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

The following table details the contracts we have in place as of March 31, 2011:

Natural Gas Contracts

Period	Type	Volume/Day	Index(1)	Weighted Average Price Swap	Fair Value (000 s)
Apr 11 - Dec 11	Swap	20,000 MMBtu	PEPL	$ 5.05	$ 3,975

Oil Contracts

Period	Type	Volume/Day	Index(1)	Weighted Average Price Floor	Weighted Average Price Ceiling	Fair Value (000 s)
Apr 11 - Dec 11	Collar	12,000 Bbls	WTI	$ 65.00	$ 105.44	$ (28,109)

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

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While these contracts limit the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. For the 2011 gas contracts listed above, a hypothetical $0.10 change in the price below or above the contracted price applied to the notional amounts would cause a change in our gain (loss) on mark-to-market derivatives in 2011 of $0.6 million. For the 2011 oil contracts listed above, a hypothetical $1.00 change in the price below or above the contracted price applied to the notional amounts would cause a change in our gain (loss) on mark-to-market derivatives in 2011 of $3.3 million.

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

Interest Rate Risk

At March 31, 2011 our debt was our senior unsecured notes that bear interest at a fixed rate of 7.125% and will mature on May 1, 2017.

At March 31, 2011, we consider our interest rate exposure to be minimal because all of our long-term debt obligations were at fixed rates. This assessment excludes accounts receivable, accounts payable and accrued liabilities because of the short-term maturity of such instruments. See Note 3 and Note 6 to the Consolidated Financial Statements in this report for additional information regarding debt.

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ITEM 4. CONTROLS AND PROCEDURES

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

Our management, with the participation of our Chief Executive Officer (CEO) and Chief Financial Officer (CFO), have evaluated the effectiveness of our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e)) as of March 31, 2011 and concluded that the disclosure controls and procedures are effective in providing reasonable assurance that the information required to be disclosed in reports filed with the SEC is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms. The disclosure controls and procedures are also designed to provide reasonable assurance that such information is accumulated and communicated to our management, including the CEO and CFO, as appropriate to allow such persons to make timely decisions regarding required disclosures.

Our management does not expect that our disclosure controls and procedures will prevent all errors and all fraud. The design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Based on the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple errors or mistakes. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the controls. The design of any system of controls is also based upon certain assumptions about the likelihood of future events. Therefore, a control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Our disclosure controls and procedures are designed to provide such reasonable assurances of achieving our desired control objectives, and our CEO and CFO have concluded, as of March 31, 2011, that our disclosure controls and procedures are effective in achieving that level of reasonable assurance.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There have been no changes in our internal controls over financial reporting or in other factors that occurred during the fiscal quarter ended March 31, 2011, that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

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PART II

ITEM 6 EXHIBITS

31.1	Certification of F. H. Merelli, Chief Executive Officer of Cimarex Energy Co. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Paul Korus, Chief Financial Officer of Cimarex Energy Co. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of F. H. Merelli, Chief Executive Officer of Cimarex Energy Co. pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350.
32.2	Certification of Paul Korus, Chief Financial Officer of Cimarex Energy Co. pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350.
101.INS	XBRL Instance Document*
101.SCH	XBRL Taxonomy Extension Schema Document*
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document*
101.LAB	XBRL Taxonomy Extension Label Linkbase Document*
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document*
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document*

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

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SIGNATURES

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

May 6, 2011

CIMAREX ENERGY CO.

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

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