CIMAREX ENERGY CO
Form 10-Q
August 07, 2013
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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 June 30, 2013

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 June 30, 2013 was 86,503,109.

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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 or NGLs 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, gas, and NGLs 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, transportation, 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 economic, 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

	June 30, 2013 (Unaudited)	December 31, 2012
	(In thousands, except share data)	
Assets		
Current assets:		
Cash and cash equivalents	$ 4,532	$ 69,538
Receivables, net	381,634	302,974
Oil and gas well equipment and supplies	66,902	81,029
Deferred income taxes	18,111	8,477
Derivative instruments	7,956	
Prepaid expenses	7,120	7,420
Other current assets	286	699
Total current assets	486,541	470,137
Oil and gas properties at cost, using the full cost method of accounting:		
Proved properties	12,097,102	11,258,748
Unproved properties and properties under development, not being amortized	567,178	645,078
	12,664,280	11,903,826
Less accumulated depreciation, depletion and amortization	(7,166,038)	(6,899,057)
Net oil and gas properties	5,498,242	5,004,769
Fixed assets, net	135,367	152,605
Goodwill	620,232	620,232
Derivative instruments	2,395	
Other assets, net	53,593	57,409
	$ 6,796,370	$ 6,305,152
Liabilities and Stockholders Equity		
Current liabilities:		
Accounts payable	$ 82,690	$ 103,653
Accrued liabilities	416,111	392,909
Derivative instruments	59	
Revenue payable	172,956	149,300
Total current liabilities	671,816	645,862
Long-term debt	892,000	750,000
Deferred income taxes	1,260,836	1,121,353
Other liabilities	292,721	313,201
Total liabilities	3,117,373	2,830,416
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, 86,503,109 and 86,595,976 shares issued, respectively	865	866
Paid-in capital	1,948,381	1,939,628

Retained earnings		1,729,178		1,533,768
Accumulated other comprehensive income		573		474
		3,678,997		3,474,736
	$	6,796,370	$	6,305,152

See accompanying notes to consolidated financial statements.

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CIMAREX ENERGY CO.

Consolidated Statements of Income and Comprehensive Income

(Unaudited)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
	(In thousands, except per share data)			
Revenues:				
Gas sales	$ 126,547	$ 69,741	$ 227,668	$ 154,894
Oil sales	304,466	229,210	561,998	496,294
NGL sales	52,309	44,286	109,184	103,300
Gas gathering, processing and other	10,844	10,179	21,571	21,886
Gas marketing, net	(409)	(294)	(308)	(216)
	493,757	353,122	920,113	776,158
Costs and expenses:				
Depreciation, depletion and amortization	147,231	121,237	283,669	239,499
Asset retirement obligation	2,884	2,441	5,283	5,966
Production	69,433	62,494	138,819	130,119
Transportation and other operating	22,022	13,169	40,656	26,485
Gas gathering and processing	5,184	4,955	11,340	9,806
Taxes other than income	27,807	23,483	52,935	48,643
General and administrative	22,836	12,634	38,413	26,781
Stock compensation	3,507	4,684	7,112	9,218
Gain on derivative instruments, net	(13,660)	(10,078)	(12,057)	(5,990)
Other operating, net	2,365	2,719	5,297	5,059
	289,609	237,738	571,467	495,586
Operating income	204,148	115,384	348,646	280,572
Other (income) and expense:				
Interest expense	14,112	13,679	27,318	22,347
Capitalized interest	(7,387)	(9,119)	(16,582)	(16,923)
Loss on early extinguishment of debt		16,214		16,214
Other, net	(8,758)	(7,829)	(11,374)	(12,555)
Income before income tax	206,181	102,439	349,284	271,489
Income tax expense	76,616	38,137	129,792	101,080
Net income	$ 129,565	$ 64,302	$ 219,492	$ 170,409
Earnings per share to common stockholders:				
Basic				
Distributed	$ 0.14	$ 0.12	$ 0.28	$ 0.24
Undistributed	1.36	0.63	2.26	1.74
	$ 1.50	$ 0.75	$ 2.54	$ 1.98
Diluted				
Distributed	$ 0.14	$ 0.12	$ 0.28	$ 0.24
Undistributed	1.35	0.62	2.25	1.73
	$ 1.49	$ 0.74	$ 2.53	$ 1.97
Comprehensive income:				

Net income	$ 129,565	$ 64,302	$ 219,492	$ 170,409
Other comprehensive income:				
Change in fair value of investments, net of tax	19	(135)	99	264
Total comprehensive income	$ 129,584	$ 64,167	$ 219,591	$ 170,673

See accompanying notes to consolidated financial statements.

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Condensed Consolidated Statements of Cash Flows

(Unaudited)

	For the Six Months Ended June 30,	
	2013	2012
	(In thousands)	
Cash flows from operating activities:		
Net income	$ 219,492	$ 170,409
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	283,669	239,499
Asset retirement obligation	5,283	5,966
Deferred income taxes	129,792	101,080
Stock compensation	7,112	9,218
Derivative instruments, net	(10,292)	(5,990)
Loss on early extinguishment of debt		16,214
Changes in non-current assets and liabilities	5,790	5,115
Other, net	(2,116)	1,955
Changes in operating assets and liabilities:		
(Increase) decrease in receivables, net	(55,060)	107,834
(Increase) decrease in other current assets	14,840	(4,910)
(Decrease) in accounts payable and accrued liabilities	(28,724)	(71,458)
Net cash provided by operating activities	569,786	574,932
Cash flows from investing activities:		
Oil and gas expenditures	(776,138)	(758,608)
Sales of oil and gas assets	14,407	1,273
Sales of other assets	31,157	408
Other expenditures	(25,475)	(26,087)
Net cash used by investing activities	(756,049)	(783,014)
Cash flows from financing activities:		
Net increase (decrease) in bank debt	142,000	(55,000)
Increase in other long-term debt		750,000
Decrease in other long-term debt		(363,595)
Financing costs incurred		(12,692)
Dividends paid	(22,448)	(18,869)
Issuance of common stock and other	1,705	2,764
Net cash provided by financing activities	121,257	302,608
Net change in cash and cash equivalents	(65,006)	94,526
Cash and cash equivalents at beginning of period	69,538	2,406
Cash and cash equivalents at end of period	$ 4,532	$ 96,932

See accompanying notes to consolidated financial statements.

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Notes to Consolidated Financial Statements

June 30, 2013

(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 2012 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. Certain amounts in prior years financial statements have been reclassified to conform to the 2012 financial statement presentation. We have evaluated subsequent events through the date of this filing.

Oil and Gas Properties

We use the full cost method of accounting for our oil and gas operations. Accounting rules require us to perform a quarterly ceiling test calculation to test our oil and gas properties for possible impairment. The primary components impacting this calculation are commodity prices, reserve quantities added and produced, overall exploration and development costs, depletion expense, and tax effects. If the net capitalized cost of our oil and gas properties subject to amortization (the carrying value) exceeds the ceiling limitation, the excess would be charged to expense. The ceiling limitation is equal to the sum of the present value discounted at 10% of estimated future net cash flows from proved reserves, the cost of properties not being amortized, the lower of cost or estimated fair value of unproven properties included in the costs being amortized, and all related tax effects.

At June 30, 2013, the calculated value of the ceiling limitation exceeded the carrying value of our oil and gas properties subject to the test, and no impairment was necessary. However, our ceiling limitation has declined since December 31, 2012. A significant component of the decrease is related to decreases in the 12-month average trailing prices for oil and NGLs, which have reduced proved reserve values. If pricing conditions decline, or if there is a negative impact on one or more of the other components of the calculation, we may incur a full cost ceiling impairment related to our oil and gas properties in future quarters.

Use of Estimates

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 (DD&A), 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 allowance 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.

Accounts Receivable, Accounts Payable, and Accrued Liabilities

The components of our receivable accounts, accounts payable, and accrued liabilities are shown below:

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Notes to Consolidated Financial Statements (Continued)

June 30, 2013

(Unaudited)

(in thousands)	June 30, 2013	December 31, 2012
Receivables, net of allowance		
Trade	$ 87,114	$ 55,528
Oil and gas sales	281,962	239,106
Gas gathering, processing, and marketing	12,347	7,901
Other	211	439
Receivables, net	$ 381,634	$ 302,974
Accounts payable		
Trade	$ 58,225	$ 88,168
Gas gathering, processing, and marketing	24,465	15,485
Accounts payable	$ 82,690	$ 103,653
Accrued liabilities		
Exploration and development	$ 175,233	$ 155,002
Taxes other than income	23,119	29,179
Other	217,759	208,728
Accrued liabilities	$ 416,111	$ 392,909

Recently Issued Accounting Standards

No significant accounting standards applicable to Cimarex have been issued during the quarter ended June 30, 2013.

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.

The following tables summarize our outstanding contracts as of June 30, 2013. We have elected not to account for these derivatives as cash flow hedges.

Oil Contracts

Period		Type	Volume/Day	Index(1)	Weighted Average Price Floor	Ceiling	Swap	Fair Value (in thousands)
Jul 13	Dec 13	Collars	6,000 Bbls	WTI	$ 85.00	$ 102.31		$ (18)
Jul 13	Dec 13	Swaps	6,000 Bbls	WTI			$ 96.13	$ 1,110

(1) WTI refers to West Texas Intermediate price as quoted on the New York Mercantile Exchange.

Gas Contracts

Period		Type	Volume/Day	Index(1)	Weighted Average Price Floor	Ceiling	Fair Value (in thousands)
Jul 13	Dec 14	Collars	80,000 MMBtu	PEPL	$ 3.51	$ 4.57	$ 9,200

(1) PEPL refers to Panhandle Eastern Pipe Line, Tex/OK Mid-Continent Index as quoted in Platt s Inside FERC.

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

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Notes to Consolidated Financial Statements (Continued)

June 30, 2013

(Unaudited)

index price is between the floor and ceiling prices. 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.

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.

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 June 30,		Six Months Ended June 30,	
(in thousands)	**2013**	**2012**	**2013**	**2012**
Settlements gains (losses):				
Natural gas contracts	$	$	$	$
Oil contracts	1,039		1,765	
Total settlements gains (losses)	1,039		1,765	
Unrealized gains (losses) on fair value change:				
Natural gas contracts	9,199		9,199	
Oil contracts	3,422	10,078	1,093	5,990
Total unrealized gains (losses) on fair value change	12,621	10,078	10,292	5,990
Gain (loss) on derivative instruments, net	$ 13,660	$ 10,078	$ 12,057	$ 5,990

Our derivative contracts are carried at their fair value on our balance sheet using Level 2 inputs. 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 value of our derivative instruments in an asset position includes a measure of counterparty credit risk and the fair value of instruments in a liability position includes 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 value of our derivative instruments is 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 table presents the estimated fair value of our derivative assets and liabilities as of June 30, 2013. All of our derivative contracts entered into prior to January 1, 2013 were settled as of December 31, 2012. Our derivatives are presented on a gross basis.

June 30, 2013:

(in thousands)	**Balance Sheet Location**		**Asset**	**Liability**
Oil contracts	Current assets	Derivative instruments	$ 1,151	$
Natural gas contracts	Current assets	Derivative instruments	$ 6,805	$
Natural gas contracts	Noncurrent assets	Derivative instruments	$ 2,395	$
Oil contracts	Current liabilities	Derivative instruments	$	$ 59
			$ 10,351	$ 59

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Notes to Consolidated Financial Statements (Continued)

June 30, 2013

(Unaudited)

Because we elect not to account for our current derivative contracts as cash flow hedges, we recognize all realized settlements 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.

We are exposed to financial risks associated with these contracts from nonperformance 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 do not require us to post collateral for our hedge liability positions.

3. Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). 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 are inputs other than quoted prices that are observable for the asset or liability, either directly or indirectly. Level 3 are unobservable inputs for an asset or liability.

The following tables provide fair value measurement information for certain assets and liabilities as of June 30, 2013 and December 31, 2012:

June 30, 2013: (in thousands)		**Carrying Amount**	**Fair Value**
Financial Assets (Liabilities):			
Bank debt		$ (142,000)	$ (142,000)
5.875% Notes due 2022		$ (750,000)	$ (780,000)
Derivative instruments	assets	$ 10,351	$ 10,351
Derivative instruments	liabilities	$ (59)	$ (59)

December 31, 2012: (in thousands)	**Carrying Amount**	**Fair Value**

Financial (Liabilities):				
5.875% Notes due 2022	$	(750,000)	$	(825,750)

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

Debt (Level 1)

The fair value of our bank debt at June 30, 2013 was estimated to approximate the carrying amount because the floating rate interest paid on such debt was set for periods of three months or less.

The fair value for our 5.875% fixed rate notes was based on their last traded value before period end.

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Notes to Consolidated Financial Statements (Continued)

June 30, 2013

(Unaudited)

Derivative Instruments (Level 2)

The fair value of our derivative instruments was 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 nonperformance for both our counterparties and our liability positions. Please see Note 2 for further information on the fair value 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.

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.

We routinely assess the recoverability of all material accounts receivable to determine their collectability. We accrue a reserve to the allowance for doubtful accounts when, based on the judgment of management, it is probable that a receivable will not be collected and the amount of the reserve may be reasonably estimated. At June 30, 2013 and December 31, 2012, the allowance for doubtful accounts was $6.5 million.

4. Capital Stock

Authorized capital stock consists of 200 million shares of common stock and 15 million shares of preferred stock. At June 30, 2013, there were no shares of preferred stock outstanding. A summary of our common stock activity for the six months ended June 30, 2013 follows:

(in thousands)	
Issued and outstanding as of December 31, 2012	86,596
Restricted shares issued under compensation plans, net of reacquired stock and cancellations	(136)
Option exercises, net of cancellations	43
Issued and outstanding as of June 30, 2013	86,503

Dividends

In May 2013, the Board of Directors declared a cash dividend of $0.14 per share. The dividend is payable on September 3, 2013 to stockholders of record on August 15, 2013. Future dividend payments will depend on our level of earnings, financial requirements, and other factors considered relevant by the Board of Directors.

5. Stock-based Compensation

Our 2011 Equity Incentive Plan (the 2011 Plan) was approved by stockholders in May 2011 and our previous plan was terminated at that time. Outstanding awards under the previous plan were not impacted. The 2011 Plan provides for grants of stock options, restricted stock, restricted stock units,

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CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

June 30, 2013

(Unaudited)

performance stock and performance stock units. A total of 5.3 million shares of common stock may be issued under the 2011 Plan.

We have recognized non-cash stock-based compensation cost as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	**2013**	**2012**	**2013**	**2012**
Restricted stock	$ 6,017	$ 6,729	$ 11,923	$ 13,550
Stock options	707	632	1,415	1,425
	6,724	7,361	13,338	14,975
Less amounts capitalized to oil and gas properties	(3,217)	(2,677)	(6,226)	(5,757)
Compensation expense	$ 3,507	$ 4,684	$ 7,112	$ 9,218

Historical amounts may not be representative of future amounts as additional awards may be granted.

Restricted Stock and Units

The following tables provide information about restricted stock awards granted during the three and six months ended June 30, 2013 and 2012.

	Three Months Ended June 30, 2013		Three Months Ended June 30, 2012	
	Number of Shares	**Weighted Average Grant-Date Fair Value**	**Number of Shares**	**Weighted Average Grant-Date Fair Value**
Performance-based stock awards		$	238,770	$ 51.95
Service-based stock awards	49,036	$ 70.92	37,598	$ 56.17
Total restricted stock awards	49,036	$ 70.92	276,368	$ 52.52

	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012

	Number of Shares	Weighted Average Grant-Date Fair Value	Number of Shares	Weighted Average Grant-Date Fair Value
Performance-based stock awards		$	238,770	$ 51.95
Service-based stock awards	49,036	$ 70.92	56,098	$ 57.59
Total restricted stock awards	49,036	$ 70.92	294,868	$ 53.02

From time to time performance-based awards are granted to eligible executives and 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. In accordance with Internal Revenue Code Section 162(m), certain of the amounts awarded may not be deductible for tax purposes. Service-based stock awards granted to other eligible employees and non-employee directors have vesting schedules of three to five years.

Compensation cost for the performance-based stock awards is based on the grant-date fair value of the award utilizing a Monte Carlo simulation model. Compensation cost for the service-based vesting restricted shares is based upon the grant-date market value of the award. Such costs are recognized ratably over the applicable vesting period.

The following table reflects the non-cash compensation cost related to our restricted stock:

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Notes to Consolidated Financial Statements (Continued)

June 30, 2013

(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	**2013**	**2012**	**2013**	**2012**
Performance-based stock awards	$ 2,568	$ 4,082	$ 5,253	$ 7,671
Service-based stock awards	3,449	2,647	6,670	5,879
	6,017	6,729	11,923	13,550
Less amounts capitalized to oil and gas properties	(2,954)	(2,439)	(5,738)	(5,169)
Restricted stock compensation expense	$ 3,063	$ 4,290	$ 6,185	$ 8,381

Unrecognized compensation cost related to unvested restricted shares at June 30, 2013 was $45.1 million, which we expect to recognize over a weighted average period of approximately 2.1 years.

The following table provides information on restricted stock and unit activity as of June 30, 2013 and changes during the year. A restricted unit held by an employee represents a right to an unrestricted share of common stock upon completion of defined vesting and holding periods. A restricted unit held by a non-employee director represents an election to defer payment of director fees until the time specified by the director in his deferred compensation agreement. The remaining outstanding restricted units shown below represent restricted units held by a non-employee director who has elected to defer payment of common stock represented by the units until termination of his service on the Board of Directors.

	Restricted Stock	Restricted Units
Outstanding as of January 1, 2013	1,838,736	33,838
Vested	(218,175)	
Converted to stock		(25,000)
Granted	49,036	
Canceled	(108,680)	
Outstanding as of June 30, 2013	1,560,917	8,838
Vested included in outstanding	N/A	8,838

Stock Options

Options granted under our 2011 and previous plans expire seven to ten years from the grant date and have service-based vesting schedules of three to five years. The plans provide 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. No options were granted during the first six months of 2013 and 2012.

Compensation cost related to stock options is based on the grant-date fair value of the award, recognized ratably over the applicable vesting period. We estimate the fair value 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. We use U.S. Treasury bond rates in effect at the grant date for our risk-free interest rates.

Non-cash compensation cost related to our stock options is reflected in the following table:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	**2013**	**2012**	**2013**	**2012**
Stock option awards	$ 707	$ 632	$ 1,415	$ 1,425
Less amounts capitalized to oil and gas properties	(263)	(238)	(488)	(588)
Stock option compensation expense	$ 444	$ 394	$ 927	$ 837

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CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

June 30, 2013

(Unaudited)

As of June 30, 2013, there was $3.3 million of unrecognized compensation cost related to non-vested stock options. We expect to recognize that cost pro rata over a weighted-average period of approximately 1.5 years.

Information about outstanding stock options is summarized below:

	Options	Weighted Average Exercise Price	Weighted Average Remaining Term	Aggregate Intrinsic Value (in thousands)
Outstanding as of January 1, 2013	687,459	$ 54.51		
Exercised	(43,156)	$ 39.53		
Canceled	(1,665)	$ 86.00		
Forfeited	(8,172)	$ 73.43		
Outstanding as of June 30, 2013	634,466	$ 55.21	5.4 Years	$ 8,587
Exercisable as of June 30, 2013	330,083	$ 50.75	5.1 Years	$ 5,738

The following table provides information regarding the options exercised:

	Six Months Ended June 30,	
(dollars in thousands)	2013	2012
Number of options exercised	43,156	58,071
Cash received from option exercises	$ 1,705	$ 2,764
Intrinsic value of options exercised	$ 1,407	$ 1,605

The following summary reflects the status of non-vested stock options as of June 30, 2013 and changes during the year:

	Options	Weighted Average Grant-Date Fair Value	Weighted Average Exercise Price
Non-vested as of January 1, 2013	317,062	$ 23.22	$ 60.58
Vested	(4,507)	$ 28.96	$ 74.34
Forfeited	(8,172)	$ 29.10	$ 73.43

Non-vested as of June 30, 2013	304,383	$	22.98	$	60.04

6. Asset Retirement Obligations

We recognize the fair value of liabilities for retirement obligations associated with tangible long-lived assets in the period in which there is a legal obligation associated with the retirement of such assets and the amount can be reasonably estimated. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. This liability includes costs related to the abandonment of wells, the removal of facilities and equipment, and site restorations. 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 included as a component of the DD&A calculations.

The following table reflects the components of the change in the carrying amount of the asset retirement obligation for the six months ended June 30, 2013:

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CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

June 30, 2013

(Unaudited)

(in thousands)		
Asset retirement obligation at January 1, 2013	$	185,138
Liabilities incurred		2,443
Liability settlements and disposals		(28,360)
Accretion expense		4,136
Revisions of estimated liabilities		(6,524)
Asset retirement obligation at June 30, 2013		156,833
Less current obligation		(48,156)
Long-term asset retirement obligation	$	108,677

7. Long-Term Debt

Debt at June 30, 2013 and December 31, 2012 consisted of the following:

(in thousands)	**June 30, 2013**	**December 31, 2012**
Bank debt	$ 142,000	$
5.875% Senior Notes due 2022	750,000	750,000
Total long-term debt	$ 892,000	$ 750,000

Bank Debt

We have a five-year senior unsecured revolving credit facility (Credit Facility), which matures July 14, 2016. Under our Credit Facility, the borrowing base is determined at the discretion of the lenders based on the value of our proved reserves. In April 2013, our borrowing base was increased from $2 billion to $2.250 billion. Our aggregate commitments remain unchanged at $1 billion. The next regular annual redetermination date is scheduled for April 15, 2014.

As of June 30, 2013, we had $142 million of bank debt outstanding at a weighted average interest rate of 2.05%. We also had letters of credit outstanding under the Credit Facility of $2.5 million, leaving an unused borrowing availability of $855.5 million.

At our option, borrowings under the Credit Facility may bear interest at either (a) LIBOR plus 1.75-2.5%, based on our leverage ratio, or (b) the higher of (i) a prime rate, (ii) the federal funds effective rate plus 0.50%, or (iii) adjusted one-month LIBOR plus 1.0% plus, in each case, an additional 0.75-1.5%, based on our leverage ratio.

The Credit Facility also has financial covenants that include the maintenance of current assets (including unused bank commitments) to current liabilities of greater than 1.0 to 1.0. We also must maintain a leverage ratio of total debt to earnings before interest expense, income taxes and noncash items (such as depreciation, depletion and amortization expense, unrealized gains and losses on commodity derivatives, ceiling test write-downs, and goodwill impairments) of not more than 3.5 to 1.0. Other covenants could limit our ability to incur additional indebtedness, pay dividends, repurchase our common stock, or sell assets. As of June 30, 2013, we were in compliance with all of the financial and nonfinancial covenants.

5.875% Notes due 2022

In April 2012, we issued $750 million of 5.875% senior notes due May 1, 2022, with interest payable semiannually in May and November. The notes were sold to the public at par. The notes are governed by an indenture containing certain covenants, events of default and other restrictive provisions.

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CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

June 30, 2013

(Unaudited)

We may redeem the notes in whole or in part, at any time on or after May 1, 2017, at redemption prices of 102.938% of the principal amount as of May 1, 2017, declining to 100% on May 1, 2020 and thereafter.

7.125% Notes due 2017

In May 2007, we issued $350 million of 7.125% senior unsecured notes at par that were scheduled to mature May 1, 2017. On March 22, 2012, we commenced a cash tender offer (Tender Offer) to purchase all of the outstanding 7.125% senior notes. The Tender Offer was completed in the second quarter of 2012. We recognized a $16.2 million loss on early extinguishment of debt during the second quarter of 2012.

8. Income Taxes

The components of our provision for income taxes are as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	**2013**	**2012**	**2013**	**2012**
Current benefit	$	$	$	$
Deferred taxes	76,616	38,137	129,792	101,080
	$ 76,616	$ 38,137	$ 129,792	$ 101,080

At December 31, 2012, we had a U.S. net tax operating loss carryforward of approximately $480.7 million, which would expire between 2031 and 2032. We believe that the carryforward will be utilized before it expires. We also had an alternative minimum tax credit carryforward of approximately $4.4 million.

At June 30, 2013, we had 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 2009-2011 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 to examination for the 2008-2011 tax years.

Our provision for income taxes differed from the U.S. statutory rate of 35% primarily due to state income taxes and nondeductible expenses. The effective income tax rate for each of the six month periods ending June 30, 2013 and June 30, 2012 was 37.2%.

9. Supplemental Disclosure of Cash Flow Information:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	**2013**	**2012**	**2013**	**2012**
Cash paid during the period for:				
Interest expense (including capitalized amounts)	$ 24,208	$ 12,598	$ 25,226	$ 14,357
Interest capitalized	$ 14,603	$ 9,288	$ 15,312	$ 10,872
Income taxes	$ 150	$ 363	$ 205	$ 374
Cash received for income taxes	$ 222	$ 48,420	$ 237	$ 49,236

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CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

June 30, 2013

(Unaudited)

10. Earnings per Share

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 June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Basic:				
Net income	$ 129,565	$ 64,302	$ 219,492	$ 170,409
Participating securities share in earnings	(2,131)	(1,293)	(3,543)	(3,589)
Net income applicable to common shareholders	$ 127,434	$ 63,009	$ 215,949	$ 166,820
Diluted:				
Net income	$ 129,565	$ 64,302	$ 219,492	$ 170,409
Participating securities share in earnings	(2,128)	(1,288)	(3,539)	(3,575)
Net income applicable to common shareholders	$ 127,437	$ 63,014	$ 215,953	$ 166,834
Shares:				
Basic shares outstanding	84,942	83,984	84,942	83,984
Incremental shares from assumed exercise of stock options	112	335	101	353
Fully diluted common stock	85,054	84,319	85,043	84,337
Excluded (1)	100	249	156	259
Earnings per share to common shareholders: (2)				
Basic	$ 1.50	$ 0.75	$ 2.54	$ 1.98
Diluted	$ 1.49	$ 0.74	$ 2.53	$ 1.97

(1) Inclusion of certain outstanding stock options would have an anti-dilutive effect.

(2) Earnings per share are based on actual figures rather than the rounded figures presented.

11. Commitments and Contingencies

Commitments

We have commitments of $173.6 million to finish drilling and completing wells in progress at June 30, 2013.

At June 30, 2013, we had firm sales contracts to deliver approximately 19.6 Bcf of natural gas over the next 10 months. If this gas is not delivered, our financial commitment would be approximately $67.8 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 proved reserves and production levels.

We have other various transportation and delivery commitments in the normal course of business, which approximate $5.6 million over the next four years.

We have various commitments for office space and equipment under operating lease arrangements totaling $123.1 million for the next five years and beyond.

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

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CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

June 30, 2013

(Unaudited)

Litigation

In the normal course of business, we have various litigation 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, we believe the resolution of them, individually or in the aggregate, would not have a material adverse effect on our financial condition or results of operations after consideration of current accruals.

Hitch Enterprises, Inc. et al. v. Cimarex Energy Co. et al.

On December 11, 2012, Cimarex entered into a preliminary resolution of the *Hitch Enterprises, Inc., et al. v. Cimarex Energy Co., et al.* (*Hitch*) litigation matter for $16.4 million. *Hitch* is a statewide royalty class action pending in the Federal District Court in Oklahoma City, Oklahoma. The settlement was reached at a mediation, which occurred after the parties began to exchange information, including damage analyses, on November 16, 2012. On July 2, 2013, the Court entered a judgment approving the parties settlement. The judgment became final and unappealable on August 2, 2013 and Cimarex will distribute the settlement proceeds pursuant to the Court s order. In the fourth quarter of 2012, we accrued $16.4 million for this matter.

H.B. Krug, et al versus H&P

In January 2009, the Tulsa County District Court issued a judgment totaling $119.6 million in the *H.B. Krug, et al. v. Helmerich & Payne, Inc.* (H&P) case. This lawsuit originally was filed in 1998 and addressed H&P s conduct pertaining to a 1989 take-or-pay settlement, along with potential drainage and other related issues. 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, including this lawsuit. In 2008, we recorded a litigation expense of $119.6 million for this lawsuit. We have accrued additional post-judgment interest and costs during the appeal of the District Court s judgment.

On August 18, 2011, the Oklahoma Court of Appeals reversed and remanded the $112.7 million disgorgement of profits award, holding the District Court erred in failing to make the required findings of fact and conclusions of law. In all other respects, the Court of Appeals affirmed the District Court s judgment, including damages of $6.845 million. On February 13, 2012, the Oklahoma Supreme Court granted Cimarex s Petition for Certiorari, which requested a review of the affirmed portion of the judgment. We are awaiting a ruling from the Oklahoma Supreme Court, and the final outcome cannot be determined at this time. If the District Court s original judgment is ultimately affirmed in its entirety, the $119.6 million, plus the then-determined amount of post-judgment interest and costs would become payable.

The following table reflects the change in the noncurrent accrued liability for this lawsuit for the six months ended June 30, 2013:

(in thousands)		
Outstanding at January 1, 2013	$	155,374
Accrued post-judgment interest and costs		4,692
Outstanding at June 30, 2013	$	160,066

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CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

June 30, 2013

(Unaudited)

12. Property Sales and Acquisitions

We sold various interests in oil and gas properties for $38.9 million during the first six months of 2013. Also during the second quarter of 2013, we sold a 50% interest in our Triple Crown gas gathering and processing system fixed assets in Culberson County, Texas for approximately $31 million. There were no significant property sales during the first half of 2012.

During the first half of 2013 and 2012, we had property acquisitions of $4.6 million and $7 million, respectively.

We intend to continue to actively evaluate acquisitions and dispositions relative to our property holdings, particularly in our core areas of operation.

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

OVERVIEW

Cimarex is an independent oil and gas exploration and production company. Our operations are entirely located in the United States, mainly in Oklahoma, Texas, New Mexico, and Kansas.

Our principal business objective is to profitably grow proved reserves and production for the long-term benefit of our shareholders through a diversified drilling portfolio. Our strategy centers on maximizing cash flow from producing properties and profitably reinvesting that cash flow in exploration and development. We occasionally consider property acquisitions and mergers to enhance our competitive position.

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. We seek geologic and geographic diversification by operating in multiple basins. In recent years, we have shifted our capital expenditures to oil and liquids-rich gas projects because of strong oil prices relative to gas prices.

Our operations are currently focused in two main areas: the Permian Basin and the Mid-Continent region. Our Permian Basin region encompasses west Texas and southeast New Mexico. The Mid-Continent region consists of Oklahoma, the Texas Panhandle, and southwest Kansas. We also have operations in the Gulf Coast area, primarily in southeast Texas.

Growth is generally funded with cash flow provided by operating activities together with bank borrowings, sale of non-strategic assets and occasional public financing. Conservative use of leverage and maintaining a strong balance sheet have long been part of our financial strategy.

Our revenue, profitability and future growth are highly dependent on the commodity prices we receive. Prices impact the amount of cash flow available for capital expenditures, our ability to raise additional capital and the fair market value of our assets. We use the full cost method of accounting for oil and gas activities. An extended decline in oil and/or gas prices could have an adverse effect on our financial position and results of operations, including the determination of full cost accounting ceiling test write-downs.

The preparation of our financial statements in conformity with generally accepted accounting principles requires us to make estimates and assumptions that impact reported results of operations and the amount of reported assets, liabilities, equity and proved reserves.

Second quarter 2013 summary of operating and financial results:

- Net income increased 101% to $129.6 million, or $1.49 per diluted share.

- Oil, gas and NGL sales for the second quarter of 2013 were $483.3 million, 41% higher than a year earlier.

- Our overall production volumes increased 16% to 686.8 MMcfe per day.

- Oil production increased 29%, NGL grew 23% and gas volumes were up 8%.

- Our average realized gas price of $4.08 per Mcf increased 69% compared to $2.42 per Mcf in the second quarter of 2012.

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- Year-to-date cash flow provided by operating activities was $569.8 million versus $574.9 million for the same period of 2012.

- Year-to-date exploration and development expenditures totaled $798.9 million.

- Total debt at June 30, 2013 was $892 million, up $142 million from year-end 2012.

Revenues

Most of our revenues are derived from the sales of oil, gas and NGL production. While revenues are a function of both production and prices, wide swings in commodity prices have had the greatest impact on our results of operations. Prices we receive are determined by prevailing market conditions. Regional and worldwide economic and geopolitical activity, weather and other variable factors influence market conditions, which often result in significant volatility in commodity prices.

The following table presents our average realized commodity prices. Realized prices do not include settlements of our commodity hedging contracts, which are financial instruments.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	**2012**	**2013**	**2012**
Oil Prices:				
Average WTI Cushing price ($/Bbl)	$ 94.22	$ 93.49	$ 94.30	$ 98.21
Average realized sales price ($/Bbl)	$ 90.72	$ 87.81	$ 88.65	$ 93.63
Gas Prices:				
Average Henry Hub price ($/Mcf)	$ 4.10	$ 2.21	$ 3.72	$ 2.47
Average realized sales price ($/Mcf)	$ 4.08	$ 2.42	$ 3.73	$ 2.67
NGL Prices:				
Average realized sales price ($/Bbl)	$ 27.76	$ 29.02	$ 28.55	$ 32.94

On an energy equivalent basis, 50% of our aggregate 2013 production was crude oil and NGL. A $1.00 per barrel change in our average realized sales price would have resulted in a $10.2 million change in our combined oil and NGL revenues. Similarly, 50% of our production was natural gas. A $0.10 per Mcf change in our average realized gas sales price would have resulted in a $6.1 million change in our gas revenues.

See **RESULTS OF OPERATIONS** below for a discussion of the impact changes in realized prices had on our 2013 revenues.

Production and other operating expenses

Costs associated with 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 2012, we owned interests in 13,127 gross wells.

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

Transportation and other operating (transportation) includes costs to prepare and move oil and gas from the wellhead to a specified sales point. In some cases we receive a payment from purchasers which

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is net of these 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. The economic life of each producing well depends upon the estimated proved reserves for that well which in turn depend upon the assumed price for future sales of production. Therefore, fluctuations in oil and gas prices will impact the level of proved reserves used in the calculation. Higher prices generally have the effect of increasing reserves, which reduces depletion expense. Conversely, lower prices generally have the effect of decreasing reserves, which increases depletion expense. The cost of replacing production also impacts our DD&A rate. In addition, changes in estimates of reserve quantities, estimates of operating and future development costs, and reclassifications of properties from unproved to proved will impact depletion expense.

We use the full cost method of accounting for our oil and gas operations. Accounting rules require us to perform a quarterly ceiling test calculation to test our oil and gas properties for possible impairment. The primary components impacting this analysis are commodity prices, reserve quantities added and produced, overall exploration and development costs, depletion expense, and tax effects. If the net capitalized cost of our oil and gas properties subject to amortization (the carrying value) exceeds the ceiling limitation, the excess would be expensed. The ceiling limitation is equal to the sum of (a) the present value discounted at 10% of estimated future net cash flows from proved reserves, (b) the cost of properties not being amortized, (c) the lower of cost or estimated fair value of unproven properties included in the costs being amortized, and (d) all related tax effects.

At June 30, 2013, the calculated value of the ceiling limitation exceeded the carrying value of our oil and gas properties subject to the test, and no impairment was necessary. However, our ceiling limitation has declined since December 31, 2012. A significant component of the decrease is related to decreases in the 12-month average trailing prices for oil and NGL, which have reduced proved reserve values. If pricing conditions decline, or if there is a negative impact on one or more of the other components of the calculation, we may incur a full cost ceiling impairment related to our oil and gas properties in future quarters.

General and administrative (G&A) 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. Our G&A expense is reported net of amounts reimbursed to us by working interest owners of the oil and gas properties we operate and net of amounts capitalized pursuant to the full cost method of accounting.

See **RESULTS OF OPERATIONS** below for a discussion of changes in production and other operating expenses.

Derivative Instruments/Hedging

We periodically enter into derivative instruments to mitigate a portion of our potential exposure to a decline in oil and/or gas 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.

For 2012, we hedged about half of our anticipated oil production. We did not hedge any of our gas or NGL production. All of the oil contracts expired during 2012 without any cash settlements. As of December 31, 2012, we did not have any hedges in place.

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In the first six months of 2013, we hedged approximately 33% of our anticipated 2013 oil production and 23% of our anticipated gas production. Through June 30, 2013 we have received net cash settlements of $1.8 million on the oil contracts and no cash settlements on our gas contracts.

The following tables summarize our outstanding contracts as of June 30, 2013:

Oil Contracts

					Weighted Average Price		
Period		**Type**	**Volume/Day**	**Index(1)**	**Floor**	**Ceiling**	**Swap**
Jul 13	Dec 13	Collars	6,000 Bbls	WTI	$ 85.00	$ 102.31	
Jul 13	Dec 13	Swaps	6,000 Bbls	WTI			$ 96.13

(1) WTI refers to West Texas Intermediate price as quoted on the New York Mercantile Exchange.

Gas Contacts

					Weighted Average Price	
Period		**Type**	**Volume/Day**	**Index(1)**	**Floor**	**Ceiling**
Jul 13	Dec 14	Collars	80,000 MMBtu	PEPL	$ 3.51	$ 4.57

(1) PEPL refers to Panhandle Eastern Pipe Line, Tex/OK Mid-Continent Index as quoted in Platt s Inside FERC.

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 hedging positions.

Since 2009, we have chosen not to apply hedge accounting treatment to our derivative contracts. As a result, 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 the discussion of our net gain/loss on hedging activities below, in **RESULTS OF OPERATIONS.** Also, see Note 2 to the Consolidated Financial Statements and Item 3 of this report for additional information regarding our derivative instruments.

RESULTS OF OPERATIONS

Three Months and Six Months Ended June 30, 2013 vs. June 30, 2012

Net income for the second quarter of 2013 was $129.6 million ($1.49 per diluted share), more than double the $64.3 million ($0.74 per diluted share) we had for the same period of 2012. For the first six months of 2013, net income was $219.5 million ($2.53 per diluted share) up 29% from net income of $170.4 million ($1.97 per diluted share) for 2012. The increases in net income for the 2013 periods were primarily a result of higher revenues from increased production volumes and higher realized commodity prices, which were partially offset by higher operating expenses in the 2013 periods. In addition, during the second quarter of 2012 we incurred a loss on early extinguishment of debt. These changes are discussed further in the analysis that follows.

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Commodity Sales (in thousands or as indicated)	2013	2012	Percent Change Between 2013/2012	Price/Volume Change Price	Volume	Total
For the Three Months Ended June 30,						
Oil sales	$ 304,466	$ 229,210	33%	$ 9,766	$ 65,490	$ 75,256
Gas sales	126,547	69,741	81%	51,550	5,256	56,806
NGL sales	52,309	44,286	18%	(2,374)	10,397	8,023
	$ 483,322	$ 343,237		$ 58,942	$ 81,143	$ 140,085
For the Six Months Ended June 30,						
Oil sales	$ 561,998	$ 496,294	13%	$ (31,573)	$ 97,277	$ 65,704
Gas sales	227,668	154,894	47%	64,666	8,108	72,774
NGL sales	109,184	103,300	6%	(16,792)	22,676	5,884
	$ 898,850	$ 754,488		$ 16,301	$ 128,061	$ 144,362

	For the Three Months Ended June 30, 2013	2012	Percent Change Between 2013/2012	For the Six Months Ended June 30, 2013	2012	Percent Change Between 2013/2012
Total oil volume thousand barrels	3,356	2,610	29%	6,340	5,301	20%
Oil volume barrels per day	36,878	28,686	29%	35,026	29,124	20%
Average oil price per barrel	$ 90.72	$ 87.81	3%	$ 88.65	$ 93.63	-5%
Total gas volume MMcf	31,054	28,877	8%	61,006	57,994	5%
Gas volume MMcf per day	341.3	317.3	8%	337.1	318.6	6%
Average gas price per Mcf	$ 4.08	$ 2.42	69%	$ 3.73	$ 2.67	40%
Total NGL volume thousand barrels	1,884	1,526	23%	3,825	3,136	22%
NGL volume barrels per day	20,705	16,770	23%	21,131	17,229	23%
Average NGL price per barrel	$ 27.76	$ 29.02	-4%	$ 28.55	$ 32.94	-13%
Total equivalent production volumes MMcfe per day	686.8	590.1	16%	674.0	596.8	13%

Commodity sales of $483.3 million for the second quarter of 2013 were 41% higher than $343.2 million for 2012. The $140.1 million increase resulted from increases in production volumes for each of the commodities and higher realized sales prices for oil and gas.

For the first six months of 2013, commodity sales totaled $898.9 million, up 19% from $754.5 million for the same period of 2012. The $144.4 million increase was attributable to increases in production volumes for each of the commodities and an increase in realized gas prices, which were partially offset by lower realized sales prices for oil and NGL in 2013.

Our second quarter 2013 aggregate average production volumes were 686.8 MMcfe per day, up 16% from 590.1 MMcfe per day for the same period in 2012. Aggregate average production volumes for the first six months of 2013 were 674.0 MMcfe per day, up 13% from 596.8 MMcfe per day compared to the 2012 period. The period over period increases in production were a result of our successful Permian Basin and Cana-Woodford shale drilling programs.

Oil production during the second quarter of 2013 averaged 36.9 thousand barrels per day, up 29% compared to 28.7 thousand barrels per day in 2012. This increase resulted in an additional $65.5 million of oil sales revenue. During the first six months of 2013, our oil production averaged 35.0 thousand barrels per day, up from 29.1 thousand barrels per day in the 2012 period. The 20% increase contributed $97.3 million of additional revenue for the first six months of 2013.

For the second quarter of 2013 gas production averaged 341.3 MMcf per day, compared to 317.3 MMcf per day in the second quarter of 2012. This 8% increase resulted in an additional $5.3 million of gas revenue for the second quarter of 2013. During the first six months of 2013 our gas production averaged 337.1 MMcf per day, up 6% from the first six months of 2012 average of

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318.6 MMcf per day. The increased gas production contributed $8.1 million for the first six months of 2013.

NGL production volumes in the second quarter of 2013 increased 23% to 20.7 thousand barrels per day compared to 16.8 thousand barrels per day in the 2012 period, which resulted in additional revenue of $10.4 million. During the first six months of 2013, NGL production averaged 21.1 thousand barrels a day, compared to 17.2 thousand barrels a day in the 2012 period. The 23% increase in production provided an additional $22.7 million of revenue in 2013.

The average realized oil price of $90.72 per barrel received in the second quarter of 2013 was 3% higher than the 2012 average price of $87.81. The increase in price contributed an additional $9.8 million in revenue for the 2013 quarter. In the first six months of 2013, our average realized oil price was $88.65 per barrel, which was 5% lower than the average price of $93.63 for the same period of 2012. The decrease in price accounted for $31.6 million of lower oil revenue during the first six months of 2013.

In the second quarter of 2013, our average realized gas price was $4.08 per Mcf, up from $2.42 per Mcf in the second quarter of 2012, or an increase of 69%, which contributed $51.6 million of additional gas revenue. The average realized gas price of $3.73 per Mcf for the first six months of 2013 was 40% higher than the 2012 average price of $2.67. The higher price received in 2013 resulted in increased gas revenues of $64.7 million compared to 2012.

The average NGL price we received in the second quarter of 2013 was $27.76 per barrel, down from $29.02 per barrel in the second quarter of 2012. The 4% decrease in the 2013 price accounted for $2.4 million of lower NGL revenue for the quarter. In the first six months of 2013, we received an average NGL price of $28.55 per barrel, which was 13% lower than the 2012 period price of $32.94 and resulted in $16.8 million of lower NGL revenue in 2013.

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

We sometimes transport, process and market third-party gas that is associated with our gas. The table below reflects our pre-tax operating margin (revenues less direct expenses) for third-party gas gathering and processing as well as the marketing margin (revenues less purchases) for marketing third-party gas.

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
Gas Gathering, Processing, Marketing and Other (in thousands):				
Gas gathering, processing and other revenues	$ 10,844	$ 10,179	$ 21,571	$ 21,886
Gas gathering and processing costs	(5,184)	(4,955)	(11,340)	(9,806)
Gas gathering, processing and other margin	$ 5,660	$ 5,224	$ 10,231	$ 12,080
Gas marketing revenues, net of related costs	$ (409)	$ (294)	$ (308)	$ (216)

Changes in net margins from gas gathering, processing, marketing and other activities result from volumetric changes and overall market conditions.

In the second quarter of 2013, our total operating costs and expenses (not including gas gathering, processing and marketing costs, or income tax expense) were $284.4 million, up 22% compared to $232.8 million in the second quarter of 2012. For the first six months of 2013, operating costs were $560.1 million, or an increase of 15% over the same period of 2012. Analyses of the year over year differences are discussed below.

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	For the Three Months Ended June 30,		Variance Between	Per Mcfe	
	2013	2012	2013/2012	2013	2012
Operating costs and expenses (in thousands):					
Depreciation, depletion and amortization	$ 147,231	$ 121,237	$ 25,994	$ 2.36	$ 2.26
Asset retirement obligation	2,884	2,441	443	$ 0.05	$ 0.05
Production	69,433	62,494	6,939	$ 1.11	$ 1.16
Transportation and other operating	22,022	13,169	8,853	$ 0.35	$ 0.25
Taxes other than income	27,807	23,483	4,324	$ 0.45	$ 0.44
General and administrative	22,836	12,634	10,202	$ 0.37	$ 0.24
Stock compensation	3,507	4,684	(1,177)	$ 0.06	$ 0.09
Gain on derivative instruments, net	(13,660)	(10,078)	(3,582)	N/A	N/A
Other operating, net	2,365	2,719	(354)	N/A	N/A
	$ 284,425	$ 232,783	$ 51,642		

	For the Six Months Ended June 30,		Variance Between	Per Mcfe	
	2013	2012	2013/2012	2013	2012
Operating costs and expenses (in thousands):					
Depreciation, depletion and amortization	$ 283,669	$ 239,499	$ 44,170	$ 2.33	$ 2.21
Asset retirement obligation	5,283	5,966	(683)	$ 0.04	$ 0.06
Production	138,819	130,119	8,700	$ 1.14	$ 1.20
Transportation and other operating	40,656	26,485	14,171	$ 0.33	$ 0.24
Taxes other than income	52,935	48,643	4,292	$ 0.43	$ 0.45
General and administrative	38,413	26,781	11,632	$ 0.32	$ 0.25
Stock compensation	7,112	9,218	(2,106)	$ 0.06	$ 0.09
Gain on derivative instruments, net	(12,057)	(5,990)	(6,067)	N/A	N/A
Other operating, net	5,297	5,059	238	N/A	N/A
	$ 560,127	$ 485,780	$ 74,347		

Our second quarter 2013 DD&A expense of $147.2 million was 21% higher than the same period of 2012 and accounted for half of the total quarter over quarter increase in costs and expenses. On a unit of production basis, second quarter 2013 DD&A increased by $0.10 to $2.36 per Mcfe. For the first six months of 2013, DD&A was $283.7 million, up 18% compared to the same period of 2012. This increase was 59% of the aggregate year over year variance. DD&A per Mcfe for the first six months of 2013 increased by $0.12 to $2.33 per Mcfe. The increases in DD&A in the 2013 periods resulted from higher production volumes in 2013 and a higher DD&A rate due to increasing the cost of reserves added at a greater rate than the increase in future production.

Production costs consist of lease operating expense and workover expense as follows:

	For the Three Months Ended June 30,		Variance Between	Per Mcfe	
(in thousands)	2013	2012	2013/2012	2013	2012
Lease operating expense	$ 53,485	$ 54,424	$ (939)	$ 0.86	$ 1.01
Workover expense	15,948	8,070	7,878	0.25	0.15
	$ 69,433	$ 62,494	$ 6,939	$ 1.11	$ 1.16

(in thousands)	For the Six Months Ended June 30, 2013	2012	Variance Between 2013/2012	Per Mcfe 2013	2012
Lease operating expense	$ 106,631	$ 110,976	$ (4,345)	$ 0.87	$ 1.02
Workover expense	32,188	19,143	13,045	0.27	0.18
	$ 138,819	$ 130,119	$ 8,700	$ 1.14	$ 1.20

Our second quarter 2013 lease operating expense (LOE) of $53.5 million declined 2% from $54.4 million for the same period of 2012. LOE for the first six months of 2013 decreased by 4% to $106.6 compared to $ 111.0 in 2012. In the 2013 periods, increases in costs due to new well activity were

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more than offset by decreases associated with property divestitures and reductions in salt-water disposal costs.

On a unit of production basis, LOE in the second quarter of 2013 declined to $0.86 per Mcfe, down 15% compared to the second quarter of 2012. Similarly, LOE during the first six months of 2013 was $0.87 per Mcfe, down 15% compared to $1.02 for the same period of 2012. The lower rates in 2013 were primarily a function of increased production volumes.

Our workover expenses for the second quarter and first six months of 2013 were considerably higher than costs incurred for the same periods of 2012. Workover costs will fluctuate based on the amount of maintenance and remedial activity planned and/or required during the period.

Transportation costs increased 67% to $22.0 million in the second quarter of 2013, compared to $13.2 million in the second quarter of 2012. For the first six months of 2013, transportation costs were $40.7 million, up 54% from $26.5 million for the same period of 2012. The increases in the 2013 periods are mostly due to increased production from our Permian Basin and Cana-Woodford shale drilling programs. We have also experienced increased transportation rates in these areas. Transportation costs will fluctuate regionally, based on increases or decreases in sales volumes, compression charges and fluctuation in the price of the fuel cost component.

Taxes other than income are assessed by state and local taxing authorities on production, revenues or the value of properties. Revenue based severance taxes, which are our largest component of these taxes, will fluctuate with increases and decreases in commodity prices.

General and administrative costs were as follows:

(in thousands)	For the Three Months Ended June 30, 2013	2012	Variance Between 2013/2012	For the Six Months Ended June 30, 2013	2012	Variance Between 2013/2012
G&A capitalized to oil & gas properties	$ 19,015	$ 15,617	$ 3,398	$ 37,693	$ 33,951	$ 3,742
G&A expense	22,836	12,634	10,202	38,413	26,781	11,632
	$ 41,851	$ 28,251	$ 13,600	$ 76,106	$ 60,732	$ 15,374
G&A expense per Mcfe	$ 0.37	$ 0.24		$ 0.32	$ 0.25	

In 2013, our overall G&A expense increased by 48% for the second quarter of the year and by 25% for the first six months of the year compared to the same periods of 2012. G&A expense for both of the 2013 periods includes $7 million for university endowments established in honor of F.H. Merelli and $1 million of contributions for tornado relief in Oklahoma. The remainder of the increases are attributable to higher employee compensation and benefits.

Stock compensation expense consists of non-cash charges resulting from the issuance of restricted stock and stock option awards, net of amounts capitalized. We have recognized non-cash stock-based compensation cost as follows:

(in thousands)	For the Three Months Ended June 30, 2013	2012	Variance Between 2013/2012	For the Six Months Ended June 30, 2013	2012	Variance Between 2013/2012
Performance-based restricted stock awards	$ 2,568	$ 4,082	$ (1,514)	$ 5,253	$ 7,671	$ (2,418)
Service-based restricted stock awards	3,449	2,647	802	6,670	5,879	791
Restricted stock	6,017	6,729	(712)	11,923	13,550	(1,627)
Stock option awards	707	632	75	1,415	1,425	(10)
Total stock compensation	6,724	7,361	(637)	13,338	14,975	(1,637)
Less amounts capitalized to oil & gas properties	(3,217)	(2,677)	(540)	(6,226)	(5,757)	(469)
Stock compensation	$ 3,507	$ 4,684	$ (1,177)	$ 7,112	$ 9,218	$ (2,106)

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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 5 to the Consolidated Financial Statements for further discussion regarding our stock-based compensation.

Net gain or loss on derivative instruments includes both realized gains and losses on settlements of derivative contracts and unrealized gains and losses stemming from changes in the fair value of outstanding derivative instruments. Realized and unrealized gains or losses are a function of fluctuations in the underlying commodity prices. We have not elected hedge accounting treatment for derivative contracts. Therefore, we recognize all realized settlements and unrealized changes in fair value in operating costs and expenses. See Note 2 to the Consolidated Financial Statements for further details regarding our derivative instruments.

The following table reflects the net realized and unrealized (gains) or losses on our derivative instruments:

(in thousands)	For the Three Months Ended June 30, 2013	2012	Variance Between 2013/2012	For the Six Months Ended June 30, 2013	2012	Variance Between 2013/2012
Realized (gain) on settlement of derivative instruments	$ (1,039)	$	$ (1,039)	$ (1,765)	$	$ (1,765)
Unrealized (gain) from changes to the fair value of the derivative instruments	(12,621)	(10,078)	(2,543)	(10,292)	(5,990)	(4,302)
(Gain) on derivative instruments, net	$ (13,660)	$ (10,078)	$ (3,582)	$ (12,057)	$ (5,990)	$ (6,067)

Other operating, net consists of costs related to various legal matters, most of which pertain to litigation, contract settlements and title and royalty issues. See Note 11 to the Consolidated Financial Statements for further information regarding litigation matters.

Other (income) and expense

(in thousands)	For the Three Months Ended June 30, 2013	2012	Variance Between 2013/2012	For the Six Months Ended June 30, 2013	2012	Variance Between 2013/2012
Interest expense	$ 14,112	$ 13,679	$ 433	$ 27,318	$ 22,347	$ 4,971
Capitalized interest	(7,387)	(9,119)	1,732	(16,582)	(16,923)	341
Loss on early extinguishment of debt		16,214	(16,214)		16,214	(16,214)
Other, net	(8,758)	(7,829)	(929)	(11,374)	(12,555)	1,181
	$ (2,033)	$ 12,945	$ (14,978)	$ (638)	$ 9,083	$ (9,721)

Interest expense includes interest on debt and amortization of financing costs. Our second quarter 2013 interest expense increased slightly compared to that of the second quarter of 2012. For the first six months of 2013 our interest expense was 22% higher than the same period of 2012. The increase was due to having an additional $400 million of outstanding senior notes for all of the six months of 2013 compared to only the second quarter of 2012. See **Long-term Debt** below for further information regarding our senior notes.

We capitalize interest on non-producing leasehold costs, the costs of drilling and completing wells and constructing qualified assets. Period over period costs will fluctuate based on the amount of costs on which interest is calculated.

In connection with the retirement of our 7.125% senior notes during the second quarter of 2012, we recognized a $16.2 million loss on early extinguishment of debt. See **Long-term Debt** below for additional information regarding our senior notes.

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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, income and expense associated with other non-operating activities, miscellaneous asset sales and interest income. The 12% increase in other, net (income) for the second quarter of 2013 versus 2012 is due to additional net gains on the sales of certain assets. The 9% decrease for the first six months of 2013 compared to the first six months of 2012 is mainly due to net decreased income from non-operating activity.

Income Tax Expense

The components of our provision for income taxes are as follows:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
(in thousands)	**2013**	**2012**	**2013**	**2012**
Current benefit	$	$	$	$
Deferred taxes	76,616	38,137	129,792	101,080
	$ 76,616	$ 38,137	$ 129,792	$ 101,080
Combined Federal and state effective income tax rate	37.2%	37.2%	37.2%	37.2%

Our combined Federal and state effective tax rates differ from the statutory rate of 35% primarily due to state income taxes and non-deductible expenses. See Note 8 to the Consolidated Financial Statements of this report for additional information regarding our income taxes.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Our liquidity is highly dependent on the commodity prices we receive for the oil, gas and NGL we produce. Because commodity prices are market driven and are very volatile, we cannot predict future commodity prices. Prices received for production heavily influence our revenue, cash flow, profitability, access to capital and future rate of growth.

In the first half of 2013, our average realized price for natural gas was $3.73 per Mcf, an increase of 40% over the realized price for the same period of 2012. During the first six months of 2013 our average realized price per barrel of oil was $88.65, a decrease of 5% compared to 2012. Our realized price for NGLs during 2013 has averaged $28.55 per barrel, which was 13% lower than the average realized price in 2012. Future prices for these commodities will likely continue to fluctuate due to supply and demand factors, seasonality and other geopolitical and economic factors.

We deal with volatility in commodity prices by maintaining flexibility in our capital investment program. In addition, we periodically hedge a portion of our oil and/or gas production to mitigate our potential exposure to price declines and the corresponding negative impact on cash flow available for investment. Based on current commodity prices, our 2013 exploration and development (E&D) capital expenditures are expected to be approximately $1.5 billion. Nearly all the capital is directed towards oil and liquids-rich gas opportunities in the Permian Basin and Cana-Woodford shale play. Actual amounts invested will depend on our calculated rates of return.

Our E&D expenditures have generally been funded by cash flow provided by operating activities (operating cash flow). During 2012, E&D expenditures of $1.6 billion were largely funded by operating cash flow and the sale of $306 million of non-strategic assets.

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We expect our 2013 E&D capital expenditures to be funded primarily by operating cash flow, long-term debt and occasional asset sales. The timing of capital expenditures and the receipt of cash flows do not necessarily match, which has caused and will cause us to borrow and repay funds under our credit facility throughout the year. We have entered into financial hedges for a portion of our 2013 and 2014 production to protect our operating cash flow for reinvestment.

We consider acquisition opportunities that play to our strengths and have drilling upside, however, the timing and size of acquisitions is unpredictable.

At June 30, 2013, our total debt outstanding was $892 million, which was comprised of $142 million of bank debt and $750 million of our 5.875% senior notes. Debt to total capitalization at June 30, 2013 was 20%. The reconciliation of debt to total capitalization, which is a non-GAAP measure, is: long-term debt of $892 million divided by long-term debt of $892 million plus stockholders equity of $3.679 billion. Management believes that this non-GAAP measure is useful information and it is a common statistic referred to by the investment community.

We believe that our operating cash flow and other capital resources will be adequate to meet our needs for our planned capital expenditures, working capital, debt servicing and dividend payments for 2013 and beyond.

Analysis of Cash Flow Changes

Cash flow provided by operating activities of $569.8 million for the first six months of 2013 decreased by $5.1 million (1%), compared to $574.9 million for the same period of 2012. Increased revenues in 2013 from higher production volumes and an increase in our realized gas price were offset by higher operating expenses and an increase in the amount of outstanding accounts receivable.

Cash flow used in investing activities for the first six months of 2013 was $756.0 million, down $27.0 million (3%) from $783.0 million for 2012. In 2013, we had oil and gas and other capital expenditures of $801.6 million, which were partially offset by $45.6 million of asset sales. For the same period of 2012, expenditures for oil and gas and other capital costs were $784.7 million and proceeds from asset sales were $1.7 million.

During the first half of 2013, net cash flow provided by financing activities was $121.3 million. In the same period of 2012, net cash flow provided by financing activities was $302.6 million. The $181.4 million decrease from 2012 to 2013 relates primarily to long-term debt activity in 2012. In 2012, we issued $750 million of 5.875% senior notes and used proceeds from that offering to retire our outstanding 7.125% senior notes and bank debt, resulting in a net cash provision of $331.4 million. During 2013, our long-term debt activity provided $142.0 million from net borrowings under our credit facility.

Reconciliation of Adjusted Cash Flow from Operations

(in thousands)	For the Six Months Ended June 30, 2013	2012
Net cash provided by operating activities	$ 569,786	$ 574,932
Change in operating assets and liabilities	68,944	(31,466)
Adjusted cash flow from operations	$ 638,730	$ 543,466

Management believes that the non-GAAP measure of adjusted cash flow from operations is useful information for investors. It is accepted by the investment community as a means of measuring a

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company s ability to fund its capital program without reflecting fluctuations caused by changes in current assets and liabilities (which are included in the GAAP measure of cash flow from operating activities). 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 our oil and gas acquisition, exploration and development activities, and property sales:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
(in thousands)	**2013**	**2012**	**2013**	**2012**
Acquisitions:				
Proved	$ 923	$ 240	$ 923	$ 291
Unproved	3,415	4,791	3,665	6,713
	4,338	5,031	4,588	7,004
Exploration and development:				
Land and seismic	36,719	21,175	68,029	58,387
Exploration and development	353,594	365,101	730,891	730,460
	390,313	386,276	798,920	788,847
Sales proceeds:				
Proved	(37,061)	(14)	(37,879)	(185)
Unproved	(960)	(146)	(1,041)	(1,088)
	(38,021)	(160)	(38,920)	(1,273)
	$ 356,630	$ 391,147	$ 764,588	$ 794,578

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 of $798.9 million during the first six months of 2013 increased $10.1 million (1%) compared to $788.8 million during the 2012 period. Approximately 65% of our 2013 expenditures were for Permian Basin projects, located in the Delaware Basin of Texas and southeast New Mexico, mainly targeting the Bone-Spring and Wolfcamp formations. Most of the remainder of our expenditures were in our Cana-Woodford shale play.

The following table reflects wells drilled by region:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2013	**2012**	**2013**	**2012**
Gross wells				
Permian Basin	55	55	90	94

Mid-Continent	35	31	87	64
Gulf Coast / Other	2	1	2	2
	92	87	179	160
Net wells				
Permian Basin	32	37	59	64
Mid-Continent	15	14	35	26
Gulf Coast / Other	1		1	1
	48	51	95	91
% Gross wells completed as producers	97%	97%	98%	96%

As of June 30, 2013, we had 29 net wells awaiting completion: 20 Mid-Continent, eight Permian Basin, and one Gulf Coast. We also had 15 operated rigs running; 12 in the Permian Basin, two in the Mid-Continent, and one in the Gulf Coast.

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In June 2013, we entered into a joint development agreement with Chevron U.S.A. Inc. for development of our combined Delaware Basin acreage located in Culberson County, Texas. In connection with the development agreement Chevron will contribute acreage and also acquired a 50% interest in the Cimarex-built Triple Crown gas gathering and processing system and wells drilled on the acreage in 2013 for an approximately $63 million payment from Chevron.

In addition to the Chevron agreement, during the first six months of 2013 we had other property acquisitions of $3.7 million and sold other various interests in oil and gas properties for $14.4 million. For the same period of 2012, we had property acquisitions of $7 million and no significant property sales.

We regularly review our capital expenditures and will adjust our investments based on changes in commodity prices, service costs and drilling success. We have a diversified portfolio that gives us the flexibility to adjust our capital expenditures based upon market conditions.

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. 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 are subject to a number of variables including success in finding and producing new reserves, 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, bank borrowings, and access to capital markets. We routinely use our credit facility to finance our working capital needs.

During the first six months of 2013 our total assets increased by $491 million to $6.8 billion, up from $6.3 billion at December 31, 2012. The increase resulted mostly from the $493 million increase in our net oil and gas properties.

At June 30, 2013, our total liabilities were $3.1 billion, up $287 million from $2.8 billion at December 31, 2012. The increase resulted primarily from a net increase in long-term debt of $142 million and an increase in noncurrent deferred income taxes of $139 million.

Our stockholders equity totaled $3.7 billion at June 30, 2013, up $204 million from $3.5 billion at December 31, 2012. The increase resulted primarily from net income of $219 million less dividends declared of $24 million.

Dividends

A quarterly cash dividend has been paid to shareholders since the first quarter of 2006. On February 26, 2013, the Board of Directors increased the cash dividend on our common stock from $0.12 to $0.14 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.

Working Capital Analysis

Our working capital balance fluctuates primarily as a result of our exploration and development activities, realized commodity prices, our operating activities and changes in inventory balances.

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Working capital is also impacted by our current tax provision, property sales, accrued G&A and changes in the fair value of our outstanding derivative instruments.

Our working capital decreased $9.6 million from a deficit of $175.7 million at year-end 2012 to a deficit of $185.3 million at June 30, 2013.

Working capital decreased primarily because of the following:

- Cash and cash equivalents decreased by $65.0 million
- Accrued liabilities related to our E&D expenditures increased by $20.2 million.
- Oil and gas well equipment and supplies decreased by $14.1 million.
- Net accounts payable and accrued liabilities related to non-E&D expenditures increased by $5.7 million.

These working capital decreases were offset by the following:

- An increase in operations related accounts receivable of $78.9 million.
- An increase in deferred income tax assets of $9.6 million.
- An increase in the aggregate fair value of our derivative instruments of $7.9 million.

Accounts receivable are a major component of our working capital and include a diverse group of companies comprised of major energy companies, pipeline companies, local distribution companies and other end-users. The collection of receivables during the periods presented has been timely. Historically, losses associated with uncollectible receivables have not been significant.

Long-term Debt

Debt at June 30, 2013 and December 31, 2012 consisted of the following:

(in thousands)	June 30, 2013	December 31, 2012
Bank debt	$ 142,000	$
5.875% Senior Notes due 2022	750,000	750,000
Total long-term debt	$ 892,000	$ 750,000

Bank Debt

We have a five-year senior unsecured revolving credit facility (Credit Facility), which matures July 14, 2016. Under our Credit Facility, the borrowing base is determined at the discretion of the lenders based on the value of our proved reserves. In April 2013, our borrowing base was increased from $2 billion to $2.250 billion. Our aggregate commitments remain unchanged at $1 billion. The next regular annual redetermination date is scheduled for April 15, 2014.

As of June 30, 2013, we had $142 million of bank debt outstanding at a weighted average interest rate of 2.05%. We also had letters of credit outstanding of $2.5 million, leaving an unused borrowing availability of $855.5 million. During the first six months of 2013, we had average daily bank debt outstanding of $118.7 million, compared to $87.2 million for the same period in 2012. Our highest amount of bank borrowings outstanding during the first half of 2013 was $261 million, occurring in mid-June. During the first half of 2012, the highest amount of outstanding bank borrowings was $275 million, occurring in mid-March.

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At our option, borrowings under the Credit Facility may bear interest at either (a) LIBOR plus 1.75-2.5%, based on our leverage ratio, or (b) the higher of (i) a prime rate, (ii) the federal funds effective rate plus 0.50%, or (iii) adjusted one-month LIBOR plus 1.0% plus, in each case, an additional 0.75-1.5%, based on our leverage ratio.

The Credit Facility has a number of financial and non-financial covenants, all of which we were in compliance at June 30, 2013. See Note 7 to the Consolidated Financial Statements for further information.

5.875% Notes due 2022

In April 2012, we issued $750 million of 5.875% senior notes due May 1, 2022, with interest payable semiannually in May and November. The notes were sold to the public at par. The notes are governed by an indenture containing certain covenants, events of default and other restrictive provisions. We may redeem the notes in whole or in part, at any time on or after May 1, 2017, at redemption prices of 102.938% of the principal amount as of May 1, 2017, declining to 100% on May 1, 2020 and thereafter.

7.125% Notes due 2017

In May 2007, we issued $350 million of 7.125% senior unsecured notes at par which were scheduled to mature May 1, 2017. On March 22, 2012, we commenced a cash tender offer (Tender Offer) to purchase all of the outstanding 7.125% senior notes. The Tender Offer was completed in the second quarter of 2012.

Off-Balance Sheet Arrangements

We may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. As of June 30, 2013, our material off-balance sheet arrangements included operating lease agreements, which are customary in the oil and gas industry and are included in the table below.

Contractual Obligations and Material Commitments

At June 30, 2013, we had contractual obligations and material commitments as follows:

	Payments Due by Period			
Contractual obligations:	**1 Year or**	**2-3**		**More than**

(in thousands)	Total	Less	Years	4-5 Years	5 Years
Long-term debt(1)	$ 892,000	$	$	$ 142,000	$ 750,000
Fixed-Rate interest payments(1)	396,563	44,063	88,125	88,125	176,250
Operating leases	123,101	8,477	19,356	19,157	76,111
Drilling commitments(2)	173,537	173,537			
Asset retirement obligation (3)	156,833	48,156	(3)	(3)	(3)
Other liabilities(4)	68,122	16,892	32,039	2,350	16,841
Firm Transportation	989	640	349		

(1) These amounts do not include interest on the $142 million of bank debt outstanding at June 30, 2013. See Item 3: Interest Rate Risk for more information regarding fixed and variable rate debt.

(2) Our drilling commitments consist of obligations to finish drilling and completing wells in progress at June 30, 2013.

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

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

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At June 30, 2013, we had firm sales contracts to deliver approximately 19.6 Bcf of natural gas over the next 10 months. In total, our financial exposure would be approximately $67.8 million should we not deliver this gas. Our exposure will fluctuate with price volatility and actual volumes delivered. However, we believe Cimarex has no financial exposure from these contracts based on our current proved reserves and production levels.

In the normal course of business we have various other delivery commitments which are not material individually or in the aggregate. 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 estimated net cash generated from operations and amounts available under our existing Credit Facility will be adequate to meet future liquidity needs.

2013 Outlook

Our 2013 E&D capital investment is presently expected to be approximately $1.5 billion. Nearly all of this capital will be used for drilling oil and liquids-rich gas wells in the Permian Basin and Cana-Woodford shale play. We have a large inventory of drilling opportunities, limited lease expirations and few service commitments. We regularly review our capital expenditures and may adjust our investments based on changes in commodity prices, service costs and drilling success. Actual amounts invested will depend on our calculated rates of return which are significantly influenced by commodity prices.

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 2013 is projected to be in the range of 680 700 MMcfe per day, or 9 12% growth over 2012. Revenues from production will be dependent not only on the level of oil and gas actually produced, but also the prices that will be realized. During all of 2012, realized prices averaged $89.25 per barrel of oil, $2.88 per Mcf of gas and $30.66 per barrel of NGL. For the first six months of 2013 our realized prices averaged $88.65 per barrel of oil, $3.73 per Mcf of gas, and $28.55 per barrel of NGL. Commodity prices can be volatile and it is likely that 2013 realized prices will vary from those received in 2012.

Certain expenses for 2013 on a per Mcfe basis are currently estimated as follows:

Production expense	$1.10	-	$1.22
Transportation and other operating	0.30	-	0.35
DD&A and asset retirement obligation	2.40	-	2.55
General and administrative	0.25	-	0.30
Production taxes (% of oil and gas revenue)	6.0%	-	6.5%

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.

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Recent Accounting Developments

No significant accounting standards applicable to Cimarex have been issued during the quarter ended June 30, 2013.

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 enter into financial derivative contracts to hedge a portion of our price risk associated with our future oil and gas production.

The following tables detail the financial derivative contracts we have in place as of as of June 30, 2013.

	Oil Contracts						
				Weighted Average Price			Fair Value
Period	Type	Volume/Day	Index(1)	Floor	Ceiling	Swap	(in thousands)
Jul 13 Dec 13	Collars	6,000 Bbls	WTI	$ 85.00	$ 102.31		$ (18)
Jul 13 Dec 13	Swaps	6,000 Bbls	WTI			$ 96.13	$ 1,110

(1) WTI refers to West Texas Intermediate price as quoted on the New York Mercantile Exchange.

	Gas Contracts					
				Weighted Average Price		Fair Value
Period	Type	Volume/Day	Index(1)	Floor	Ceiling	(in thousands)

Jul 13	Dec 14	Collars	80,000 MMBtu	PEPL	$ 3.51	$ 4.57	$	9,200

(1) PEPL refers to Panhandle Eastern Pipe Line, Tex/OK Mid-Continent Index as quoted in Platt s Inside FERC.

While these contracts limit the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. For the 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 2013 of $2.2 million. For the 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 2013 of $1.5 million.

Counterparty credit risk did not have a significant effect on our cash flow calculations and commodity derivative valuations. This is primarily because we have mitigated our exposure to any single counterparty by contracting with numerous counterparties and because our derivative contracts are held with investment grade counterparties that are a part of our credit facility. See Note 2 to the

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Consolidated Financial Statements of this report for additional information regarding our derivative instruments.

Interest Rate Risk

At June 30, 2013, our debt was comprised of the following:

(in thousands)	Fixed Rate Debt	Variable Rate Debt
Bank debt	$	$ 142,000
5.875% Notes due 2022	750,000	
Total long-term debt	$ 750,000	$ 142,000

As of June 30, 2013, the amounts outstanding under our five-year senior unsecured revolving credit facility bears interest at either (a) LIBOR plus 1.75-2.5%, based on our leverage ratio, or (b) the higher of (i) a prime rate, (ii) the federal funds effective rate plus 0.50%, or (iii) adjusted one-month LIBOR plus 1.0% plus, in each case, an additional 0.75-1.5%, based on our leverage ratio. Our senior unsecured notes bear interest at a fixed rate of 5.875% and will mature on May 1, 2022.

We consider our interest rate exposure to be minimal because approximately 84% of our long-term debt obligations were at fixed rates. An increase of 100 basis points in the interest rate of our variable rate debt would increase our annual interest expense by $1.4 million. This sensitivity analysis for interest rate risk excludes accounts receivable, accounts payable and accrued liabilities because of the short-term maturity of such instruments. See Note 3 and Note 7 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 June 30, 2013 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 June 30, 2013, 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 June 30, 2013, 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 Thomas E. Jorden, 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 Thomas E. Jorden, 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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SIGNATURE

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

August 7, 2013

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)