CIMAREX ENERGY CO
Form 10-Q
August 06, 2014
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

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

For the Quarterly Period ended June 30, 2014

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 No

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 No

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

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

The number of shares of Cimarex Energy Co. common stock outstanding as of June 30, 2014 was 87,021,935.

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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

MMBbl/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 working interest percentage

Net Production—Gross production multiplied by net revenue interest

NGL or NGLs—Natural gas liquids

Tcf—Trillion cubic feet

Tcfe—Trillion cubic feet equivalent

Energy equivalent is determined using the ratio of one barrel of crude oil, condensate or NGL to 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 or areas 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, 2014	December 31, 2013
	(Unaudited)	
	(in thousands, except share data)	
Assets		
Current assets:		
Cash and cash equivalents	$ 128,555	$ 4,531
Receivables, net	449,456	367,754
Oil and gas well equipment and supplies	85,278	66,772
Deferred income taxes	13,725	16,854
Derivative instruments	—	4,268
Prepaid expenses	7,906	7,867
Other current assets	1,432	1,093
Total current assets	686,352	469,139
Oil and gas properties at cost, using the full cost method of accounting:		
Proved properties	13,801,249	12,863,961
Unproved properties and properties under development, not being amortized	886,361	585,361
	14,687,610	13,449,322
Less — accumulated depreciation, depletion and amortization	(7,838,007)	(7,483,685)
Net oil and gas properties	6,849,603	5,965,637
Fixed assets, net	182,521	146,918
Goodwill	620,232	620,232
Other assets, net	60,299	51,209
	$ 8,399,007	$ 7,253,135
Liabilities and Stockholders’ Equity		
Current liabilities:		
Accounts payable	$ 126,259	$ 116,110
Accrued liabilities	468,952	412,495
Derivative instruments	8,506	389
Revenue payable	197,473	154,173
Total current liabilities	801,190	683,167
Long-term debt	1,500,000	924,000
Deferred income taxes	1,626,206	1,459,841

Other liabilities	184,980	163,919
Total liabilities	4,112,376	3,230,927
Commitments and contingencies		
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, 87,021,935 and 87,152,197 shares issued, respectively	870	872
Paid-in capital	1,975,159	1,970,113
Retained earnings	2,309,429	2,050,034
Accumulated other comprehensive income	1,173	1,189
	4,286,631	4,022,208
	$ 8,399,007	$ 7,253,135

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,	
	2014	2013	2014	2013
	(in thousands, except per share data)			
Revenues:				
Gas sales	$ 172,503	$ 126,547	$ 342,600	$ 227,668
Oil sales	354,882	304,466	679,953	561,998
NGL sales	95,470	52,309	185,427	109,184
Gas gathering and other	14,284	10,844	26,748	21,571
Gas marketing, net	(470)	(409)	1,157	(308)
	636,669	493,757	1,235,885	920,113
Costs and expenses:				
Depreciation, depletion and amortization	194,989	147,231	368,920	283,669
Asset retirement obligation	3,650	2,884	6,868	5,283
Production	86,085	69,433	161,226	138,819
Transportation, processing, and other operating	46,478	22,022	90,726	40,656
Gas gathering and other	10,041	5,184	18,825	11,340
Taxes other than income	32,323	27,807	65,944	52,935
General and administrative	16,571	22,836	37,283	38,413
Stock compensation	3,548	3,507	7,272	7,112
(Gain) loss on derivative instruments, net	2,454	(13,660)	18,189	(12,057)
Other operating, net	112	2,365	215	5,297
	396,251	289,609	775,468	571,467
Operating income	240,418	204,148	460,417	348,646
Other (income) and expense:				
Interest expense	16,724	14,112	30,766	27,318
Capitalized interest	(8,575)	(7,387)	(15,865)	(16,582)
Other, net	(4,129)	(8,758)	(11,084)	(11,374)
Income before income tax	236,398	206,181	456,600	349,284
Income tax expense	87,758	76,616	169,503	129,792
Net income	$ 148,640	$ 129,565	$ 287,097	$ 219,492
Earnings per share to common stockholders:				
Basic				
Distributed	$ 0.16	$ 0.14	$ 0.32	$ 0.28
Undistributed	1.55	1.36	2.98	2.26
	$ 1.71	$ 1.50	$ 3.30	$ 2.54
Diluted				
Distributed	$ 0.16	$ 0.14	$ 0.32	$ 0.28
Undistributed	1.54	1.35	2.97	2.25

	$ 1.70	$ 1.49	$ 3.29	$ 2.53
Comprehensive income:				
Net income	$ 148,640	$ 129,565	$ 287,097	$ 219,492
Other comprehensive income:				
Change in fair value of investments, net of tax	(56)	19	(16)	99
Total comprehensive income	$ 148,584	$ 129,584	$ 287,081	$ 219,591

See accompanying notes to consolidated financial statements.

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CIMAREX ENERGY CO.

Condensed Consolidated Statements of Cash Flows

(Unaudited)

	For the Six Months Ended June 30,	
	2014	2013
	(in thousands)	
Cash flows from operating activities:		
Net income	$ 287,097	$ 219,492
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	368,920	283,669
Asset retirement obligation	6,868	5,283
Deferred income taxes	169,503	129,792
Stock compensation	7,272	7,112
(Gain) loss on derivative instruments	18,189	(12,057)
Settlements on derivative instruments	(5,804)	1,765
Changes in non-current assets and liabilities	(2,436)	5,790
Other, net	2,395	(2,116)
Changes in operating assets and liabilities:		
Receivables, net	(81,702)	(55,060)
Other current assets	(19,182)	14,840
Accounts payable and accrued liabilities	18,649	(28,724)
Net cash provided by operating activities	769,769	569,786
Cash flows from investing activities:		
Oil and gas expenditures	(1,138,539)	(776,138)
Sales of oil and gas assets	1,123	14,407
Sales of other assets	251	31,157
Other expenditures	(51,401)	(25,475)
Net cash used by investing activities	(1,188,566)	(756,049)
Cash flows from financing activities:		
Net bank debt borrowings	(174,000)	142,000
Proceeds from other long-term debt	750,000	—
Financing costs incurred	(11,218)	—
Dividends paid	(26,022)	(22,448)
Issuance of common stock and other	4,061	1,705
Net cash provided by financing activities	542,821	121,257
Net change in cash and cash equivalents	124,024	(65,006)
Cash and cash equivalents at beginning of period	4,531	69,538
Cash and cash equivalents at end of period	$ 128,555	$ 4,532

See accompanying notes to consolidated financial statements.

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Notes to Consolidated Financial Statements

June 30, 2014

(Unaudited)

1. Basis of Presentation

The accompanying unaudited financial statements have been prepared by Cimarex Energy Co. ("Cimarex", "we", or "us") 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 2013 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 and as of the dates shown. 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, 2014, 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, a decline of 9% in the value of the ceiling limitation would have resulted in an impairment. 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.

Oil, Gas and NGL sales

Oil, gas and NGL sales are based on the sales method by which revenue is recognized on actual volumes sold to purchasers. There is a ready market for our products and sales occur soon after production. The determination to record and separately disclose NGL volumes is based on the location at which both title contractually transfers from Cimarex to a buyer and the associated volumes can be physically quantified. For those NGL volumes that we have recorded and disclosed separately, contractual title of the volumes has passed from Cimarex to a buyer at a point where the NGL volumes have been physically separated from the production stream. Should title contractually transfer before NGL volumes can be physically separated and quantified (typically at the wellhead), we do not report separate NGL volumes and the value of the NGLs are included in the reported value of the disclosed gas volumes.

Under certain contracts, when NGLs are extracted from the gas stream, processors receive as compensation a portion of the sales value from both the residue gas and the NGLs as a processing fee and remit the contractual proceeds to us. Prior to 2014, revenue was recognized net of these processing fees for residue gas and NGLs sold under these contracts as allowed under EITF 00-10 Accounting for Shipping and Handling Fees and Costs. Beginning in 2014, we believe that with the increase in NGL production and the impact of recent changes to these contracts, these processing costs will become more significant in the future. Accordingly, we have changed our policy to record these processing costs with operating costs as allowed under EITF 00-10. As a result, beginning in 2014, our realized prices for sales under these contracts reflect the value of 100% of the residue gas and NGLs yielded by processing, rather than the value associated with the contractual proceeds we received. The related processing fees now are included in “transportation, processing and other” operating costs. The effect of this change

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CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

June 30, 2014

(Unaudited)

in the current quarter and six months ended was that total revenue was $12.2 million and $24.1 million, respectively, higher with an offsetting increase in total transportation, processing and other costs. There was no impact on operating income. Financial statements for periods prior to 2014 have not been reclassified to reflect this change in accounting treatment as it was impracticable to do so.

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:

(in thousands)	June 30, 2014	December 31, 2013
Receivables, net of allowance		

Trade	$ 95,201	$ 83,070
Oil and gas sales	333,614	265,050
Gas gathering, processing, and marketing	20,452	19,102
Other	189	532
Receivables, net	$ 449,456	$ 367,754
Accounts payable		
Trade	$ 84,567	$ 80,918
Gas gathering, processing, and marketing	41,692	35,192
Accounts payable	$ 126,259	$ 116,110
Accrued liabilities		
Exploration and development	$ 251,663	$ 173,298
Taxes other than income	27,134	27,509
Other	190,155	211,688
Accrued liabilities	$ 468,952	$ 412,495

Recently Issued Accounting Standards

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2014-09, Revenue from Contracts with Customers (Topic 606). The new revenue standard provides a five-step analysis of transactions to determine when and how revenue is recognized. The core principle of the guidance is that a company should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The guidance in this update supersedes the revenue recognition requirements in Topic 605, Revenue

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Notes to Consolidated Financial Statements (Continued)

June 30, 2014

(Unaudited)

Recognition, and most industry-specific guidance throughout the Industry Topics of the Codification. We must comply with this ASU beginning in fiscal year 2017 and early adoption is not permitted. Entities can choose to apply the standard using either the full retrospective approach or a modified retrospective approach. We are currently evaluating the impact of the provisions of Topic 606 and the effects of adoption cannot be determined at this time.

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 hedging contracts as of June 30, 2014:

Oil Contracts

				Weighted Average Price		Fair Value
Period	Type	Volume/Day	Index (1)	Floor	Ceiling	(in thousands)
Jul 14 – Dec 14	Collars	12,000 Bbls	WTI	$ 85.00	$ 103.47	$ (5,974)

(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 14 – Dec 14	Collars	80,000 MMBtu	PEPL	$ 3.51	$ 4.57	$ (969)
Jul 14 – Dec 14	Collars	60,000 MMBtu	Perm EP	$ 3.62	$ 4.50	$ (1,563)

(1) PEPL refers to Panhandle Eastern Pipe Line, Tex/OK Mid-Continent Index as quoted in Platt’s Inside FERC. Perm EP refers to El Paso Natural Gas Company, Permian Basin 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 if the index price is above the contracted ceiling price. No amounts are paid or received if the index price is between the floor and ceiling prices.

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.

We have elected not to account for our derivatives as cash flow hedges. Therefore, we recognize settlements and changes in the assets or liabilities relating to our open derivative contracts in earnings. Cash settlements of our contracts are included in cash flows from operating activities in our statements of cash flows.

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CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

June 30, 2014

(Unaudited)

The following table summarizes the net 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)	2014	2013	2014	2013
Gain (loss) on derivative instruments, net:				
Natural gas contracts	$ 2,062	$ 9,199	$ (9,820)	$ 9,199
Oil contracts	(4,516)	4,461	(8,369)	2,858
Gain (loss) on derivative instruments, net	$ (2,454)	$ 13,660	$ (18,189)	$ 12,057
Gains (losses) from settlement of derivative instruments:				
Natural gas contracts	$ (37)	$ —	$ (4,824)	$—
Oil contracts	(980)	1,039	(980)	1,765
Settlement gains (losses)	$ (1,017)	$ 1,039	$ (5,804)	$ 1,765

Our derivative contracts are carried at their fair value on our balance sheet using Level 2 inputs. We estimate the fair value with 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 non-performance 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.

Our derivative instruments are subject to enforceable master netting arrangements, which allow us to offset recognized asset and liability fair value amounts on contracts with the same counterparty. Our policy is to not offset asset and liability positions in our accompanying balance sheets.

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CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

June 30, 2014

(Unaudited)

The following table presents the amounts and classifications of our derivative assets and liabilities as of June 30, 2014 and December 31, 2013, as well as the potential effect of netting arrangements on contracts with the same counterparty.

June 30, 2014:			
(in thousands)	Balance Sheet Location	Asset	Liability
Oil contracts	Current liabilities — Derivative instruments	$ —	$ 5,974
Natural gas contracts	Current liabilities — Derivative instruments	—	2,532
Total gross amounts presented in accompanying balance sheet		—	8,506
Less: gross amounts not offset in the accompanying balance sheet		—	—
Net amount:		$ —	$ 8,506

December 31, 2013:			
(in thousands)	Balance Sheet Location	Asset	Liability
Oil contracts	Current assets — Derivative instruments	$ 1,805	$ —
Natural gas contracts	Current assets — Derivative instruments	2,463	—
Oil contracts	Current liabilities — Derivative instruments	—	389
Total gross amounts presented in accompanying balance sheet		4,268	389
Less: gross amounts not offset in the accompanying balance sheet		(389)	(389)
Net amount:		$ 3,879	$ —

We are exposed to financial risks associated with our derivative contracts from non-performance by our counterparties. 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. Because some of the member banks have discontinued hedging activities, in the future we may hedge with counterparties outside our bank group to obtain competitive terms and to spread counterparty risk.

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 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.

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Notes to Consolidated Financial Statements (Continued)

June 30, 2014

(Unaudited)

The following tables provide fair value measurement information for certain assets and liabilities as of June 30, 2014 and December 31, 2013:

June 30, 2014: (in thousands)	Carrying Amount	Fair Value
Financial Assets (Liabilities):		
5.875% Notes due 2022	$ (750,000)	$ (832,500)
4.375% Notes due 2024	$ (750,000)	$ (765,938)
Derivative instruments — liabilities	$ (8,506)	$ (8,506)

December 31, 2013: (in thousands)	Carrying Amount	Fair Value
Financial Assets (Liabilities):		
Bank debt	$ (174,000)	$ (174,000)
5.875% Notes due 2022	$ (750,000)	$ (799,988)
Derivative instruments — assets	$ 4,268	$ 4,268
Derivative instruments — liabilities	$ (389)	$ (389)

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 December 31, 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 4.375% and 5.875% fixed rate notes was based on their last traded value before period end.

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 non-performance 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, 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 it is probable that a receivable will

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CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

June 30, 2014

(Unaudited)

not be collected and the amount of the reserve may be reasonably estimated. At June 30, 2014 and December 31, 2013, the allowance for doubtful accounts was $3.2 million and $6.0 million, respectively.

4.Capital Stock

Authorized capital stock consists of 200 million shares of common stock and 15 million shares of preferred stock. At June 30, 2014, there were no shares of preferred stock outstanding. A summary of our common stock activity for the six months ended June 30, 2014 follows:

(in thousands)	
Issued and outstanding as of December 31, 2013	87,152
Issuance of restricted stock awards	14
Common stock reacquired and retired	(117)
Restricted stock forfeited and retired	(101)
Option exercises, net of cancellations	74
Issued and outstanding as of June 30, 2014	87,022

Dividends

In May 2014, the Board of Directors declared a cash dividend of $0.16 per share. The dividend is payable on September 2, 2014 to stockholders of record on August 15, 2014. 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

In May 2014, our 2014 Equity Incentive Plan (the 2014 Plan) was approved by stockholders and our previous plan was terminated at that time. Outstanding awards under the previous plan were not impacted. The primary purposes of the 2014 Plan are to increase the number of shares available in connection with awards, provide flexibility in the types of available awards and design of awards, modify certain individual award limits and revise the performance measures for qualified performance-based awards. The 2014 Plan provides for grants of stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance units, dividend equivalents and other stock-based awards. A total of 6.6 million shares of common stock may be issued under the 2014 Plan, including shares available from the previous plan.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2014	2013	2014	2013
Restricted stock	$ 5,979	$ 6,017	$ 12,430	$ 11,923
Stock options	782	707	1,555	1,415
	6,761	6,724	13,985	13,338
Less amounts capitalized to oil and gas properties	(3,213)	(3,217)	(6,713)	(6,226)
Compensation expense	$ 3,548	$ 3,507	$ 7,272	$ 7,112

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

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

June 30, 2014

(Unaudited)

Restricted Stock and Units

During the six months ended June 30, 2014 and 2013, we granted 13,652 and 49,036 service-based stock awards at a weighted average grant-date fair value of $127.30 and $70.92, respectively.

From time to time performance 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 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:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2014	2013	2014	2013
Performance stock awards	$ 2,867	$ 2,568	$ 5,814	$ 5,253
Service-based stock awards	3,112	3,449	6,616	6,670

	5,979	6,017	12,430	11,923
Less amounts capitalized to oil and gas properties	(2,891)	(2,954)	(6,071)	(5,738)
Restricted stock compensation expense	$ 3,088	$ 3,063	$ 6,359	$ 6,185

Unrecognized compensation cost related to unvested restricted shares at June 30, 2014 was $55.6 million, which we expect to recognize over a weighted average period of approximately 2.3 years.

The following table provides information on restricted stock and unit activity as of June 30, 2014 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.

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CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

June 30, 2014

(Unaudited)

	Restricted Stock	Restricted Units
Outstanding as of January 1, 2014	1,863,834	8,838
Vested	(287,047)	N/A
Converted to stock	N/A	—
Granted	13,652	—
Canceled	(100,568)	—
Outstanding as of June 30, 2014	1,489,871	8,838
Vested included in outstanding	N/A	8,838

Stock Options

Options that have been granted under the 2014 plan and previous plans expire seven to ten years from the grant date and have service-based vesting schedules of three to five years. The exercise price for an option under the 2014 plan is the closing price of our common stock as reported by the New York Stock Exchange on the date of grant. The previous plans provided 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 2014 and 2013.

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)	2014	2013	2014	2013
Stock option awards	$ 782	$ 707	$ 1,555	$ 1,415
Less amounts capitalized to oil and gas properties	(322)	(263)	(642)	(488)
Stock option compensation expense	$ 460	$ 444	$ 913	$ 927

As of June 30, 2014, there was $2.7 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 1.2 years.

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Notes to Consolidated Financial Statements (Continued)

June 30, 2014

(Unaudited)

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, 2014	531,016	$ 59.78		
Exercised	(73,935)	$ 54.92		
Forfeited	(7,670)	$ 63.42		
Outstanding as of June 30, 2014	449,411	$ 60.52	4.9 Years	$ 36,989
Exercisable as of June 30, 2014	114,067	$ 50.82	4.0 Years	$ 10,495

The following table provides information regarding the options exercised:

	Six months ended June 30,	
(dollars in thousands)	2014	2013
Number of options exercised	73,935	43,156
Cash received from option exercises	$ 4,061	$ 1,705
Intrinsic value of options exercised	$ 4,632	$ 1,407

The following table provides information on non-vested stock option activity as of June 30, 2014 and changes during the year:

	Options	Weighted Average Grant-Date Fair Value	Weighted Average Exercise Price
Non-vested as of January 1, 2014	343,014	$ 21.64	$ 63.81
Forfeited	(7,670)	$ 21.94	$ 63.42
Non-vested as of June 30, 2014	335,344	$ 21.63	$ 63.82

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 plugging and 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.

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June 30, 2014

(Unaudited)

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, 2014:

(in thousands)	
Asset retirement obligation at January 1, 2014	$ 154,026
Liabilities incurred	7,905
Liability settlements and disposals	(7,302)
Accretion expense	3,756
Revisions of estimated liabilities	8,210
Asset retirement obligation at June 30, 2014	166,595
Less current obligation	(15,176)
Long-term asset retirement obligation	$ 151,419

7.Long-Term Debt

Debt at June 30, 2014 and December 31, 2013 consisted of the following:

(in thousands)	June 30, 2014	December 31, 2013
Bank debt	$ —	$ 174,000
5.875% Senior Notes due 2022	750,000	750,000
4.375% Senior Notes due 2024	750,000	—
Total long-term debt	$ 1,500,000	$ 924,000

Bank Debt

In May 2014, we amended our senior unsecured revolving credit facility (Credit Facility) to extend the maturity date two years to July 14, 2018 and lowered the margins applicable to loans and commitments. The amendment also raised our borrowing base from $2.25 billion to $2.5 billion until the next regular annual redetermination date scheduled for April 15, 2015. The borrowing base under the Credit Facility is determined at the discretion of the lenders based on the value of our proved reserves. Our aggregate commitments remained unchanged at $1 billion.

As of June 30, 2014, we had letters of credit outstanding under the Credit Facility of $2.5 million, leaving an unused borrowing availability of $997.5 million.

At our option, borrowings under the Credit Facility, as amended in May 2014, may bear interest at either (a) LIBOR plus 1.5-2.25%, 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 0.5-1.25%, 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. We also must maintain a leverage ratio of total debt to earnings before interest expense, income taxes and non-cash 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. Other covenants could limit our ability to incur additional indebtedness, pay

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

June 30, 2014

(Unaudited)

dividends, repurchase our common stock, or sell assets. As of June 30, 2014, we were in compliance with all of the financial and non-financial 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. 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.

4.375% Notes due 2024

In June 2014, we issued $750 million of 4.375% senior notes due June 1, 2024, with interest payable semiannually in June and December. 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. At any time prior to March 1, 2024, we may redeem all or a part of the notes at a defined make-whole redemption price calculated at the time of redemption. At any time on or after March 1, 2024, we may redeem all or part of the notes at a price equal to 100% of the principal amount.

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)	2014	2013	2014	2013
Current benefit	$ —	$ —	$ —	$ —
Deferred taxes	87,758	76,616	169,503	129,792
	$ 87,758	$ 76,616	$ 169,503	$ 129,792

At December 31, 2013, we had a U.S. net tax operating loss carryforward of approximately $605.4 million, which would expire in tax years 2031 through 2033. We believe that the carryforward will be utilized before it expires. The amount of U.S. net tax operating loss carryforward that will be recorded to equity when utilized to reduce taxes payable is $56.4 million. We also had an alternative minimum tax credit carryforward of approximately $4.1 million.

At June 30, 2014, we had no unrecognized tax benefits that would impact our effective tax rate and we have made no provisions for interest or penalties related to uncertain tax positions. The tax years 2009-2012 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 2009-2012 tax years.

Our provision for income taxes differed from the U.S. statutory rate of 35% primarily due to state income taxes and non-deductible expenses. The effective income tax rates for the three and six months ended June 30, 2014 and June 30, 2013 were 37.1% and 37.2%, respectively.

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Notes to Consolidated Financial Statements (Continued)

June 30, 2014

(Unaudited)

9.Supplemental Disclosure of Cash Flow Information

(in thousands)	Three months ended June 30, 2014	Three months ended June 30, 2013	Six months ended June 30, 2014	Six months ended June 30, 2013
Cash paid during the period for:				
Interest expense (including capitalized amounts)	$ 24,195	$ 24,208	$ 26,290	$ 25,226
Interest capitalized	$ 12,469	$ 14,603	$ 13,557	$ 15,312
Income taxes	$ 353	$ 150	$ 354	$ 205
Cash received for income taxes	$ 133	$ 222	$ 342	$ 237

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, 2014	Three months ended June 30, 2013	Six months ended June 30, 2014	Six months ended June 30, 2013

Basic:				
Net income	$ 148,640	$ 129,565	$ 287,097	$ 219,492
Participating securities' share in earnings	(2,320)	(2,131)	(4,464)	(3,543)
Net income applicable to common stockholders	$ 146,320	$ 127,434	$ 282,633	$ 215,949
Diluted:				
Net income	$ 148,640	$ 129,565	$ 287,097	$ 219,492
Participating securities' share in earnings	(2,316)	(2,128)	(4,457)	(3,539)
Net income applicable to common stockholders	$ 146,324	$ 127,437	$ 282,640	$ 215,953
Shares:				
Basic shares outstanding	85,532	84,942	85,532	84,942
Incremental shares from assumed exercise of stock options	157	112	147	101
Fully diluted common stock	85,689	85,054	85,679	85,043
Excluded (1)	—	100	1	156
Earnings per share to common stockholders (2):				
Basic	$ 1.71	$ 1.50	$ 3.30	$ 2.54
Diluted	$ 1.70	$ 1.49	$ 3.29	$ 2.53

(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.

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Notes to Consolidated Financial Statements (Continued)

June 30, 2014

(Unaudited)

11.Commitments and Contingencies

Commitments

We have commitments of $192.0 million to finish drilling and completing wells in progress at June 30, 2014. We also have various commitments for drilling rigs. The total minimum expenditure commitments under these agreements are $53.6 million.

In New Mexico and Texas, we are constructing gathering facilities and pipelines. At June 30, 2014, we had commitments of $6.6 million relating to these construction projects.

At June 30, 2014, we had firm sales contracts to deliver approximately 34.7 Bcf of natural gas over the next 12 months. If this gas is not delivered, our financial commitment would be approximately $146.4 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 from which we can fulfill these obligations.

We have other various transportation and delivery commitments in the normal course of business, which approximate $2 million over the next four years.

We have various commitments for office space and equipment under operating lease arrangements totaling $131.7 million for the next five years and beyond.

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

Litigation

In the ordinary 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.

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 of H&P, Cimarex assumed the assets and liabilities of H&P's exploration and production business, including this lawsuit. For 2008, we recorded a litigation expense of $119.6 million plus additional post-judgment interest and costs after the trial court entered a final judgment for these amounts.

On December 10, 2013, the Oklahoma Supreme Court reversed the trial court's original judgment of $119.6 million and affirmed an alternative jury verdict for $3.65 million. In light of the Oklahoma Supreme Court's ruling, on December 31, 2013, we reduced previously recognized litigation expense and the associated long-term liability by $142.8 million.

On March 14, 2014, after denying the Plaintiffs' Petition for Rehearing, the Oklahoma Supreme Court remanded the matter back to the trial court. On March 31, 2014, the trial court entered a final judgment for damages, post-judgment interest and a payment in lieu of bond. The following day Cimarex paid the Plaintiffs $15.8 million in satisfaction of these awards, which now are final and not appealable.

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Notes to Consolidated Financial Statements (Continued)

June 30, 2014

(Unaudited)

On June 24, 2014, the trial court ruled that the Plaintiffs were not entitled to prejudgment interest but were entitled to an award of attorney's fees and costs. At a subsequent hearing the trial court will determine the amount of the attorney's fees and costs owed to Plaintiffs. The outcome of these remaining issues cannot be determined at this time and will be subject to an appeal. Our current assessments and estimates likely will change in the future as a result of subsequent legal proceedings both in the trial court and on appeal.

12.Property Acquisitions and Sales

The following acquisitions and sales were made in the ordinary course of business.

During the first half of 2014, we had property acquisitions of $259 million, primarily in the Cana-Woodford shale play in Western Oklahoma. In order to acquire and sell oil and gas properties in a tax efficient manner, we periodically enter into like-kind exchange tax deferred transactions. Certain of these property acquisitions were structured to qualify as the first step of a reverse like-kind exchange. We utilized an exchange accommodation titleholder, a type of variable interest entity, for which we are the primary beneficiary. Accordingly, we have consolidated the oil and gas assets and reserves attributable to these properties. During the same period of 2013, we had property acquisitions of $4.6 million.

There were no significant property sales during the first half of 2014. Subsequent to June 30, 2014, we sold interests in Kansas non-core oil and gas properties for net proceeds of approximately $136 million. In the first half of 2013, we sold interests in non-core oil and gas properties for $38.9 million. During the second quarter of 2013, we also sold a 50% interest in our Culberson County, Texas Triple Crown gas gathering and processing system for approximately $31 million.

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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 and New Mexico.

Our principal business objective is to profitably grow proved reserves and production for the long-term benefit of our stockholders 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 portfolio of exploration and development projects targeting both oil and gas. 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. 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 gas production to mitigate our potential exposure to price declines and the corresponding negative impact on cash flow available for investment.

Our operations are currently focused in two main areas: the Permian Basin and the Mid-Continent region. The Permian Basin region encompasses west Texas and southeast New Mexico. The Mid-Continent region consists of Oklahoma and the Texas Panhandle.

Growth is generally funded with cash flow provided by operating activities together with bank borrowings, sales 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. We have a long track record of profitable growth.

Second quarter 2014 summary of operating and financial results:

- Average daily production was 838.7 MMcfe/d.

- Oil production grew 13%, gas production was up by 20% and NGL volumes increased by 43% compared to the same period of 2013.

- Oil, gas and NGL sales for the second quarter of 2014 were $622.9 million, 29% higher than a year earlier.

- Cash flow provided by operating activities during the first six months of 2014 increased 35% to $769.8 million compared to $569.8 million for the same period of 2013.

- Net income was $148.6 million ($1.70 per diluted share) versus $129.6 million ($1.49 per diluted share) a year ago.

- Exploration and development expenditures for the quarter totaled $497.6 million.

- Total debt at June 30, 2014 was $1.5 billion.

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Revenues

Almost all of our revenues are derived from the sales of oil, gas and NGL production. In addition to increases and decreases in our production volumes, our revenue, profitability and future growth are highly dependent on the commodity prices we receive. Prices we receive are determined by prevailing market conditions. Regional and worldwide economic and geopolitical activity, weather and other factors influence market conditions, which often result in significant volatility in commodity prices.

Our average realized prices do not include settlements of our commodity hedging contracts. Prior to 2014, our average realized prices for gas and NGLs were net of certain processing fees. Beginning in 2014, these fees are no longer included in these prices. The resulting positive impact on realized gas prices for the three and six months ended June 30, 2014 was $0.07 per Mcf and $0.08 per Mcf, respectively. The positive impact on realized prices for NGLs was $3.47 per Bbl and $3.72 per Bbl for the three and six months ended June 30, 2014, respectively. (See Note 1, Oil, Gas and NGL Sales, to the Consolidated Financial Statements in this report for additional information.)

The following table presents our average realized commodity prices:

	Three months ended June 30,		Six months ended June 30,	
	2014	2013	2014	2013
Oil Prices:				
Average WTI Cushing price ($/Bbl)	$ 102.99	$ 94.22	$ 100.84	$ 94.30
Average realized sales price ($/Bbl)	$ 93.39	$ 90.72	$ 92.82	$ 88.65
Gas Prices:				
Average Henry Hub price ($/Mcf)	$ 4.68	$ 4.10	$ 4.81	$ 3.72
Average realized sales price ($/Mcf)	$ 4.62	$ 4.08	$ 4.94	$ 3.73
NGL Prices:				
Average realized sales price ($/Bbl)	$ 35.35	$ 27.76	$ 37.43	$ 28.55

On an energy equivalent basis, 52% of our aggregate 2014 production was crude oil and NGLs. A $1.00 per barrel change in our average realized sales price would have resulted in a $12.3 million change in our combined oil and NGL revenues. Similarly, 48% of our production was natural gas. A $0.10 per Mcf change in our average realized gas sales price would have resulted in a $6.9 million change in our gas revenues.

See RESULTS OF OPERATIONS below for a discussion of the impact changes in production and realized prices had on our 2014 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 2013, we owned interests in 12,079 gross wells.

Production expense generally consists of costs for labor, equipment, maintenance, salt water disposal, compression, power, treating and miscellaneous other costs. Production expense also includes well workover activity necessary to maintain production from existing wells.

Transportation, processing and other operating costs include processing costs and expenditures to prepare and transport production from the wellhead to a specified sales point. These costs vary by region and will fluctuate with increases or decreases in production volumes and changes in fuel and compression costs.

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

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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 properties. 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, 2014, 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, a decline of 9% in the value of the ceiling limitation would have resulted in an impairment. 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. An impairment charge would have no effect on liquidity or our capital resources, but it could adversely affect our results of operations in the period incurred.

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.

During the first three and six months of 2014, we had hedges covering approximately 29% of our oil production and 34% of our gas production. Through June 30, 2014, we had net cash settlement losses of $4.8 million on our gas contracts and $1.0 million on our oil contracts.

The following tables summarize our outstanding hedging contracts as of June 30, 2014:

Oil Contracts

				Weighted Average Price	
Period	Type	Volume/Day	Index (1)	Floor	Ceiling
Jul 14 – Dec 14	Collars	12,000 Bbls	WTI	$ 85.00	$ 103.47

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

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Gas Contracts

				Weighted Average Price	
Period	Type	Volume/Day	Index (1)	Floor	Ceiling
Jul 14 – Dec 14	Collars	80,000 MMBtu	PEPL	$ 3.51	$ 4.57
Jul 14 – Dec 14	Collars	60,000 MMBtu	Perm EP	$ 3.62	$ 4.50

(1) PEPL refers to Panhandle Eastern Pipe Line, Tex/OK Mid-Continent Index as quoted in Platt's Inside FERC. Perm EP refers to El Paso Natural Gas Company, Permian Basin 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 in this report for additional information regarding our derivative instruments.

RESULTS OF OPERATIONS

Three Months and Six Months Ended June 30, 2014 vs. June 30, 2013

Net income for the second quarter of 2014 was $148.6 million ($1.70 per diluted share), up 15% from $129.6 million ($1.49 per diluted share) for the same period of 2013. For the first six months of 2014, net income of $287.1 million ($3.29 per diluted share) was 31% greater than net income of $219.5 million ($2.53 per diluted share) for the same period of 2013. The increases in net income for the 2014 periods resulted from increased production volumes and higher realized commodity prices, which were partially offset by higher operating expenses and income taxes compared to the 2013 periods. These changes are discussed further in the analysis that follows.

Production Revenue			Percent Change Between 2014 / 2013	Price/Volume Change		
(in thousands or as indicated)	2014	2013		Price	Volume	Total
For the Three Months Ended June 30,						
Oil sales	$ 354,882	$ 304,466	17 %	$ 10,146	$ 40,270	$ 50,416
Gas sales	172,503	126,547	36 %	20,152	25,804	45,956
NGL sales	95,470	52,309	83 %	20,501	22,660	43,161
	$ 622,855	$ 483,322	29 %	$ 50,799	$ 88,734	$ 139,533
For the Six Months Ended June 30,						
Oil sales	$ 679,953	$ 561,998	21 %	$ 30,545	$ 87,410	$ 117,955
Gas sales	342,600	227,668	50 %	83,842	31,090	114,932
NGL sales	185,427	109,184	70 %	43,983	32,260	76,243
	$ 1,207,980	$ 898,850	34 %	$ 158,370	$ 150,760	$ 309,130

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	For the Three Months Ended June 30,		Percent Change Between 2014 / 2013	For the Six Months Ended June 30,		Percent Change Between 2014 / 2013
	2014	2013		2014	2013	
Total oil volume — thousand barrels	3,800	3,356	13 %	7,325	6,340	16 %
Oil volume — barrels per day	41,759	36,878	13 %	40,471	35,026	16 %
Average oil price — per barrel	$ 93.39	$ 90.72	3 %	$ 92.82	$ 88.65	5 %
Total gas volume — MMcf	37,318	31,054	20 %	69,291	61,006	14 %
Gas volume — MMcf per day	410.1	341.3	20 %	382.8	337.1	14 %
Average gas price — per Mcf	$ 4.62	$ 4.08	13 %	$ 4.94	$ 3.73	32 %
Total NGL volume — thousand barrels	2,701	1,884	43 %	4,953	3,825	29 %
NGL volume — barrels per day	29,680	20,705	43 %	27,367	21,131	30 %
Average NGL price — per barrel	$ 35.35	$ 27.76	27 %	$ 37.43	$ 28.55	31 %
Total equivalent production volumes — MMcfe per day	838.7	686.8	22 %	789.9	674.0	17 %

Revenue from our second quarter 2014 production totaled $622.9 million compared to $483.3 million for the same quarter of last year. For the first six months of 2014, revenue from our production totaled $1.208 billion, up 34% from $898.9 million for the same period of 2013. Increased production volumes together with higher realized commodity prices resulted in the year-over-year improvements.

Our second-quarter 2014 aggregate production volumes averaged 838.7 MMcfe per day, up 22% from 686.8 MMcfe per day for the second quarter of 2013. Average production volumes for the first six months of 2014 were 789.9 MMcfe per day, up 17% from 674.0 MMcfe per day for the comparable 2013 period. The growth in production resulted from our successful drilling programs in the Permian Basin and Mid-Continent region.

Oil production for the second quarter of 2014 averaged 41,759 Bbl/d, up 13% from 36,878 Bbl/d in 2013. The growth in 2014 volume provided an additional $40.3 million of oil revenue. During the first six months of 2014, our oil production averaged 40,471 barrels per day, up from 35,026 barrels per day in the 2013 period. The 16% increase contributed $87.4 million of additional revenue for the first six months of 2014.

Second-quarter 2014 gas production averaged 410.1 MMcf/d, compared to 341.3 MMcf/d in 2013. The 20% year-over-year increase resulted in additional revenue of $25.8 million. In the first six months of 2014 our gas production averaged 382.8 MMcf/d, up 14% from the first six months of 2013 average of 337.1 MMcf/d. The increase in gas production accounted for additional revenue of $31.1 million for the first six months of 2014.

During the second quarter of 2014, our average NGL production volumes of 29,680 Bbl/d were 43% greater than 20,705 Bbl/d for 2013 as a result of more Permian Basin gas being fully processed. The increase contributed $22.7 million of additional revenue and accounted for approximately half of the overall 83% increase in quarter-over-quarter NGL revenue. Our NGL production for the first six months of 2014 averaged 27,367 Bbl/d, compared to 21,131 barrels per day in the 2013 period. The 30% increase in 2014 production provided an additional $32.3 million of revenue and accounted for 42% of the aggregate year-over-year increase in NGL revenue.

Realized oil prices during the second quarter of 2014 averaged $93.39 per barrel, an increase of 3% from $90.72 per barrel received in the same period of 2013. The higher price in 2014 contributed $10.1 million of additional oil revenue. In the first six months of 2014, our average realized oil price was $92.82 per barrel, which was 5% higher than the average price of $88.65 for the same period of 2013. The increase in price accounted for $30.5 million of higher oil revenue for the first six months of 2014.

Our average realized gas price for the second quarter of 2014 improved by 13% to $4.62 per Mcf, compared to $4.08 per Mcf in 2013. The 2014 increase in price provided additional revenue of $20.2 million. Our average realized gas price of $4.94 per Mcf for the first six months of 2014 was 32% higher than an average realized

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price of $3.73 for the same period of 2013 as revenues of $83.8 million. As noted above under Revenues, beginning in 2014, our average realized price for gas no longer includes deductions for certain processing fees, thus positively impacting revenue by $2.8 million ($0.07 per Mcf) for the second quarter of 2014 and by $5.6 million ($0.08 per Mcf) for the first six months of 2014.

In the three months ended June 30, 2014, our realized price for NGLs averaged $35.35 per barrel, which was 27% higher than the average realized price of $27.76 per barrel in the 2013 period. The higher price in the second quarter of 2014 accounted for additional revenues of $20.5 million. In the first six months of 2014, we received an average NGL price of $37.43 per barrel, which was 31% higher than the 2013 realized average price of $28.55 which resulted in $44.0 million of additional NGL revenue. As noted above under Revenues, beginning in 2014, our realized price for NGLs no longer includes deductions for certain processing fees, thus positively impacting revenue by $9.4 million ($3.47 per barrel) for the second quarter of 2014 and by $18.4 million ($3.72 per barrel) for the first six months of 2014.

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,	
	2014	2013	2014	2013
Gas Gathering and Marketing (in thousands):				
Gas gathering and other revenues	$ 14,284	$ 10,844	$ 26,748	$ 21,571
Gas gathering and other costs	(10,041)	(5,184)	(18,825)	(11,340)
Gas gathering and other margin	$ 4,243	$ 5,660	$ 7,923	$ 10,231
Gas marketing revenues, net of related costs	$ (470)	$ (409)	$ 1,157	$ (308)

Fluctuations in net margins from gas gathering and gas marketing activities are a function of increases and decreases in volumes, prices and costs associated with third-party gas.

In the second quarter of 2014, our total operating costs and expenses (not including gas gathering and marketing costs, or income tax expense) were $386.2 million, up 36% compared to $284.4 million in the same period of 2013. For the first six months of 2014, operating costs were $756.6 million, or an increase of 35% over the same period of

2013. Analyses of the year-over-year differences are discussed below.

	For the Three Months Ended June 30,		Variance Between 2014 /	Per Mcfe	
	2014	2013	2013	2014	2013
Operating costs and expenses (in thousands, except per Mcfe):					
Depreciation, depletion and amortization	$ 194,989	$ 147,231	$ 47,758	$ 2.55	$ 2.36
Asset retirement obligation	3,650	2,884	766	$ 0.05	$ 0.05
Production	86,085	69,433	16,652	$ 1.13	$ 1.11
Transportation, processing and other operating	46,478	22,022	24,456	$ 0.61	$ 0.35
Taxes other than income	32,323	27,807	4,516	$ 0.42	$ 0.45
General and administrative	16,571	22,836	(6,265)	$ 0.22	$ 0.37
Stock compensation	3,548	3,507	41	$ 0.05	$ 0.06
(Gain) loss on derivative instruments, net	2,454	(13,660)	16,114	N/A	N/A
Other operating, net	112	2,365	(2,253)	N/A	N/A
	$ 386,210	$ 284,425	$ 101,785		

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	For the Six Months Ended June 30,		Variance Between 2014 /	Per Mcfe	
	2014	2013	2013	2014	2013
Operating costs and expenses (in thousands, except per Mcfe):					
Depreciation, depletion and amortization	$ 368,920	$ 283,669	$ 85,251	$ 2.58	$ 2.33
Asset retirement obligation	6,868	5,283	1,585	$ 0.05	$ 0.04
Production	161,226	138,819	22,407	$ 1.13	$ 1.14
Transportation, processing and other operating	90,726	40,656	50,070	$ 0.64	$ 0.33
Taxes other than income	65,944	52,935	13,009	$ 0.46	$ 0.43
General and administrative	37,283	38,413	(1,130)	$ 0.26	$ 0.32
Stock compensation	7,272	7,112	160	$ 0.05	$ 0.06
(Gain) loss on derivative instruments, net	18,189	(12,057)	30,246	N/A	N/A
Other operating, net	215	5,297	(5,082)	N/A	N/A
	$ 756,643	$ 560,127	$ 196,516		

Our second quarter 2014 DD&A expense of $195.0 million was 32% higher than the same period of 2013 and accounted for 47% of the total quarter-over-quarter increase in costs and expenses. On a unit of production basis, second-quarter 2014 DD&A increased by 8% to $2.55 per Mcfe. In the first six months of 2014 DD&A was $368.9 million, up 30% compared to the same period of 2013 and was 43% of the aggregate year-over-year variance. DD&A per Mcfe for the first six months of 2014 increased by $0.25 (11%) to $2.58 per Mcfe.

Increases in our 2014 year-over-year production volumes were responsible for about 63% of our second quarter increase in DD&A expense and approximately 52% of the increase for the first six months of 2014. The remainder of the period-over-period increases in our DD&A expense results from increases in our DD&A rates. Our DD&A rates have increased primarily because the cost of adding new proved reserves has exceeded the net remaining book basis of proved reserves added in prior years. We expect our annual average DD&A rate to increase modestly during 2014 compared to 2013.

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

	For the Three Months Ended June 30,		Variance Between 2014 /	Per Mcfe	
(in thousands, except per Mcfe)	2014	2013	2013	2014	2013
Lease operating expense	$ 72,168	$ 53,485	$ 18,683	$ 0.95	$ 0.86

Workover expense	13,917	15,948	(2,031)	$ 0.18	$ 0.25
	$ 86,085	$ 69,433	$ 16,652	$ 1.13	$ 1.11

	For the Six Months Ended June 30,		Variance Between 2014 /	Per Mcfe	
(in thousands, except per Mcfe)	2014	2013	2013	2014	2013
Lease operating expense	$ 133,246	$ 106,631	$ 26,615	$ 0.93	$ 0.87
Workover expense	27,980	32,188	(4,208)	$ 0.20	$ 0.27
	$ 161,226	$ 138,819	$ 22,407	$ 1.13	$ 1.14

Second quarter 2014 lease operating expense (LOE) of $72.2 million increased 35% compared to 2013. LOE for the first six months of 2014 increased by 25% to $133.2 million compared to the same period of 2013. As we continue to put new wells on production, we have experienced higher costs for compression, rental equipment, chemical treating and fuel. We have also had year-over-year increased costs for site maintenance, road repairs and labor.

Workover expense for both the second quarter and first six months of 2014 was 13% lower than comparable periods of 2013. Generally, these costs will fluctuate based on the amount of maintenance and remedial

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activity planned and/or required during the period. The decreases in 2014 were primarily a result of less workover expense incurred in the Permian Basin.

Transportation, processing and other operating costs for the second quarter and first six months of 2014 increased significantly compared to the same periods of 2013. In general, these costs will vary by product type and region. Increases or decreases in sales and processing volumes, compression charges and fuel costs also have an impact. During the 2014 periods, about half of the increases in period-over-period costs resulted from higher contractual fees, increases in fuel costs and greater production volumes. The remaining increases relate to the inclusion of certain processing fees which in previous periods were treated as a reduction in realized sales prices for residue gas and NGLs. See Note 1, Oil, Gas and NGL Sales, to the Consolidated Financial Statements of this report for additional information.

Taxes other than income are assessed by state and local taxing authorities on production, revenues or the value of properties. Revenue based production/severance taxes are our largest component of these taxes. During the second quarter and first six months of 2014, these taxes increased by 16% and 25%, respectively, compared to the same periods of 2013. The increases are primarily due to increased production/severance taxes on higher production volumes and prices.

General and administrative (G&A) costs were as follows:

	For the Three Months Ended June 30,		Variance Between 2014 / 2013	For the Six Months Ended June 30,		Variance Between 2014 / 2013
(in thousands)	2014	2013		2014	2013	
G&A capitalized to oil & gas properties	$ 25,265	$ 19,015	$ 6,250	$ 42,440	$ 37,693	$ 4,747
G&A expense	16,571	22,836	(6,265)	37,283	38,413	(1,130)
	$ 41,836	$ 41,851	$ (15)	$ 79,723	$ 76,106	$ 3,617
G&A expense per Mcfe	$ 0.22	$ 0.37	$ (0.15)	$ 0.26	$ 0.32	$ (0.06)

While second quarter 2014 G&A costs of $41.8 million were flat compared to the second quarter of 2013, there was a change in the mix between capitalized and expensed G&A. Second quarter capitalized G&A in 2014 was 33% higher than the 2013 period due to higher capitalized salaries and benefits. G&A expense in the second quarter of 2014 was $6.3 million (27%) lower than the comparable 2013 expense primarily resulting from an $8 million decrease in contributions, which was partially offset by $2 million of higher salaries and benefits. Contributions of $8 million in the second quarter of 2013 were comprised of $7 million for university endowments established in honor of our former Chairman, F.H. Merelli, and $1 million of contributions for tornado relief in Oklahoma.

G&A costs of $79.7 million for the first six months of 2014 were 5% higher than G&A for the same period of 2013. Capitalized G&A in the first six months of 2014 included increased costs for salaries and benefits. G&A expense in the first six months of 2014 also included increases related to salaries and benefits and increased rent, which were partially offset by an $8 million decrease in the aforementioned contributions.

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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:

	For the Three Months Ended June 30,		Variance Between 2014 /	For the Six Months Ended June 30,		Variance Between 2014 /
(in thousands)	2014	2013	2013	2014	2013	2013
Performance stock awards	$ 2,867	$ 2,568	$ 299	$ 5,814	$ 5,253	$ 561
Service-based stock awards	3,112	3,449	(337)	6,616	6,670	(54)
Restricted stock awards	5,979	6,017	(38)	12,430	11,923	507
Stock option awards	782	707	75	1,555	1,415	140
Total stock compensation	6,761	6,724	37	13,985	13,338	647
Less amounts capitalized to oil & gas properties	(3,213)	(3,217)	4	(6,713)	(6,226)	(487)
Stock compensation	$ 3,548	$ 3,507	$ 41	$ 7,272	$ 7,112	$ 160

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.

We have not elected hedge accounting treatment for our derivative instruments. Therefore, we recognize settlements and changes in the assets or liabilities relating to our open derivative contracts in earnings. Cash settlements of our contracts are included in cash flows from operating activities in our statements of cash flows.

Gains and losses on our derivative contracts are a function of fluctuations in the underlying commodity prices and the monthly settlement of the instruments. See Item 3 and Note 2 to the Consolidated Financial Statements in this report for further details regarding our derivative instruments.

The following table summarizes the net (gains) and losses from settlements and changes in fair value of our derivative contracts.

(in thousands)	For the Three Months Ended June 30, 2014	2013	For the Six Months Ended June 30, 2014	2013
(Gain) loss on derivative instruments, net:				
Natural gas contracts	$ (2,062)	$ (9,199)	$ 9,820	$ (9,199)
Oil contracts	4,516	(4,461)	8,369	(2,858)
(Gain) loss on derivative instruments, net	$ 2,454	$ (13,660)	$ 18,189	$ (12,057)
Settlement (gains) losses:				
Natural gas contracts	$ 37	$ —	$ 4,824	$ —
Oil contracts	980	(1,039)	980	(1,765)
Settlement (gains) losses	$ 1,017	$ (1,039)	$ 5,804	$ (1,765)

Other operating, net consists of costs related to various legal matters. The 2014 periods decreased considerably compared to 2013 because the 2013 periods included accruals for certain litigation that has been settled. See Note 11 to the Consolidated Financial Statements and Part II, Item 1, in this report for further information regarding litigation matters and recent events regarding H.B. Krug, et al versus H&P.

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Other (income) and expense

(in thousands)	For the Three Months Ended June 30, 2014	2013	Variance Between 2014 / 2013	For the Six Months Ended June 30, 2014	2013	Variance Between 2014 / 2013
Interest expense	$ 16,724	$ 14,112	$ 2,612	$ 30,766	$ 27,318	$ 3,448
Capitalized interest	(8,575)	(7,387)	(1,188)	(15,865)	(16,582)	717
Other, net	(4,129)	(8,758)	4,629	(11,084)	(11,374)	290
	$ 4,020	$ (2,033)	$ 6,053	$ 3,817	$ (638)	$ 4,455

Interest expense includes interest on debt and amortization of financing costs. Our second quarter 2014 interest expense increased 19% compared to the second quarter of 2013. Interest expense for the first six months of 2014 was 13% higher than the same period of 2013. The year-over-year increases were primarily a result of issuing new senior notes in June 2014.

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 current rate of interest and the amount of costs on which interest is calculated. Capitalized interest in the second quarter of 2014 increased 16% compared to the same period of 2013. While the second quarter 2014 average interest rate was lower than the applicable rate in 2013, the amount of qualifying capitalized expenditures was higher in 2014. During the six months ended June 30, 2014, capitalized interest decreased 4% compared to the same period of 2013 primarily due to a lower average interest rate in 2014.

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 and supplies, income and expense associated with other non-operating activities, miscellaneous asset sales and interest income. The $4.6 million decrease in other, net (income) for the second quarter of 2014 versus 2013 is mainly due to higher gains from asset sales in the second quarter of 2013. Other, net (income) for the first six months of 2014 was flat compared to the same period of 2013. During the first six months of 2014, lower gains from asset sales were offset by higher gains on sales of oil and gas well equipment and supplies.

Income Tax Expense

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

	Three months ended June 30,		Six months ended June 30,	
(in thousands)	2014	2013	2014	2013
Current benefit	$ —	$ —	$ —	$ —
Deferred taxes	87,758	76,616	169,503	129,792
	$ 87,758	$ 76,616	$ 169,503	$ 129,792
Combined Federal and State effective income tax rate	37.1 %	37.2 %	37.1 %	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 prices we receive for the oil, gas and NGLs we produce. Prices received for production heavily influence our revenue, cash flow, profitability, access to capital and future rate of growth. See RESULTS OF OPERATIONS above for a discussion of the impact changes in realized prices has had on our 2014 revenues.

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Commodity prices are market driven and future prices 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 economic conditions, our 2014 exploration and development (E&D) capital expenditures are estimated to be $1.95 billion. Our total 2014 capital expenditures are estimated to approximate $2.30 billion. We expect our capital expenditures to be funded mostly with cash flow provided by operating activities and long-term debt. The timing of capital expenditures and the receipt of cash flows do not necessarily match, causing us to borrow and repay funds under our bank credit facility throughout the year. Occasional sales of non-core assets may also be used to supplement funding of capital expenditures.

At June 30, 2014, our long-term debt totaled $1.5 billion and consisted of $750 million of 5.875% senior notes and $750 million of 4.375% senior notes. We also had letters of credit outstanding under our bank credit facility of $2.5 million, leaving an unused borrowing availability of $997.5 million.

Our debt to total capitalization at June 30, 2014 was 26%. The reconciliation of debt to total capitalization, which is a non-GAAP measure, is: long-term debt of $1.5 billion divided by long-term debt of $1.5 billion plus stockholders' equity of $4.3 billion. Management believes that this non-GAAP measure is useful information as it is a common statistic used in the investment community to assist with the analysis of the financial condition of an entity.

We believe that our operating cash flow and other capital resources will be adequate to meet our needs for planned capital expenditures, working capital, debt servicing and dividend payments in 2014 and beyond.

Analysis of Cash Flow Changes

Cash flow provided by operating activities for the six months of 2014 was $769.8 million compared to $569.8 million for the same period of 2013. The $200.0 million (35%) increase was a result of increased revenues from higher realized commodity prices and increased production volumes, which were partially offset primarily by higher operating expenses.

During the first six months of 2014, net cash flow used for investing activities was $1.189 billion, up $432.5 million (57%) from $756.0 million for 2013. Net cash flow used for investing activities exceeded net cash flow provided by operating activities by $418.8 million. The shortfall was made up primarily by net cash inflows from bank borrowings and other long-term debt.

Cash provided by financing activities during the first six months of 2014 was $542.8 million. In June of 2014 we issued $750 million of senior notes. Most of the proceeds from the debt offering were used to pay outstanding bank debt, financing costs associated with the debt offering and to fund investing activities. After additional financing activities which included proceeds from issuance of common stock and dividend payments, remaining cash and cash equivalents from financing activities was $124.0 million.

For the first six months of 2013, $756.0 million of net cash flow used for investing activities was $186.3 million greater than net cash flow provided by operating activities. Net bank borrowings of $142.0 million plus proceeds from issuance of common stock upon the exercise of stock options less dividend payments provided $121.3 million of net cash flow from financing activities to fund investing activities. The remaining shortfall was made up from the use of cash and cash equivalents of $65 million.

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Reconciliation of Adjusted Cash Flow from Operations

(in thousands)	Six months ended June 30, 2014	2013
Net cash provided by operating activities	$ 769,769	$ 569,786
Change in operating assets and liabilities	82,235	68,944
Adjusted cash flow from operations	$ 852,004	$ 638,730

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 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:

	Three months ended June 30,		Six months ended June 30,	
(in thousands)	2014	2013	2014	2013
Acquisitions:				
Proved	$ 144,516	$ 923	$ 144,516	$ 923
Unproved	114,732	3,415	114,732	3,665
	259,248	4,338	259,248	4,588
Exploration and development:				
Land and seismic	43,869	36,719	109,194	68,029
Exploration and development	453,714	353,594	855,175	730,891

	497,583	390,313	964,369	798,920
Sales proceeds:				
Proved	(464)	(37,061)	(223)	(37,879)
Unproved	(900)	(960)	(900)	(1,041)
	(1,364)	(38,021)	(1,123)	(38,920)
	$ 755,467	$ 356,630	$ 1,222,494	$ 764,588

Capital expenditures in the table above are presented on an accrual basis. Oil and gas expenditures and sales in the Condensed Consolidated Statements of Cash Flows in this report reflect activities on a cash basis, when payments are made.

Our 2014 E&D capital expenditures are expected to approximate $1.95 billion, almost all of which will be directed towards drilling oil and liquids-rich gas wells in the Permian Basin and Mid-Continent region. Our E&D expenditures of $964.4 million during the first half of 2014 were $165.5 million (21%) higher than $798.9 million of expenditures during the 2013 period. Approximately 71% of our 2014 expenditures were for Permian Basin projects and the majority of the remainder was invested in projects in the Mid-Continent.

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The following table reflects wells drilled by region:

	Three months ended June 30,		Six months ended June 30,	
	2014	2013	2014	2013
Gross wells				
Permian Basin	47	55	81	90
Mid-Continent	37	35	76	87
Other	1	2	2	2
	85	92	159	179
Net wells				
Permian Basin	30	32	51	59
Mid-Continent	21	15	35	35
Other	—	1	1	1
	51	48	87	95
% Gross wells completed as producers	99 %	97 %	99 %	98 %

As of June 30, 2014, we had 46 gross wells awaiting completion: 22 Permian Basin and 24 Mid-Continent. We also had 21 operated rigs running: 18 in the Permian Basin and 3 in the Mid-Continent region.

We regularly review our E&D capital expenditures and will adjust our activity based on changes in commodity prices, service costs and drilling success. In addition, we actively evaluate acquisitions, particularly in our core area of operations. We also evaluate our non-core property holdings for potential divestures.

On June 30, 2014, in the ordinary course of business, we closed on an acquisition of Mid-Continent producing and nonproducing assets, located primarily in the Cana-Woodford shale play, for approximately $238 million. Subsequent to June 30, 2014, we sold non-core producing properties in Kansas for net proceeds of approximately $136 million.

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 economically producing new reserves, production from existing wells and realized commodity prices. To meet 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 bank credit facility to finance our working capital needs.

During the first six months of 2014, our total assets increased by $1.1 billion to $8.4 billion, up from $7.3 billion at December 31, 2013. The increase resulted mostly from an $884.0 million increase in our net oil and gas properties and $217.2 million increase in our current assets. An increase in cash and cash equivalents due to our June 2014 debt offering accounted for $124.0 million (57%) of the increase in current assets.

Total liabilities at June 30, 2014 increased to $4.1 billion, up $881.4 million from $3.2 billion at year-end 2013. The increase resulted from an additional $576.0 million in debt and a $187.4 million increase in non-current liabilities. An increase in deferred income taxes of $166.4 million accounted for most of the increase in non-current liabilities.

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Our stockholders' equity totaled $4.3 billion at June 30, 2014, up $264.4 million from $4.0 billion at December 31, 2013. The increase resulted mainly from net income of $287.1 million less dividends of $27.7 million.

Dividends

A quarterly cash dividend has been paid to stockholders every quarter since the second quarter of 2006. In February 2014, the quarterly dividend was increased to $0.16 per share from $0.14 per share. Future dividend payments will depend on our 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 changes in our cash and cash equivalents, exploration and development activities, realized commodity prices, and changes related to our operating activities. Working capital is also impacted by changes in our oil and gas well equipment and supplies, our current tax provision and changes in the fair value of our outstanding derivative instruments.

At June 30, 2014, our working capital deficit of $114.8 million was $99.2 million less than our deficit of $214.0 million at December 31, 2013.

Working capital increases consisted of the following:

- Cash and cash equivalents increased by $124.0 million.

- Operations-related accounts receivable increased by $82.0 million.

- Oil and gas well equipment and supplies increased by $18.5 million.

Working capital increases were partially offset by:

· Accrued liabilities related to our E&D expenditures increased by $78.4 million.

· Operations related accounts payable and accrued liabilities increased by $31.5 million.

· The net fair value of our derivative instruments declined by $12.4 million.

· Current deferred income taxes decreased by $3.1 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

Long-term debt at June 30, 2014 and December 31, 2013 consisted of the following:

(in thousands)	June 30, 2014	December 31, 2013
Bank debt	$ —	$ 174,000
5.875% Senior Notes due 2022	750,000	750,000
4.375% Senior Notes due 2024	750,000	—
Total long-term debt	$ 1,500,000	$ 924,000

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Bank Debt

In May 2014, we amended our senior unsecured revolving credit facility (Credit Facility) to extend the maturity date two years to July 14, 2018 and lowered the margins applicable to loans and commitments. The amendment also raised our borrowing base from $2.25 billion to $2.5 billion until the next regular annual redetermination date scheduled for April 15, 2015. The borrowing base is determined at the discretion of the lenders based on the value of our proved reserves. Our aggregate commitments remained unchanged at $1 billion.

As of June 30, 2014, we had letters of credit outstanding of $2.5 million, leaving an unused borrowing availability of $997.5 million. During the first six months of 2014 we had average daily bank debt outstanding of $267.1 million, compared to $118.7 million for the same period of 2013. Our highest amount of bank borrowings outstanding during the first six months of 2014 was $515.0 million, occurring in May. During the same period of 2013, the highest amount of outstanding bank borrowings was $261.0 million, occurring in June.

At our option, borrowings under the Credit Facility, as amended in May 2014, may bear interest at either (a) LIBOR plus 1.5-2.25%, 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 0.5-1.25%, based on our leverage ratio.

The Credit Facility has a number of financial and non-financial covenants of which we were in compliance with at June 30, 2014. See Note 7 to the Consolidated Financial Statements in this report 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.

4.375% Notes due 2024

In June 2014, we issued $750 million of 4.375% senior notes due June 1, 2024, with interest payable semiannually in June and December. 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. At any time prior to March 1, 2024, we may redeem all or a part of the notes at a defined make-whole redemption price calculated at the time of redemption. At any time on or after March 1, 2024, we may redeem all or part of the notes at a price equal to 100% of the principal amount.

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, 2014, 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.

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Contractual Obligations and Material Commitments

At June 30, 2014, we had contractual obligations and material commitments as follows:

Contractual obligations: (in thousands)	Payments Due by Period Total	1 Year or Less	2 - 3 Years	4 - 5 Years	More than 5 Years
Long-term debt (1)	$ 1,500,000	$ —	$ —	$ —	$ 1,500,000
Fixed-Rate interest payments (1)	680,352	76,602	153,750	153,750	296,250
Operating leases	131,674	16,690	22,105	20,770	72,109
Drilling commitments (2)	245,625	224,250	21,375	—	—
Gathering facilities and pipelines (3)	6,613	6,613	—	—	—
Asset retirement obligation (4)	166,595	15,176	— (4)	— (4)	— (4)
Other liabilities (5)	76,790	18,880	38,438	539	18,933
Firm transportation	610	439	171	—	—

(1) See Item 3: Quantitative and Qualitative Disclosures About Market Risk for more information regarding fixed and variable rate debt.
(2) We have drilling commitments of approximately $192.0 million consisting of obligations to finish drilling and completing wells in progress at June 30, 2014. We also have various commitments for drilling rigs. The total minimum expenditure commitments under these agreements are $53.6 million.
(3) We have projects in New Mexico and Texas where we are constructing gathering facilities and pipelines. At June 30, 2014, we had commitments of $6.6 million relating to this construction.
(4) We have not included the long-term asset retirement obligations because we are not able to precisely predict the timing of these amounts.
(5) Other liabilities include the estimated value of our commitment associated with our benefit obligations and other miscellaneous commitments.

At June 30, 2014, we had firm sales contracts to deliver approximately 34.7 Bcf of natural gas over the next 12 months. In total, our financial exposure would be approximately $146.4 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 from which we can fulfill these obligations.

In the normal course of business we have various 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 our other capital resources will be adequate to meet future liquidity needs.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

We consider accounting policies related to oil and gas reserves, full cost accounting, goodwill, 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.

Recent Accounting Developments

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2014-09, Revenue from Contracts with Customers (Topic 606). The new revenue standard provides a five-step analysis of transactions to determine when and how revenue is recognized. The core principle of the guidance

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is that a company should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The guidance in this update supersedes the revenue recognition requirements in Topic 605, Revenue Recognition, and most industry-specific guidance throughout the Industry Topics of the Codification. We must comply with this ASU beginning in fiscal year 2017 and early adoption is not permitted. Entities can choose to apply the standard using either the full retrospective approach or a modified retrospective approach. We are currently evaluating the impact of the provisions of Topic 606 and the effects of adoption cannot be determined at this time.

ITEM 3. QUANTITATIVE AND QUALITATIVE 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 June 30, 2014:

Oil Contracts

				Weighted Average Price		Fair Value
Period	Type	Volume/Day	Index (1)	Floor	Ceiling	(in thousands)
Jul 14 – Dec 14	Collars	12,000 Bbls	WTI	$ 85.00	$ 103.47	$ (5,974)

(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 14 – Dec 14	Collars	80,000 MMBtu	PEPL	$ 3.51	$ 4.57	$ (969)
Jul 14 – Dec 14	Collars	60,000 MMBtu	Perm EP	$ 3.62	$ 4.50	$ (1,563)

(1) PEPL refers to Panhandle Eastern Pipe Line, Tex/OK Mid-Continent Index as quoted in Platt's Inside FERC. Perm EP refers to El Paso Natural Gas Company, Permian Basin 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 2014 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 2014 of $2.6 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 Consolidated Financial Statements of this report for additional information regarding our derivative instruments.

Interest Rate Risk

At June 30, 2014, our long-term debt consisted of $750 million in 5.875% senior notes that will mature on May 1, 2022 and $750 million in 4.375% senior notes that will mature on June 1, 2024.   Because all of our long-term debt is at a fixed rate, we consider our interest rate exposure to be minimal.   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.

ITEM 4. CONTROLS AND PROCEDURES

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

Cimarex's management, under the supervision and with the participation of the Chief Executive Officer (CEO) and Chief Financial Officer (CFO), have evaluated the effectiveness of Cimarex's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the Exchange Act)) as of June 30, 2014. Based on that evaluation, the CEO and CFO concluded that the disclosure controls and procedures are effective in providing reasonable assurance that 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 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.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There was no change in our internal control over financial reporting that occurred during the fiscal quarter ended June 30, 2014 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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PART II

ITEM 1. LEGAL PROCEEDINGS

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 of H&P, Cimarex assumed the assets and liabilities of H&P's exploration and production business, including this lawsuit. For 2008, we recorded a litigation expense of $119.6 million plus additional post-judgment interest and costs after the trial court entered a final judgment for these amounts. On December 10, 2013, the Oklahoma Supreme Court reversed the trial court's original judgment of $119.6 million and affirmed an alternative jury verdict for $3.65 million. In light of the Oklahoma Supreme Court's ruling, on December 31, 2013, we reduced previously recognized litigation expense and the associated long-term liability by $142.8 million. On March 14, 2014, after denying the Plaintiffs' Petition for Rehearing, the Oklahoma Supreme Court remanded the matter back to the trial court. On March 31, 2014, the trial court entered a final judgment for damages, post-judgment interest and a payment in lieu of bond. The following day Cimarex paid the Plaintiffs $15.8 million in satisfaction of these awards, which now are final and not appealable. On June 24, 2014, the trial court ruled that the Plaintiffs were not entitled to prejudgment interest but were entitled to an award of attorney's fees and costs. At a subsequent hearing the trial court will determine the amount of the attorney's fees and costs owed to Plaintiffs. The outcome of these remaining issues cannot be determined at this time and will be subject to an appeal. Our current assessments and estimates likely will change in the future as a result of subsequent legal proceedings both in the trial court and on appeal.

Additional information regarding this and other litigation is included in Note 11 to the Consolidated Financial Statements included in Part I, Item 1 of this report.

ITEM 6. EXHIBITS

10.1	Form of Notice of Grant of Restricted Stock (Director) and Award Agreement
10.2	Form of Notice of Grant of Nonqualified Stock Option and Award Agreement
10.3	Form of Notice of Grant of Restricted Stock and Award Agreement
10.4	Form of Notice of Grant of Restricted Stock and Award Agreement (Performance Award)
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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SIGNATURES

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

August 6, 2014

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)