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 March 31, 2015

Commission File No. 001-31446

CIMAREX ENERGY CO.

1700 Lincoln Street, Suite 3700

Denver, Colorado 80203

(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 March 31, 2015, was 87,673,459.

CIMAREX ENERGY CO.

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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, as amended, and Section 21E of the Securities and Exchange Act of 1934, as amended. 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, full cost ceiling impairments to the carrying values of our oil and gas properties, 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, weather 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

(Unaudited)

	March 31, 2015	December 31, 2014
	(in thousands, except share data)	
Assets		
Current assets:		
Cash and cash equivalents	$ 120,932	$ 405,862
Receivables, net	339,711	412,108
Oil and gas well equipment and supplies	81,462	89,780
Deferred income taxes	10,077	13,475
Prepaid expenses	8,003	9,356
Other current assets	1,000	1,223
Total current assets	561,185	931,804
Oil and gas properties at cost, using the full cost method of accounting:		
Proved properties	14,761,734	14,402,064
Unproved properties and properties under development, not being amortized	713,409	759,149
	15,475,143	15,161,213
Less — accumulated depreciation, depletion, amortization and impairment	(9,067,931)	(8,257,502)
Net oil and gas properties	6,407,212	6,903,711
Fixed assets, net	213,358	211,031
Goodwill	620,232	620,232
Other assets, net	58,064	58,515
	$ 7,860,051	$ 8,725,293
Liabilities and Stockholders’ Equity		
Current liabilities:		
Accounts payable	$ 74,749	$ 138,051
Accrued liabilities	336,606	447,384
Revenue payable	141,840	190,892
Total current liabilities	553,195	776,327
Long-term debt	1,500,000	1,500,000
Deferred income taxes	1,522,629	1,754,706
Other liabilities	198,089	193,628
Total liabilities	3,773,913	4,224,661
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, 87,673,459 and 87,592,535 shares issued, respectively	877	876
Paid-in capital	2,011,454	1,997,080
Retained earnings	2,072,603	2,501,574
Accumulated other comprehensive income	1,204	1,102
	4,086,138	4,500,632
	$ 7,860,051	$ 8,725,293

See accompanying notes to consolidated financial statements.

CIMAREX ENERGY CO.

Consolidated Statements of Operations and Comprehensive Income (Loss)

(Unaudited)

	For the Three Months Ended March 31, 2015	2014
	(in thousands, except per share data)	
Revenues:		
Oil sales	$ 196,005	$ 325,071
Gas sales	110,962	170,097
NGL sales	45,600	89,957
Gas gathering and other	8,270	12,464
Gas marketing, net	165	1,627
	361,002	599,216
Costs and expenses:		
Impairment of oil and gas properties	603,599	—
Depreciation, depletion and amortization	216,778	173,931
Asset retirement obligation	1,736	3,218
Production	82,211	75,141
Transportation, processing, and other operating	39,642	44,248
Gas gathering and other	8,864	8,784
Taxes other than income	21,981	33,621
General and administrative	15,938	20,712
Stock compensation	5,155	3,724
(Gain) loss on derivative instruments, net	—	15,735
Other operating, net	524	103
	996,428	379,217
Operating income (loss)	(635,426)	219,999
Other (income) and expense:		
Interest expense	21,256	14,042
Capitalized interest	(9,417)	(7,290)
Other, net	(3,585)	(6,955)
Income (loss) before income tax	(643,680)	220,202
Income tax expense (benefit)	(228,739)	81,745
Net income (loss)	$ (414,941)	$ 138,457
Earnings (loss) per share to common stockholders:		
Basic	$ (4.84)	$ 1.59
Diluted	$ (4.84)	$ 1.59
Dividends per share	$ 0.16	$ 0.16

Comprehensive income (loss):		
Net income (loss)	$ (414,941)	$ 138,457
Other comprehensive income:		
Change in fair value of investments, net of tax	101	40
Total comprehensive income (loss)	$ (414,840)	$ 138,497

See accompanying notes to consolidated financial statements.

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CIMAREX ENERGY CO.

Condensed Consolidated Statements of Cash Flows

(Unaudited)

	For the Three Months Ended March 31,	
	2015	2014
	(in thousands)	
Cash flows from operating activities:		
Net income (loss)	$ (414,941)	$ 138,457
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Impairment of oil and gas properties	603,599	—
Depreciation, depletion and amortization	216,778	173,931
Asset retirement obligation	1,736	3,218
Deferred income taxes	(228,739)	81,745
Stock compensation	5,155	3,724
(Gain) loss on derivative instruments	—	15,735
Settlements on derivative instruments	—	(4,787)
Changes in non-current assets and liabilities	1,046	(4,207)
Other, net	2,311	1,076
Changes in operating assets and liabilities:		
Receivables, net	72,397	(35,529)
Other current assets	9,894	(16,772)
Accounts payable and other current liabilities	(156,063)	(8,567)
Net cash provided by operating activities	113,173	348,024
Cash flows from investing activities:		
Oil and gas expenditures	(371,106)	(420,040)
Sales of oil and gas assets and other assets	1,180	104
Other capital expenditures	(18,848)	(19,854)
Net cash used by investing activities	(388,774)	(439,790)
Cash flows from financing activities:		
Net bank debt borrowings	—	101,000
Dividends paid	(13,947)	(12,143)
Issuance of common stock and other	4,618	2,908
Net cash provided by (used in) financing activities	(9,329)	91,765
Net change in cash and cash equivalents	(284,930)	(1)
Cash and cash equivalents at beginning of period	405,862	4,531
Cash and cash equivalents at end of period	$ 120,932	$ 4,530

See accompanying notes to consolidated financial statements.

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CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements

March 31, 2015

(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 Annual Report on Form 10-K/A for the year ended December 31, 2014.

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.

Use of Estimates

Areas of significance requiring the use of management's judgments relate to the estimation of proved oil and gas reserves, the use of proved reserves in calculating depletion, depreciation, and amortization (DD&A), 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 also are 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 contingencies.

Oil and Gas Well Equipment and Supplies

Our oil and gas well equipment and supplies are valued at the lower of cost or market using weighted average cost. An analysis of our oil and gas well equipment and supplies was performed and no impairment was required. However, the industry-wide decline in drilling operations has put downward pressure on the price of oil and gas well equipment and supplies. Further declines in future periods could cause us to recognize impairments on these assets. An impairment would not affect cash flow from operating activities, but would adversely affect our net income and stockholders' equity.

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. If the net capitalized cost of our oil and gas properties subject to amortization (the carrying value) exceeds the ceiling limitation, the excess is 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. Estimated future net cash flows are determined by commodity prices and proved reserve quantities.

At March 31, 2015, the carrying value of our oil and gas properties subject to the test exceeded the calculated value of the ceiling limitation, and we recognized an impairment of $603.6 million ($383.2 million, net of tax). This impairment resulted from the impact of decreases in the 12-month average trailing prices for oil, natural gas and NGLs utilized in determining the future net cash flows from proved reserves. If pricing conditions stay at current levels or decline further, or if there is a negative impact on one or more of the other components of the calculation, we will incur full cost ceiling impairments in future quarters. The ceiling calculation is not intended to be indicative of the fair market value of our proved reserves.

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Notes to Consolidated Financial Statements

March 31, 2015

(Unaudited)

Accounts Receivable, Accounts Payable, and Accrued Liabilities

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

(in thousands)	March 31, 2015	December 31, 2014
Receivables, net of allowance		
Trade	$ 124,862	$ 134,443
Oil and gas sales	200,622	259,220
Gas gathering, processing, and marketing	14,091	18,009
Other	136	436
Receivables, net	$ 339,711	$ 412,108
Accounts payable		
Trade	$ 48,653	$ 102,276
Gas gathering, processing, and marketing	26,096	35,775
Accounts payable	$ 74,749	$ 138,051
Accrued liabilities		
Exploration and development	$ 116,852	$ 200,929
Taxes other than income	17,018	26,950
Other	202,736	219,505
Accrued liabilities	$ 336,606	$ 447,384

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). In April 2015, the FASB submitted a proposal to defer for one year the effective date of the new revenue standard (ASU 2014-09) for public and non-public entities reporting under U.S. GAAP. The FASB proposal would also permit entities to early adopt the standard. We are currently evaluating the potential impact of this guidance. At this time we do not expect that the adoption of this standard will have a material effect on our financial position or results of operation and related disclosures.

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Notes to Consolidated Financial Statements

March 31, 2015

(Unaudited)

2.Capital Stock

Authorized capital stock consists of 200 million shares of common stock and 15 million shares of preferred stock. At March 31, 2015, there were no shares of preferred stock outstanding. A summary of our common stock activity for the three months ended March 31, 2015, follows:

(in thousands)	
Issued and outstanding as of December 31, 2014	87,592
Issuance of service-based restricted stock awards	7
Common stock reacquired and retired	(7)
Option exercises, net of cancellations	81
Issued and outstanding as of March 31, 2015	87,673

Dividends

In February 2015, the Board of Directors declared a cash dividend of $0.16 per share. The dividend is payable on June 1, 2015, to stockholders of record on May 15, 2015. Future dividend payments will depend on our level of earnings, financing requirements, and other factors considered relevant by the Board of Directors.

3.Stock-based Compensation

We have recognized stock-based compensation cost as shown below. Historical amounts may not be representative of future amounts as the value of future awards may vary from historical amounts.

	Three Months Ended March 31,	
(in thousands)	2015	2014
Restricted stock awards		
Performance stock awards	$ 4,998	$ 2,947
Service-based stock awards	4,937	3,504
	9,935	6,451
Stock option awards	639	773
	10,574	7,224
Less amounts capitalized to oil and gas properties	(5,419)	(3,500)
Compensation expense	$ 5,155	$ 3,724

The increase in compensation expense is primarily due to performance stock awards granted in December 2014.

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(Unaudited)

4.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.

The following table reflects the components of the change in the carrying amount of the asset retirement obligation for the three months ended March 31, 2015:

(in thousands)		
Asset retirement obligation at January 1, 2015	$	173,008
Liabilities incurred		1,197
Liability settlements and disposals		(4,185)
Accretion expense		1,950
Revisions of estimated liabilities		4,362
Asset retirement obligation at March 31, 2015		176,332
Less current obligation		(13,897)
Long-term asset retirement obligation	$	162,435

5.Long-Term Debt

Debt at March 31, 2015, and December 31, 2014, consisted of the following:

(in thousands)	March 31, 2015	December 31, 2014
5.875% Senior Notes, due May 1, 2022	$ 750,000	$ 750,000
4.375% Senior Notes, due June 1, 2024	750,000	750,000
Total long-term debt	$ 1,500,000	$ 1,500,000

All of our long-term debt is senior unsecured debt and is pari passu with respect to the payment of both principal and interest.

Bank Debt

We have a senior unsecured revolving credit facility (Credit Facility) which matures July 14, 2018. The Credit Facility has a borrowing base of $2.5 billion and aggregate commitments of $1.0 billion. The borrowing base under the Credit Facility is determined at the discretion of the lenders based on the value of our proved reserves. Our borrowing base was reaffirmed in April 2015. The next regular annual redetermination date is scheduled for April 15, 2016.

As of March 31, 2015, we had letters of credit outstanding under the Credit Facility of $2.5 million, leaving an unused borrowing availability of $997.5 million.

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements

March 31, 2015

(Unaudited)

The Credit Facility also has customary covenants with which we were in compliance as of March 31, 2015.

Senior Notes

Each of our senior notes is governed by an indenture containing certain covenants, events of default and other restrictive provisions with which we were in compliance as of March 31, 2015. Interest on each of the senior notes is payable semi-annually.

6.Earnings (loss) per Share

The calculations of basic and diluted net earnings (loss) per common share under the two-class method are presented below:

	Three Months Ended March 31,	
(in thousands, except per share data)	2015	2014
Basic:		
Net income (loss)	$ (414,941)	$ 138,457
Participating securities’ share in earnings (1)	—	(2,287)
Net income (loss) applicable to common stockholders	$ (414,941)	$ 136,170

Diluted:		
Net income (loss)	$ (414,941)	$ 138,457
Participating securities’ share in earnings (1)	—	(2,284)
Net income (loss) applicable to common stockholders	$ (414,941)	$ 136,173
Shares:		
Basic shares outstanding	85,770	85,443
Dilutive effect of stock options	—	136
Fully diluted common stock	85,770	85,579
Excluded (2)	2,216	1
Earnings (loss) per share to common stockholders:		
Basic	$ (4.84)	$ 1.59
Diluted	$ (4.84)	$ 1.59

(1) Participating securities are not included in undistributed earnings when a loss exists.
(2) Inclusion of certain shares would have an anti-dilutive effect.

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Notes to Consolidated Financial Statements

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(Unaudited)

7.Income Taxes

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

	Three Months Ended March 31,	
(in thousands)	2015	2014
Current taxes (benefit)	$ —	$ —
Deferred taxes (benefit)	(228,739)	81,745
	$ (228,739)	$ 81,745
Combined Federal and State effective income tax rate	35.5 %	37.1 %

At December 31, 2014, we had a U.S. net tax operating loss carryforward of approximately $651.1 million, which will expire in tax years 2031 through 2034. 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 $83.1 million. We also had an alternative minimum tax credit carryforward of approximately $4.1 million.

At March 31, 2015, we had no unrecognized tax benefits that would impact our effective tax rate and have made no provisions for interest or penalties related to uncertain tax positions. The tax years 2011 through 2013 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 2010 through 2013 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.

8.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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(Unaudited)

The following tables provide fair value measurement information for certain assets and liabilities as of March 31, 2015, and December 31, 2014:

March 31, 2015:	Carrying	Fair
(in thousands)	Amount	Value
Financial Assets (Liabilities):		
5.875% Notes due 2022	$ (750,000)	$ (807,000)
4.375% Notes due 2024	$ (750,000)	$ (748,125)

December 31, 2014:	Carrying	Fair
(in thousands)	Amount	Value
Financial Assets (Liabilities):		
5.875% Notes due 2022	$ (750,000)	$ (776,250)
4.375% Notes due 2024	$ (750,000)	$ (720,000)

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 fair value (Level 1) of our 4.375% and 5.875% fixed rate notes was based on their last traded value before period end.

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 not be collected and the amount of the reserve may be reasonably estimated. At March 31, 2015, and December 31, 2014, the allowance for doubtful accounts was $1.6 million and $1.5 million, respectively.

9.Derivative Instruments/Hedging

We had derivative contracts outstanding during 2014, all of which had settled as of December 31, 2014. We have not entered into any new contracts. 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.

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements

March 31, 2015

(Unaudited)

The following table presents the net losses from settlements and changes in fair value of our derivative contracts, and the losses only from settlements during the periods shown below.

	Three Months Ended March 31,	
(in thousands)	2015	2014
Gain (loss) on derivative instruments, net	$ —	$ (15,735)
Settlement gains (losses)	$ —	$ (4,787)

10.Commitments and Contingencies

Commitments

We have commitments of $200.4 million to finish drilling and completing wells in progress at March 31, 2015. We also have minimum commitments for six drilling rigs of $45.3 million.

We had commitments of $6.0 million relating to the construction of gathering facilities and pipelines in New Mexico and Texas.

At March 31, 2015, we had firm sales contracts to deliver approximately 51.3 Bcf of natural gas over the next 43 months. If this gas is not delivered, our financial commitment would be approximately $120.9 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 are not material individually or in the aggregate.

We have various commitments for office space and equipment under operating lease arrangements totaling $118.5 million.

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

Litigation

We have various litigation matters related to the ordinary course of our business. We assess the probability of estimable amounts related to those 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

On April 1, 2014, Cimarex paid the plaintiffs $15.8 million for damages, post-judgment interest, and other expenses, all of which are now final and not appealable. On June 24, 2014, the trial court ruled the plaintiffs were not entitled to prejudgment interest but were entitled to attorney's fees and costs, the amount of which will be determined at a subsequent hearing. On July 31, 2014, the plaintiffs appealed the trial court's denial of prejudgment interest, which will be determined by the Oklahoma Supreme Court. The outcome of these remaining issues cannot be determined, and our current estimates and assessments will likely change as a result of future legal proceedings.

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CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements

March 31, 2015

(Unaudited)

11.Supplemental Disclosure of Cash Flow Information

	Three Months Ended March 31,	
(in thousands)	2015	2014
Cash paid during the period for:		
Interest expense (including capitalized amounts)	$ 935	$ 2,095
Interest capitalized	$ 414	$ 1,088
Income taxes	$ 1	$ 1
Cash received for income taxes	$ 300	$ 209

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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. Currently our operations are focused in two main areas: the Permian Basin and the Mid-Continent region. Our Permian Basin region encompasses west Texas and southeast New Mexico. Our Mid-Continent region includes Oklahoma and the Texas Panhandle.

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 consider property acquisitions, dispositions and occasional mergers to enhance our competitive position.

We believe that detailed technical analysis, operational focus and a disciplined capital investment process mitigates risk and positions us to continue to achieve increases in proved reserves and production. Our diversified drilling portfolio and limited long-term commitments provide the flexibility to respond quickly to industry volatility.

Our investments are generally funded with cash flow provided by operating activities together with bank borrowings, sales of non-strategic assets and public financing. Conservative use of leverage has long been a part of our financial strategy. We believe that maintaining a strong balance sheet mitigates financial risk and enables us to withstand low prices.

Market Conditions

The oil and gas industry is cyclical and commodity prices can be volatile. In the second half of 2014 oil prices began a rapid and significant decline as global supply outpaced demand. There has been little to no recovery of oil prices thus far in 2015 and it is likely that prices will remain erratic due to an ongoing supply and demand imbalance and geopolitical factors.

Prices for domestic natural gas and NGLs began to decline following the winter of 2013-2014 and have continued to be weak into 2015. The decline in these prices is primarily due to an imbalance between supply and demand across North America, which could result in further declines.

Compared to the first quarter of 2014, our realized oil price fell 54% to $42.50/Bbl. Similarly our gas price dropped 48% to $2.77/Mcf and our NGL price declined 61% to $15.71/Bbl.

This dramatic decrease in commodity prices has had a significant adverse impact on our results of operations and the amount of cash flow available to invest in exploration and development (E&D).

In the first quarter of 2015, the impact of lower prices on the present value of future cash flows from our proved reserves resulted in an after-tax, non-cash full cost ceiling impairment to our oil and gas properties of $383.2 million. See a discussion of the ceiling impairment calculation below under Operating costs and expenses.

Based on current economic conditions and our expectations for 2015 cash flows from operations, our 2015 E&D capital expenditures are expected to range from $900 million to $1.1 billion, down from $1.88 billion in 2014.

See Part II, Item 1A, Risk Factors, in this report, and Item 1A, Risk Factors, in our Annual Report on Form 10-K/A for the year ended December 31, 2014, for a discussion of risk factors that affect our business, financial condition and results of operations. Also see CAUTIONARY INFORMATION ABOUT FORWARD-LOOKING STATEMENTS in this report for important information about these types of statements.

First quarter 2015 summary of operating and financial results:

· Average daily production increased 28% to 946.7 MMcfe/d.

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- Oil production grew 31% to 51,241 Bbl/d, gas production increased 25% to 445.8 MMcf/d and NGL volumes were up 29% to 32,242 Bbls/d.
- Exploration and development expenditures totaled $308.2 million.
- Oil, gas and NGL sales totaled $352.6 million, down from $585.1 million a year earlier.
- Cash flow provided by operating activities was $113.2 million versus $348.0 million last year.
- We incurred a net loss of $414.9 million ($4.84 per share).
- Total debt at March 31, 2015, was $1.5 billion, unchanged from year-end 2014.

Revenues

Almost all of our revenues are derived from the sales of oil, gas and NGL production. Increases or decreases in our revenue, profitability and future production growth are highly dependent on the commodity prices we receive. Prices are market driven and we expect that future prices will continue to fluctuate due to supply and demand factors, seasonality and geopolitical and economic factors.

Oil sales contributed 56% of our total production revenue for the first quarter of 2015. Gas sales accounted for 31% and NGL sales contributed 13%. A $1.00 per barrel change in our realized oil price would have resulted in a $4.6 million change in revenues. A $0.10 per Mcf change in our realized gas price would have resulted in a $4.0 million change in our gas revenues. A $1.00 per barrel change in NGL prices would have changed revenues by $2.9 million.

The following table presents our average realized commodity prices and certain major U.S. index prices. Our average realized prices in 2014 do not include settlements of commodity derivative contracts. We had no derivative contracts outstanding in the first quarter of 2015.

	Three Months Ended March 31,	
	2015	2014
Oil Prices:		
Average realized sales price ($/Bbl)	$ 42.50	$ 92.22
Average WTI Midland price ($/Bbl)	$ 46.65	$ 95.15
Average WTI Cushing price ($/Bbl)	$ 48.63	$ 98.68
Gas Prices:		

Average realized sales price ($/Mcf)	$ 2.77	$ 5.32
Average Henry Hub price ($/Mcf)	$ 2.99	$ 4.95
NGL Prices:		
Average realized sales price ($/Bbl)	$ 15.71	$ 39.94

For the first quarter of 2015 and 2014, approximately 84% and 81%, respectively, of our oil production was in the Permian Basin, the sale of which is tied to the WTI Midland benchmark price. The impact of changes in realized prices is discussed below under RESULTS OF OPERATIONS.

Operating costs and 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.

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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. If the net capitalized cost of our oil and gas properties subject to amortization (the carrying value) exceeds the ceiling limitation, the excess is 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. Estimated future net cash flows are determined by commodity prices and proved reserve quantities.

At March 31, 2015, the carrying value of our oil and gas properties subject to the test exceeded the calculated value of the ceiling limitation, and we recognized an impairment of $603.6 million ($383.2 million, net of tax). This impairment resulted from the impact of decreases in the 12-month average trailing prices for oil, natural gas and NGLs utilized in determining the future net cash flows from proved reserves. If pricing conditions stay at current levels or decline further, or if there is a negative impact on one or more of the other components of the calculation, we will incur full cost ceiling impairments in future quarters. The ceiling calculation is not intended to be indicative of the fair market value of our proved reserves.

Because the ceiling calculation requires rolling 12-month average commodity prices, the effect of lower quarter-over-quarter prices in 2015 compared to 2014 will be a lower ceiling value each quarter. This will result in ongoing impairments until prices stabilize or improve over a twelve-month period. Impairment charges do not affect cash flow from operating activities, but do adversely affect our net income and stockholders' equity.

Depreciation, depletion and amortization (DD&A) of our producing properties is computed using the units-of-production method. The economic life of each producing well depends upon the estimated proved reserves for that well, which in turn depend upon the assumed realized sales 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, reclassifications of properties from unproved to proved and impairments will impact depletion expense.

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 principally consists of expenditures to prepare and transport production from the wellhead to a specified sales point as well as gas processing costs. Costs vary by region and will fluctuate with increases or decreases in production volumes, contractual fees and changes in fuel and compression costs.

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.

A discussion of changes in operating costs and expenses is included in RESULTS OF OPERATIONS, below.

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RESULTS OF OPERATIONS

Three Months Ended March 31, 2015 vs. March 31, 2014

In the first quarter of 2015 we had a net loss of $414.9 million ($4.84 per share) compared to net income of $138.5 million ($1.59 per diluted share) for the same period of 2014. The decrease in 2015 net income resulted primarily from significantly lower realized commodity prices which also brought about an impairment of our oil and gas properties. These changes are discussed further in the analysis that follows.

Production Revenue			Change Between 2015 /	Price/Volume Change		
(in thousands or as indicated)	2015	2014	2014	Price	Volume	Total
For the Three Months Ended March 31,						
Oil sales	$ 196,005	$ 325,071	(40) %	$ (229,309)	$ 100,243	$ (129,066)
Gas sales	110,962	170,097	(35) %	(102,319)	43,184	(59,135)
NGL sales	45,600	89,957	(49) %	(70,315)	25,958	(44,357)
	$ 352,567	$ 585,125	(40) %	$ (401,943)	$ 169,385	$ (232,558)

	For the Three Months Ended March 31,		Change Between 2015 /
	2015	2014	2014
Total oil volume — thousand barrels	4,612	3,525	31 %
Oil volume — barrels per day	51,241	39,168	31 %
Average oil price — per barrel	$ 42.50	$ 92.22	(54) %
Total gas volume — MMcf	40,125	31,973	25 %
Gas volume — MMcf per day	445.8	355.3	25 %

Average gas price — per Mcf	$ 2.77	$ 5.32	(48)	%
Total NGL volume — thousand barrels	2,902	2,252	29	%
NGL volume — barrels per day	32,242	25,028	29	%
Average NGL price — per barrel	$ 15.71	$ 39.94	(61)	%
Total equivalent production volumes — MMcfe per day	946.7	740.4	28	%

As reflected in the table above, our 2015 production revenue was 40% lower than that of 2014. Increased revenues from greater production volumes were more than offset by decreased revenues from lower realized commodity prices. See Revenues above for a discussion regarding realized prices.

First quarter 2015 aggregate production volumes were 85.2 Bcfe, comprised of 47% natural gas, 33% oil and 20% NGL. This compares to 2014 aggregate production volumes of 66.6 Bcfe, made up of 48% natural gas, 32% oil and 20% NGL. The 28% year-over-year growth in aggregate is primarily due to our drilling programs in the Permian Basin and Mid-Continent region.

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The table below reflects our regional production volumes.

	For the Three Months Ended March 31,	
	2015	2014
Oil (Bbls per day)		
Permian Basin	43,089	31,624
Mid-Continent	7,436	6,057
Other	716	1,487
	51,241	39,168
Gas (MMcf per day)		
Permian Basin	150.4	102.5
Mid-Continent	287.0	243.8
Other	8.4	9.0
	445.8	355.3
NGL (Bbls per day)		
Permian Basin	13,156	9,124
Mid-Continent	18,762	15,196
Other	324	708
	32,242	25,028
Total Equivalent (MMcfe per day)		
Permian Basin	487.8	347.0
Mid-Continent	444.1	371.3
Other	14.8	22.1
	946.7	740.4

We sometimes transport, process and market third-party gas that is associated with our equity 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 March 31,	
	2015	2014
Gas Gathering and Marketing (in thousands):		

Gas gathering and other revenues	$ 8,270	$ 12,464
Gas gathering and other costs	(8,864)	(8,784)
Gas gathering and other margin	$ (594)	$ 3,680
Gas marketing revenues, net of related costs	$ 165	$ 1,627

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.

Analysis of Operating Costs and Expenses

First quarter of 2015 total operating costs and expenses (not including gas gathering and marketing costs, other income and expense or income tax expense) were $987.6 million compared to $370.4 million in the same period of 2014. As discussed above in Operating costs and expenses, at March 31, 2015, our ceiling limitation calculation resulted in an impairment of our oil and gas properties of $603.6 million. Excluding the effect of the

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impairment, our quarter-over-quarter increase in operating costs and expenses was $13.5 million (4%). Year-over-year differences are discussed below.

	For the Three Months Ended March 31,		Variance Between 2015 / 2014	Per Mcfe	
	2015	2014		2015	2014
Operating costs and expenses (in thousands, except per Mcfe):					
Impairment of oil and gas properties	$ 603,599	$ —	$ 603,599	N/A	N/A
Depreciation, depletion and amortization	216,778	173,931	42,847	$ 2.54	$ 2.61
Asset retirement obligation	1,736	3,218	(1,482)	$ 0.02	$ 0.05
Production	82,211	75,141	7,070	$ 0.97	$ 1.13
Transportation, processing and other operating	39,642	44,248	(4,606)	$ 0.47	$ 0.66
Taxes other than income	21,981	33,621	(11,640)	$ 0.26	$ 0.51
General and administrative	15,938	20,712	(4,774)	$ 0.19	$ 0.31
Stock compensation	5,155	3,724	1,431	$ 0.06	$ 0.06
(Gain) loss on derivative instruments, net	—	15,735	(15,735)	N/A	N/A
Other operating, net	524	103	421	N/A	N/A
	$ 987,564	$ 370,433	$ 617,131		

Our first quarter 2015 DD&A expense of $216.8 million was 25% higher than the same period of 2014. DD&A is calculated before the ceiling test impairment calculation. The year-over-year increase is a result of higher production volumes in 2015, however, the higher production volumes cause the DD&A per Mcfe to decline.

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

	For the Three Months Ended March 31,		Variance Between 2015 / 2014	Per Mcfe	
(in thousands, except per Mcfe)	2015	2014		2015	2014
Lease operating expense	$ 68,505	$ 61,078	$ 7,427	$ 0.80	$ 0.92
Workover expense	13,706	14,063	(357)	$ 0.17	$ 0.21

	$ 82,211	$ 75,141	$ 7,070	$ 0.97	$ 1.13

First quarter 2015 lease operating expense increased 12% compared to the first quarter of 2014. Higher costs associated with putting new wells on production accounted for most of the year-over-year increase. Most of the higher costs were for salt water disposal, rental equipment and labor, which were partially offset by decreased costs resulting from property divestitures in 2014. The lower rate per Mcfe in 2015 was primarily a function of increased 2015 production volumes.

Workover expense for the first quarter of 2015 was relatively flat compared to the same period of 2014. Generally, these costs will fluctuate based on the amount of maintenance and remedial activity planned and/or required during the period.

Our transportation, processing and other operating costs in the first quarter of 2015 were 10% lower than the same period of 2014. These costs will vary by product type and region. In 2015, lower commodity prices resulted in lower costs associated with fuel and processing fees. The lower costs in 2015 were partially offset by higher processing volumes.

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. Taxes in the first quarter of 2015 were 35% lower than the same periods of 2014. The decrease was primarily a result of the

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significant year-over-year decline in realized commodity prices, which was only partially offset by increased production volumes.

G&A costs were as follows:

(in thousands)	For the Three Months Ended March 31, 2015	2014	Variance Between 2015 / 2014
G&A capitalized to oil & gas properties	$ 16,231	$ 17,175	$ (944)
G&A expense	15,938	20,712	(4,774)
	$ 32,169	$ 37,887	$ (5,718)
G&A expense per Mcfe	$ 0.19	$ 0.31	$ (0.12)

Our aggregate G&A of $32.2 million for the first quarter of 2015 was 15% lower than the same period of 2014. Because of the adverse effect of lower oil and gas prices on our financial results, we have reduced our expectations and accrual for short-term incentive-based cash compensation. The decrease in 2015 G&A expense per Mcfe also benefited from higher production volumes in 2015.

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

(in thousands)	For the Three Months Ended March 31, 2015	2014	Variance Between 2015 / 2014
Restricted stock awards			

Performance stock awards	$ 4,998	$ 2,947	$ 2,051
Service-based stock awards	4,937	3,504	1,433
	9,935	6,451	3,484
Stock option awards	639	773	(134)
	10,574	7,224	3,350
Less amounts capitalized to oil & gas properties	(5,419)	(3,500)	(1,919)
Stock compensation	$ 5,155	$ 3,724	$ 1,431

Expense associated with stock compensation will fluctuate based on the grant-date fair value of awards, the number and size of awards and the timing of the awards. The increase in 2015 stock compensation is primarily related to performance awards in December 2014. Historical amounts may not be representative of future amounts as the value of future awards may vary from historical amounts.

Net gains and losses on derivative instruments are a function of fluctuations in the underlying commodity prices and the monthly settlement of contracts. We did not have any derivative contracts outstanding during the first quarter of 2015.

Other (income) and expense

	For the Three Months Ended March 31,		Variance Between 2015 /
(in thousands)	2015	2014	2014
Interest expense	$ 21,256	$ 14,042	$ 7,214
Capitalized interest	(9,417)	(7,290)	(2,127)
Other, net	(3,585)	(6,955)	3,370
	$ 8,254	$ (203)	$ 8,457

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Interest expense is primarily made up of interest on debt and amortization of financing costs. The 51% year-over-year increase is primarily due to the issuance of $750 million of senior notes in June, 2014.

We capitalize interest on non-producing leasehold costs, the in-progress 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.

Components of "Other, net" consist of miscellaneous income and expense items that will vary from period to period, including gain or loss related to oil and gas well equipment and supplies, income and expense associated with other non-operating activities, miscellaneous asset sales and interest income. The 48% decrease in income for the first quarter of 2015 compared to the same period of 2014 is due primarily to lower gains on oil and gas well equipment and supplies in 2015.

We carry our oil and gas well equipment and supplies at their weighted average historical cost. Accounting rules require that these assets be valued at the lower of cost or market value. At March 31, 2015, the aggregate historical cost of our assets was lower than their market value. However, the industry-wide decline in drilling operations has put downward pressure on the price of oil and gas well equipment and supplies. Further declines in future periods could cause us to recognize impairments on these assets. An impairment would not affect cash flow from operating activities, but would adversely affect our net income and stockholders' equity.

Income Tax Expense

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

	Three Months Ended March 31,	
(in thousands)	2015	2014
Current taxes (benefit)	$ —	$ —
Deferred taxes (benefit)	(228,739)	81,745
	$ (228,739)	$ 81,745
Combined Federal and State effective income tax rate	35.5 %	37.1 %

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 7 to the Consolidated Financial Statements of this report for additional information regarding our income taxes.

LIQUIDITY AND CAPITAL RESOURCES

Overview

We strive to maintain an adequate liquidity level to address volatility and risk. Sources of liquidity include our cash flow from operations, cash on hand, available borrowing capacity under our senior unsecured revolving credit facility (Credit Facility), proceeds from sales of non-core assets and public financings.

Our liquidity is highly dependent on prices we receive for the oil, gas and NGLs we produce. Prices we receive are determined by prevailing market conditions and greatly influence our revenue, cash flow, profitability, access to capital and future rate of growth. See Market Conditions, Revenues and RESULTS OF OPERATIONS above for further information and analysis of the impact realized prices had on our 2015 revenues.

We deal with volatility in commodity prices primarily by maintaining flexibility in our capital investment program. We have a diversified drilling portfolio and limited long-term commitments, which enables us to respond quickly to industry volatility. Based on current economic conditions and our expectations for 2015 cash flows from operations, our 2015 E&D capital expenditures are expected to range from $900 million to $1.1 billion, down from $1.88 billion in 2014.

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In addition, we believe our conservative use of leverage and strong balance sheet will mitigate our exposure to lower prices. At March 31, 2015, our long-term debt consisted of $1.5 billion of senior notes. We had letters of credit outstanding under our Credit Facility of $2.5 million, leaving an unused borrowing availability of $997.5 million.

Our debt to total capitalization at March 31, 2015, was 27%, up slightly from 25% at December 31, 2014. The reconciliation of debt to total capitalization, which is a non-GAAP measure, is: long-term debt divided by the sum of long-term debt plus stockholders' equity. Management believes 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 fund our currently planned 2015 capital expenditures, working capital, debt service and dividend payments. Funding of accelerated or future activities may require additional sources of external capital, which may include bank borrowings or proceeds from public debt or common equity offerings.

Analysis of Cash Flow Changes (See the Condensed Consolidated Statements of Cash Flows)

Net cash flow provided by operating activities (operating cash flow) for the first quarter of 2015 was $113.2 million, compared to $348.0 million in the same period of 2014. The $234.9 million decrease resulted primarily from a year-over-year net decrease in production revenue of $232.6 million. See RESULTS OF OPERATIONS above for details regarding the 2015 decrease in production revenue.

For the first three months of 2015, net cash flow used for investing activities was $388.8 million, a decrease of $51.0 million (12%) from $439.8 million in the first quarter of 2014. Almost all of the decrease resulted from reduced E&D investments in 2015. Due to the prevailing economic conditions, management decreased our 2015 E&D budget significantly compared to 2014. See Market Conditions above.

During the first quarter of 2015, net cash flow used in financing activities was $9.3 million compared to net cash provided by financing activities of $91.8 million for the same period of 2014. The primary difference in the year-over-year amounts was $101.0 million of net cash provided by bank debt borrowings in the 2014 period. We had no debt borrowings in the 2015 period.

Reconciliation of Adjusted Cash Flow from Operations

(in thousands)	Three Months Ended March 31, 2015	2014
Net cash provided by operating activities	$ 113,173	$ 348,024
Change in operating assets and liabilities	73,772	60,868
Adjusted cash flow from operations	$ 186,945	$ 408,892

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.

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Capital Expenditures

The following table sets forth certain historical information regarding capitalized expenditures for oil and gas acquisitions, E&D activities and property sales.

	Three Months Ended March 31,	
(in thousands)	2015	2014
Acquisitions:		
Proved	$ 30	$ —
Unproved	1,869	—
	1,899	—
Exploration and development:		
Land and seismic	22,690	65,325
Exploration and development	285,527	401,702
	308,217	467,027
Sales proceeds:		
Proved	(1,145)	—
Unproved	—	—
	(1,145)	—
	$ 308,971	$ 467,027

Amounts in the table above are presented on an accrual basis. The Condensed Consolidated Statements of Cash Flows in this report reflect activities on a cash basis, when payments are made or received.

Our 2015 E&D capital investment is presently expected to range from $900 million to $1.1 billion, which will again be directed toward drilling in the Permian Basin and Mid-Continent regions. During the first quarter of 2015 and 2014, approximately 68% and 69%, respectively, of our E&D expenditures were for Permian Basin projects with the majority of the remainder invested in projects in the Mid-Continent region.

We intend to fund our capital program with cash on hand and cash flow from our operating activities. Sales of non-core assets, borrowings under our Credit Facility and public financings may also be used to supplement funding of planned capital expenditures. The timing of capital expenditures and the receipt of cash flows do not necessarily match, which may also cause us to borrow and repay funds under our Credit Facility throughout the year.

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The following table reflects wells brought on production by region.

	Three Months Ended March 31,	
	2015	2014
Gross wells		
Permian Basin	42	34
Mid-Continent	11	39
Other	—	1
	53	74
Net wells		
Permian Basin	30	21
Mid-Continent	3	14
Other	—	1
	33	36
% Gross wells completed as producers	98 %	99 %

As of March 31, 2015, we had 59 gross wells awaiting completion: 23 Permian Basin and 36 Mid-Continent. We also had 8 operated rigs running: 3 in the Permian Basin and 5 in the Mid-Continent region. We regularly review our E&D capital expenditures and will adjust our activity based on changes in our outlook for market conditions, including commodity prices and service costs.

In the ordinary course of business we regularly evaluate opportunities to purchase properties that we believe could benefit from our technical capabilities. We also evaluate our non-core property holdings for potential divestitures.

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

Financial Condition

In the first quarter of 2015, our total assets decreased by $865.2 million to $7.86 billion, down from $8.73 billion at December 31, 2014. The decrease was primarily attributable to the $603.6 million impairment of our oil and gas properties and a $284.9 million decrease in cash and cash equivalents.

Total liabilities at March 31, 2015, were $3.77 billion, compared to $4.22 billion at December 31, 2014. Approximately half of the $450.7 million decrease was from a decrease in total current liabilities related to our oil and gas operations and drilling activity. The remaining decrease comes from a decrease in deferred income taxes mostly resulting from our net loss for the first quarter of 2015.

Stockholders' equity totaled $4.09 billion at March 31, 2015, down $414.5 million from $4.50 billion at December 31, 2014. The decrease resulted mainly from a net loss of $414.9 for the first quarter of 2015.

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Long-term Debt

Long-term debt at March 31, 2015, and December 31, 2014, consisted of the following:

(in thousands)	March 31, 2015	December 31, 2014
5.875% Senior Notes, due May 1, 2022	$ 750,000	$ 750,000
4.375% Senior Notes, due June 1, 2024	750,000	750,000
Total long-term debt	$ 1,500,000	$ 1,500,000

All of our long-term debt is senior unsecured debt and is pari passu with respect to the payment of both principal and interest.

Bank Debt

Our Credit Facility matures July 14, 2018. The Credit Facility has a borrowing base of $2.5 billion and aggregate commitments of $1.0 billion. The borrowing base is determined at the discretion of the lenders based on the value of our proved reserves. Our borrowing base was reaffirmed in April 2015. The next regular annual redetermination date is scheduled for April 15, 2016.

At March 31, 2015, we had letters of credit outstanding of $2.5 million, leaving an unused borrowing availability of $997.5 million. During the first three months of 2015 we did not have any bank debt outstanding. During the same period of 2014, we had average daily bank debt outstanding of $259.8 million. In the 2014 period our highest amount of bank borrowings outstanding was $365.0 million, occurring in March.

At our option, borrowings under the Credit Facility 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 with which we were in compliance at March 31, 2015.

Senior Notes

Interest on our senior notes is payable semi-annually. Each of the senior notes is governed by an indenture containing customary covenants, events of default and other restrictive provisions with which we were in compliance at March 31, 2015.

Working Capital Analysis

Our working capital fluctuates primarily as a result of our realized commodity prices, increases or decreases in our production volumes and changes in our operating and E&D activities.

At March 31, 2015, we had working capital of $8.0 million, a decrease of $147.5 million compared to working capital of $155.5 million at December 31, 2014.

Working capital decreases consisted of the following:

- Cash and cash equivalents decreased by $284.9 million.
- Operations-related accounts receivable decreased by $72.1 million.
- Oil and gas well equipment and supplies decreased by $8.3 million.

Decreases in working capital were partially offset by the following:

- Operations-related accounts payable and accrued liabilities decreased by $139.1 million.

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- Accrued liabilities related to our E&D expenditures decreased by $84.1 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.

Dividends

A quarterly cash dividend has been paid to stockholders every quarter since the first quarter of 2006. Future dividend payments will depend on our level of earnings, financing requirements, and other factors considered relevant by our Board of Directors.

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 March 31, 2015, our material off-balance sheet arrangements included customary operating lease agreements and are included in the table below.

Contractual Obligations and Material Commitments

At March 31, 2015, we had contractual obligations and material commitments as follows:

	Payments Due by Period				
Contractual obligations:		1 Year or	2 - 3	4 - 5	More than
(in thousands)	Total	Less	Years	Years	5 Years
Long-term debt (1)	$ 1,500,000	$ —	$ —	$ —	$ 1,500,000

Fixed-Rate interest payments (1)	642,188	76,876	153,750	153,750	257,812
Operating leases	118,520	10,293	22,100	20,982	65,145
Drilling commitments (2)	245,715	234,388	11,327	—	—
Gathering facilities and pipelines (3)	5,956	5,956	—	—	—
Asset retirement obligation (4)	176,332	13,897	— (4)	— (4)	— (4)
Other liabilities (5)	85,855	21,164	43,669	322	20,700
Firm transportation	259,921	250,985	8,936	—	—

(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 $200.4 million consisting of obligations to finish drilling and completing wells in progress at March 31, 2015. We also have minimum commitments for six drilling rigs of $45.3 million.

(3) We have commitments relating to projects in New Mexico and Texas where we are constructing gathering facilities and pipelines.

(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 March 31, 2015, we had firm sales contracts to deliver approximately 51.3 Bcf of natural gas over the next 43 months. In total, our financial exposure would be approximately $120.9 million should we not deliver this gas. Our exposure will fluctuate with price volatility and actual volumes delivered. However, we believe we will have no financial exposure from these contracts based on our current proved reserves and production levels from which we can fulfill these obligations.

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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.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

We consider accounting policies related to oil and gas reserves, full cost accounting, goodwill, contingencies, asset retirement obligations and income taxes to be critical policies and estimates. These are summarized in Management's Discussion and Analysis of Financial Condition and Results of Operations in our Annual Report on Form 10-K/A for the year ended December 31, 2014.

Recent Accounting Developments

Please refer to Note 1, Basis of Presentation – Recently Issued Accounting Standards, to the Consolidated Financial Statements in this report for a discussion of recent accounting pronouncements and their anticipated effect on our business.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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, gas and NGL 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, gas and NGL 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. At March 31, 2015, we had no hedges in place. See Note 9 to the Consolidated Financial Statements of this report for additional information regarding our derivative instruments.

Oil sales contributed 56% of our total production revenue for the first quarter of 2015. Gas sales accounted for 31% and NGL sales contributed 13%. A $1.00 per barrel change in our realized oil price would have resulted in a $4.6 million change in revenues. A $0.10 per Mcf change in our realized gas price would have resulted in a $4.0 million change in our gas revenues. A $1.00 per barrel change in NGL prices would have changed revenues by $2.9 million.

Interest Rate Risk

At March 31, 2015, 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. No sensitivity analysis is provided for the Credit Facility, which has variable interest rates, because no amounts were outstanding at March 31, 2015. See Note 5 and Note 8 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 management, under the supervision and with the participation of the Chief Executive Officer (CEO) and Chief Financial Officer (CFO), have evaluated the effectiveness of 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

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Act)) as of March 31, 2015. 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 March 31, 2015, 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

The information set forth under the heading “Litigation” in Note 10 to the Consolidated Financial Statements included in Part I, Item 1 of this report is incorporated by reference in response to this item.

ITEM 1A. RISK FACTORS

In addition to the other information set forth in this report, you should carefully consider the risks discussed in our Annual Report on Form 10-K/A for the year ended December 31, 2014 as well as the updated risk factor set forth below. Other than with respect to the updated risk factor below, there have been no material changes in our risk factors from those described in the Annual Report on Form 10-K/A for the year ended December 31, 2014. The risks described in the Annual Report on Form 10-K/A for the year ended December 31, 2014 and below are not the only risks facing us. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition or future results.

Our hydraulic fracturing activities are subject to risks that could negatively impact our operations and profitability.

We use hydraulic fracturing for the completion of almost all of our wells. Hydraulic fracturing is a process that involves pumping fluid and proppant at high pressure into a hydrocarbon bearing formation to create and hold open fractures. Those fractures enable gas or oil to move through the formation's pores to the well bore. Typically, the fluid used in this process is primarily water. In plays where hydraulic fracturing is necessary for successful development, the demand for water may exceed the supply. A lack of readily available water or a significant increase in the cost of water could cause delays or increased completion costs.

While hydraulic fracturing historically has been regulated by state oil and natural gas commissions, the practice has become increasingly controversial in certain parts of the country, resulting in increased scrutiny and regulation from federal agencies. For example, the U.S. Environmental Protection Agency (EPA) has asserted federal regulatory authority over certain hydraulic-fracturing activities under the Safe Drinking Water Act (SDWA) involving the use of diesel fuels and published permitting guidance in February 2014 addressing the use of diesel in fracturing operations. Although the EPA is not the permitting authority for the SDWA’s Underground Injection Control Class II programs in Oklahoma, Texas or New Mexico, where we maintain operational acreage, the EPA is encouraging state programs to review and consider use of such draft guidance. Also, the EPA is updating chloride water quality criteria for the protection of aquatic life under the Clean Water Act, which criteria are used by states for establishing acceptable discharge limits. The EPA is expected to release draft criteria in early 2016. On April 7, 2015, the EPA published in the Federal Register a proposed rule requiring federal pre-treatment standards for wastewater generated during the hydraulic fracturing process. Hydraulic fracturing stimulation requires the use of a significant volume of water with some resulting “flowback,” as well as “produced water.” If adopted, the new pretreatment rules will require shale gas operations to pretreat wastewater before transferring it to treatment facilities. The proposed rule is undergoing a public comment period, which ends on June 8, 2015. Moreover, in May 2014, the EPA issued an Advanced Notice of Proposed Rulemaking seeking public comment on its intent to develop and issue regulations under the Toxic Substances Control Act regarding the disclosure of information related to the chemicals used in hydraulic fracturing. The public comment period ended on September 18, 2014.

In August 2012, the EPA adopted rules that subject oil and natural gas production, processing, transmission, and storage operations to regulation under the New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants programs. The rules include NSPS standards for completions of hydraulically fractured gas wells and establishes specific new requirements for emissions from compressors, controllers, dehydrators, storage vessels, natural gas processing plants and certain other equipment. The final rules seek to achieve a 95% reduction in volatile organic compounds (VOCs) emitted by requiring the use of reduced emission completions or “green completions” on all hydraulically-fractured wells constructed or refractured after January 1, 2015. The EPA received numerous requests for reconsideration of these rules from both industry and the environmental community. In response, the EPA has issued, and will likely continue to issue, revised rules responsive to some of these requests for reconsideration. In addition, on January 14, 2015, the EPA announced a series of steps it plans to take to address methane and smog-forming VOC emissions from the oil and

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gas industry. These standards, as well as any future laws and their implementing regulations, may require us to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities expected to produce air emissions, impose stringent air permit requirements, or utilize specific equipment or technologies to control emissions. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

In addition, on March 26, 2015, the federal Bureau of Land Management published a final rule governing hydraulic fracturing on federal and Indian lands. The rule requires public disclosure of chemicals used in hydraulic fracturing on federal and Indian lands, confirmation that wells used in fracturing operations meet appropriate construction standards, development of appropriate plans for managing flowback water that returns to the surface, increased standards for interim storage of recovered waste fluids, and submission to the Bureau of Land Management of detailed information on the geology, depth and location of preexisting wells. This rule will take effect on June 24, 2015, although it is the subject of several pending lawsuits recently filed by industry groups and at least three states, alleging that federal law does not give the Bureau of Land Management authority to regulate hydraulic fracturing.

There are also certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater. A draft report is expected to be released for public comment; however the report is still pending. The EPA’s study could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies could spur initiatives to further regulate hydraulic fracturing.

Additionally, Congress from time to time has considered the adoption of legislation to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. Certain states, including Texas and Colorado, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure, and well construction requirements on hydraulic-fracturing operations or otherwise seek to ban fracturing activities altogether. For example, in October 2011, the Louisiana Department of Natural Resources adopted new rules requiring the public disclosure of the composition and volume of fracturing fluids used in hydraulic fracturing operations. Also, October 28, 2014, the Texas Railroad Commission adopted disposal well rule amendments designed, amongst other things, to require applicants for new disposal wells that will receive non-hazardous produced water and hydraulic fracturing flowback fluid to conduct seismic activity searches utilizing the U.S. Geological Survey. The searches are intended to determine the potential for earthquakes within a circular area of 100 square miles around a proposed, new disposal well. The disposal well rule amendments also clarify the Commission’s authority to modify, suspend or terminate a disposal well permit if scientific data indicates a disposal well is likely to contribute to seismic activity. The disposal well rule amendments became effective November 17, 2014. Furthermore, in May 2013, the Texas Railroad Commission adopted new rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular. In the event state, local, or municipal legal restrictions are adopted in areas where we are currently conducting, or in the future plan to conduct operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling of wells.

Any of the above factors could have a material adverse effect on our financial position, results of operations or cash flows and could make it more difficult or costly for us to perform fracturing to stimulate production from dense subsurface rock formations and, in the event of local prohibitions against commercial production of natural gas, may preclude our ability to drill wells. In addition, our fracturing activities could become subject to additional permitting requirements and result in permitting delays as well as potential increases in costs. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

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We may be subject to information technology system failures, network disruptions and breaches in data security, and our business, financial position, results of operations and cash flows could be negatively affected by such security threats and disruptions.

As an oil and gas producer, we face various security threats, including cybersecurity threats such as attempts to gain unauthorized access to sensitive information or to render data or systems unusable; threats to the security of our facilities and infrastructure or third-party facilities and infrastructure, such as gathering and processing facilities, pipelines and refineries; and threats from terrorist acts. Cybersecurity attacks are becoming more sophisticated and include, but are not limited to, malicious software, attempts to gain unauthorized access to data and systems, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information, and corruption of data, which could have an adverse effect on our reputation, business, financial condition, results of operations or cash flows. While we have not suffered any material losses relating to such attacks, there can be no assurance that we will not suffer such losses in the future.

We rely heavily on our information systems, and the availability and integrity of these systems are essential for us to conduct our business and operations. In addition to cybersecurity and data security threats, other information system failures and network disruptions could have a material adverse effect on our ability to conduct our business. We could experience system failures due to power or telecommunications failures, human error, natural disasters, fire, sabotage, hardware or software malfunction or defects, computer viruses, intentional acts of vandalism or terrorism and similar acts or occurrences. Such system failures could result in the unanticipated disruption of our operations, communications or processing of transactions, as well as loss of, or damage to, sensitive information, facilities, infrastructure and systems essential to our business and operations, the failure to meet regulatory standards and the reporting of our financial results, and other disruptions to our operations, which, in turn, could have a material adverse effect on our business, financial position, results of operations and cash flows.

While management has taken steps to address these concerns by implementing network security and internal control measures to monitor and mitigate security threats and to increase security for our information, facilities, and infrastructure, our implementation of such procedures and controls may result in increased costs, and there can be no assurance that a system failure or data security breach will not occur and have a material adverse effect on our business, financial condition and results of operations. In addition, as cybersecurity threats continue to evolve, we may be required to expend additional resources to continue to modify or enhance our protective measures or to investigate or remediate any cybersecurity or information technology infrastructure vulnerabilities.

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ITEM 6. EXHIBITS

3.1	Amended and Restated Certificate of Incorporation of Cimarex Energy Co. (filed as Exhibit 3.1 to Registrant’s Form 8-K (Commission File no. 001-31446) dated June 7, 2005, and incorporated herein by reference).
3.2	Amended and Restated By-laws of Cimarex Energy Co. dated December 11, 2013, (filed on December 16, 2013, (Commission File No. 001-31446) and incorporated herein by reference).
4.1	Specimen Certificate of Cimarex Energy Co. common stock (filed as Exhibit 4.3 to Registration Statement on Form S-3 filed September 17, 2012, (Registration No. 333-183939) and incorporated herein by reference).
10.1	Form of Notice of Grant of Restricted Stock and Award Agreement (Performance Award) (filed as Exhibit 10.24 to the Annual Report on Form 10-K for the year ended December 31, 2014, filed on February 25, 2015, (Commission File No. 001-31446) and incorporated herein by reference).
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.

May 5, 2015

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)