CIMAREX ENERGY CO
Form 10-Q
August 05, 2015
Table of Contents

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, 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 June 30, 2015 was 94,456,420.

CIMAREX ENERGY CO.

Table of Contents

Table of Contents

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.

Table of Contents

PART I

ITEM 1 - Financial Statements

CIMAREX ENERGY CO.

Condensed Consolidated Balance Sheets

(Unaudited)

	June 30, 2015	December 31, 2014
	(in thousands, except share data)	
Assets		
Current assets:		
Cash and cash equivalents	$ 856,880	$ 405,862
Receivables, net	319,370	412,108
Oil and gas well equipment and supplies	75,165	89,780
Deferred income taxes	6,961	13,475
Prepaid expenses	8,208	9,356
Other current assets	865	1,223
Total current assets	1,267,449	931,804
Oil and gas properties at cost, using the full cost method of accounting:		
Proved properties	15,043,625	14,402,064
Unproved properties and properties under development, not being amortized	599,654	759,149
	15,643,279	15,161,213
Less — accumulated depreciation, depletion, amortization and impairment	(10,242,417)	(8,257,502)
Net oil and gas properties	5,400,862	6,903,711
Fixed assets, net	223,646	211,031
Goodwill	620,232	620,232
Other assets, net	56,315	58,515
	$ 7,568,504	$ 8,725,293
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable	$ 71,486	$ 138,051
Accrued liabilities	262,727	447,384
Revenue payable	164,671	190,892
Total current liabilities	498,884	776,327
Long-term debt	1,500,000	1,500,000
Deferred income taxes	1,177,289	1,754,706
Other liabilities	196,168	193,628
Total liabilities	3,372,341	4,224,661
Commitments and contingencies		
Stockholders' equity:		
Preferred stock, $0.01 par value, 15,000,000 shares authorized, no shares issued	—	—
	945	876

Common stock, $0.01 par value, 200,000,000 shares authorized, 94,456,420 and 87,592,535 shares issued, respectively		
Paid-in capital	2,737,008	1,997,080
Retained earnings	1,457,298	2,501,574
Accumulated other comprehensive income	912	1,102
	4,196,163	4,500,632
	$ 7,568,504	$ 8,725,293

See accompanying notes to consolidated financial statements.

4

Table of Contents

CIMAREX ENERGY CO.

Consolidated Statements of Operations and Comprehensive Income (Loss)

(Unaudited)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	2015	2014
	(in thousands, except per share data)			
Revenues:				
Oil sales	$ 259,344	$ 354,882	$ 455,349	$ 679,953
Gas sales	106,374	172,503	217,336	342,600
NGL sales	49,477	95,470	95,077	185,427
Gas gathering and other	9,141	14,284	17,411	26,748
Gas marketing, net	(53)	(470)	112	1,157
	424,283	636,669	785,285	1,235,885
Costs and expenses:				
Impairment of oil and gas properties	967,287	—	1,570,886	—
Depreciation, depletion and amortization	217,451	194,989	434,229	368,920
Asset retirement obligation	2,042	3,650	3,778	6,868
Production	70,600	86,085	152,811	161,226
Transportation, processing, and other operating	43,713	46,478	83,355	90,726
Gas gathering and other	11,306	10,041	20,170	18,825
Taxes other than income	25,980	32,323	47,961	65,944
General and administrative	14,054	16,571	29,992	37,283
Stock compensation	4,988	3,548	10,143	7,272
(Gain) loss on derivative instruments, net	—	2,454	—	18,189
Other operating, net	260	112	784	215
	1,357,681	396,251	2,354,109	775,468
Operating income (loss)	(933,398)	240,418	(1,568,824)	460,417
Other (income) and expense:				
Interest expense	21,297	16,724	42,553	30,766
Capitalized interest	(8,570)	(8,575)	(17,987)	(15,865)
Other, net	(3,854)	(4,129)	(7,439)	(11,084)
Income (loss) before income tax	(942,271)	236,398	(1,585,951)	456,600
Income tax expense (benefit)	(342,056)	87,758	(570,795)	169,503
Net income (loss)	$ (600,215)	$ 148,640	$ (1,015,156)	$ 287,097
Earnings (loss) per share to common stockholders:				
Basic	$ (6.47)	$ 1.71	$ (10.94)	$ 3.30
Diluted	$ (6.47)	$ 1.70	$ (10.94)	$ 3.29
Dividends per share	$ 0.16	$ 0.16	$ 0.32	$ 0.32
Comprehensive income (loss):				

Net income (loss)	$ (600,215)	$ 148,640	$ (1,015,156)	$ 287,097
Other comprehensive income (loss):				
Change in fair value of investments, net of tax	(292)	(56)	(190)	(16)
Total comprehensive income (loss)	$ (600,507)	$ 148,584	$ (1,015,346)	$ 287,081

See accompanying notes to consolidated financial statements.

Table of Contents

CIMAREX ENERGY CO.

Condensed Consolidated Statements of Cash Flows

(Unaudited)

	For the Six Months Ended June 30,	
	2015	2014
	(in thousands)	
Cash flows from operating activities:		
Net income (loss)	$ (1,015,156)	$ 287,097
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Impairment of oil and gas properties	1,570,886	—
Depreciation, depletion and amortization	434,229	368,920
Asset retirement obligation	3,778	6,868
Deferred income taxes	(570,795)	169,503
Stock compensation	10,143	7,272
(Gain) loss on derivative instruments	—	18,189
Settlements on derivative instruments	—	(5,804)
Changes in non-current assets and liabilities	2,942	(2,436)
Other, net	3,276	2,395
Changes in operating assets and liabilities:		
Receivables, net	92,473	(81,702)
Other current assets	16,121	(19,182)
Accounts payable and other current liabilities	(177,352)	18,649
Net cash provided by operating activities	370,545	769,769
Cash flows from investing activities:		
Oil and gas expenditures	(599,222)	(1,138,539)
Sales of oil and gas assets and other assets	9,233	1,374
Other capital expenditures	(35,882)	(51,401)
Net cash used by investing activities	(625,871)	(1,188,566)
Cash flows from financing activities:		
Net bank debt borrowings	—	(174,000)
Proceeds from other long-term debt	—	750,000
Proceeds from sale of common stock	752,100	—
Financing and underwriting fees	(22,563)	(11,218)
Dividends paid	(28,129)	(26,022)
Proceeds from exercise of stock options and other	4,936	4,061
Net cash provided by financing activities	706,344	542,821
Net change in cash and cash equivalents	451,018	124,024
Cash and cash equivalents at beginning of period	405,862	4,531
Cash and cash equivalents at end of period	$ 856,880	$ 128,555

See accompanying notes to consolidated financial statements.

6

Table of Contents

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements

June 30, 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. Due to continued decreases in the 12-month average trailing prices, we recognized an additional impairment of $967.3 million ($614.6 million, net of tax) at June 30, 2015. 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 or future results. Impairment charges do not affect cash flow from operating activities, but do adversely affect our net income and stockholders' equity. Any recorded impairment of oil and gas properties is not reversible at a later date.

Table of Contents

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements

June 30, 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)	June 30, 2015	December 31, 2014
Receivables, net of allowance		
Trade	$ 77,680	$ 134,443
Oil and gas sales	227,868	259,220
Gas gathering, processing, and marketing	13,795	18,009
Other	27	436
Receivables, net	$ 319,370	$ 412,108
Accounts payable		
Trade	$ 44,696	$ 102,276
Gas gathering, processing, and marketing	26,790	35,775
Accounts payable	$ 71,486	$ 138,051
Accrued liabilities		
Exploration and development	$ 62,970	$ 200,929
Taxes other than income	23,682	26,950
Other	176,075	219,505
Accrued liabilities	$ 262,727	$ 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 July 2015, the FASB deferred the effective date by one year to annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period. Early adoption is permitted, but not before the original effective date of reporting periods beginning after December 15, 2016. We do not intend to adopt the standard early and 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.

Table of Contents

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements

June 30, 2015

(Unaudited)

2.Capital Stock

In May 2015, we completed an underwritten public offering of 6,900,000 shares of common stock, which included 900,000 shares of common stock issued pursuant to an overallotment option to purchase additional shares granted to the underwriters. The stock was sold to the public at $109.00 per share, with a par value of $0.01, and we received net proceeds of approximately $730 million from the sale of these shares of common stock, after deducting underwriting fees.

Authorized capital stock consists of 200 million shares of common stock and 15 million shares of preferred stock. At June 30, 2015, there were no shares of preferred stock outstanding. A summary of our common stock activity for the six months ended June 30, 2015 follows:

(in thousands)	
Issued and outstanding as of December 31, 2014	87,592
Issuance of common stock	6,900
Issuance of service-based restricted stock awards	23
Restricted stock forfeited and retired	(16)
Common stock reacquired and retired	(129)
Option exercises, net of cancellations	86
Issued and outstanding as of June 30, 2015	94,456

Dividends

In May 2015, the Board of Directors declared a cash dividend of $0.16 per share. The dividend is payable on September 1, 2015, to stockholders of record on August 14, 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 June 30,		Six Months Ended June 30,	
(in thousands)	2015	2014	2015	2014
Restricted stock awards				
Performance stock awards	$ 4,645	$ 2,867	$ 9,643	$ 5,814
Service-based stock awards	3,861	3,112	8,798	6,616
	8,506	5,979	18,441	12,430
Stock option awards	647	782	1,286	1,555
	9,153	6,761	19,727	13,985
Less amounts capitalized to oil and gas properties	(4,165)	(3,213)	(9,584)	(6,713)
Compensation expense	$ 4,988	$ 3,548	$ 10,143	$ 7,272

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

Table of Contents

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements

June 30, 2015

(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 six months ended June 30, 2015:

(in thousands)		
Asset retirement obligation at January 1, 2015	$	173,008
Liabilities incurred		2,019
Liability settlements and disposals		(13,593)
Accretion expense		3,900
Revisions of estimated liabilities		3,783
Asset retirement obligation at June 30, 2015		169,117
Less current obligation		(9,963)
Long-term asset retirement obligation	$	159,154

5.Long-Term Debt

Debt at June 30, 2015 and December 31, 2014 consisted of the following:

(in thousands)	June 30, 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 June 30, 2015, we had letters of credit outstanding under the Credit Facility of $2.5 million, leaving an unused borrowing availability of $997.5 million.

The Credit Facility also has customary covenants with which we were in compliance as of June 30, 2015.

Table of Contents

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements

June 30, 2015

(Unaudited)

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 June 30, 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 June 30,		Six Months Ended June 30,	
(in thousands, except per share data)	2015	2014	2015	2014
Basic:				
Net income (loss)	$ (600,215)	$ 148,640	$ (1,015,156)	$ 287,097
Participating securities’ share in earnings (1)	—	(2,320)	—	(4,464)
Net income (loss) applicable to common stockholders	$ (600,215)	$ 146,320	$ (1,015,156)	$ 282,633
Diluted:				
Net income (loss)	$ (600,215)	$ 148,640	$ (1,015,156)	$ 287,097
Participating securities’ share in earnings (1)	—	(2,316)	—	(4,457)
Net income (loss) applicable to common stockholders	$ (600,215)	$ 146,324	$ (1,015,156)	$ 282,640
Shares:				
Basic shares outstanding	92,831	85,532	92,831	85,532

Dilutive effect of stock options	—	157	—	147
Fully diluted common stock	92,831	85,689	92,831	85,679
Excluded (2)	1,931	—	1,931	1
Earnings (loss) per share to common stockholders (3):				
Basic	$ (6.47)	$ 1.71	$ (10.94)	$ 3.30
Diluted	$ (6.47)	$ 1.70	$ (10.94)	$ 3.29

(1) Participating securities are not included in undistributed earnings when a loss exists.
(2) Inclusion of certain shares would have an anti-dilutive effect.
(3) Earnings (loss) per share are based on actual figures rather than the rounded figures presented.

11

Table of Contents

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements

June 30, 2015

(Unaudited)

7.Income Taxes

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

(in thousands)	Three Months Ended June 30, 2015	2014	Six Months Ended June 30, 2015	2014
Current taxes (benefit)	$ —	$ —	$ —	$ —
Deferred taxes (benefit)	(342,056)	87,758	(570,795)	169,503
	$ (342,056)	$ 87,758	$ (570,795)	$ 169,503
Combined Federal and State effective income tax rate	36.3 %	37.1 %	36.0 %	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 June 30, 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.

Table of Contents

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements

June 30, 2015

(Unaudited)

The following tables provide fair value measurement information for certain assets and liabilities as of June 30, 2015 and December 31, 2014:

June 30, 2015:	Carrying	Fair
(in thousands)	Amount	Value
Financial Assets (Liabilities):		
5.875% Notes due 2022	$ (750,000)	$ (802,500)
4.375% Notes due 2024	$ (750,000)	$ (742,500)

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 June 30, 2015 and December 31, 2014, the allowance for doubtful accounts was $1.8 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. As of June 30, 2015, we had not entered into any new contracts. Subsequent to June 30, 2015, we entered into the following gas hedges:

				Weighted Average Price	
Period	Type	Volume/Day	Index (1)	Floor	Ceiling
Jan 16 - Dec 16	Collars	10,000 MMBtu	PEPL	$ 2.70	$ 2.85

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

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.

Table of Contents

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements

June 30, 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.

(in thousands)	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
Gain (loss) on derivative instruments, net	$ —	$ (2,454)	$ —	$ (18,189)
Settlement gains (losses)	$ —	$ (1,017)	$ —	$ (5,804)

10.Commitments and Contingencies

Commitments

We have commitments of $138.1 million to finish drilling and completing wells in progress at June 30, 2015. We also have minimum commitments for six drilling rigs of $37.8 million.

We had commitments of $6.3 million relating to the construction of gathering facilities and pipelines in New Mexico and Texas.

At June 30, 2015, we had firm sales contracts to deliver approximately 44.3 Bcf of natural gas over the next 40 months. If this gas is not delivered, our financial commitment would be approximately $116.2 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.

In connection with gas gathering and processing agreements, we have volume commitments over the next seven years. If no gas is delivered, the maximum amount that would be payable under these commitments would be approximately $85.8 million. 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 $44.1 million.

We have various commitments for office space and equipment under operating lease arrangements totaling $101.9 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

Table of Contents

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements

June 30, 2015

(Unaudited)

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.

11.Supplemental Disclosure of Cash Flow Information

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2015	2014	2015	2014
Cash paid during the period for:				
Interest expense (including capitalized amounts)	$ 39,277	$ 24,195	$ 40,212	$ 26,290
Interest capitalized	$ 16,583	$ 12,469	$ 16,997	$ 13,557
Income taxes	$ 555	$ 353	$ 556	$ 354
Cash received for income taxes	$ 109	$ 133	$ 409	$ 342

Table of Contents

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. Thus far in 2015 there has been little recovery of oil prices 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 second quarter of 2014, our realized oil price fell 46% to $50.66/Bbl. Similarly, our realized natural gas price dropped 46% to $2.51/Mcf and our realized price for NGL declined 59% to $14.67/Bbl.

This dramatic decrease in commodity prices 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 second quarter of 2015, the continued impact of lower prices on the present value of future cash flows from our proved reserves resulted in a non-cash full cost ceiling impairment to our oil and gas properties of $967.3 million ($614.6 million, net of tax). For the six months ended June 30, 2015, full cost ceiling impairments have totaled $1.57 billion ($997.8 million, net of tax). See a discussion of the ceiling impairment calculation below under Operating costs and expenses.

Our 2015 E&D capital expenditures are expected to approximate $1.0 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.

Table of Contents

Second quarter 2015 summary of operating and financial results:

- Average daily production increased 22% to 1,026.2 MMcfe/d.
- Oil production grew 35% to 56,261 Bbl/d, gas production increased 14% to 466.3 MMcf/d and NGL volumes were up 25% to 37,070 Bbl/d.
- Oil, gas and NGL sales totaled $415.2 million, down from $622.9 million a year earlier.
- Exploration and development expenditures totaled $190.3 million versus $497.6 million a year earlier.
- Cash flow provided by operating activities during the first six months of 2015 was $370.5 million compared to $769.8 million for the same period of 2014.
- We incurred a net loss of $600.2 million ($6.47 per share).
- We completed a public offering of 6.9 million shares of our common stock with net proceeds of approximately $730 million.
- Total debt at June 30, 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 59% of our total production revenue for the first six months of 2015. Gas sales accounted for 28% and NGL sales contributed 13%. A $1.00 per barrel change in our realized oil price would have resulted in a $9.7 million change in revenues. A $0.10 per Mcf change in our realized gas price would have resulted in an $8.3 million change in our gas revenues. A $1.00 per barrel change in NGL prices would have changed revenues by $6.3 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 six months of 2015.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Oil Prices:				

Average realized sales price ($/Bbl)	$ 50.66	$ 93.39	$ 46.79	$ 92.82
Average WTI Midland price ($/Bbl)	$ 57.36	$ 94.58	$ 52.01	$ 94.87
Average WTI Cushing price ($/Bbl)	$ 57.94	$ 102.99	$ 53.29	$ 100.84
Gas Prices:				
Average realized sales price ($/Mcf)	$ 2.51	$ 4.62	$ 2.63	$ 4.94
Average Henry Hub price ($/Mcf)	$ 2.65	$ 4.68	$ 2.82	$ 4.81
NGL Prices:				
Average realized sales price ($/Bbl)	$ 14.67	$ 35.35	$ 15.15	$ 37.43

Subsequent to June 30, 2015, we entered into certain derivative contracts. See Note 9 to the Consolidated Financial Statements of this report for additional information.

17

Table of Contents

During 2015 and 2014, approximately 85% and 80%, 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.

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 June 30, 2015, the carrying value of our oil and gas properties subject to the ceiling test exceeded the calculated value of the ceiling limitation, and we recognized an impairment of $967.3 million ($614.6 million, net of tax). For the six months ended June 30, 2015, ceiling test impairments totaled $1.57 billion ($997.8 million, net of tax).

These impairments resulted primarily 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. An amount of any future write-downs or impairment is difficult to predict, and will depend upon not only commodity prices but also incremental proved reserves that may be added each period, revisions to previous reserve estimates, capital expenditures, operating costs, and all related tax effects. The future variability, both individually and combined, of these attributes cannot be reasonably predicted.

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, the magnitude of which will be affected by one or more of the other components of the ceiling test calculations, until prices stabilize or improve over a twelve-month period. An example of the sensitivity related to only price declines on the ceiling calculation follows.

At June 30, 2015, commodity prices used in the ceiling calculation were $3.39 per Mcf of gas and $71.68 per barrel of oil. Holding all other components of the calculation constant and only adjusting commodity prices to amounts based on average prices for the first seven months of 2015 of $2.72 per Mcf of gas and $53.95 per barrel of oil, the pre-tax ceiling impairment would have increased to $2.5 billion.

The ceiling limitation calculation is not intended to be indicative of the fair market value of our proved reserves or future results. Impairment charges do not affect cash flow from operating activities, but do adversely affect our net income and stockholders' equity. Any recorded impairment of oil and gas properties is not reversible at a later date.

Depletion, depreciation 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 of oil and gas properties will also impact depletion expense. Due to the variability of the noted factors, we are unable to predict future DD&A rates.

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 consist 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.

RESULTS OF OPERATIONS

Three Months and Six Months Ended June 30, 2015 vs. June 30, 2014

In the second quarter of 2015 we had a net loss of $600.2 million ($6.47 per share) compared to net income of $148.6 million ($1.70 per diluted share) for the same period of 2014. For the first six months of 2015, we had a net loss of $1.015 billion ($10.94 per share) versus net income of $287.1 million ($3.29 per diluted share) in 2014.

The decreases in 2015 net income were due primarily to significantly lower realized commodity prices, which also brought about impairments 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 June 30,						
Oil sales	$ 259,344	$ 354,882	(27) %	$ (218,778)	$ 123,240	$ (95,538)
Gas sales	106,374	172,503	(38) %	(89,527)	23,398	(66,129)
NGL sales	49,477	95,470	(48) %	(69,754)	23,761	(45,993)
	$ 415,195	$ 622,855	(33) %	$ (378,059)	$ 170,399	$ (207,660)
For the Six Months Ended June 30,						
Oil sales	$ 455,349	$ 679,953	(33) %	$ (447,918)	$ 223,314	$ (224,604)
Gas sales	217,336	342,600	(37) %	(190,702)	65,438	(125,264)
NGL sales	95,077	185,427	(49) %	(139,807)	49,457	(90,350)
	$ 767,762	$ 1,207,980	(36) %	$ (778,427)	$ 338,209	$ (440,218)

Table of Contents

	For the Three Months Ended June 30,		Change Between 2015 / 2014	For the Six Months Ended June 30,		Change Between 2015 / 2014
	2015	2014		2015	2014	
Total oil volume — thousand barrels	5,120	3,800	35 %	9,731	7,325	33 %
Oil volume — barrels per day	56,261	41,759	35 %	53,765	40,471	33 %
Percent of total equivalent production	33 %	30 %	3 %	33 %	31 %	2 %
Average oil price — per barrel	$ 50.66	$ 93.39	(46) %	$ 46.79	$ 92.82	(50) %
Total gas volume — MMcf	42,430	37,318	14 %	82,555	69,291	19 %
Gas volume — MMcf per day	466.3	410.1	14 %	456.1	382.8	19 %
Percent of total equivalent production	45 %	49 %	(4) %	46 %	48 %	(2) %
Average gas price — per Mcf	$ 2.51	$ 4.62	(46) %	$ 2.63	$ 4.94	(47) %
Total NGL volume — thousand barrels	3,373	2,701	25 %	6,275	4,953	27 %
NGL volume — barrels per day	37,070	29,680	25 %	34,670	27,367	27 %
Percent of total equivalent production	22 %	21 %	1 %	21 %	21 %	— %
Average NGL price — per barrel	$ 14.67	$ 35.35	(59) %	$ 15.15	$ 37.43	(60) %
Total equivalent production — MMcfe	93,389	76,324	22 %	178,595	142,963	25 %
Equivalent production — MMcfe per day	1,026.2	838.7	22 %	986.7	789.9	25 %

As reflected in the tables above, for the second quarter and first six months of 2015 our production revenues were 33% and 36%, respectively, lower than those in the same periods 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. The year-over-year growth in aggregate production is primarily due to our drilling programs in the Permian Basin and Mid-Continent region.

Table of Contents

The table below reflects our regional production volumes.

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	2015	2014
Oil (Bbls per day)				
Permian Basin	48,448	33,317	45,783	32,475
Mid-Continent	7,181	7,259	7,308	6,662
Other	632	1,183	674	1,334
	56,261	41,759	53,765	40,471
Gas (MMcf per day)				
Permian Basin	189.4	123.6	170.0	113.1
Mid-Continent	270.2	276.6	278.6	260.3
Other	6.7	9.9	7.5	9.4
	466.3	410.1	456.1	382.8
NGL (Bbls per day)				
Permian Basin	19,169	11,633	16,180	10,386
Mid-Continent	17,633	17,543	18,194	16,376
Other	268	504	296	605
	37,070	29,680	34,670	27,367
Total Equivalent (MMcfe per day)				
Permian Basin	595.1	393.3	541.8	370.3
Mid-Continent	419.1	425.5	431.6	398.5
Other	12.0	19.9	13.3	21.1
	1,026.2	838.7	986.7	789.9

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 June 30,		For the Six Months Ended June 30,	
	2015	2014	2015	2014
Gas Gathering and Marketing (in thousands):				
Gas gathering and other revenues	$ 9,141	$ 14,284	$ 17,411	$ 26,748
Gas gathering and other costs	(11,306)	(10,041)	(20,170)	(18,825)
Gas gathering and other margin	$ (2,165)	$ 4,243	$ (2,759)	$ 7,923

Gas marketing revenues, net of related costs	$ (53)	$ (470)	$ 112	$ 1,157

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

21

Table of Contents

Total operating costs and expenses (not including gas gathering and marketing costs, other income and expense or income tax expense) for the 2015 periods shown in the tables below were significantly greater than those for the same periods of 2014. The significant increases resulted because for both the first and second quarters of 2015 our ceiling limitation calculations resulted in impairments of our oil and gas properties. See Operating costs and expenses above for a discussion of the ceiling limitation calculation.

Excluding the effect of the impairment, our total quarter-over-quarter operating costs and expenses declined by $7.1 million (2%). Aggregate operating costs and expenses for the first six months of 2015 (excluding the impairment) increased by $6.4 million (1%). Period-over-period differences are discussed below.

	For the Three Months Ended June 30,		Variance Between	Per Mcfe	
	2015	2014	2015 / 2014	2015	2014
Operating costs and expenses (in thousands, except per Mcfe):					
Impairment of oil and gas properties	$ 967,287	$ —	$ 967,287	N/A	N/A
Depletion, depreciation and amortization	217,451	194,989	22,462	$ 2.33	$ 2.55
Asset retirement obligation	2,042	3,650	(1,608)	$ 0.02	$ 0.05
Production	70,600	86,085	(15,485)	$ 0.76	$ 1.13
Transportation, processing and other operating	43,713	46,478	(2,765)	$ 0.47	$ 0.61
Taxes other than income	25,980	32,323	(6,343)	$ 0.28	$ 0.42
General and administrative	14,054	16,571	(2,517)	$ 0.15	$ 0.22
Stock compensation	4,988	3,548	1,440	$ 0.05	$ 0.05
(Gain) loss on derivative instruments, net	—	2,454	(2,454)	N/A	N/A
Other operating, net	260	112	148	N/A	N/A
	$ 1,346,375	$ 386,210	$ 960,165		

	For the Six Months Ended June 30,		Variance Between	Per Mcfe	
	2015	2014	2015 / 2014	2015	2014
Operating costs and expenses (in thousands, except per Mcfe):					
Impairment of oil and gas properties	$ 1,570,886	$ —	$ 1,570,886	N/A	N/A
Depletion, depreciation and amortization	434,229	368,920	65,309	$ 2.43	$ 2.58
Asset retirement obligation	3,778	6,868	(3,090)	$ 0.02	$ 0.05
Production	152,811	161,226	(8,415)	$ 0.86	$ 1.13
Transportation, processing and other operating	83,355	90,726	(7,371)	$ 0.47	$ 0.64
Taxes other than income	47,961	65,944	(17,983)	$ 0.27	$ 0.46
General and administrative	29,992	37,283	(7,291)	$ 0.17	$ 0.26
Stock compensation	10,143	7,272	2,871	$ 0.06	$ 0.05

(Gain) loss on derivative instruments, net	—	18,189	(18,189)	N/A	N/A
Other operating, net	784	215	569	N/A	N/A
	$ 2,333,939	$ 756,643	$ 1,577,296		

Second quarter 2015 DD&A expense was 12% higher than the same period of 2014. DD&A expense for the six months ended June 30, 2015 increased by 18% compared to a year earlier. The period-over-period increases

Table of Contents

are due to higher 2015 production volumes partially offset by lower DD&A rates in 2015. DD&A is calculated before the quarterly ceiling test impairment calculation.

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

	For the Three Months Ended June 30,		Variance Between 2015 /	Per Mcfe	
(in thousands, except per Mcfe)	2015	2014	2014	2015	2014
Lease operating expense	$ 61,509	$ 72,168	$ (10,659)	$ 0.66	$ 0.95
Workover expense	9,091	13,917	(4,826)	$ 0.10	$ 0.18
	$ 70,600	$ 86,085	$ (15,485)	$ 0.76	$ 1.13

	For the Six Months Ended June 30,		Variance Between 2015 /	Per Mcfe	
(in thousands, except per Mcfe)	2015	2014	2014	2015	2014
Lease operating expense	$ 130,014	$ 133,246	$ (3,232)	$ 0.73	$ 0.93
Workover expense	22,797	27,980	(5,183)	$ 0.13	$ 0.20
	$ 152,811	$ 161,226	$ (8,415)	$ 0.86	$ 1.13

Lease operating expense in the second quarter of 2015 declined 15% compared to the same quarter of 2014. Year-over-year lease operating expense for the six months ended June 30th declined by 2%. Period-over-period declines were primarily a result of property divestitures and lower equipment and maintenance costs, which were only partially offset by increases in other lease operating expenses. Increased production volumes in the 2015 periods also contributed to lower rates per Mcfe in 2015.

Workover expense for the three months and six months ended June 30, 2015, were lower than the same periods of 2014 by 35% and 19%, respectively. Generally, these costs will fluctuate based on the amount of maintenance and remedial activity planned and/or required during the period.

In 2015, transportation, processing and other operating costs for the second quarter were 6% lower than the same period of 2014. For the six months ended June 30, 2015, these costs were 8% lower than the prior year. These costs will vary by product type and region. In 2015, lower commodity prices resulted in lower costs associated with fuel and processing fees which 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. During the second quarter and first six months of 2015, aggregate taxes decreased by 20% and 27%, respectively, compared to the same periods of 2014. The decreases were primarily a result of the significant year-over-year declines in realized commodity prices, which were only partially offset by increased production volumes.

Table of Contents

G&A costs were as follows:

(in thousands)	For the Three Months Ended June 30, 2015	2014	Variance Between 2015 / 2014	For the Six Months Ended June 30, 2015	2014	Variance Between 2015 / 2014
G&A capitalized to oil & gas properties	$ 17,824	$ 25,265	$ (7,441)	$ 34,055	$ 42,440	$ (8,385)
G&A expense	14,054	16,571	(2,517)	29,992	37,283	(7,291)
	$ 31,878	$ 41,836	$ (9,958)	$ 64,047	$ 79,723	$ (15,676)
G&A expense per Mcfe	$ 0.15	$ 0.22	$ (0.07)	$ 0.17	$ 0.26	$ (0.09)

During 2015, aggregate G&A has declined compared to the same periods of 2014 by 24% for the second quarter and by 20% for the first six months of the year. Because of the adverse effect of lower commodity prices on our financial results, we have reduced our expectations and accruals for short-term incentive-based cash compensation and benefits. 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 to oil and gas properties. We have recognized stock-based compensation expense as follows:

(in thousands)	For the Three Months Ended June 30, 2015	2014	Variance Between 2015 / 2014	For the Six Months Ended June 30, 2015	2014	Variance Between 2015 / 2014
Restricted stock awards						
Performance stock awards	$ 4,645	$ 2,867	$ 1,778	$ 9,643	$ 5,814	$ 3,829
Service-based stock awards	3,861	3,112	749	8,798	6,616	2,182
	8,506	5,979	2,527	18,441	12,430	6,011
Stock option awards	647	782	(135)	1,286	1,555	(269)
	9,153	6,761	2,392	19,727	13,985	5,742
Less amounts capitalized	(4,165)	(3,213)	(952)	(9,584)	(6,713)	(2,871)
Stock compensation	$ 4,988	$ 3,548	$ 1,440	$ 10,143	$ 7,272	$ 2,871

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 granted 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 six months ended June 30, 2015. Subsequent to June 30, 2015, we entered into certain derivative contracts. See Note 9 to the Consolidated Financial Statements of this report for additional information.

Table of Contents

Other (income) and expense

(in thousands)	For the Three Months Ended June 30, 2015	2014	Variance Between 2015 / 2014	For the Six Months Ended June 30, 2015	2014	Variance Between 2015 / 2014
Interest expense	$ 21,297	$ 16,724	$ 4,573	$ 42,553	$ 30,766	$ 11,787
Capitalized interest	(8,570)	(8,575)	5	(17,987)	(15,865)	(2,122)
Other, net	(3,854)	(4,129)	275	(7,439)	(11,084)	3,645
	$ 8,873	$ 4,020	$ 4,853	$ 17,127	$ 3,817	$ 13,310

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

Pursuant to the full cost method of accounting, 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. Other, net quarter-over-quarter income was relatively flat. The 33% decrease in income for the first six months of 2015 compared to the same period of 2014 was 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 June 30, 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 June 30,		Six Months Ended June 30,	
(in thousands)	2015	2014	2015	2014
Deferred tax expense (benefit)	$ (342,056)	$ 87,758	$ (570,795)	$ 169,503
	$ (342,056)	$ 87,758	$ (570,795)	$ 169,503
Combined Federal and State effective income tax rate	36.3 %	37.1 %	36.0 %	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.

Table of Contents

In May 2015, we completed an underwritten public offering of 6.9 million shares of our common stock, 900 thousand of which were issued pursuant to an overallotment option to purchase additional shares granted to the underwriters. The stock was sold to the public at $109.00 per share, with a par value of $0.01. After deducting customary underwriting discounts, net proceeds of approximately $730 million were received from this offering. We intend to use the net proceeds for general corporate purposes and to fund increased drilling and completion activity in the second half of 2015 and more significantly in 2016.

Our liquidity is highly dependent on prices we receive for the oil, natural 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 earnings.

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. See Capital Expenditures below for information regarding our 2015 E&D investment program.

In addition, we believe our conservative use of leverage and strong balance sheet will mitigate our exposure to lower prices. Cash and cash equivalents at June 30, 2015 totaled $856.9 million. 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 June 30, 2015, was 26%, compared to 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 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 need for planned capital expenditures, working capital, debt service and dividend payments in 2015 and beyond.

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 six months of 2015 was $370.5 million, compared to $769.8 million in the same period of 2014. The $399.3 million decrease resulted primarily from a year-over-year net decrease in production revenue of $440.2 million, which was partially offset by net decreases in operating expenses. See RESULTS OF OPERATIONS above for details regarding the 2015 decreases in production revenue and certain operating expenses.

For the first six months of 2015, net cash flow used for investing activities was $625.9 million, a decrease of $562.7 million (47%) from $1.189 billion in the first six months of 2014. Almost all of the decrease resulted from reduced E&D expenditures in 2015. Due to the prevailing economic conditions, management decreased our 2015 E&D activity significantly compared to 2014. See Market Conditions above and Capital Expenditures below for further discussion.

During the first six months of 2015, net cash provided by financing activities was $706.3 million compared to $542.8 million for the same period of 2014. In the first six months of 2015 cash provided by financing activities included approximately $730 million of net proceeds from the sale of common stock, which was partially offset by dividend payments of $28.1 million. In the same period of 2014, cash provided by financing activities included net proceeds of $740.9 million from the issuance of senior notes which was reduced by payments of $174.0 million of outstanding bank debt and $26.0 million of dividends.

Table of Contents

Reconciliation of Adjusted Cash Flow from Operations

(in thousands)	Six Months Ended June 30, 2015	2014
Net cash provided by operating activities	$ 370,545	$ 769,769
Change in operating assets and liabilities	68,758	82,235
Adjusted cash flow from operations	$ 439,303	$ 852,004

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 capitalized expenditures for oil and gas acquisitions, E&D activities and property sales.

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2015	2014	2015	2014
Acquisitions:				
Proved (*)	$ (2,258)	$ 144,516	$ (2,228)	$ 144,516
Unproved (*)	(9,617)	114,732	(7,748)	114,732
	(11,875)	259,248	(9,976)	259,248
Exploration and development:				
Land and seismic	5,275	43,869	27,965	109,194
Exploration and development	184,999	453,714	470,526	855,175
	190,274	497,583	498,491	964,369
Sales proceeds:				

Proved	(1,160)	(464)	(2,305)	(223)
Unproved	(6,211)	(900)	(6,211)	(900)
	(7,371)	(1,364)	(8,516)	(1,123)
	$ 171,028	$ 755,467	$ 479,999	$ 1,222,494

(*) The negative amounts in 2015 reflect purchase price adjustments related to an acquisition in the second quarter of 2014.

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.

We expect 2015 E&D capital expenditures to approximate $1.0 billion, down from $1.88 billion in 2014. Based on our current development plans, our estimates of proved reserves have not been materially impacted by our response to lower prices. Our E&D activity is directed toward drilling in the Permian Basin and Mid-Continent regions. During the first six months of 2015 and 2014, approximately 66% and 71%, 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.

Table of Contents

In the ordinary course of business we regularly evaluate opportunities to purchase properties that we believe could benefit from our technical capabilities.

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

The following table reflects wells brought on production by region.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Gross wells				
Permian Basin	26	47	68	81
Mid-Continent	19	37	30	76
Other	—	1	—	2
	45	85	98	159
Net wells				
Permian Basin	18	30	48	51
Mid-Continent	6	21	9	35
Other	—	—	—	1
	24	51	57	87
% Gross wells completed as producers	96%	99 %	97%	99 %

As of June 30, 2015, we had 61 gross wells awaiting completion: three Permian Basin and 58 Mid-Continent. We also had six operated rigs running: two in the Permian Basin and four 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.

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

During the first six months of 2015, our total assets decreased by $1.16 billion to $7.57 billion, down from $8.73 billion at December 31, 2014. The decrease was mainly attributable to the $1.57 billion impairment of our oil and gas properties, partially offset by a $451.0 million increase in cash and cash equivalents.

Total liabilities at June 30, 2015, were $3.37 billion, compared to $4.22 billion at December 31, 2014. Of the approximate $852.3 million decrease, $277.4 million comes from a decrease in total current liabilities related to our oil and gas operations and drilling activity. The remaining decrease is attributable to a $577.4 million decrease in deferred income taxes resulting primarily from our net loss for the first six months of 2015.

Stockholders' equity totaled $4.20 billion at June 30, 2015, down seven percent from $4.50 billion at December 31, 2014. Decreases resulted primarily from a net loss of $1.02 billion for the first six months of 2015 and dividends of $29.1 million, partially offset by net proceeds of $730 million from our common stock offering.

Table of Contents

Long-term Debt

Long-term debt at June 30, 2015, and December 31, 2014, consisted of the following:

(in thousands)	June 30, 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 and was reaffirmed in April 2015. The next regular annual redetermination date is scheduled for April 2016.

At June 30, 2015, 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 2015 we had average daily bank debt outstanding of $55.2 thousand, compared to $267.1 million for the same period of 2014. Our highest amount of bank borrowings outstanding during the first six months of 2015 was $10.0 million, occurring in May. In the same period of 2014, our highest amount of bank borrowings outstanding was $515.0 million, occurring in May.

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 June 30, 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 June 30, 2015.

Working Capital Analysis

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

At June 30, 2015, we had working capital of $768.6 million, an increase of $613.1 million compared to working capital of $155.5 million at December 31, 2014.

Working capital increases consisted of the following:

- Cash and cash equivalents increased by $451.0 million, primarily from our second quarter common stock offering.
- Operations-related accounts payable and accrued liabilities decreased by $139.7 million.
    - Accrued liabilities related to our E&D expenditures decreased by $138.0 million.

Table of Contents

Increases in working capital were partially offset by the following:

- Operations-related accounts receivable decreased by $92.3 million.
- Oil and gas well equipment and supplies decreased by $14.6 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 June 30, 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 June 30, 2015, we had contractual obligations and material commitments as follows:

	Payments Due by Period				
Contractual obligations: (in thousands)	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)	603,751	76,876	153,750	153,750	219,375
Operating leases	101,849	9,166	19,299	18,479	54,905
Drilling commitments (2)	175,917	171,478	4,439	—	—
Gathering facilities and pipelines (3)	6,269	6,269	—	—	—
Asset retirement obligation (4)	169,117	9,963	— (4)	— (4)	— (4)
Other liabilities (5)	91,666	21,242	48,522	162	21,740
Firm transportation	38,062	1,456	6,037	8,734	21,835

(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 $138.1 million consisting of obligations to finish drilling and completing wells in progress at June 30, 2015. We also have minimum commitments for six drilling rigs of $37.8 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.

Table of Contents

At June 30, 2015, we had firm sales contracts to deliver approximately 44.3 Bcf of natural gas over the next 40 months. In total, our financial exposure would be approximately $116.2 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.

In connection with gas gathering and processing agreements, we have volume commitments over the next seven years. If no gas is delivered, the maximum amount that would be payable under these commitments would be approximately $85.8 million. 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.

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 June 30, 2015, we had no hedges in place. Subsequent to June 30, 2015, we entered into gas collars. See Note 9 to the Consolidated Financial Statements of this report for additional information regarding derivative instruments.

Oil sales contributed 59% of our total production revenue for the first six months of 2015. Gas sales accounted for 28% and NGL sales contributed 13%. A $1.00 per barrel change in our realized oil price would have resulted in a $9.7 million change in revenues. A $0.10 per Mcf change in our realized gas price would have resulted in an $8.3 million change in our gas revenues. A $1.00 per barrel change in NGL prices would have changed revenues by $6.3 million.

Interest Rate Risk

At June 30, 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

Table of Contents

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 June 30, 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 Act)) as of June 30, 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 June 30, 2015 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Table of Contents

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 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 originally was scheduled to take effect on June 24, 2015. However, the rule is the subject of several pending lawsuits recently filed by industry groups, two Indian tribes, and at least four states, alleging that federal law does not give the Bureau of Land Management authority to regulate hydraulic fracturing. The federal judge in the consolidated industry/state

Table of Contents

cases delayed the implementation of the rule until at least August 28, 2015 when the administrative record is due to be filed by the government.

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. The EPA's draft report was released on June 4, 2015. The findings of the report suggest that hydraulic fracturing does not pose a systemic risk to groundwater although there are risks to both groundwater and soils posed by inadequate water handling practices in certain situations. A public comment period on the report is open until August 28, 2015 and a series of public hearings is being conducted by the EPA's Scientific Advisory Board throughout the fall. 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. Most producing 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.

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.

Air quality regulations could negatively impact our operations and profitability.

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 gas industry. The various elements of the package are all expected to be finalized before the end of 2015. 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.

Regulation of disposal wells could negatively impact our operations and profitability.

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. In Oklahoma, the Oklahoma Corporation Commission has acted twice to address induced seismicity identifying a receiving formation and wells drilled to a certain depth as potentially increasing the likelihood of seismic activity. The Commission has created Areas of Interest in which operators must demonstrate they are not injecting at certain depths or at particular volumes. The Commission continues to monitor the situation and has stated they may take additional action if the situation warrants. Compliance with existing and potential future rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

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.

Table of Contents

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 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 as Exhibit 3.1 to Registrant's Form 8-K dated December 16, 2013 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 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

Table of Contents

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 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)