CIMAREX

ANNUAL REPORT 2016

core VALUES

Cimarex Energy Co. (NYSE: XEC) is an oil and gas exploration and production company with operations mainly located in Oklahoma, Texas and New Mexico. We pride ourselves on having strong technical teams with the common goal of adding shareholder value through drilling and production. The cornerstone to our approach is detailed pre- and post-drill economic evaluation of after-tax rate-of-return on invested capital. We continually strive to maximize our cash flow from producing properties for reinvestment.

- *IDEA GENERATION*
- *FOCUSED ASSETS*
- *RATE-OF-RETURN DRIVEN*
- *ADD VALUE*

Performance SUMMARY

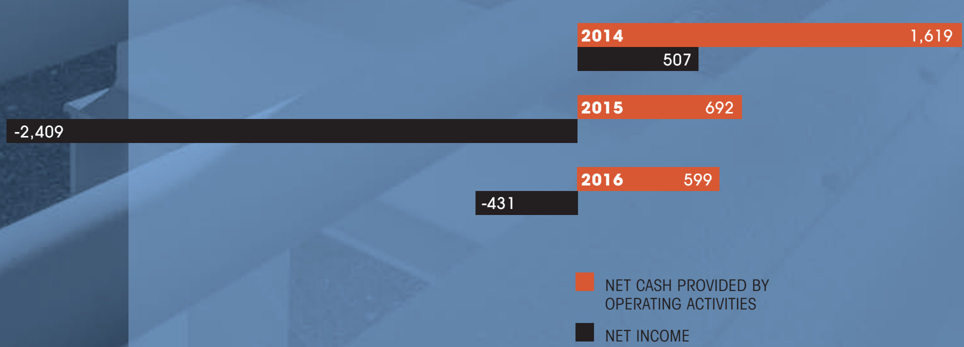
		YEAR ENDED DECEMBER 31,	
	2016	**2015**	**2014**
FINANCIAL (IN MILLIONS, EXCEPT PER SHARE DATA)			
Oil, gas & NGL sales	$1,221.2	$1,417.5	$2,372.8
Net income (loss)	(431.0)	(2,408.9)	507.2
Net income (loss) per diluted share	(4.62)	(25.92)	5.78
Net cash provided by operating activities	599.2	691.5	1,619.4
Capital investment:			
Exploration and development	734.8	877.0	1,881.0
Acquisition	14.5	(5.0)*	249.7
	749.3	872.0	2,130.7

		DECEMBER 31,	
	2016	**2015**	**2014**
Total assets	4,681.7	5,243.3	8,708.5
Debt (principal)	1,500.0	1,500.0	1,500.0
Stockholders' equity	2,360.1	2,797.7	4,500.6

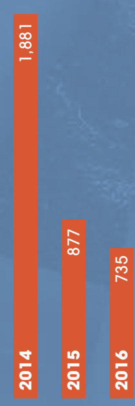
*Includes purchase price adjustments.

		YEAR ENDED DECEMBER 31,	
	2016	**2015**	**2014**
OPERATIONAL			
Proved reserves:			
Oil (MMBbls)	105.9	107.8	119.0
NGL (MMBbls)	130.6	124.3	125.3
Gas (Bcf)	1,471.4	1,517.0	1,666.7
Total (Bcfe)	2,890.5	2,909.4	3,132.3
Proved developed (Bcfe)	2,292.0	2,189.9	2,402.0
Daily production:			
Oil (Bbls)	45,158	51,132	42,846
NGL (Bbls)	38,797	35,789	31,078
Gas (MMcf)	460	463	425
Total (MMcfe)	963	985	869
Realized price:			
Oil (per Bbl)	$ 38.30	$ 43.38	$ 83.70
NGL (per Bbl)	$ 14.05	$ 13.75	$ 33.14
Gas (per Mcf)	$ 2.31	$ 2.53	$ 4.43

NET INCOME AND CASH FLOW
(Millions of Dollars)



EXPLORATION AND DEVELOPMENT CAPITAL INVESTMENT
(Millions of Dollars)



Fellow SHAREHOLDERS

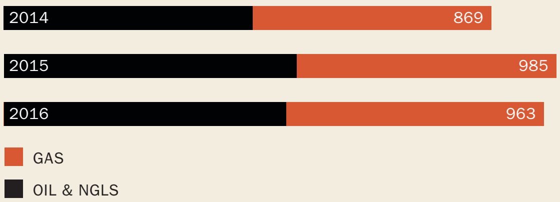
The theme of our 2016 Annual Report to Shareholders is *Core Values*. Our core values are what got us through a turbulent 2016 and this is a good time to reflect upon them. During 2016, oil hit a low of $26.21 per barrel in February and a high of $54.06 per barrel on December 28. Natural Gas hit a low of $1.64 per Mcf in March and a high of $3.93 per Mcf on December 28. This had a whipsaw effect on our cash flow, investment outlook, and our ability to chart and maintain a stable course. We found ourselves making mid-course adjustments continuously throughout the year. On the bright side, our cost structure continued to decrease and we made tremendous advances in well productivity. We finished the year strong, having returned to profitability in the fourth quarter. Through it all, our core values were our guiding light.

As we enter 2017, Cimarex stands stronger and better positioned than ever. Our cash flow is strong and growing. We are achieving historically good returns on our investments. Our balance sheet is rock solid. Our organization is intact, motivated, and ready for the challenges ahead.

I came across this quote from Craig Pearce, Director, Deloitte Leadership Institute, "The culture of an organization is the only long-term source of competitive advantage that a company has." Nothing could be truer for Cimarex. Assets change over time. People will come and go. The single constant that defines an organization through time is its corporate culture.

Cimarex has always been an organization grounded firmly in measureable, objective results. Our internal incentive systems are transparent and simple. The part of our organization that is tasked with making drilling and completion investment decisions (which comprise the overwhelming majority of our capital investments) is graded on a single metric — after tax (ATAX) return on investment. These ATAX returns are fully burdened with all ancillary expenses including land, seismic, salaries and corporate overhead. An independent corporate reservoir engineering group analyzes our results and calculates the ATAX return on our program. We do not grade our own papers. We are accountable to our results and live by them. At times it can be a very uncomfortable process.

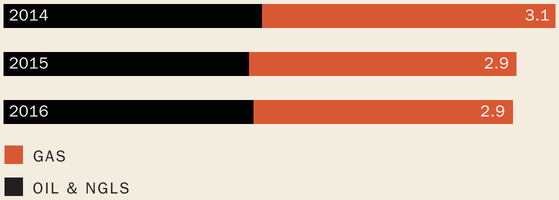
PRODUCTION
(MMcfe/d)



In 2017, our focus will continue to be on both the prudent development of our existing assets and the hunt for new ones. We will continue to push the envelope in our attempt to optimize completion efficiency, landing zone selection, and well to well spacing. We will strive for greater capital efficiency through prudent infrastructure investments, water management, and using technological improvements as a way to push back against the effects of service cost inflation. In 2016 we emphasized preservation — preservation of our assets, preservation of our balance sheet, and preservation of our organization. In 2017, we will emphasize technical innovation and opportunity capture.

Our assets are primarily concentrated in the Delaware Basin of West Texas and Southeast New Mexico and the Woodford and Stack plays in Western Oklahoma. These plays have become among the hottest in the country. There has been a tremendous asset grab as companies have sought to reposition themselves into these areas. Assets have sold for stratospheric prices. Thus far, while we have evaluated many of the assets for sale, Cimarex has chosen not to participate in this heated marketplace. We have decades of high quality drilling inventory in our portfolio and we would rather invest our capital in developing and exploring for opportunity rather than paying full retail price in the acquisition market. We have the balance sheet and wherewithal to strike when we see assets that can compete with our existing returns. We are disciplined and patient.

PROVED RESERVES
(Tcfe)



Our core value creation thesis is the generation of good ideas, careful economic analysis to select those ideas that are highly profitable, and good execution in the capture and development of these good ideas. As commodity prices stabilized in 2016, we refocused our organization on the generation of exploratory ideas and on the capture of opportunity. We seek to step away from the herd and capitalize on proprietary ideas. This is how we built Cimarex. We are confident that we can compete and deliver top tier returns and consistent growth for decades to come.

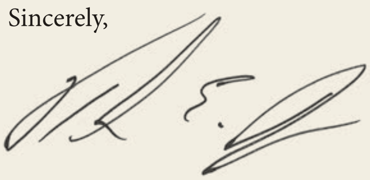
We are frequently asked about the new administration in Washington and what impact we foresee on our business. Government regulation and permit turnaround time have a strong impact on us. As I write this letter, we are uncertain about upcoming regulatory and policy changes. However, I want to stress that Cimarex is deeply committed to being a responsible operator. Our commitment to environmental quality and safety will not change with changing government policies. This includes environmentally sound water sourcing and disposal, clean and safe field operations, seeking to reduce greenhouse gas emissions, and the careful management of induced seismicity associated with water injection and hydraulic fracturing. These, too, are our core values. Our commitment to safety and the environment goes hand in hand with our commitment to long-term profitability. In 2017 and beyond, look for Cimarex to increase our disclosure of the safe, clean practices that characterize our operations.

I would like to close by acknowledging our talented and dedicated employees for whom 2016 was a difficult year, as many of our peer companies underwent significant layoffs and office closings. Throughout the year, our employees kept their focus on the business and kept their morale high. We promised our employees that we would work our way through the downturn and attempt to preserve our organization as best we could. We operate lean at Cimarex and I am grateful that we were able to keep our organization intact without involuntary reductions. As we look ahead into 2017, we are positioned with an organization that is motivated and full of tremendous talent and dedication. In the long run, the only source of competitive advantage that an organization has is its culture. This culture burns bright in the hearts and minds of each of our employees.

I also want to acknowledge and thank our Board of Directors, whose patience and wisdom were central to helping us get through the downturn. Our Board of Directors understands our business and helped us maintain a long-term focus as we worked through the short-term volatility of the past year. I cannot express my appreciation to our Board in strong enough terms.

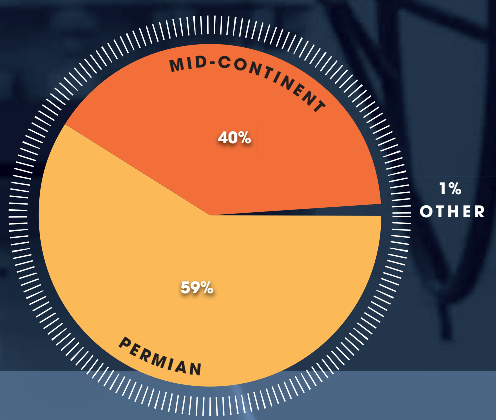
Finally, I want to thank you, our long-term owners. Our entire organization is committed to be good stewards of your investment and run our business with your interests in mind. We never forget our purpose.

Sincerely,



THOMAS E. JORDEN
Chief Executive Officer,
President and
Chairman of the Board
March 3, 2017

2016 EXPLORATION & DEVELOPMENT CAPITAL
($735 million)



CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(IN THOUSANDS, EXCEPT PER SHARE DATA)	YEAR ENDED DECEMBER 31,		
	2016	2015	2014
REVENUES:			
Oil sales	$ 632,934	$ 809,664	$ 1,308,958
Gas sales	388,786	428,227	687,930
NGL sales	199,498	179,647	375,941
Gas gathering and other	36,033	34,688	49,602
Gas marketing, net of related costs of $122,655, $144,673 and $256,836 respectively	94	393	1,745
	1,257,345	1,452,619	2,424,176
COSTS AND EXPENSES:			
Impairment of oil and gas properties	719,142	3,716,883	—
Depreciation, depletion and amortization	465,936	778,923	806,021
Asset retirement obligation	7,828	9,121	10,082
Production	232,002	299,374	342,304
Transportation, processing, and other operating	190,725	182,362	195,414
Gas gathering and other	31,785	38,138	35,113
Taxes other than income	61,946	84,764	128,793
General and administrative	73,901	74,688	81,160
Stock compensation	24,523	19,559	15,001
(Gain) loss on derivative instruments, net	55,749	(11,246)	(3,762)
Other operating expense, net	755	856	116
	1,864,292	5,193,422	1,610,242
Operating income (loss)	(606,947)	(3,740,803)	813,934
Other (income) and expense:			
Interest expense	83,272	85,746	72,865
Capitalized interest	(21,248)	(30,589)	(35,925)
Other, net	(10,707)	(13,576)	(28,907)
INCOME (LOSS) BEFORE INCOME TAX	(658,264)	(3,782,384)	805,901
INCOME TAX EXPENSE (BENEFIT)	(227,215)	(1,373,436)	298,697
Net income (loss)	$ (431,049)	$(2,408,948)	$ 507,204
EARNINGS (LOSS) PER SHARE TO COMMON STOCKHOLDERS:			
Basic			
Distributed	$ 0.32	$ 0.64	$ 0.64
Undistributed	(4.94)	(26.56)	5.15
	$ (4.62)	$ (25.92)	$ 5.79
Diluted			
Distributed	$ 0.32	$ 0.64	$ 0.64
Undistributed	(4.94)	(26.56)	5.14
	$ (4.62)	$ (25.92)	$ 5.78
COMPREHENSIVE INCOME (LOSS):			
Net income (loss)	$ (431,049)	$(2,408,948)	$ 507,204
Other comprehensive income (loss):			
Change in fair value of investments, net of tax	504	(661)	(87)
Total comprehensive income (loss)	$ (430,545)	$(2,409,609)	$ 507,117

The notes in the accompanying Form 10-K are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(IN THOUSANDS)	YEAR ENDED DECEMBER 31,		
	2016	2015	2014
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ (431,049)	$(2,408,948)	$ 507,204
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Impairments and other valuation losses	719,142	3,716,883	—
Depreciation, depletion and amortization	465,936	778,923	806,021
Asset retirement obligation	7,828	9,121	10,082
Deferred income taxes	(226,100)	(1,388,146)	298,293
Stock compensation	24,523	19,559	15,001
(Gain) loss on derivative instruments	55,749	(11,246)	(3,762)
Settlements on derivative instruments	7,437	—	7,641
Changes in non-current assets and liabilities	3,867	23,230	(2,440)
Other, net	1,805	4,206	(3,828)
Changes in operating assets and liabilities:			
Receivables, net	(49,340)	186,699	(35,133)
Other current assets	20,880	37,954	(25,428)
Accounts payable and other current liabilities	(1,453)	(276,735)	45,714
Net cash provided by operating activities	599,225	691,500	1,619,365
CASH FLOWS FROM INVESTING ACTIVITIES:			
Oil and gas expenditures	(699,558)	(979,044)	(2,108,250)
Sales of oil and gas assets	21,487	39,853	449,981
Sales of other assets	7,889	1,178	8,413
Other capital expenditures	(22,228)	(70,592)	(90,611)
Net cash used by investing activities	(692,410)	(1,008,605)	(1,740,467)
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	(101)	(24,633)	(11,616)
Dividends paid	(38,024)	(58,281)	(53,849)
Proceeds from exercise of stock options and other	4,804	21,439	11,898
Net cash (used) provided by financing activities	(33,321)	690,625	522,433
Net change in cash and cash equivalents	(126,506)	373,520	401,331
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	779,382	405,862	4,531
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 652,876	$ 779,382	$ 405,862

The notes in the accompanying Form 10-K are an integral part of these consolidated financial statements.

CONSOLIDATED BALANCE SHEETS

(IN THOUSANDS, EXCEPT SHARE AND PER SHARE INFORMATION)	DECEMBER 31, 2016	2015
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 652,876	$ 779,382
Accounts receivable:		
Trade, net of allowance	42,287	81,888
Oil and gas sales, net of allowance	217,395	136,537
Gas gathering, processing, and marketing, net of allowance	14,888	6,935
Other	27	38
Oil and gas well equipment and supplies	33,342	54,579
Derivative instruments	—	10,745
Prepaid expenses	7,335	7,036
Other current assets	1,154	790
Total current assets	969,304	1,077,930
OIL AND GAS PROPERTIES AT COST, using the full cost method of accounting:		
Proved properties	16,225,495	15,546,948
Unproved properties and properties under development, not being amortized	478,277	440,166
	16,703,772	15,987,114
Less — accumulated depreciation, depletion and amortization and impairment	(13,849,701)	(12,710,968)
Net oil and gas properties	2,854,071	3,276,146
Fixed assets, less accumulated depreciation of $246,901 and $207,173	205,465	230,009
Goodwill	620,232	620,232
Derivative instruments	—	501
Other assets, net	32,621	38,468
	$ 4,681,693	$ 5,243,286
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable:		
Trade	$ 49,163	$ 53,384
Gas gathering, processing, and marketing	25,323	13,431
Accrued liabilities:		
Exploration and development	82,320	56,721
Taxes other than income	18,766	17,545
Other	177,695	173,242
Derivative instruments	49,370	—
Revenue payable	119,715	95,744
Total current liabilities	522,352	410,067
Long-term debt:		
Principal	1,500,000	1,500,000
Less — unamortized debt issuance costs	(12,061)	(14,380)
Long-term debt, net	1,487,939	1,485,620
Deferred income taxes	126,894	352,705
Asset retirement obligation	140,770	153,857
Derivative instruments	2,570	—
Other liabilities	41,104	43,359
Total liabilities	2,321,629	2,445,608
Commitments and contingencies		
Stockholders' equity:		
Preferred stock, $0.01 par value, 15,000,000 shares authorized, no shares issued	—	—
Common stock, $0.01 par value, 200,000,000 shares authorized, 95,123,525 and 94,820,570 shares issued, respectively	951	948
Paid-in capital	2,763,452	2,762,976
Retained earnings (Accumulated deficit)	(405,284)	33,313
Accumulated other comprehensive income	945	441
	2,360,064	2,797,678
	$ 4,681,693	$ 5,243,286

The notes in the accompanying Form 10-K are an integral part of these consolidated financial statements.

BOARD OF DIRECTORS

THOMAS E. JORDEN – CHAIRMAN

JOSEPH R. ALBI

HANS HELMERICH (**) (***)

DAVID A. HENTSCHEL (**) (***)

HAROLD R. LOGAN, JR. – LEAD DIRECTOR (*) (***)

FLOYD R. PRICE (**) (***)

MONROE W. ROBERTSON (*) (***)

LISA A. STEWART (*) (***)

MICHAEL J. SULLIVAN (*) (***)

L. PAUL TEAGUE (**) (***)

* MEMBER OF THE AUDIT COMMITTEE
** MEMBER OF THE COMPENSATION AND GOVERNANCE COMMITTEE
*** MEMBER OF THE NOMINATING COMMITTEE

Corporate Management

THOMAS E. JORDEN
CHIEF EXECUTIVE OFFICER, PRESIDENT AND CHAIRMAN OF THE BOARD

JOSEPH R. ALBI
EXECUTIVE VICE PRESIDENT – OPERATIONS, CHIEF OPERATING OFFICER

G. MARK BURFORD
VICE PRESIDENT – CHIEF FINANCIAL OFFICER

STEPHEN P. BELL
EXECUTIVE VICE PRESIDENT – BUSINESS DEVELOPMENT

FRANCIS B. BARRON
SENIOR VICE PRESIDENT – GENERAL COUNSEL, CORPORATE SECRETARY

JOHN A. LAMBUTH
SENIOR VICE PRESIDENT – EXPLORATION

GARY R. ABBOTT
VICE PRESIDENT – CORPORATE ENGINEERING

KRISTA L. JOHNSON
VICE PRESIDENT – HUMAN RESOURCES, GOVERNMENT RELATIONS AND EXTERNAL AFFAIRS

TIMOTHY A. FICKER
VICE PRESIDENT – CONTROLLER, CHIEF ACCOUNTING OFFICER

Exploration Management

ROGER G. ALEXANDER
VICE PRESIDENT – PERMIAN BASIN

EDWARD J. FETKOVICH
REGIONAL EXPLORATION MANAGER – MID-CONTINENT

MARK HOLLAND
MANAGER – NEW VENTURES EXPLORATION

Operations Management

WAYNE C. CHANG
VICE PRESIDENT – MARKETING AND MIDSTREAM

THOMAS F. McCOY
VICE PRESIDENT – PRODUCTION

STEVEN J. SIMONTON
VICE PRESIDENT – DRILLING AND COMPLETION OPERATIONS

Investor Contact

KAREN ACIERNO
DIRECTOR – INVESTOR RELATIONS

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2016
OR
☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission file number 001-31446

CIMAREX ENERGY CO.
(Exact name of registrant as specified in its charter)

Delaware	**45-0466694**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1700 Lincoln Street, Suite 3700, Denver, Colorado 80203
(Address of principal executive offices)

(303) 295-3995
(Registrant's telephone number)

Securities Registered Pursuant to Section 12(b) of the Act:

Title of Each Class	Name of each exchange on which registered
Common Stock ($0.01 par value)	New York Stock Exchange

Securities Registered Pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. YES ☒ NO ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. YES ☐ NO ☒

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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

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 Act). YES ☐ NO ☒

Aggregate market value of the voting stock held by non-affiliates of Cimarex Energy Co. as of June 30, 2016 was approximately $11.1 billion.

Number of shares of Cimarex Energy Co. common stock outstanding as of January 31, 2017 was 95,121,492.

Documents Incorporated by Reference: Portions of the Registrant's Proxy Statement for its 2017 Annual Meeting of Stockholders are incorporated by reference into Part III of this Form 10-K.

TABLE OF CONTENTS
DESCRIPTION

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

GAAP—Generally accepted accounting principles in the U.S.

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

PUD—Proved undeveloped

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

PART I

Cautionary Information about Forward-Looking Statements

Throughout this Form 10-K, we make statements that may be deemed "forward-looking" statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. In particular, in our Management's Discussion and Analysis of Financial Condition and Results of Operations, we are providing "*2017 Outlook,*" which contains projections for certain 2017 operational activities. All statements, other than statements of historical facts, that address activities, events, outcomes and other matters that Cimarex plans, expects, intends, assumes, believes, budgets, predicts, forecasts, projects, estimates or anticipates (and other similar expressions) will, should or may occur in the future are forward-looking statements. These forward-looking statements are based on management's current belief, based on currently available information, as to the outcome and timing of future events. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements in this Form 10- K. Forward-looking statements include statements with respect to, among other things:

- Fluctuations in the price we receive for our oil, gas and NGL production;
- Timing and amount of future production of oil, gas and NGLs;
- Reductions in the quantity of oil, gas and NGLs sold due to decreased industrywide demand and/or curtailments in production from specific properties or areas due to mechanical, transportation, marketing, weather or other problems;
- Estimates of proved reserves, exploitation potential or exploration prospect size;
- Cash flow and anticipated liquidity;
- Amount, nature and timing of capital expenditures;
- Access to capital markets;
- Administrative, legislative, and regulatory changes;
- Operating costs and other expenses;
- 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;
- Exploration and development opportunities that we pursue may not result in economic, productive oil and gas properties;
- Drilling of wells;
- Increased financing costs due to a significant increase in interest rates;
- De-risking of acreage.

We caution you that these forward-looking statements are subject to all of the risks and uncertainties, many of which are beyond our control, incident to the exploration for and development, production and sale of oil, gas and NGLs. These risks include, but are not limited to, commodity price volatility, inflation, lack of availability of goods and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating proved oil and natural gas reserves and in projecting future rates of production and timing of development expenditures and other risks described herein.

Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data and the interpretation of such data by our engineers. As a result, estimates made by different engineers often vary from one another. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions could change the timing of future production and development drilling. Accordingly, reserve estimates are generally different from the quantities of oil and natural gas that are ultimately recovered.

Should one or more of the risks or uncertainties described above or elsewhere in this Form 10-K cause our underlying assumptions to be incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements.

All forward-looking statements, express or implied, included in this Form 10-K and attributable to Cimarex are qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that Cimarex or persons acting on its behalf may issue. Cimarex does not undertake any obligation to update any forward-looking statements to reflect events or circumstances after the date of filing this Form 10-K with the Securities and Exchange Commission, except as required by law.

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

General

Cimarex Energy Co., a Delaware corporation formed in 2002, is an independent oil and gas exploration and production company. Our operations are located mainly in Oklahoma, Texas and New Mexico. On our website — www.cimarex.com — you will find our annual reports, proxy statements and all of our Securities and Exchange Commission (SEC) filings. Throughout this Form 10-K we use the terms "Cimarex," "company," "we," "our," and "us" to refer to Cimarex Energy Co. and its subsidiaries.

Our principal business objective is to profitably grow proved reserves and production for the long-term benefit of our shareholders. Our strategy centers on maximizing cash flow from producing properties to reinvest in exploration and development opportunities. We consider merger and acquisition opportunities that enhance our competitive position and we occasionally divest non-core assets. Key elements to our approach include:

- Maintain a strong financial position;
- Investment in a diversified portfolio of drilling opportunities;
- Rate-of-return driven evaluation and ranking of investment decisions;
- Tracking predicted versus actual results in a centralized exploration management system, providing feedback to improve results;
- Attracting quality employees and maintaining integrated teams of geoscientists, landmen and engineers;
- Maximizing profitability.

Conservative use of leverage has long been the key to our financial strategy. We believe that low leverage coupled with strong full-cycle returns enables us to better withstand volatility in commodity prices and provide competitive returns and growth to shareholders. See Item 5 Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities – Stock Performance Graph and Item 6 Selected Financial Data for additional financial and operating information for fiscal years 2012 – 2016.

Proved Oil and Gas Reserves

Our total proved reserves were essentially flat in 2016. Proved undeveloped reserves as a percentage of total proved reserves decreased to 21% from 25% a year ago. We added 324.0 Bcfe of new reserves through extensions and discoveries and 126.2 Bcfe through net positive performance revisions, replacing 128% of production. The change in our proved reserves is as follows (in Bcfe):

Reserves at December 31, 2015	2,909.4
Revisions of previous estimates	19.8
Extensions and discoveries	324.0
Purchases of reserves	0.9
Production	(352.6)
Sales of reserves	(11.0)
Reserves at December 31, 2016	2,890.5

Revisions of previous estimates in the above table include net positive performance and operating cost related revisions of 126.2 Bcfe and 138.5 Bcfe, respectively, partially offset by negative commodity price revisions of 244.9 Bcfe.

A breakdown by commodity of our proved oil and gas reserves follows:

	December 31,		
	2016	2015	2014
Total Proved Reserves:			
Gas (Bcf)	1,471.4	1,517.0	1,666.7
Oil (MMBbls)	105.9	107.8	119.0
NGL (MMBbls)	130.6	124.3	125.3
Equivalent (Bcfe)	2,890.5	2,909.4	3,132.3
% Developed	79	75	77

See "Supplemental Oil and Gas Information" in Item 8 of this report for further information.

Production Volumes, Prices, and Costs

Our 2016 production volumes totaled 963 MMcfe per day, a 2% decrease from 2015, and were comprised of 48% natural gas, 28% oil and 24% NGLs. The following tables show our production volumes by region, the average commodity prices received and production cost per unit of production. Separate data is also included for the Cana area, which comprises the majority of the production of our largest producing field, the Watonga-Chickasha in western Oklahoma.

	Production Volumes				Net Average Daily Volumes			
Years Ended December 31,	Gas (MMcf)	Oil (MBbls)	NGL (MBbls)	Total (MMcfe)	Gas (MMcf)	Oil (MBbls)	NGL (MBbls)	Total (MMcfe)
2016								
Permian Basin	65,191	13,183	6,677	184,351	178.1	36.0	18.2	503.7
Mid-Continent	102,501	3,283	7,508	167,243	280.1	9.0	20.5	456.9
Other	535	62	15	997	1.4	0.2	0.1	2.8
Total Company	168,227	16,528	14,200	352,591	459.6	45.2	38.8	963.4
Cana area	82,423	2,848	6,855	140,647	225.2	7.8	18.7	384.3
2015								
Permian Basin	66,006	15,719	6,220	197,644	180.8	43.1	17.0	541.5
Mid-Continent	100,801	2,746	6,757	157,821	276.2	7.5	18.5	432.4
Other	2,180	198	86	3,878	6.0	0.5	0.3	10.6
Total Company	168,987	18,663	13,063	359,343	463.0	51.1	35.8	984.5
Cana area	77,882	2,206	5,957	126,865	213.4	6.0	16.3	347.6
2014								
Permian Basin	45,200	12,552	4,187	145,636	123.8	34.4	11.5	399.0
Mid-Continent	106,711	2,682	6,980	164,682	292.4	7.3	19.1	451.2
Other	3,217	405	176	6,704	8.8	1.1	0.5	18.4
Total Company	155,128	15,639	11,343	317,022	425.0	42.8	31.1	868.6
Cana area	76,915	1,903	5,937	123,952	210.7	5.2	16.3	339.6

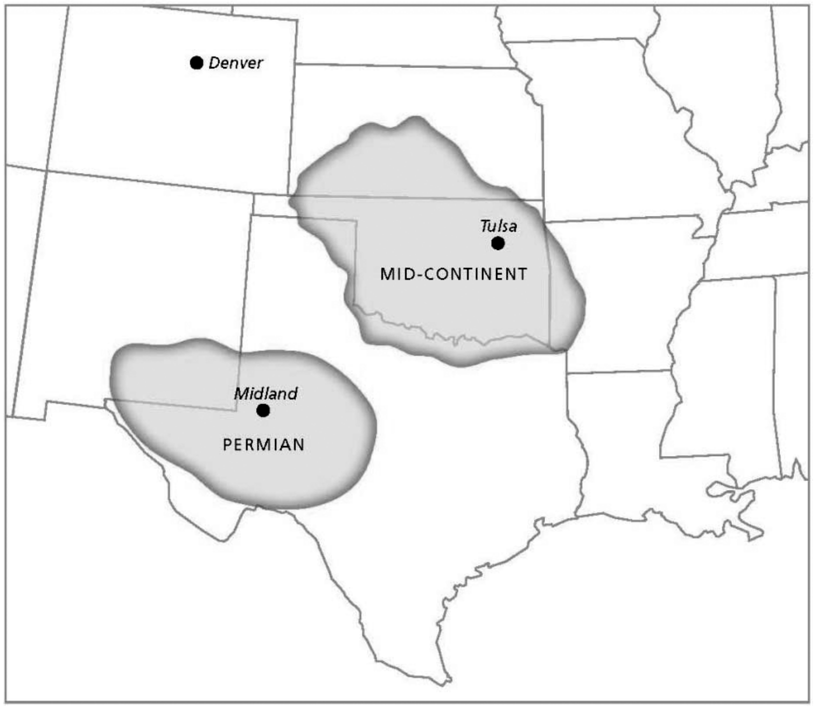
Years Ended December 31,	Average Realized Price Gas (per Mcf)	Oil (per Bbl)	NGL (per Bbl)	Production Cost (per Mcfe)
2016				
Permian Basin	$ 2.35	$ 38.45	$ 12.32	$ 0.86
Mid-Continent	$ 2.29	$ 37.65	$ 15.59	$ 0.43
Other	$ 2.00	$ 38.86	$ 14.80	$ 1.59
Total Company	$ 2.31	$ 38.30	$ 14.05	$ 0.66
Cana area	$ 2.28	$ 37.73	$ 15.80	$ 0.23
2015				
Permian Basin	$ 2.55	$ 43.58	$ 11.94	$ 1.06
Mid-Continent	$ 2.51	$ 41.90	$ 15.41	$ 0.52
Other	$ 3.16	$ 48.01	$ 14.72	$ 1.72
Total Company	$ 2.53	$ 43.38	$ 13.75	$ 0.83
Cana area	$ 2.51	$ 41.54	$ 15.59	$ 0.26
2014				
Permian Basin	$ 4.48	$ 82.44	$ 30.04	$ 1.58
Mid-Continent	$ 4.42	$ 88.23	$ 35.03	$ 0.58
Other	$ 4.40	$ 92.82	$ 32.09	$ 2.31
Total Company	$ 4.43	$ 83.70	$ 33.14	$ 1.08
Cana area	$ 4.32	$ 88.21	$ 34.89	$ 0.24

Acquisitions and Divestitures

In 2016 we sold interests in various non-core oil and gas properties for $21 million and made various acquisitions totaling $11 million.

Exploration and Development Overview

Cimarex has one reportable segment, exploration and production (E&P). Our E&P activities take place primarily in two areas: the Permian Basin and the Mid-Continent region. Almost all of our exploration and development (E&D) capital is allocated between these two areas. In 2016, E&D investment totaled $735 million. Of that, 59% was invested in the Permian Basin and 40% in the Mid-Continent region.



In 2016, Cimarex drilled or participated in 154 gross (61.0 net) wells, of which we operated 73 gross (51.2 net) wells. At year-end, we were in the process of drilling or participating in 19 gross (8.4 net) wells and there were 93 gross (27.0 net) wells waiting on completion. A summary of our 2016 exploration and development activity by region is as follows:

	E&D Capital (in millions)	Gross Wells Drilled	Net Wells Drilled	% Completed As Producers
Permian Basin	$ 433	48	30.3	100
Mid-Continent	291	106	30.7	99
Other	11	—	—	—
	$ 735	154	61.0	99

The Permian region encompasses west Texas and southeast New Mexico. Cimarex's Permian Basin efforts are located in the western half of the Permian Basin known as the Delaware Basin. In 2016, we focused on drilling horizontal wells that yielded oil and liquids-rich gas from the Wolfcamp shale and the Bone Spring formation. Cimarex saw improved results in its Wolfcamp shale wells, as measured by production and reserves, with the further implementation of long laterals and continued improvement in well completion design and in the Bone Spring wells via upsized well completions.

The Permian region produced 504 MMcfe per day in 2016, which was 52% of our total company production. Total production from the region decreased 7% in 2016 over 2015.

Our Mid-Continent region consists of Oklahoma and the Texas Panhandle. Our activity in 2016 in the Mid-Continent was focused in the Woodford shale and the Meramec horizon, both in Oklahoma. We continued to implement larger well completions in the Woodford shale and we applied those same techniques to delineate the Meramec horizon, located above the Woodford. Cimarex continues to evaluate the size and potential of the Meramec play.

During 2016, production from the Mid-Continent averaged 457 MMcfe per day, or 47% of total company production. Total production from the region increased 6% in 2016 over 2015.

Drilling Activity

We completed the following number of exploratory and developmental wells in the years indicated:

	Wells Completed					
	2016		2015		2014	
	Gross	Net	Gross	Net	Gross	Net
Exploratory						
Productive	—	—	—	—	1	0.4
Dry	—	—	—	—	1	0.5
Total	—	—	—	—	2	0.9
Developmental						
Productive	153	61.0	219	98.7	309	173.6
Dry	1	—	3	1.7	1	0.1
Total	154	61.0	222	100.4	310	173.7

We have working interests in the following number of productive wells by region as of December 31, 2016:

	Gas		Oil	
	Gross	Net	Gross	Net
Mid-Continent	3,831	1,480	531	166
Permian Basin	831	406	4,967	1,029
Other	100	9	19	4
	4,762	1,895	5,517	1,199

Significant Properties

All of our oil and gas assets are located in the United States. We have varying levels of ownership interests in our properties consisting of working, royalty and overriding royalty interests. Operated wells account for 76% of our proved reserves. In 2016, proved reserves in the Cana area of the Watonga-Chickasha field were approximately 57% of Cimarex's total proved reserves. No other field had reserves in excess of 15% of our total proved reserves.

At December 31, 2016, 63% of our total proved reserves were located in the Mid-Continent region and 37% were in the Permian Basin. We owned an interest in 10,279 gross (3,094 net) productive oil and gas wells. The following table summarizes our estimated proved oil and gas reserves by region as of December 31, 2016.

	Gas (Bcf)	Oil (MMBbl)	NGL (MMBbl)	Total (Bcfe)	% of Total Proved Reserves
Mid-Continent	1,095.2	31.4	89.6	1,821.3	63
Permian Basin	372.4	74.3	41.0	1,064.0	37
Other	3.8	0.2	—	5.2	—
	1,471.4	105.9	130.6	2,890.5	100

At December 31, 2016, our ten largest producing fields held 86% of total proved reserves. We are the principal operator of our production in each of these fields.

Field	Region	% of Total Proved Reserves	Average Working Interest %	Approximate Average Depth (feet)	Primary Formation
Watonga-Chickasha	Mid-Continent	57.1	34.1	13,000'	Woodford
Ford, West	Permian Basin	8.4	56.9	9,500'	Wolfcamp
Dixieland	Permian Basin	6.1	96.8	11,000'	Wolfcamp
Lusk	Permian Basin	3.9	54.8	9,500'	Bone Spring
Cottonwood Draw	Permian Basin	2.6	73.7	3,000' - 10,000'	Delaware/Wolfcamp
Grisham	Permian Basin	1.8	100.0	11,000'	Wolfcamp
Phantom	Permian Basin	1.7	57.5	11,500'	Bone Spring
Two Georges	Permian Basin	1.7	90.5	11,500'	Bone Spring
Sandbar	Permian Basin	1.4	58.8	7,500'	Bone Spring
Quail Ridge	Permian Basin	1.0	36.5	8,000' - 13,000'	Bone Spring/Morrow
		85.7			

Acreage

The following table sets forth the gross and net acres of both developed and undeveloped leases held by Cimarex as of December 31, 2016. Gross acres are the total number of acres in which we own a working interest. Net acres are the gross acres multiplied by our working interest.

	Acreage					
	Undeveloped		Developed		Total	
	Gross	Net	Gross	Net	Gross	Net
Mid-Continent						
Kansas	18,231	18,191	—	—	18,231	18,191
Oklahoma	107,015	71,658	686,489	295,176	793,504	366,834
Texas	22,045	11,301	133,839	56,708	155,884	68,009
	147,291	101,150	820,328	351,884	967,619	453,034
Permian Basin						
New Mexico	73,882	52,669	175,842	119,597	249,724	172,266
Texas	81,443	63,289	201,078	147,829	282,521	211,118
	155,325	115,958	376,920	267,426	532,245	383,384
Other						
Arizona	2,097,201	2,097,201	17,847	—	2,115,048	2,097,201
California	383,647	383,647	—	—	383,647	383,647
Colorado	41,992	18,867	40,800	1,642	82,792	20,509
Gulf of Mexico	25,000	13,000	28,848	6,381	53,848	19,381
Louisiana	3,533	484	2,877	170	6,410	654
Michigan	26,491	26,414	1,183	1,183	27,674	27,597
Montana	34,381	9,167	7,688	1,721	42,069	10,888
Nevada	1,007,167	1,007,167	440	1	1,007,607	1,007,168
New Mexico	1,641,206	1,633,821	18,371	2,436	1,659,577	1,636,257
Texas	10,478	3,724	27,174	6,167	37,652	9,891
Utah	80,527	59,433	32,552	1,575	113,079	61,008
Wyoming	97,157	13,744	43,626	4,197	140,783	17,941
Other	194,398	171,229	9,734	3,460	204,132	174,689
	5,643,178	5,437,898	231,140	28,933	5,874,318	5,466,831
Total	5,945,794	5,655,006	1,428,388	648,243	7,374,182	6,303,249

The table below summarizes by year and region our undeveloped acreage expirations in the next five years. In most cases, the drilling of a commercial well will hold the acreage beyond the expiration.

	Acreage									
	2017		2018		2019		2020		2021	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Mid-Continent	22,804	18,383	11,288	6,462	1,695	1,525	—	—	—	—
Permian Basin	17,025	17,005	5,527	5,527	8,360	8,198	40	40	598	598
Other	51,036	50,281	30,709	29,992	63,334	59,092	28,867	28,652	7,042	6,953
	90,865	85,669	47,524	41,981	73,389	68,815	28,907	28,692	7,640	7,551
% of undeveloped acreage	1.5	1.5	0.8	0.7	1.2	1.2	0.5	0.5	0.1	0.1

At December 31, 2016, we had no proved undeveloped reserves associated with expiring acreage.

Marketing

Our oil and gas production is sold under short-term arrangements at market-responsive prices. We sell our oil at prices tied directly or indirectly to field postings. Our gas is sold under price mechanisms related to either monthly or daily index prices on pipelines where we deliver our gas.

We sell our oil and gas to a broad portfolio of customers. Our major customer during 2016 was Sunoco Logistics Partners L.P. (Sunoco), which accounted for 20% of our consolidated revenues for the year.

If Sunoco were to stop purchasing our production, we believe there are a number of other purchasers to whom we could sell our production with some delay. If multiple significant customers were to discontinue purchasing our product, we believe there would be challenges initially, but ample markets to handle the disruption.

We regularly monitor the credit worthiness of all our customers and may require parent company guarantees, letters of credit or prepayments when deemed necessary.

Corporate Headquarters and Employees

Our corporate headquarters is located at 1700 Lincoln St., Suite 3700, Denver, Colorado 80203. On December 31, 2016 and 2015, Cimarex had 856 and 925 employees, respectively. None of our employees are subject to collective bargaining agreements.

Competition

The oil and gas industry is highly competitive, particularly for prospective undeveloped leases and purchases of proved reserves. There is also competition for rigs and related equipment used to drill for and produce oil and gas, however, to a lesser extent in the current market environment. Our competitive position is also highly dependent on our ability to recruit and retain geological, geophysical and engineering expertise. We compete for prospects, proved reserves, oil-field services and qualified oil and gas professionals with major and diversified energy companies and other independent operators that have larger financial, human and technological resources than we do.

We compete with integrated, independent and other energy companies for the sale and transportation of our oil, gas and NGLs to marketing companies and end users. The oil and gas industry competes with other energy industries that supply fuel and power to industrial, commercial and residential consumers. Many of these competitors have greater financial and human resources. The effect of these competitive factors cannot be predicted.

Proved Reserves Estimation Procedures

Proved oil and gas reserve quantities are based on estimates prepared by Cimarex in accordance with the SEC's rules for reporting oil and gas reserves. Our reserve definitions conform with definitions of Rule 4-10(a) (1)-(32) of Regulation S-X of the SEC. All of our reserve estimates are maintained by our internal Corporate Reservoir Engineering group, which is comprised of reservoir engineers and engineering technicians. The objectives and management of this group are separate from and independent of the exploration and production functions of the company. The primary objective of our Corporate Reservoir Engineering group is to maintain accurate forecasts on all properties of the company through ongoing monitoring and timely updates of operating and economic parameters (production forecasts, prices and regional differentials, operating expenses, ownership, etc.) in accordance with guidelines established by the SEC. This separation of function and responsibility is a key internal control.

Cimarex engineers are responsible for estimates of proved reserves. Corporate engineers interact with the exploration and production departments to ensure all available engineering and geologic data is taken into account prior to establishing or revising an estimate. After preparing the reserves update, the corporate engineers review their recommendations with the Vice President of Corporate Engineering. After approval from the Vice President of Corporate Engineering, the revisions are entered into our reserves database by the engineering technician.

During the course of the year, the Vice President of Corporate Engineering presents summary reserves information to senior management and to our Board of Directors for their review. From time to time, the Vice President of Corporate Engineering also will confer with the Vice President of Exploration, Chief Operating Officer and the Chief Executive Officer regarding specific reserves-related issues. In addition, Corporate Reservoir Engineering maintains a set of basic guidelines and procedures to ensure that critical checks and reviews of the reserves database are performed on a regular basis.

Together, these internal controls are designed to promote a comprehensive, objective and accurate reserves estimation process. As an additional confirmation of the reasonableness of our internal estimates, DeGolyer and MacNaughton, an independent petroleum engineering consulting firm, reviewed reserves associated with greater than 80% of the total future net revenue discounted at 10% attributable to the total interests owned by Cimarex as of December 31, 2016. The individual primarily responsible for overseeing the review is a Senior Vice President with DeGolyer and MacNaughton and a Registered Professional Engineer in the State of Texas with over 37 years of experience in oil and gas reservoir studies and evaluations.

The technical employee primarily responsible for overseeing the oil and gas reserves estimation process is Cimarex's Vice President of Corporate Engineering. This individual graduated from the Colorado School of Mines with a Bachelor of Science degree in Engineering and has more than 22 years of practical experience in oil and gas reservoir evaluation. He has been directly involved in the annual reserves reporting process of Cimarex since 2002 and has served in his current role for the past 12 years.

Title to Oil and Gas Properties

We undertake title examination and perform curative work at the time we lease undeveloped acreage, prepare for the drilling of a prospect or acquire proved properties. We believe title to our properties is good and defensible, and is in accordance with industry standards. Nevertheless, we are involved in title disputes from time to time that result in litigation. Our oil and gas properties are subject to customary royalty interests, liens incidental to operating agreements, tax liens and other burdens and minor encumbrances, easements and restrictions.

Government Regulation

Oil and gas production and transportation is subject to extensive federal, state and local laws and regulations. Compliance with existing laws often is difficult and costly, but has not had a significant adverse effect on our operations or financial condition. In recent years, we have been most directly impacted by federal and state environmental regulations and energy conservation rules. We are also impacted by federal and state regulation of pipelines and other oil and gas transportation systems.

The states in which we conduct operations establish requirements for drilling permits, the method of developing fields, the size of well spacing units, drilling density within productive formations and the unitization or pooling of properties. In addition, state conservation laws include requirements for waste prevention, establish limits on the maximum rate of production from wells, generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability of production.

Environmental Regulation. Various federal, state and local laws regulating the discharge of materials into the environment, or otherwise relating to the protection of the environment, directly impact oil and gas exploration, development and production operations, which consequently impact our operations and costs. These laws and regulations govern, among other things, emissions into the atmosphere, discharges of pollutants into waters, underground injection of waste water, the generation, storage, transportation and disposal of waste materials, and protection of public health, natural resources and wildlife. These laws and regulations may impose substantial liabilities for noncompliance and for any contamination resulting from our operations and may require the suspension or cessation of operations in affected areas.

Cimarex is committed to environmental protection and believes we are in material compliance with applicable environmental laws and regulations. We obtain permits for our facilities and operations in accordance with the applicable laws and regulations. There are no known issues that have a significant adverse effect on the permitting process or permit compliance status of any of our facilities or operations. Expenditures are required to comply with environmental regulations. These costs are a normal, recurring expense of operations and not an extraordinary cost of compliance with current government regulations.

We do not anticipate that we will be required under current environmental laws and regulations to expend amounts that will have a material adverse effect on our financial position or operations. However, due to continuing changes in these laws and regulations, we are unable to predict with any reasonable degree of certainty any potential delays in development plans that could arise, or our future costs of complying with governmental requirements. We maintain levels of insurance customary in the industry to limit our financial exposure in the event of a substantial environmental claim resulting from sudden, unanticipated and accidental discharges of oil, produced water or other substances as well as additional coverage for certain other pollution events.

Gas Gathering and Transportation. The Federal Energy Regulatory Commission (FERC) requires interstate gas pipelines to provide open access transportation. FERC also enforces the prohibition of market manipulation by any entity, and the facilitation of the sale or transportation of natural gas in interstate commerce. Interstate pipelines have implemented these requirements, providing us with additional market access and more fairly applied transportation services and rates. FERC continues to review and modify its open access and other regulations applicable to interstate pipelines.

Under the Natural Gas Policy Act (NGPA), natural gas gathering facilities are expressly exempt from FERC jurisdiction. What constitutes “gathering” under the NGPA has evolved through FERC decisions and judicial review of such decisions. We believe that our gathering systems meet the test for non-jurisdictional “gathering” systems under the NGPA and that our facilities are not subject to federal regulations. Although exempt from FERC oversight, our natural gas gathering systems and services may receive regulatory scrutiny by state and federal agencies regarding the safety and operating aspects of the transportation and storage activities of these facilities.

In addition to using our own gathering facilities, we may use third-party gathering services or interstate transmission facilities (owned and operated by interstate pipelines) to ship our gas to markets.

Additional proposals and proceedings that might affect the oil and gas industry are pending before the U.S. Congress, FERC, Bureau of Land Management (BLM), U.S. Environmental Protection Agency (EPA), state legislatures, state agencies, local governments and the courts. We cannot predict when or whether any such proposals may become effective and what effect they will have on our operations. We do not anticipate that compliance with existing federal, state and local laws, rules or regulations will have a material adverse effect upon our capital expenditures, earnings or competitive position.

Federal and State Income and Other Local Taxation

Cimarex and the petroleum industry in general are affected by both federal and state income tax laws, as well as other local tax regulations involving ad valorem, personal property, franchise, severance and other excise taxes. We have considered the effects of these provisions on our operations and do not anticipate that there will be any material undisclosed impact on our capital expenditures, earnings or competitive position.

Executive Officers of the Registrant

See Part III, Item 10, Directors, Executive Officers and Corporate Governance for information regarding our executive officers as of February 24, 2017.

ITEM 1A. RISK FACTORS

The following risks and uncertainties, together with other information set forth in this Form 10-K, should be carefully considered by current and future investors in our securities. These risks and uncertainties are not the only ones we face. Additional risks and uncertainties presently unknown to us or currently deemed immaterial also may impair our business operations. The occurrence of one or more of these risks or uncertainties could materially and adversely affect our business, our financial condition, and the results of our operations, which in turn could negatively impact the value of our securities.

Oil, gas, and NGL prices fluctuate due to a number of uncontrollable factors, creating a component of uncertainty in our development plans and overall operations. Declines in prices adversely affect our financial results and rate of growth in proved reserves and production.

Oil and gas markets are volatile. We cannot predict future prices. The prices we receive for our production heavily influence our revenue, profitability, access to capital, and future rate of growth. The prices we receive depend on numerous factors beyond our control. These factors include, but are not limited to, changes in domestic and global supply and demand for oil and gas, the level of domestic and global oil and gas exploration and production activity, geopolitical instability, the actions of the Organization of Petroleum Exporting Countries, weather conditions, technological advances affecting energy consumption, governmental regulations and taxes, and the price and technological advancement of alternative fuels.

Our proved oil and gas reserves and production volumes will decrease unless those reserves are replaced with new discoveries or acquisitions. Accordingly, for the foreseeable future, we expect to make substantial capital investments for the exploration and development of new oil and gas reserves. Historically, we have paid for these types of capital expenditures with cash flow provided by our production operations, our revolving credit facility, and proceeds from the sale of senior notes or equity. Low prices reduce our cash flow and the amount of oil and gas that we can economically produce and may cause us to curtail, delay, or defer certain exploration and development projects. Moreover, low prices may impact our abilities to borrow under our revolving credit facility and to raise additional debt or equity capital to fund acquisitions.

If prices decrease, we will be required to take write-downs of the carrying values of our oil and gas properties and/or our goodwill.

Accounting rules require that we periodically review the carrying value of our oil and gas properties and goodwill for possible impairment.

In 2016, we recognized ceiling test impairments totaling $719.1 million ($456.9 million, net of tax). In 2015, we recognized ceiling test impairments in each quarter totaling $3.7 billion ($2.4 billion, net of tax). The 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 estimated future net cash flows from proved reserves. At December 31, 2016, the calculated value of the ceiling limitation exceeded the carrying value of our oil and gas properties subject to the test, and no impairment was necessary. However, a decline of 11% or more in the value of the ceiling limitation would have resulted in an impairment. Because the ceiling calculation uses rolling 12-month average commodity prices, the effect of increases and decreases in period-over-period prices can significantly impact the ceiling limitation calculation. Impairment charges do not affect cash flow from operating activities, but do adversely affect our net income and various components of our balance sheet.

U.S. or global financial markets may impact our business and financial condition.

A credit crisis or other turmoil in the U.S. or global financial system may have a negative impact on our business and our financial condition. Our ability to access the capital markets may be restricted at a time when we would like, or need, to raise financing. This could have an impact on our flexibility to react to changing economic and business conditions. Deteriorating economic conditions could have a negative impact on our lenders, the purchasers of our oil and gas production and the working interest owners in properties we operate, causing them to fail to meet their obligations to us.

Failure to economically replace oil and gas reserves could negatively affect our financial results and future rate of growth.

In order to replace the reserves depleted by production and to maintain or increase our total proved reserves and overall production levels, we must either locate and develop new oil and gas reserves or acquire producing properties from others. This requires significant capital expenditures and can impose reinvestment risk for us, as we may not be able to continue to replace our reserves economically. While we occasionally may seek to acquire proved reserves, our main business strategy is to grow through exploration and drilling. Without successful exploration and development, our reserves, production and revenues could decline rapidly, which would negatively impact the results of our operations.

Exploration and development involves numerous risks, including new governmental regulations and the risk that we will not discover any commercially productive oil or gas reservoirs. Additionally, it can be unprofitable, not only from drilling dry holes, but also from drilling productive wells that do not return a profit because of insufficient reserves or declines in commodity prices.

Our drilling operations may be curtailed, delayed, or canceled for many reasons. Factors such as unforeseen poor drilling conditions, title problems, unexpected pressure irregularities, equipment failures, accidents, adverse weather conditions, compliance with environmental and other governmental requirements, bans, moratoria or other restrictions implemented by local governments and the cost of, or shortages or delays in the availability of, drilling and completion services could negatively impact our drilling operations.

Our proved reserve estimates may be inaccurate and future net cash flows are uncertain.

Estimates of total proved oil and gas reserves (consisting of proved developed and proved undeveloped reserves) and associated future net cash flow depend on a number of variables and assumptions. Refer to "*Cautionary Information about Forward-Looking Statements*" in Part I of this report. Among others, changes in any of the following factors may cause actual results to vary considerably from our estimates:

- timing of development expenditures;
- amount of required capital expenditures and associated economics;
- recovery efficiencies, decline rates, drainage areas, and reservoir limits;
- anticipated reservoir and production characteristics and interpretations of geologic and geophysical data;
- production rates, reservoir pressure, unexpected water encroachment, and other subsurface conditions;
- oil, gas, and NGL prices;
- governmental regulation;
- access to assets restricted by local government action;
- operating costs;

- property, severance, excise and other taxes incidental to oil and gas operations;
- workover and remediation costs; and
- federal and state income taxes.

Our proved oil and gas reserve estimates are prepared by Cimarex engineers in accordance with guidelines established by the SEC. DeGolyer and MacNaughton, independent petroleum engineers, reviewed our reserve estimates for properties that comprised at least 80% of the discounted future net cash flows before income taxes, using a 10% discount rate, as of December 31, 2016.

The cash flow amounts referred to in this filing should not be construed as the current market value of our proved reserves. In accordance with SEC guidelines, the estimated discounted net cash flow from proved reserves is based on the average of the previous 12 months' first-day-of-the-month prices and costs as of the date of the estimate, whereas actual future prices and costs may be materially different.

Our business depends on oil and gas pipeline and transportation facilities, some of which are owned by others.

In addition to the existence of adequate markets, our oil and natural gas production depends in large part on the proximity and capacity of pipeline systems, as well as storage, transportation, processing and fractionation facilities, most of which are owned by third parties. The lack of availability or the lack of capacity on these systems and facilities could result in the curtailment of production or the delay or discontinuance of drilling plans. This is more likely in remote areas without established infrastructure, such as our Delaware Basin area where we have significant development activities. The lack of availability or capacity in these facilities or the loss of these facilities due to construction delays, weather, fire or other reasons, for an extended period of time could negatively affect our revenues.

A limited number of companies purchase a majority of our oil, NGLs and natural gas. The loss of a significant purchaser could have a material adverse effect on our ability to sell production.

Federal and state regulation of oil and natural gas, local government activity, adverse court rulings, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and general economic conditions could adversely affect our ability to produce and market oil and natural gas.

Hedging transactions may limit our potential gains and involve other risks.

To limit our exposure to price risk, we enter into hedging agreements from time to time, and use commodity derivatives. Hedges limit volatility and increase the predictability of a portion of our cash flow. These transactions also limit our potential gains when oil and gas prices exceed the prices established by the hedges.

In certain circumstances, hedging transactions may expose us to the risk of financial loss, including instances in which:

- the counterparties to our hedging agreements fail to perform;
- there is a sudden unexpected event that materially increases oil and natural gas prices; or
- there is a widening of price basis differentials between delivery points for our production and the delivery point assumed in the hedge arrangement.

Because we account for derivative contracts under mark-to-market accounting, during periods we have hedging transactions in place we expect continued volatility in derivative gains or losses on our income statement as changes occur in the relevant price indexes.

The adoption of derivatives legislation could have an adverse effect on our ability to use derivative instruments as hedges against fluctuating commodity prices.

In July 2010, the Dodd-Frank Act was enacted, representing an extensive overhaul of the framework for regulation of U.S. financial markets. The Dodd-Frank Act called for various regulatory agencies, including the SEC and the Commodities Futures Trading Commission (CFTC), to establish regulations for implementation of many of its provisions. The Dodd-Frank Act contains significant derivatives regulations, including requirements that certain transactions be cleared on exchanges and that cash collateral (margin) be posted for such transactions. The Dodd-Frank Act provides for an exemption from the clearing and cash collateral requirements for commercial end-users, such as Cimarex, and it includes a number of defined terms used in determining how this exemption applies to particular derivative transactions and the parties to those transactions.

We have satisfied the requirements for the commercial end-user exception to the clearing requirement and intend to continue to engage in derivative transactions. In December 2015, the CFTC approved final rules on margin requirements that will have an impact on our hedging counterparties and an interim final rule exemption from the margin requirements for certain uncleared swaps with commercial end-users. The final rules did not impose additional requirements on commercial end-users. The ultimate effect of these new rules and any additional regulations is currently uncertain. New rules and regulations in this area may result in significant increased costs and disclosure obligations as well as decreased liquidity as entities that previously served as hedge counterparties exit the market.

We have been an early entrant into new or emerging resource plays. As a result, our drilling results in these areas are uncertain. The value of our undeveloped acreage may decline and we may incur impairment charges if drilling results are unsuccessful.

New or emerging oil and gas resource plays have limited or no production history. Consequently, in those areas it is difficult to predict our future drilling costs and results. Therefore, our cost of drilling, completing and operating wells in these areas may be higher than initially expected. Similarly, our production may be lower than initially expected, and the value of our undeveloped acreage may decline if our results are unsuccessful. As a result, we may be required to impair the carrying value of our undeveloped acreage in new or emerging plays.

Furthermore, unless production is established during the primary term of certain of our undeveloped oil and gas leases, the leases will expire, and we will lose our right to develop those properties.

Competition in our industry is intense and many of our competitors have greater financial and technological resources.

We operate in the competitive area of oil and gas exploration and production. Many of our competitors are large, well-established companies that have larger operating staffs and greater capital resources. These competitors may be willing to pay more for exploratory prospects and productive oil and gas properties. They may also be able to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit.

Because our activity is also concentrated in areas of heavy industry competition, there is heightened demand for personnel, equipment, power, services, facilities and resources, resulting in higher costs than in other areas. Such intense competition also could result in delays in securing, or the inability to secure, the personnel, equipment, power, services, resources or facilities necessary for our development activities, which could negatively impact our production volumes. We also face higher costs in remote areas where vendors can charge higher rates due to that remoteness along with the inability to attract employees to those areas and the ability to deploy their resources in easier to access areas.

We are subject to complex laws and regulations that can adversely affect the cost, manner, and feasibility of doing business.

Exploration, production and the sale of oil and gas are subject to extensive laws and regulations, including those implemented to protect the environment, human health and safety and wildlife. Federal, state, and local regulatory agencies frequently require permitting and impose conditions on our activities. During the permitting process, these regulatory agencies often exercise considerable discretion in both the timing and scope of the permits, and the public, including special interest groups, often has an opportunity to influence the timing and outcome of the process. The requirements or conditions imposed by these agencies can be costly and can delay the commencement of our operations. In addition, a number of initiatives had been put forth by the Obama administration in the form of Presidential or Secretarial Memoranda, which are still in effect, and have the potential to impact the cost of doing business or could result in substantial delays in permitting, drilling and other oil and gas activities. One example is the Presidential Memorandum on "no net loss" which will take the form of agency action by the Department of Interior, EPA and other agencies to ensure that harmful effects to lands are avoided, minimized and those which remain mitigated up to and including prohibiting actions which may have been previously allowed or requiring compensation.

Failing to comply with any of the applicable laws and regulations, or Presidential initiatives, could result in the suspension or termination of our operations and subject us to administrative, civil and criminal liabilities and penalties. Such costs could have a material adverse effect on both our financial condition and operations. In addition, it is uncertain what impact the 2016 U.S. presidential and congressional elections will have on the energy industry.

Environmental matters and costs can be significant.

As an owner, lessee, or operator of oil and gas properties, we are subject to various complex, stringent and constantly evolving environmental laws and regulations. Our operations inherently create the risk of environmental liability to the government and private parties stemming from our use, generation, handling and disposal of water and waste materials, as well as the release of hydrocarbons or other substances into the air, soil, or water. The environmental laws and regulations to which we are subject impose numerous obligations applicable to our operations, including: the acquisition of permits before conducting regulated activities associated with drilling for and producing oil and gas; the restriction of types, quantities, and concentration of materials that can be released into the environment; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands, waters of the United States, and other protected areas; the application of specific health and safety criteria addressing worker protection; and the imposition of substantial liabilities for pollution resulting from our operations. Numerous governmental authorities, such as the EPA and analogous state agencies have the power to enforce compliance with these laws and regulations and the permits issued under them. Such enforcement actions often involve taking difficult and costly compliance measures or corrective actions. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, the imposition of investigatory or remedial obligations, and the issuance of orders limiting or prohibiting some or all of our operations. In addition, we may experience delays in obtaining or be unable to obtain required permits, which may delay or interrupt our operations and limit our growth and revenue.

Liabilities under certain environmental laws can be joint and several and may in some cases be imposed regardless of fault on our part such as where we own a working interest in a property operated by another party. We also could be held liable for damages or remediating lands or facilities previously owned or operated by others regardless of whether such contamination resulted from our own actions and regardless if we were in compliance with all applicable law at the time. Further, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations. Since these environmental risks generally are not fully insurable and can result in substantial costs, such liabilities could have a material adverse effect on both our financial condition and operations.

Our financial condition and results of operations may be materially adversely affected if we incur costs and liabilities due to a failure to comply with environmental regulations or a release of hazardous substances into the environment.

Our operations are subject to environmental laws and regulations relating to the management and release of hazardous substances, pollutants, solid and hazardous wastes and petroleum hydrocarbons. These laws generally regulate the generation, storage, treatment, discharge, transportation and disposal of pollutants and solid and hazardous waste and may impose strict and, in some cases, joint and several liability for the investigation and remediation of affected areas where hazardous substances may have been released or disposed. The most significant of these environmental laws are as follows:

- The Comprehensive Environmental Response, Compensation, and Liability Act, as amended, referred to as CERCLA or the Superfund law, and comparable state laws, which imposes liability on generators, transporters and arrangers of hazardous substances at sites where hazardous substance releases have occurred or are threatening to occur;

- The Oil Pollution Act of 1990 (OPA), under which owners and operators of onshore facilities and pipelines, lessees or permittees of an area in which an offshore facility is located, and owners and operators of vessels are liable for removal costs and damages that result from a discharge of oil into navigable waters of the United States;

- The Resource Conservation and Recovery Act (RCRA), as amended, and comparable state statutes, which governs the treatment, storage and disposal of solid waste;

- The Federal Water Pollution Control Act, as amended, also known as the Clean Water Act (CWA), which governs the discharge of pollutants, including natural gas wastes into federal and state waters;

- The Safe Drinking Water Act (SDWA), which governs the disposal of wastewater in underground injection wells; and

- The Clean Air Act (CAA) which governs the emission of pollutants into the air.

We believe we are in substantial compliance with the requirements of CERCLA, RCRA, OPA, CWA, SDWA, CAA and related state and local laws and regulations. We also believe we hold all necessary and up-to-date permits, registrations and other authorizations required under such laws and regulations. Although the current costs of managing our wastes as they presently are classified are reflected in our budget, any legislative or regulatory reclassification of oil and natural gas exploration and production wastes could increase our costs to manage and dispose of such wastes and have a material adverse effect on our financial condition and operations.

Federal regulatory initiatives relating to the protection of threatened or endangered species could result in increased costs and additional operating restrictions or delays.

The Federal Endangered Species Act (ESA) was established to protect endangered and threatened species. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' habitat. The U.S. Fish and Wildlife Service (FWS) may designate critical habitat and suitable habitat areas it believes are necessary for survival of a threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and may materially delay or prohibit land access for oil and natural gas development. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. We conduct operations on federal oil and natural gas leases in areas where certain species are currently listed as threatened or endangered, or could be listed as such, under the ESA. Operations in areas where threatened or endangered species or their habitat are known to exist may require us to incur increased costs to implement mitigation or protective measures and also may restrict or preclude our drilling activities in those areas or during certain seasons, such as breeding and nesting seasons. On March 27, 2014, the FWS announced the listing of the lesser prairie chicken, whose habitat is over a five-state region, including Texas, New Mexico and Oklahoma, where we conduct operations, as a threatened species under the ESA. Listing of the lesser prairie chicken as a threatened species imposes restrictions on disturbances to critical habitat by landowners and drilling companies that would harass, harm or otherwise result in a "taking" of this species. However, the FWS also announced a final rule that will limit regulatory impacts on landowners and businesses from the listing if those landowners and businesses have entered into certain range-wide conservation planning agreements, such as those developed by the Western Association of Fish and Wildlife Agencies (WAFWA), pursuant to which such parties agreed to take steps to protect the lesser prairie chicken's habitat and to pay a mitigation fee if its actions harm the lesser prairie chicken's habitat. We entered into a voluntary Candidate Conservation Agreement (CCA) with the WAFWA, whereby we agreed to take certain actions and limit certain activities, such as limiting drilling on certain portions of our acreage during nesting seasons, in an effort to protect the lesser prairie chicken. Such CCA could result in increased costs to us from species protection measures, time delays or limitations on drilling activities, which costs, delays or limitations may be significant. While a federal judge in Texas vacated the listing of the lesser prairie chicken in 2015, listing petitions continue to be filed with the FWS which could impact our operations. Many non-governmental organizations (NGOs) work closely with the FWS regarding the listing of many species, including species with broad and even nationwide ranges. The recent listing of the Mexican Long Nosed bat, whose habitat includes the Permian Basin where we operate, is an example of the NGOs' influence on ESA listing decisions. The increase in endangered species listings may impact our ability to explore for or produce oil and gas in certain areas and increase our costs.

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 EPA has asserted federal regulatory authority over certain hydraulic-fracturing activities under the 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 has delegated the permitting authority for the SDWA's Underground Injection Control Class II programs in Oklahoma, Texas and New Mexico where we maintain operational acreage, the EPA is encouraging state programs to review and consider use of such draft guidance.

In addition, on March 26, 2015, the federal BLM 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 BLM 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 filed by industry groups, two Indian tribes, and at least four states, alleging that federal law does not give the BLM authority to regulate hydraulic fracturing. The federal judge has enjoined the rule while the case is pending. The district court held that BLM did not have jurisdiction to promulgate the rule. The Obama Justice Department appealed and that appeal is pending.

There are also certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The EPA has concluded 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 was open until August 28, 2015 and a series of public hearings were conducted by the EPA's Scientific Advisory Board (SAB) throughout the fall of 2015. The EPA issued its final report and has reached two different topline conclusions, although the content of the study itself remains unchanged. 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.

The adoption of climate change legislation or regulations restricting emission of greenhouse gases could result in increased operating costs and reduced demand for the oil and natural gas we produce.

Studies have suggested that emission of certain gases, commonly referred to as greenhouse gases (GHGs) may be impacting the earth's climate. Methane, a primary component of natural gas, and carbon dioxide, also present in natural gas as a secondary product, sometimes considered an impurity or a by-product of the burning of oil and natural gas, are examples of GHGs. The U.S. Congress and various states have been evaluating, and in some cases implementing, climate-related legislation and other regulatory initiatives that restrict emissions of GHGs. In December 2009, the EPA published its findings that emissions of GHGs present an endangerment to public health and the environment because emissions of such gases are contributing to the warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA adopted regulations under existing provisions of the Federal Clean Air Act that establish Prevention of Significant Deterioration (PSD) and Title V permit reviews for GHG emissions from certain large stationary sources. Facilities required to obtain PSD and/or Title V permits under EPA's GHG Tailoring Rule for their GHG emissions also may be required to meet "Best Available Control Technology" standards that will be established by the states or, in some cases, by the EPA on a case-by-case basis. The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States, including, among others, certain oil and natural gas production facilities on an annual basis, which includes certain of our operations. In recent proposed rulemaking EPA is widening the scope of annual GHG reporting to include not only activities associated with completion and workover of gas wells with hydraulic fracturing and activities associated with oil and natural gas production operations, but also completions and workovers of oil wells with hydraulic fracturing, gathering and boosting systems and transmission pipelines.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. In January 2015, President Obama announced a series of administration actions to reduce methane emissions, including rulemaking by the EPA and the BLM as well as updating of standards by the Department of Transportation's Pipeline and Hazardous Materials Administration. The previous administration intended to promulgate proposed climate change rulemaking aimed at reducing GHG emissions by 45% by 2025 compared to 2012 levels. These proposals target both new and existing sources. On January 22, 2016, the Department of the Interior announced its proposed emissions mandate on oil and natural gas producers who operate on federal and Indian lands. While this rule was finalized in November of 2016, it is currently being challenged by several states and industry. While we expect new legislation and regulations to increase the cost of business, at this time it is not possible to quantify the impact on our business. Any such future laws and final regulations that require reporting of GHGs or otherwise limit emissions of GHGs from our equipment and operations could require us to incur costs to develop and implement best management practices aimed at reducing GHG emissions, install and maintain emissions control technologies, as well as monitor and report on GHG emissions associated with our operations, which would increase our operating costs, and such requirements also could adversely affect demand for the oil and natural gas that we produce.

Legislation or regulatory initiatives intended to address seismic activity could restrict our ability to engage in hydraulic fracturing during completion operations and to dispose of saltwater produced in connection with our oil and gas production, which could limit our ability to produce oil and gas economically and have a material adverse effect on our business.

We dispose of large volumes of saltwater produced in connection with our drilling and production operations, pursuant to permits issued to us or third party operators of disposal wells by governmental authorities overseeing produced water disposal activities. While these permits are issued pursuant to existing laws and regulations, these legal requirements are subject to change, which could result in the imposition of more stringent operating constraints or new monitoring and reporting requirements, owing to, among other things, concerns of the public or governmental authorities regarding such gathering or disposal activities.

There exists a growing concern that hydraulic fracturing during well completion operations and the injection of produced water into belowground disposal wells triggers seismic activity in certain areas, including Oklahoma and Texas, where we operate. In response to these concerns, regulators in some states are pursuing initiatives designed to impose additional requirements in connection with hydraulic fracturing and in the permitting of saltwater disposal wells or otherwise to assess any relationship between seismicity and these oil and gas operations. For example, in 2014, the Oklahoma Corporation Commission began adopting rules for operators of saltwater disposal wells in certain seismically-active areas, or Areas of Interest, in the Arbuckle formation, requiring operators to monitor and record well pressure and discharge volume on a daily basis and further requiring operators of wells permitted for disposal of 20,000 barrels per day or more of saltwater to conduct mechanical integrity testing. Throughout 2015 and 2016, the Oklahoma Corporation Commission's Oil and Gas Conservation Division, or OGCD, issued a series of directives, expanding the areas of interest for induced seismicity and enhanced disposal restrictions and limiting the depths at which produced water could be injected or, in the alternative, reducing disposal volumes. Additional regulations and restrictions are possible as more is understood about this issue. In addition and separate from induced seismicity associated with injection, the OGCD has issued guidelines to operators to follow when engaged in well stimulation activities, which some studies now seem to correlate with a small number of low intensity seismic events.

In addition, in 2014 the Texas Railroad Commission, or TRC, published a new rule governing permitting or re-permitting of disposal wells in Texas that would require, among other things, the submission of information on seismic events occurring within a specified radius of the disposal well location, as well as logs, geologic cross sections and structure maps relating to the disposal area in question. If a permittee or a prospective permittee fails to demonstrate that the saltwater or other fluids are confined to the disposal zone or if scientific data indicates such a disposal well is likely to be or determined to be contributing to seismic activity, then the TRC may deny, modify, suspend or terminate the permit application or existing operating permit for that well.

The adoption and implementation of any new laws, regulations, or directives that restrict our ability to stimulate wells or to dispose of produced water, by changing the depths of disposal wells, reducing the volume of oil and natural gas wastewater disposed in such wells, restricting disposal well locations or otherwise, or by requiring us or third parties who dispose of our saltwater to shut down disposal wells, could increase disposal costs or require us to shut in a substantial number of our oil and natural gas wells or otherwise have a material adverse effect on our ability to produce oil and gas economically and, accordingly, could materially and adversely affect our business, financial condition and results of operations.

A substantial portion of our producing properties are located in limited geographic areas, making us vulnerable to risks associated with having geographically concentrated operations.

A substantial portion of our producing properties are geographically concentrated in the Permian Basin in Texas and New Mexico and our Cana area in the Mid-Continent region in Oklahoma, with these two areas comprising approximately 52% and 47%, respectively, of our oil, gas, and NGL production and approximately 61% and 39%, respectively, of our oil, gas, and NGL revenues for the year ended December 31, 2016. Approximately 37% of our estimated proved reserves were located in the Permian Basin and approximately 63% of our estimated proved reserves were located in the Mid-Continent region as of December 31, 2016.

Because of this concentration in limited geographic areas, the success and profitability of our operations may be disproportionately exposed to regional factors relative to our competitors that have more geographically dispersed operations. These factors include, among others: (i) the prices of crude oil and natural gas produced from wells in the regions and other regional supply and demand factors, including gathering, pipeline and rail transportation capacity constraints; (ii) the availability of rigs, equipment, oil field services, supplies, and labor; (iii) the availability of processing and refining facilities; and (iv) infrastructure capacity. In addition, our operations in the Permian Basin and Mid-Continent region, as well as other areas, may be adversely affected by severe weather events such as floods, lightning, ice and other storms, and tornadoes, which can intensify competition for the items described above during months when drilling is possible and may result in periodic shortages. The concentration of our operations in limited geographic areas also increases our exposure to changes in local laws and regulations including concerning hydraulic fracturing and waste water disposal as discussed above in "Legislation or regulatory initiatives intended to address seismic activity could restrict our ability to engage in hydraulic fracturing during completion operations and to dispose of saltwater produced in connection with our oil and gas production, which could limit our ability to produce oil and gas economically and have a material adverse effect on our business", certain lease stipulations designed to protect wildlife, and unexpected events that may occur in the regions such as natural disasters, seismic events, industrial accidents or labor difficulties. Any one of these events has the potential to cause producing wells to be shut-in, delay operations, decrease cash flows, increase operating and capital costs and prevent development of lease inventory before expiration. Any of the risks described above could have a material adverse effect on our financial condition, results of operations and cash flows.

We use some of the latest available horizontal drilling and completion techniques, which involve risk and uncertainty in their application.

Our horizontal drilling operations utilize some of the latest drilling and completion techniques. The risks or such techniques include, but are not limited to, the following:

- landing the wellbore in the desired drilling zone;
- staying in the desired drilling zone while drilling horizontally through the formation;
- running casing the entire length of the wellbore;
- being able to run tools and other equipment consistently through the horizontal wellbore;
- the ability to fracture stimulate the planned number of stages;
- the ability to run tools the entire length of the wellbore during completion operations; and
- the ability to successfully clean out the wellbore after completion of the final fracture stimulation stage.

Any of the above factors could have a material adverse effect on our financial position, results of operations or cash flows.

Many of our properties are in areas that may have been partially depleted or drained by offset wells and certain of our wells may be adversely affected by actions other operators may take when drilling, completing or operating wells that they own.

Many of our properties are in areas that may have already been partially depleted or drained by earlier offset drilling. The owners of leasehold interests adjoining any of our properties could take actions, such as drilling and completing additional wells, which could adversely affect our operations. When a new well is completed and produced, the pressure differential in the vicinity of the well causes the migration of reservoir fluids toward the new wellbore (and potentially away from existing wellbores). As a result, the drilling and production of these potential locations could cause a depletion of our proved reserves and may inhibit our ability to further develop our proved reserves. In addition, completion operations and other activities conducted on adjacent or nearby wells could cause production from our wells to be shut in for indefinite periods of time, could result in increased lease operating expenses and could adversely affect the production and reserves from our wells after they re-commence production. We have no control over the operations or activities of offsetting operators.

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.

A cyber attack involving our information systems and related infrastructure, or those of our business associates, could disrupt our business and negatively impact our operations in a variety of ways, including but not limited to:

- unauthorized access to seismic data, reserves information, strategic information, or other sensitive or proprietary information could have a negative impact on our ability to compete for oil and gas resources;

- data corruption or operational disruption of production-related infrastructure could result in a loss of production, or accidental discharge;

- a cyber attack on a vendor or service provider could result in supply chain disruptions, which could delay or halt our major development projects;

- a cyber attack on third party gathering, pipeline, or rail transportation systems could delay or prevent us from transporting and marketing our production, resulting in a loss of revenues; and

- a cyber attack on our accounting or accounts payable systems could expose us to liability to employees and third parties if their personal identifying information is obtained.

These events could damage our reputation and lead to financial losses from remedial actions, loss of business or potential liability, which could have a material adverse effect on our financial condition, results of operations or 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.

Our limited ability to influence operations and associated costs on non-operated properties could result in economic losses that are partially beyond our control.

For the year ended December 31, 2016, other companies operated approximately 22% of our net production. Our success in properties operated by others depends upon a number of factors outside of our control. These factors include timing and amount of capital expenditures, the operator's expertise and financial resources, approval of other participants in drilling wells, selection of technology and maintenance of safety and environmental standards. Our dependence on the operator and other working interest owners for these projects could prevent the realization of our targeted returns on capital in drilling or acquisition activities.

Our business involves many operating risks that may result in substantial losses for which insurance may be unavailable or inadequate.

Our operations are subject to hazards and risks inherent in drilling for oil and gas, such as fires, natural disasters, explosions, formations with abnormal pressures, casing collapses, uncontrollable flows of underground gas, blowouts, surface cratering, pipeline ruptures or cement failures. Other such risks include theft, vandalism, environmental hazards such as natural gas leaks, oil spills and discharges of toxic gases. Any of these risks can cause substantial losses resulting from:

- injury or loss of life;
- damage to, loss of or destruction of, property, natural resources and equipment;
- pollution and other environmental damages;
- regulatory investigations, civil litigation and penalties;
- damage to our reputation;
- suspension of our operations; and
- costs related to repair and remediation.

In addition, our liability for environmental hazards may include conditions created by the previous owners of properties that we purchase or lease.

We maintain insurance coverage against some, but not all, potential losses. We do not believe that insurance coverage for all environmental damages that could occur is available at a reasonable cost. Losses could occur for uninsurable or uninsured risks, or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could harm our financial condition and results of operation.

We may not be able to generate enough cash flow to meet our debt obligations.

At December 31, 2016, our long-term debt consisted of $750 million of 4.375% senior notes due in 2024 and $750 million of 5.875% senior notes due in 2022. In addition to interest expense and principal on our long-term debt, we have demands on our cash resources including, among others, contractual commitments, operating expenses and capital expenditures.

Our ability to pay the principal and interest on our long-term debt and to satisfy our other liabilities will depend upon future performance and our ability to repay or refinance our debt as it becomes due. Our future operating performance and ability to refinance will be affected by economic and capital market conditions, results of operations and other factors, many of which are beyond our control. Our ability to meet our debt service obligations also may be impacted by changes in prevailing interest rates, as borrowing under our existing revolving credit facility bears interest at floating rates.

We may not generate sufficient cash flow from operations. Without sufficient cash flow, there may not be adequate future sources of capital to enable us to service our indebtedness or to fund our other liquidity needs. If we are unable to service our indebtedness and fund our operating costs, we will be forced to adopt alternative strategies that may include:

- reducing or delaying capital expenditures;
- seeking additional debt financing or equity capital;
- selling assets; or
- restructuring or refinancing debt.

We may be unable to complete any such strategies on satisfactory terms, if at all. Our inability to generate sufficient cash flows to satisfy our debt obligations or contractual commitments, or to refinance our indebtedness on commercially reasonable terms, would materially and adversely affect our financial condition and results of operations.

The instruments governing our indebtedness contain various covenants limiting the discretion of our management in operating our business.

The indenture governing our senior notes and our credit agreement contain various restrictive covenants that may limit management's discretion in certain respects. In particular, these agreements limit Cimarex's and its subsidiaries' ability to, among other things:

- create certain liens;
- consolidate, merge or transfer all, or substantially all, of our assets and our restricted subsidiaries;
- enter into sale and leaseback transactions.

In addition, our revolving credit agreement requires us to maintain a total debt to capitalization ratio (as defined in the credit agreement) of not more than 65%. See Note 3 to the Consolidated Financial Statements for further information.

If we fail to comply with the restrictions in the indenture governing our senior notes or the agreement governing our credit facility or any other subsequent financing agreements, a default may allow the creditors, if the agreements so provide, to accelerate the related indebtedness as well as any other indebtedness to which a cross-acceleration or cross-default provision applies. In addition, lenders may be able to terminate any commitments they had made to make available further funds.

Our acquisition activities may not be successful, which may hinder our replacement of reserves and adversely affect our results of operations.

The successful acquisition of properties requires an assessment of several factors, including:

- geological risks and recoverable reserves;
- future oil and gas prices and their appropriate market differentials;
- operating costs; and
- potential environmental risks and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. Inspections will not likely be performed on every well or facility, and structural and environmental problems are not necessarily observable even when an inspection is undertaken. Furthermore, the seller may be unwilling or unable to provide effective contractual protection against all or part of the identified problems.

We may lose leases if production is not established within the time periods specified in the leases.

Unless production is established within the spacing units covering the undeveloped acres on which some of the locations are identified, the leases for such acreage will expire. If we are not able to renew leases before they expire, any proved undeveloped reserves associated with such leases will be removed from our proved reserves. The combined net acreage expiring in the next three years represents 3.5% of our total net undeveloped acreage at December 31, 2016. At that date, we had leases representing 85,669 net acres expiring in 2017, 41,981 net acres expiring in 2018, and 68,815 net acres expiring in 2019. Our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

Our disposition activities may be subject to factors beyond our control, and in certain cases we may retain unforeseen liabilities for certain matters.

We regularly sell non-core assets in order to increase capital resources available for other core assets and to create organizational and operational efficiencies. We also occasionally sell interests in core assets for the purpose of accelerating the development and increasing efficiencies in such core assets. Various factors could materially affect our ability to dispose of such assets, including the approvals of governmental agencies or third parties and the availability of purchasers willing to acquire the assets with terms we deem acceptable.

Sellers often retain certain liabilities or agree to indemnify buyers for certain matters related to the sold assets. The magnitude of any such retained liability or of the indemnification obligation is difficult to quantify at the time of the transaction and ultimately could be material. Also, as is typical in divestiture transactions, third parties may be unwilling to release the company from guarantees or other credit support provided prior to the sale of the divested assets. As a result, after a divestiture, the company may remain secondarily liable for the obligations guaranteed or supported to the extent that the buyer of the assets fails to perform these obligations.

Competition for experienced, technical personnel may negatively impact our operations.

Our exploratory and development drilling success depends, in part, on our ability to attract and retain experienced professional personnel. The loss of any key executives or other key personnel could have a material adverse effect on our operations. As we continue to develop our asset base and the scope of our operations, our future profitability will depend on our ability to attract and retain qualified personnel, particularly individuals with a strong background in geology, geophysics, engineering and operations.

We are involved in various legal proceedings, the outcome of which could have an adverse effect on our liquidity.

In the normal course of business, we have various lawsuits and related disputed claims, including but not limited to claims concerning title, royalty payments, environmental issues, personal injuries, and contractual issues. Although we currently believe the resolution of these lawsuits and claims, individually or in the aggregate, would not have a material adverse effect on our financial condition or results of operations, our assessment of our current litigation and other legal proceedings could change in light of the discovery of facts with respect to legal actions or other proceedings pending against us not presently known to us or determinations by judges, juries or other finders of fact that are not in accord with our evaluation of the possible liability or outcome of such proceedings. Therefore, there can be no assurance that outcomes of future legal proceedings would not have an adverse effect on our liquidity and capital resources.

Certain federal income tax deductions currently available with respect to natural gas and oil exploration and development may be eliminated, as a result of future legislation.

Various proposals have been made recommending the elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. Legislation is often introduced in Congress which would implement many of these proposals. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; and (iii) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear, however, whether any such changes will be enacted or how soon such changes could be effective.

The passage of this legislation or any other similar change in U.S. federal income tax law could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such change could have an adverse effect on our financial position.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

The information set forth under the heading "Litigation" in Note 10 of the Notes to the Consolidated Financial Statements included in Part II, Item 8 of this Annual Report on Form 10-K is incorporated by reference in response to this item.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our $0.01 par value common stock trades on the New York Stock Exchange (NYSE) under the symbol XEC. A cash dividend was paid to stockholders in each quarter of 2016. Future dividend payments will depend on the company's level of earnings, financial requirements and other factors considered relevant by the Board of Directors.

Stock Prices and Dividends by Quarter. The following table sets forth, for the periods indicated, the high and low sales price per share of our common stock on the NYSE and the per share dividends declared during the period.

2016	High	Low	Dividends Declared Per Share
First Quarter	$ 100.07	$ 72.77	$ 0.08
Second Quarter	$ 123.48	$ 93.21	$ 0.08
Third Quarter	$ 136.95	$ 112.19	$ 0.08
Fourth Quarter	$ 146.96	$ 118.59	$ 0.08

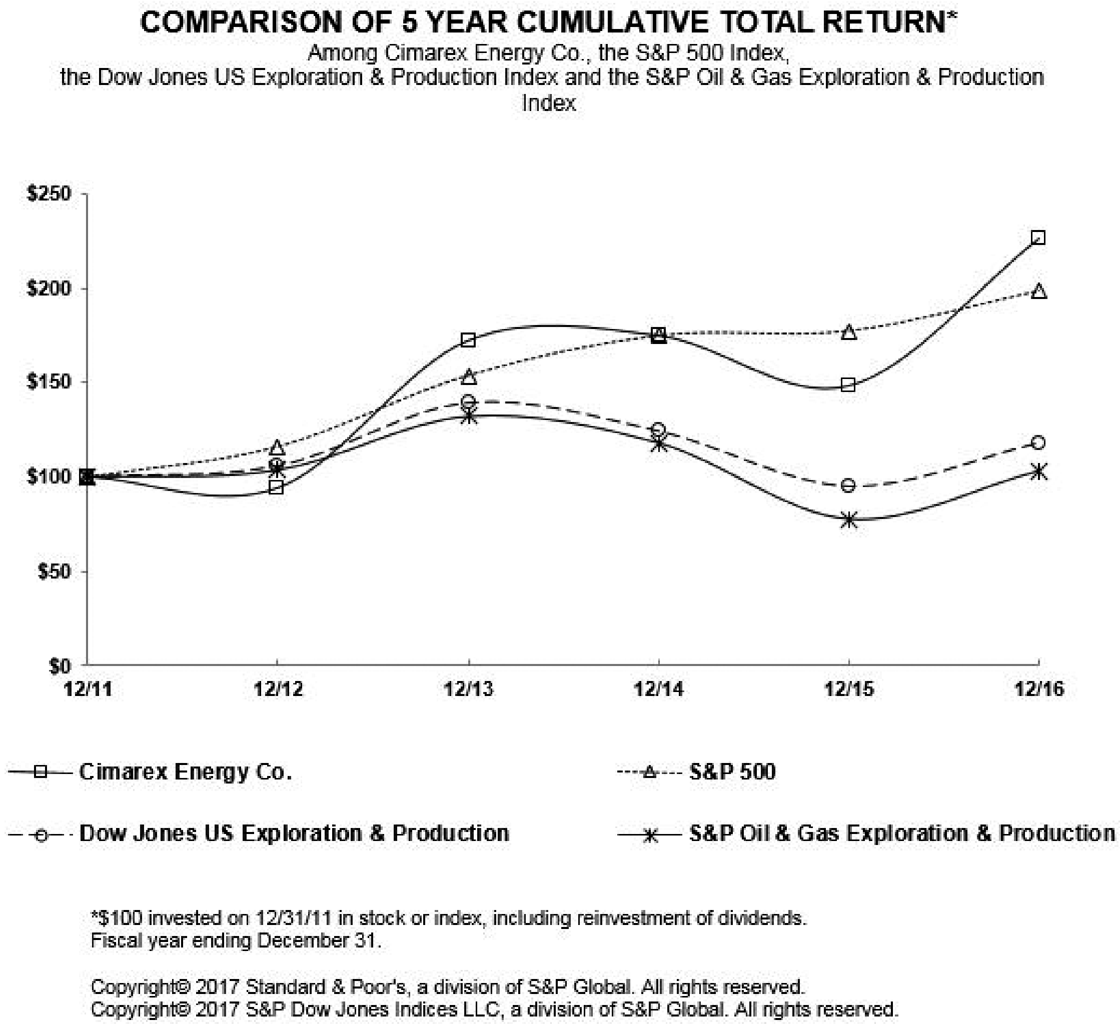
2015	High	Low	Dividends Declared Per Share
First Quarter	$ 118.87	$ 91.74	$ 0.16
Second Quarter	$ 132.18	$ 108.59	$ 0.16
Third Quarter	$ 118.87	$ 97.23	$ 0.16
Fourth Quarter	$ 124.91	$ 85.00	$ 0.16

The closing price of Cimarex stock as reported on the NYSE on January 31, 2017, was $135.21. At January 31, 2017, Cimarex's 95,121,492 shares of outstanding common stock were held by approximately 1,393 stockholders of record.

The following table sets forth information with respect to the equity compensation plans available to directors, officers, and employees of the company at December 31, 2016:

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants, and rights	(b) Weighted-average exercise price of outstanding options, warrants, and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders	307,810	$ 101.72	3,287,830
Equity compensation plans not approved by security holders	—	—	—
Total	307,810	$ 101.72	3,287,830

The following graph compares the cumulative 5-year total return attained by stockholders on Cimarex Energy Co.'s common stock relative to the cumulative total returns of the S&P 500 index, the Dow Jones US Exploration & Production index, and the S&P Oil & Gas Exploration & Production index. The graph tracks the performance of a $100 investment in our common stock and in each of the indexes (with the reinvestment of all dividends) from December 31, 2011 to December 31, 2016. The stock price performance included in this graph is not necessarily indicative of future stock price performance.



	12/2011	12/2012	12/2013	12/2014	12/2015	12/2016
Cimarex Energy Co.	$ 100.00	$ 93.95	$ 171.90	$ 174.58	$ 148.03	$ 225.95
S&P 500	$ 100.00	$ 116.00	$ 153.58	$ 174.60	$ 177.01	$ 198.18
Dow Jones US Exploration & Production	$ 100.00	$ 105.82	$ 139.52	$ 124.48	$ 94.94	$ 118.19
S&P Oil & Gas Exploration & Production	$ 100.00	$ 103.65	$ 132.14	$ 118.15	$ 77.80	$ 103.36

ITEM 6. SELECTED FINANCIAL DATA

The selected financial data set forth below should be read in conjunction with the Consolidated Financial Statements and accompanying notes thereto provided in Item 8 of this report.

	Years Ended December 31,				
	2016	2015	2014	2013	2012
	(in millions, except per share amounts)				
Operating Results:					
Oil, gas and NGL sales	$ 1,221	$ 1,418	$ 2,373	$ 1,953	$ 1,582
Total Revenues (1)	$ 1,257	$ 1,453	$ 2,424	$ 1,998	$ 1,624
Net income (loss) (2)	$ (431)	$ (2,409)	$ 507	$ 565	$ 354
Earnings (loss) per share to common stockholders:					
Basic	$ (4.62)	$ (25.92)	$ 5.79	$ 6.48	$ 4.08
Diluted	$ (4.62)	$ (25.92)	$ 5.78	$ 6.47	$ 4.07
Cash dividends declared per share	$ 0.32	$ 0.64	$ 0.64	$ 0.56	$ 0.48
Cash flow data:					
Net cash provided by operating activities	$ 599	$ 692	$ 1,619	$ 1,324	$ 1,193
Net cash used by investing activities	$ (692)	$ (1,009)	$ (1,740)	$ (1,531)	$ (1,415)
Net cash (used) provided by financing activities	$ (33)	$ 691	$ 522	$ 142	$ 289

	December 31,				
	2016	2015	2014	2013	2012
	(in millions, except proved reserves amounts)				
Balance sheet data:					
Cash and cash equivalents	$ 653	$ 779	$ 406	$ 5	$ 70
Oil and gas properties, net (2)	$ 2,854	$ 3,276	$ 6,904	$ 5,966	$ 5,005
Goodwill	$ 620	$ 620	$ 620	$ 620	$ 620
Total assets (2) (3)	$ 4,682	$ 5,243	$ 8,708	$ 7,243	$ 6,294
Long-term obligations					
Long-term debt (principal)	$ 1,500	$ 1,500	$ 1,500	$ 924	$ 750
Deferred income taxes	$ 127	$ 353	$ 1,755	$ 1,460	$ 1,121
Other	$ 184	$ 197	$ 194	$ 164	$ 313
Stockholders' equity	$ 2,360	$ 2,798	$ 4,501	$ 4,022	$ 3,475
Proved Reserves:					
Oil (MBbls)	105,878	107,798	118,992	108,533	77,921
Gas (Bcf)	1,471	1,517	1,667	1,294	1,252
NGL (MBbls)	130,633	124,277	125,273	92,044	89,909
Total (Bcfe)	2,890	2,909	3,132	2,497	2,259

(1) Prior to 2014, our average realized prices for gas and NGLs were net of certain processing fees. Beginning in 2014, these fees were no longer netted against realized prices, but were included in "Transportation, processing and other operating" costs. The effect of this change in 2014 was that total revenue was $51.4 million higher with an offsetting increase in total transportation, processing and other operating costs. This change had no effect on operating income. Periods prior to 2014 were not reclassified to reflect this change in accounting treatment as it was impracticable.

(2) During 2016 and 2015, we recorded non-cash full cost ceiling test impairments to our oil and gas properties totaling $719.1 million ($456.9 million, net of tax) and $3.7 billion ($2.4 billion, net of tax), respectively.

(3) At December 31, 2015, we adopted new guidance which requires debt issuance costs (except for those related to revolving credit facilities) to be presented in the balance sheet as a direct deduction from the carrying amount of the related debt liability rather than as an asset. Such costs were previously recorded as deferred assets. Prior periods have been adjusted to conform to this guidance.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with our Consolidated Financial Statements included in Item 8 of this report and also with *"Risk Factors"* in Item 1A of this report. This discussion also includes forward-looking statements. Refer to "*Cautionary Information about Forward-Looking Statements*" in Part I of this report for important information about these types of statements.

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. Our Permian Basin region encompasses west Texas and southeast New Mexico. Our Mid-Continent region consists of 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 balanced and abundant drilling inventory. Our strategy centers on maximizing cash flow from producing properties and profitably reinvesting that cash flow in exploration and development activities. 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 mitigate risk and position us to continue to achieve profitable increases in proved reserves and production. Our drilling inventory 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 cash on hand, bank borrowings, sales of non-strategic assets and occasional public financing based on our monitoring of capital markets and our balance sheet. 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 unpredictable fluctuations in commodity 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 oil supplies began to outpace demand. During 2015 and through the first quarter of 2016, global oil supply continued to outpace demand. While oil prices have been, and will likely remain, erratic, beginning in the second quarter of 2016 and thus far in 2017, realized oil prices have improved.

Due to an imbalance between supply and demand across North America, prices for domestic natural gas and NGLs began to decline during the third quarter of 2014 and continued to be weak through the first quarter of 2016. Beginning late in the second quarter of 2016, prices for natural gas and NGLs strengthened, but continue to fluctuate.

Our revenue, profitability and future growth are highly dependent on the prices we receive for our oil and natural gas production. Compared to 2015, our realized oil price for 2016 fell 12% to $38.30 per barrel. Similarly, our realized price for natural gas dropped 9% to $2.31 per Mcf, while our realized price for NGLs increased 2% to $14.05 per barrel. See ***Revenues*** below for further information regarding our realized commodity prices.

The U.S. oil and gas industry continues to confront weak commodity prices, which has had adverse effects on our business and financial position. Our ability to access capital markets may be restricted, which could have an impact on our flexibility to react to changing economic and business conditions. Further, oversupply and high oil and natural gas inventory storage levels could put downward pressure on commodity prices and have an adverse impact on our business partners, customers and lenders, potentially causing them to fail to meet their obligations to us.

2016 Summary of Operating and Financial Results

Weakness in commodity prices has continued to have a significant adverse impact on our results of operations, our balance sheet and the amount of cash flow available to invest in exploration and development activities.

The following is a summary of certain 2016 operating and financial results:

- In response to lower commodity prices, we reduced exploration and development expenditures 16% to $734.8 million compared to $877.0 million in 2015.
- Year-over-year average daily production declined 2% to 963.4 MMcfe per day.
- During 2016, oil production declined by 12% to 45,158 barrels per day, gas volumes remained relatively flat at 459.6 MMcf per day and NGL volumes rose 8% to 38,797 barrels per day.
- Year-over-year production revenues declined 14% to $1.2 billion.
- During 2016, non-cash impairments of our oil and gas properties were $719.1 million, down from $3.7 billion in 2015.
- In 2016, we incurred a net loss of $431.0 million ($4.62 per diluted share) compared to a net loss of $2.4 billion ($25.92 per diluted share) in 2015.
- Cash flow provided by operating activities of $599.2 million was 13% lower than that of the prior year.
- Cash on hand at December 31, 2016 was $652.9 million.
- Year-end proved reserves were 2.89 Tcfe compared to 2.91 Tcfe at year-end 2015.

Total debt at December 31, 2016 consisted of $1.5 billion of senior notes, with $750 million maturing in 2022 and $750 million maturing in 2024, unchanged from total debt at December 31, 2015.

Proved Reserves

	December 31, 2016			
	Gas (MMcf)	**Oil (MBbl)**	**NGL (MBbl)**	**Total (MMcfe)**
Permian Basin	372,371	74,295	40,977	1,064,000
Mid-Continent	1,095,194	31,399	89,615	1,821,278
Other	3,855	184	41	5,209
Total	1,471,420	105,878	130,633	2,890,487

	December 31, 2015			
	Gas (MMcf)	**Oil (MBbl)**	**NGL (MBbl)**	**Total (MMcfe)**
Permian Basin	378,516	78,482	36,598	1,069,002
Mid-Continent	1,134,434	29,048	87,639	1,834,554
Other	4,002	268	40	5,851
Total	1,516,952	107,798	124,277	2,909,407

Year-end 2016 proved reserves declined by less than 1% to 2.89 Tcfe, compared to 2.91 Tcfe at year-end 2015. Proved natural gas reserves were 1.47 Tcf, proved oil reserves were 0.64 Tcfe, and proved NGL reserves were 0.78 Tcfe. Reserves in our Mid-Continent region accounted for 63% of total proved reserves with the majority of the remainder in the Permian Basin.

During 2016, we added 324.0 Bcfe of proved reserves through extensions and discoveries, primarily in the Mid-Continent and Permian Basin, where we added 121.6 Bcfe and 198.7 Bcfe, respectively. In addition, we had net positive revisions of previous estimates of 19.8 Bcfe. Revisions were comprised of an increase of 126.2 Bcfe for net positive performance revisions, an increase of 138.5 Bcfe related to lower operating expenses and a decrease of 244.9 Bcfe for negative revisions due to lower commodity prices. See **SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)** in Item 8 of this report for a more detailed discussion regarding year-over-year changes in our proved reserves.

The process of estimating quantities of oil, gas and NGL reserves is complex. Significant decisions are required in the evaluation of all available geological, geophysical, engineering and economic data. Although every reasonable effort is made to ensure that our reserve estimates represent the most accurate assessments possible, subjective decisions and available data for our various fields make these estimates generally less precise than other estimates included in financial statement disclosures. See ***Proved Reserves Estimation Procedures*** in Items 1 and 2 of this report for a discussion of our reserve estimation process and Item 1A. **RISK FACTORS** for a discussion of factors that affect our proved reserves estimates.

Revenues

Almost all our revenues are derived from sales of our oil, natural 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 52% of our total production revenue for 2016. Gas sales accounted for 32% and NGL sales contributed 16%. A $1.00 per barrel change in our realized oil price would have resulted in a $16.5 million change in revenues. A $0.10 per Mcf change in our realized gas price would have resulted in a $16.8 million change in our gas revenues. A $1.00 per barrel change in our realized NGL price would have changed revenues by $14.2 million.

The following table presents our average realized commodity prices and certain major U.S. index prices. Our realized prices do not include settlements of commodity derivative contracts.

	Years Ended December 31,		
	2016	2015	2014
Oil Prices ($/Bbl):			
Average realized sales price	$ 38.30	$ 43.38	$ 83.70
Average WTI Midland price	$ 43.34	$ 48.39	$ 86.18
Average WTI Cushing price	$ 43.32	$ 48.80	$ 93.01
Gas Prices ($/Mcf):			
Average realized sales price	$ 2.31	$ 2.53	$ 4.43
Average Henry Hub price	$ 2.46	$ 2.67	$ 4.43
NGL Prices ($/Bbl):			
Average realized sales price	$ 14.05	$ 13.75	$ 33.14

During 2016, 2015 and 2014, approximately 80%, 84% 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 majority of the remaining oil production is from our Mid-Continent region, the sale of which is tied to the WTI Cushing benchmark price.

See **RESULTS OF OPERATIONS** below for analysis of the impact changes in realized prices had on our year-over-year revenues.

Operating costs and expenses

Costs associated with producing oil and natural gas are substantial. Some of these costs vary with commodity prices, some trend with the type and volume of production and others are a function of the number of wells we own. At the end of 2016, we owned interests in 10,279 gross productive wells.

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 capitalized oil and gas property costs 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 proved reserve quantities and commodity prices net of operating costs and capital expenditures.

We recognized ceiling test impairments in each quarter of 2015 totaling $3.7 billion ($2.4 billion, net of tax). In the first three quarters of 2016 we recognized ceiling test impairments totaling $719.1 million ($456.9 million, net of tax). The 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 estimated future net cash flows from proved reserves.

At December 31, 2016, the calculated value of the ceiling limitation exceeded the carrying value of our oil and gas properties subject to the test, and no impairment was necessary. However, a decline of 11% or more in the value of the ceiling limitation would have resulted in an impairment. Because the ceiling calculation uses rolling 12-month average commodity prices, the effect of increases and decreases in period-over-period prices can significantly impact the ceiling limitation calculation. In addition, other factors that also impact the ceiling limitation calculation include, but are not limited to, incremental proved reserves that may be added each period, revisions to previous reserve estimates, capital expenditures, operating costs, depletion expense and all related tax effects.

There are numerous uncertainties inherent in the estimation of proved reserves and accounting for oil and natural gas properties. 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 (loss) and various components of our balance sheet. Any recorded impairment of oil and gas properties is not reversible at a later date.

Depletion, depreciation and amortization (DD&A) of our proved oil and gas 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. DD&A is calculated quarterly before the ceiling test impairment calculation. The impairments of our oil and gas properties, discussed above, resulted in lower DD&A rates in each quarter following an impairment.

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, together with gas processing costs and costs to transport production to a specified sales point. 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 expenses consist primarily of salaries and related benefits, office rent, legal and consultants fees, 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

2016 compared to 2015

For the year ended December 31, 2016, we had a net loss of $431.0 million ($4.62 per diluted share), down from a net loss of $2.4 billion ($25.92 per diluted share) in 2015. Production revenues in 2016 and 2015 were adversely affected by low realized commodity prices, which also brought about impairments of our oil and gas properties and net losses for each year. Although production revenue in 2016 was lower than 2015, the decrease was more than offset by lower impairment, DD&A and other operating costs in 2016. Year-over-year changes are discussed further in the analysis that follows.

	Years Ended December 31,		Percent Change Between	Price / Volume Change		
Production Revenue	2016	2015	2016 / 2015	Price	Volume	Total
(in thousands or as indicated)						
Oil sales	$ 632,934	$ 809,664	(22)%	$ (83,962)	$ (92,768)	$ (176,730)
Gas sales	388,786	428,227	(9)%	(37,010)	(2,431)	(39,441)
NGL sales	199,498	179,647	11 %	4,260	15,591	19,851
Total production revenue	$ 1,221,218	$ 1,417,538	(14)%	$ (116,712)	$ (79,608)	$ (196,320)
Total oil volume — MBbls	16,528	18,663	(11)%			
Oil volume — barrels per day	45,158	51,132	(12)%			
Oil percentage of total production	28 %	31 %				
Average oil price — per barrel	$ 38.30	$ 43.38	(12)%			
Total gas volume — MMcf	168,227	168,987	0%			
Gas volume — MMcf per day	459.6	463.0	(1)%			
Gas percentage of total production	48 %	47 %				
Average gas price — per Mcf	$ 2.31	$ 2.53	(9)%			
Total NGL volume — MBbls	14,200	13,063	9 %			
NGL volume — barrels per day	38,797	35,789	8 %			
NGL percentage of total production	24 %	22 %				
Average NGL price — per barrel	$ 14.05	$ 13.75	2 %			
Total production — MMcfe	352,591	359,343	(2)%			
Total production — MMcfe per day	963.4	984.5	(2)%			

As reflected in the table above, our 2016 production revenue was 14% lower than that of 2015. Lower realized prices and production volumes for oil and gas were only partially offset by higher average realized prices and production volumes for NGLs.

Our 2016 aggregate production volumes were 352.6 Bcfe, a 2% decrease from 2015. Production volumes in 2016 were comprised of 48% natural gas, 28% oil and 24% NGL. In 2015, aggregate production volumes of 359.3 Bcfe were made up of 47% natural gas, 31% oil and 22% NGL. See ***Production Volumes, Prices, and Costs*** and ***Exploration and Development Overview*** in Items 1 and 2 of this report for production information by region and a discussion of our drilling activities. See ***Revenues*** above, for information regarding realized prices.

Other revenues

We sometimes transport, process and market third-party gas that is associated with our equity gas. The table below reflects income from third-party gas gathering and processing and our net marketing margin (revenues less purchases) for marketing third-party gas. We market and sell natural gas for working interest owners under short term sales and supply agreements and may earn a fee for such services.

	Years Ended December 31,	
	2016	2015
Gas Gathering and Marketing (in thousands):		
Gas gathering and other revenues	$ 36,033	$ 34,688
Gas marketing revenues, net of related costs	$ 94	$ 393

Fluctuations in revenues from gas gathering and gas marketing activities are a function of increases and decreases in volumes, commodity prices and gathering rate charges.

Analysis of operating costs and expenses

Total operating costs and expenses of $1.9 billion in 2016 were 64% lower than $5.2 billion incurred in 2015. Most of the decrease resulted from lower ceiling test impairments of our oil and gas properties and lower DD&A expense. See ***Operating costs and expenses*** above for a discussion of the ceiling limitation and DD&A calculations. Analyses of year-over-year differences are discussed below.

Operating Costs and Expenses	Years Ended December 31, 2016	Years Ended December 31, 2015	Variance Between 2016 / 2015	Per Mcfe 2016	Per Mcfe 2015
(in thousands)					
Impairment of oil and gas properties	$ 719,142	$ 3,716,883	$ (2,997,741)	N/A	N/A
DD&A	465,936	778,923	(312,987)	$ 1.32	$ 2.17
Asset retirement obligation	7,828	9,121	(1,293)	$ 0.02	$ 0.03
Production	232,002	299,374	(67,372)	$ 0.66	$ 0.83
Transportation, processing and other operating	190,725	182,362	8,363	$ 0.54	$ 0.51
Gas gathering and other	31,785	38,138	(6,353)	$ 0.09	$ 0.11
Taxes other than income	61,946	84,764	(22,818)	$ 0.18	$ 0.24
General and administrative	73,901	74,688	(787)	$ 0.21	$ 0.21
Stock compensation	24,523	19,559	4,964	$ 0.07	$ 0.05
(Gain) loss on derivative instruments, net	55,749	(11,246)	66,995	N/A	N/A
Other operating (income) expense, net	755	856	(101)	N/A	N/A
	$ 1,864,292	$ 5,193,422	$ (3,329,130)		

DD&A expense in 2016 decreased 40% compared to 2015. The impairments of our oil and gas properties discussed above resulted in lower DD&A rates in each quarter following an impairment. DD&A is calculated quarterly before the ceiling test impairment calculation. We did not incur a ceiling test impairment in the fourth quarter of 2016. Our 2017 DD&A rate will likely fluctuate depending on the per-unit cost of adding new proved reserves and the average trailing twelve-month commodity prices to be utilized in the DD&A calculations.

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

(in thousands)	Years Ended December 31, 2016	Years Ended December 31, 2015	Variance Between 2016 / 2015	Per Mcfe 2016	Per Mcfe 2015
Lease operating expense	$ 189,291	$ 249,744	$ (60,453)	$ 0.54	$ 0.70
Workover expense	42,711	49,630	(6,919)	0.12	0.13
	$ 232,002	$ 299,374	$ (67,372)	$ 0.66	$ 0.83

Lease operating expense in 2016 declined 24% compared to 2015. In 2016, we incurred lower salt water disposal costs due to implementation of operational efficiencies as well as lower costs associated with labor, rental equipment and property divestitures.

Workover expense decreased by 14% in 2016 compared to 2015. Generally, these costs will fluctuate based on the amount of maintenance and remedial activity planned and/or required during the period.

Our 2016 year-over-year transportation, processing and other operating costs were 5% higher than those of 2015. These costs will vary by product type and region. The increase in 2016 is primarily a result of more gas production and higher fees associated with our Mid-Continent region.

Gas gathering and other includes costs associated with operating our gas gathering and processing infrastructure, including product costs, operating and maintenance expenses. The 17% year-over-year decrease is primarily attributable to higher repair and maintenance activities occurring in 2015.

Taxes other than income are assessed by state and local taxing authorities on production, revenues or the value of properties. Revenue based production and severance taxes are the largest components of these taxes. The 27% decrease in 2016 taxes is a result of lower production revenues due to lower realized commodity prices and lower production volumes.

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

	Years Ended December 31,		Variance Between
(in thousands)	**2016**	**2015**	**2016 / 2015**
G&A capitalized to oil and gas properties	$ 72,531	$ 58,332	$ 14,199
G&A expense	73,901	74,688	(787)
	$ 146,432	$ 133,020	$ 13,412

During 2016, aggregate G&A increased 10% compared to 2015. The year-over-year increase in aggregate G&A results from a combination of higher accruals in 2016 for short-term incentive based compensation together with severance payments in connection with a voluntary early retirement incentive program, which were partially offset by lower salaries and wages and lower corporate contributions and consulting fees.

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 cost as follows:

	Years Ended December 31,		Variance Between
(in thousands)	**2016**	**2015**	**2016 / 2015**
Restricted stock awards			
Performance stock awards	$ 24,183	$ 18,991	$ 5,192
Service-based stock awards	18,391	14,547	3,844
	42,574	33,538	9,036
Stock option awards	2,565	2,803	(238)
	45,139	36,341	8,798
Less amounts capitalized	(20,616)	(16,782)	(3,834)
Stock compensation	$ 24,523	$ 19,559	$ 4,964

Expense associated with stock compensation will fluctuate based on the grant-date fair value of awards, the number of awards and the timing of the awards. The increase in 2016 stock compensation is primarily related to performance awards granted in December 2015, a portion of which were amortized during 2016, forfeiture rate adjustments on the service-based stock awards and acceleration of expense on a portion of service-based awards for employees who participated in a voluntary early retirement incentive program. Historical amounts may not be representative of future amounts as the value of future awards may vary from historical amounts. See Note 6 to the Consolidated Financial Statements in Item 8 of this report for further discussion regarding our stock-based compensation.

Net gains and losses on our derivative instruments are a function of fluctuations in the underlying commodity prices and the monthly settlement (if any) of the instruments. We have chosen not to apply hedge accounting treatment to our derivative instruments. Therefore, settlements on the contracts are included as a component of operating costs and expenses as either a net gain or loss on derivative instruments.

The following table presents the aggregate net (gain) loss from settlements and changes in the fair value of our derivative contracts and the (gains) losses from cash settlements included in the aggregate gain (loss) on derivative instruments, net. See Note 4 to the Consolidated Financial Statements in Item 8 of this report for further details regarding our derivative instruments.

	Years Ended December 31,	
(in thousands)	**2016**	**2015**
(Gain) loss on derivative instruments, net	$ 55,749	$ (11,246)
Settlement (gains) losses	$ (7,437)	$ —

Other (income) and expense

	Years Ended December 31,		Variance Between
(in thousands)	**2016**	**2015**	**2016 / 2015**
Interest expense	$ 83,272	$ 85,746	$ (2,474)
Capitalized interest	(21,248)	(30,589)	9,341
Other, net	(10,707)	(13,576)	2,869
	$ 51,317	$ 41,581	$ 9,736

The majority of our interest expense relates to interest on debt and amortization of financing costs. See ***Long-Term Debt*** below for further information regarding our debt.

We capitalize interest on the capitalized cost of unproved properties, the in-progress costs of drilling and completing wells and constructing qualified assets. Capitalized interest will fluctuate based on our current rate of interest and the amount of costs on which interest is calculated. The 31% decrease in year-over-year capitalized expense resulted from lower average unproved property costs in 2016.

Components of "Other, net" consist of miscellaneous income and expense items that will vary from period to period, including gain or loss on the sale or value of oil and gas well equipment and supplies, income and expense associated with other non-operating activities, miscellaneous asset sales and interest income. The 21% decrease in 2016 income was primarily due to lower net gains on transactions related to oil and gas well equipment and supplies.

Income tax expense

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

	Years Ended December 31,	
(in thousands)	**2016**	**2015**
Current tax (benefit) expense	$ (1,115)	$ 14,710
Deferred tax benefit	(226,100)	(1,388,146)
	$ (227,215)	$ (1,373,436)
Combined federal and state effective income tax rate	34.5 %	36.3 %

Our combined federal and state effective tax rates differ from the statutory rate of 35% primarily due to state income taxes, non-deductible expenses and revisions. See Note 9 to the Consolidated Financial Statements in Item 8 of this report for further information regarding our income taxes.

RESULTS OF OPERATIONS

2015 compared to 2014

For the year ended December 31, 2015, we had a net loss of $2.4 billion ($25.92 per diluted share), compared to net income of $507.2 million ($5.78 per diluted share) for 2014. The net loss in 2015 was primarily a result of lower realized commodity prices, which also brought about impairments of our oil and gas properties. Year-over-year changes are discussed further in the analysis that follows.

Production Revenue	Years Ended December 31,		Percent Change Between	Price / Volume Change		
	2015	2014	2015 / 2014	Price	Volume	Total
(in thousands or as indicated)						
Oil sales	$ 809,664	$ 1,308,958	(38)%	$ (752,492)	$ 253,198	$ (499,294)
Gas sales	428,227	687,930	(38)%	(321,075)	61,372	(259,703)
NGL sales	179,647	375,941	(52)%	(253,292)	56,998	(196,294)
Total production revenue	$ 1,417,538	$ 2,372,829	(40)%	$ (1,326,859)	$ 371,568	$ (955,291)
Total oil volume — MBbls	18,663	15,639	19 %			
Oil volume — barrels per day	51,132	42,846	19 %			
Oil percentage of total production	31 %	30 %				
Average oil price — per barrel	$ 43.38	$ 83.70	(48)%			
Total gas volume — MMcf	168,987	155,128	9 %			
Gas volume — MMcf per day	463.0	425.0	9 %			
Gas percentage of total production	47 %	49 %				
Average gas price — per Mcf	$ 2.53	$ 4.43	(43)%			
Total NGL volume — MBbls	13,063	11,343	15 %			
NGL volume — barrels per day	35,789	31,078	15 %			
NGL percentage of total production	22 %	21 %				
Average NGL price — per barrel	$ 13.75	$ 33.14	(59)%			
Total production — MMcfe	359,343	317,022	13 %			
Total production — MMcfe per day	984.5	868.6	13 %			

As reflected in the table above, our 2015 production revenue was 40% lower than that of 2014. Increased revenues from higher production volumes were more than offset by decreased revenues from lower realized commodity prices. The 13% year-over-year growth in production volumes was primarily due to our successful drilling programs in the Permian Basin and Mid-Continent region. See ***Production Volumes, Prices, and Costs*** and ***Exploration and Development Overview*** in Items 1 and 2 of this report for further information and a discussion of 2015 activity in these regions. See ***Revenues*** above, for information regarding realized prices.

Our 2015 aggregate production volumes were 359.3 Bcfe, comprised of 47% natural gas, 31% oil and 22% NGL. This compares to 2014 aggregate production volumes of 317.0 Bcfe, made up of 49% natural gas, 30% oil and 21% NGL.

Other revenues

We sometimes transport, process and market third-party gas that is associated with our equity gas. The table below reflects income from third-party gas gathering and processing and our net marketing margin (revenues less purchases) for marketing third-party gas. We market and sell natural gas for working interest owners under short term sales and supply agreements and may earn a fee for such services.

	Years Ended December 31,	
	2015	2014
Gas Gathering and Marketing (in thousands):		
Gas gathering and other revenues	$ 34,688	$ 49,602
Gas marketing revenues, net of related costs	$ 393	$ 1,745

Fluctuations in revenues from gas gathering and marketing activities are a function of increases and decreases in volumes and prices associated with third party gas. In 2015, revenue from gas gathering declined by $14.9 million (30%), primarily due to lower realized prices which were partially offset by increased volumes.

Total operating costs and expenses in 2015 were $5.19 billion compared to $1.61 billion for the prior year. As discussed above in ***Operating costs and expenses***, during 2015 our quarterly ceiling limitation calculations resulted in impairments totaling $3.7 billion. Excluding the effect of the impairments, our year-over-year operating costs and expenses decreased by $133.7 million. Analyses of the year-over-year differences are discussed below.

Operating Costs and Expenses	Years Ended December 31, 2015	Years Ended December 31, 2014	Variance Between 2015 / 2014	Per Mcfe 2015	Per Mcfe 2014
(in thousands)					
Impairment of oil and gas properties	$ 3,716,883	$ —	$ 3,716,883	N/A	N/A
DD&A	778,923	806,021	(27,098)	$ 2.17	$ 2.54
Asset retirement obligation	9,121	10,082	(961)	$ 0.03	$ 0.03
Production	299,374	342,304	(42,930)	$ 0.83	$ 1.08
Transportation, processing and other operating	182,362	195,414	(13,052)	$ 0.51	$ 0.62
Gas gathering and other	38,138	35,113	3,025	$ 0.11	$ 0.11
Taxes other than income	84,764	128,793	(44,029)	$ 0.24	$ 0.41
General and administrative	74,688	81,160	(6,472)	$ 0.21	$ 0.26
Stock compensation	19,559	15,001	4,558	$ 0.05	$ 0.05
(Gain) loss on derivative instruments, net	(11,246)	(3,762)	(7,484)	N/A	N/A
Other operating (income) expense, net	856	116	740	N/A	N/A
	$ 5,193,422	$ 1,610,242	$ 3,583,180		

DD&A expense in 2015 decreased 3% compared to 2014. Increased expense due to higher 2015 production volumes was more than offset by lower DD&A rates in 2015. The impairments of our oil and gas properties, discussed above, resulted in lower DD&A rates in each quarter following an impairment. DD&A is calculated quarterly before the ceiling test impairment calculation.

Our year-over-year production costs decreased by 13% and accounted for 32% of the aggregate decrease in operating costs and expenses, excluding impairments. Production costs consist of lease operating expense and workover expense as follows:

(in thousands)	Years Ended December 31, 2015	Years Ended December 31, 2014	Variance Between 2015 / 2014	Per Mcfe 2015	Per Mcfe 2014
Lease operating expense	$ 249,744	$ 276,395	$ (26,651)	$ 0.70	$ 0.87
Workover expense	49,630	65,909	(16,279)	0.13	0.21
	$ 299,374	$ 342,304	$ (42,930)	$ 0.83	$ 1.08

Lease operating expense in 2015 declined 10% compared to 2014. The decline was primarily a result of property divestitures, lower salt water disposal costs and decreased equipment and maintenance costs. These decreases were partially offset by increased expense related to new wells acquired and drilled. Increased production volumes in 2015 also contributed to the lower rate per Mcfe in 2015.

Workover expense decreased by 25% in 2015 compared to 2014. Generally, these costs will fluctuate based on the amount of maintenance and remedial activity planned and/or required during the period.

Our 2015 year-over-year transportation, processing and other operating costs were 7% lower than those in 2014. These costs will vary by product type and region. In 2015, lower prices for natural gas and NGLs resulted in lower costs associated with fuel and processing fees, which were partially offset by higher processing volumes. Approximately 5% of the 2015 costs relates to accruals for expected minimum volume agreement shortfalls due to reduced drilling activity in 2015 and projected at the time for 2016.

Gas gathering and other includes costs associated with operating our gas gathering and processing infrastructure, including product costs, operating and maintenance expenses. The year-over-year increase is due primarily to higher overall costs related to increased activity, which were largely offset by lower costs associated with product purchases.

Taxes other than income are assessed by state and local taxing authorities on production, revenues or the value of properties. Revenue based production and severance taxes comprised approximately 81% and 85% of these taxes for 2015 and 2014, respectively. The 34% decrease in 2015 taxes resulted primarily from lower production revenues due to lower realized commodity prices and accounted for 33% of the aggregate decrease in operating costs and expenses, excluding impairments.

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

(in thousands)	Years Ended December 31, 2015	Years Ended December 31, 2014	Variance Between 2015 / 2014
G&A capitalized to oil and gas properties	$ 58,332	$ 76,636	$ (18,304)
G&A expense	74,688	81,160	(6,472)
	$ 133,020	$ 157,796	$ (24,776)

During 2015, aggregate G&A declined 16% compared to 2014. Because of the adverse effect of lower commodity prices on our financial results, we reduced our expectations and accruals for short-term incentive-based cash compensation and benefits.

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 cost as follows:

(in thousands)	Years Ended December 31, 2015	Years Ended December 31, 2014	Variance Between 2015 / 2014
Restricted stock awards			
Performance stock awards	$ 18,991	$ 12,141	$ 6,850
Service-based stock awards	14,547	13,607	940
	33,538	25,748	7,790
Stock option awards	2,803	3,057	(254)
	36,341	28,805	7,536
Less amounts capitalized	(16,782)	(13,804)	(2,978)
Stock compensation	$ 19,559	$ 15,001	$ 4,558

Expense associated with stock compensation will fluctuate based on the grant-date fair value of awards, the number of awards and the timing of the awards. The increase in 2015 stock compensation is primarily related to performance awards granted in December 2014, a portion of which were amortized during 2015. Historical amounts may not be representative of future amounts as the value of future awards may vary from historical amounts. See Note 6 to the Consolidated Financial Statements in Item 8 of this report for further discussion regarding our stock-based compensation.

Net gains and losses on our derivative instruments are a function of fluctuations in the underlying commodity prices and the monthly settlement (if any) of the instruments. We have chosen not to apply hedge accounting treatment to our derivative instruments. As a result, settlements on the contracts are included as a component of operating costs and expenses as either a net gain or loss on derivative instruments.

The following table presents the aggregate net (gain) loss from settlements and changes in the fair value of our derivative contracts and the (gains) losses from cash settlements included in the aggregate gain (loss) on derivative instruments, net. See Note 4 to the Consolidated Financial Statements in Item 8 of this report for further details regarding our derivative instruments.

	Years Ended December 31,	
(in thousands)	2015	2014
(Gain) loss on derivative instruments, net	$ (11,246)	$ (3,762)
Settlement (gains) losses	$ —	$ (7,641)

Other (income) and expense

	Years Ended December 31,		Variance Between
(in thousands)	2015	2014	2015 / 2014
Interest expense	$ 85,746	$ 72,865	$ 12,881
Capitalized interest	(30,589)	(35,925)	5,336
Other, net	(13,576)	(28,907)	15,331
	$ 41,581	$ 8,033	$ 33,548

The majority of our interest expense relates to interest on debt and amortization of financing costs. The 18% year-over-year increase is primarily due to the issuance of $750 million of senior notes in June of 2014. See ***Long-Term Debt*** below for further information regarding our debt.

We capitalize interest on the capitalized cost of unproved properties, the in-progress costs of drilling and completing wells and constructing qualified assets. Capitalized interest will fluctuate based on our 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 on the sale or value of oil and gas well equipment and supplies, income and expense associated with other non-operating activities, miscellaneous asset sales and interest income. Most of the 53% year-over-year decrease in income was due to lower net gains on transactions related to oil and gas well equipment and supplies and lower gains from sales of fixed assets.

Income tax expense

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

	Years Ended December 31,	
(in thousands)	2015	2014
Current tax expense (benefit)	$ 14,710	$ 404
Deferred tax expense	(1,388,146)	298,293
	$ (1,373,436)	$ 298,697
Combined federal and state effective income tax rate	36.3 %	37.1 %

Our combined federal and state effective tax rates differ from the statutory rate of 35% primarily due to state income taxes, non-deductible expenses and revisions. See Note 9 to the Consolidated Financial Statements in Item 8 of this report for further 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 revolving credit facility, proceeds from sales of non-core assets and occasional public financings based on our monitoring of capital markets and our balance sheet.

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 have had on our 2016 earnings.

We deal with volatility in commodity prices primarily by maintaining flexibility in our capital investment program. We have a balanced and abundant drilling inventory and limited long-term commitments, which enables us to respond quickly to industry volatility. Based on current economic conditions, our 2017 exploration and development expenditures are projected to range from $1.1 – $1.2 billion. Investments in gathering and processing infrastructure and other fixed assets are expected to approximate an additional $60 million. See ***Capital Expenditures*** below for information regarding our 2016 exploration and development (E&D) activities.

We periodically use derivative instruments to mitigate volatility in commodity prices. At December 31, 2016, we had derivative contracts covering a portion of our 2017 and 2018 production. Depending on changes in oil and gas futures markets and management's view of underlying supply and demand trends, we may hedge up to 50% of our oil and natural gas production on a forward five-quarter basis. See Note 4 to the Consolidated Financial Statements in Item 8 of this report for information regarding our derivative instruments.

We believe our conservative use of leverage, strong balance sheet and hedging activities will mitigate our exposure to lower prices. Cash and cash equivalents at December 31, 2016 were $652.9 million. Our long-term debt consisted of $1.5 billion of senior notes, with $750 million due in 2022 and $750 million due in 2024. 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 December 31, 2016 was 39%. The reconciliation of debt to total capitalization, which is a non-GAAP measure, is: long-term debt of $1.5 billion divided by the sum of long-term debt of $1.5 billion plus stockholders' equity of $2.36 billion. Management uses this non-GAAP measure as one indicator of our financial condition. Management believes professional research analysts and rating agencies use this non-GAAP measure for this purpose and to compare our financial condition to other companies' financial conditions.

We expect our operating cash flow and other capital resources to be adequate to meet our needs for planned capital expenditures, working capital, debt service and dividends declared in 2017 and beyond.

Sources and Uses of Cash

Our primary sources of liquidity and capital resources are operating cash flow, borrowings under our credit facility, asset sales and occasional public financings based on our monitoring of capital markets and our balance sheet. Our primary uses of funds are expenditures for exploration and development, leasehold and property acquisitions, other capital expenditures, debt service, and cash dividends paid to holders of our common stock.

The decline in year-over-year realized prices for our oil and natural gas production adversely impacted our operating cash flow for 2016 and consequently reduced the amount of cash flow available for exploration and development activities. See ***Market Conditions*** above for further information regarding prevailing economic conditions.

The following table presents our sources and uses of cash and cash equivalents from 2014 to 2016. Capital expenditures are presented on a cash basis. These amounts differ from capital expenditures (including accruals) that are referred to elsewhere in this report.

	Years Ended December 31,		
(in thousands)	**2016**	**2015**	**2014**
Sources of cash and cash equivalents:			
Operating cash flow	$ 599,225	$ 691,500	$ 1,619,365
Sales of oil and gas and other assets	29,376	41,031	458,394
Increase in other long-term debt	—	—	750,000
Proceeds from sale of common stock	—	752,100	—
Proceeds from exercise of stock options and other	4,804	21,439	11,898
Total sources of cash and cash equivalents	633,405	1,506,070	2,839,657
Uses of cash and cash equivalents:			
Oil and gas capital expenditures	(699,558)	(979,044)	(2,108,250)
Other capital expenditures	(22,228)	(70,592)	(90,611)
Net decrease in bank debt	—	—	(174,000)
Financing and underwriting fees	(101)	(24,633)	(11,616)
Dividends paid	(38,024)	(58,281)	(53,849)
Total uses of cash and cash equivalents	(759,911)	(1,132,550)	(2,438,326)
Net increase (decrease) in cash and cash equivalents	$ (126,506)	$ 373,520	$ 401,331
Cash and cash equivalents at end of year	$ 652,876	$ 779,382	$ 405,862

Analysis of Cash Flow Changes (See the Consolidated Statements of Cash Flows in Item 8 of this Report)

Net cash flow provided by operating activities (operating cash flow) for 2016 was $599.2 million, down 13% from $691.5 million for 2015. The $92.3 million decrease was primarily a result of a net decrease in production revenue from lower realized commodity prices and production volumes in 2016. The 2016 decrease in production revenue was partially offset by lower net operating expenses and increased proceeds from settlements of our derivative instruments. In 2015, operating cash flow was 57% lower than 2014, resulting from a net decrease in production revenue due to lower realized commodity prices in 2015, which was partially offset by lower net operating costs in 2015. See **RESULTS OF OPERATIONS** above for details regarding year-over-year changes in production revenues and operating expenses.

In 2016, net cash flow used for investing activities was $692.4 million, compared to $1.0 billion for 2015 and $1.7 billion for 2014. Weakness in commodity prices has had a significant adverse impact on the amount of cash flow available to invest in exploration and development (E&D) activities. In 2016, our E&D and other capital expenditures were $721.8 million, and were partially offset by proceeds from asset sales of $29.4 million. Our 2015 E&D and other capital expenditures were $1.0 billion, which were partially offset by proceeds from asset sales of $41.0 million. For 2014, our E&D and other capital expenditures were $2.2 billion, which were partially offset by proceeds from asset sales of $458.4 million.

Net cash flow used by financing activities in 2016 was $33.3 million compared to net cash flow provided by financing activities in 2015 of $690.6 million. In 2016, proceeds of $4.8 million from issuance of common stock from employee option exercises and other were more than offset by dividend payments and financing fees of $38.1 million.

In 2015, net cash flow provided by financing activities of $690.6 million included approximately $730 million of net proceeds from the sale of common stock and $21.4 million of proceeds from issuance of common stock from employee option exercises and other. These cash flows were partially offset by dividend payments of $58.3 million and $2.5 million of financing costs.

Net cash flow provided by financing activities of $522.4 million in 2014 included the issuance of $750 million of senior notes and $11.9 million of proceeds from the issuance of common stock from employee option exercises and other, which were partially offset by payments of $174.0 million on our credit facility, $11.6 million for financing and underwriting fees and dividend payments of $53.8 million.

Adjusted Cash Flow from Operations

The following table provides a reconciliation from the GAAP measure of net cash provided by operating activities to the non-GAAP measure adjusted cash flow from operations:

	Years Ended December 31,		
(in thousands)	**2016**	**2015**	**2014**
Net cash provided by operating activities	$ 599,225	$ 691,500	$ 1,619,365
Change in operating assets and liabilities	29,913	52,082	14,847
Adjusted cash flow from operations	$ 629,138	$ 743,582	$ 1,634,212

Management uses the non-GAAP measure of adjusted cash flow from operations as a means of measuring our ability to fund our capital program and dividends, without fluctuations caused by changes in current assets and liabilities, which are included in the GAAP measure of cash provided by operating activities. Management believes this non-GAAP measure provides useful information to investors for the same reason, and that 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 reflects capitalized expenditures for oil and gas acquisitions, exploration and development activities and property sales:

	Years Ended December 31,	
(in thousands)	**2016**	**2015**
Acquisitions:		
Proved	$ 2,678	$ 30
Unproved	11,865	6,666
Net purchase price adjustments (*)	—	(11,653)
	14,543	(4,957)
Exploration and development:		
Land and seismic	61,870	52,049
Exploration	40	1,073
Development	672,842	823,830
	734,752	876,952
Property sales	(24,687)	(41,276)
	$ 724,608	$ 830,719

(*) The net 2015 purchase price adjustments relate to activity in prior periods.

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

Because of lower commodity prices, we reduced our 2016 E&D expenditures 16% to $734.8 million compared to $877.0 million in 2015. Approximately 59% of our 2016 E&D expenditures were in the Permian Basin and 40% were in our Mid-Continent region. During 2016, we participated in the drilling and completion of 154 gross (61 net) wells, 73 of which we operated. See Items 1 and 2 of this report for further information regarding our wells drilled and other information regarding our oil and gas properties.

Approximately 66% of our planned 2017 E&D capital investment of $1.1 – $1.2 billion is expected to be invested in the Permian Basin and most of the remainder in the Mid-Continent region.

As has been our historical practice, we regularly review capital expenditures throughout the year and will adjust our investments based on increases or decreases in commodity prices, service costs and drilling success. We have the flexibility to adjust our capital expenditures based upon market conditions.

We intend to fund our 2017 capital program with cash flow from our operating activities and cash on hand at December 31, 2016. 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. See *Bank Debt* below for further information regarding our credit facility.

In the ordinary course of business we actively evaluate opportunities to purchase properties that we believe could benefit from our technical capabilities, particularly in our core areas of operations. We also evaluate our non-core property holdings for potential divestitures. For further information on our property acquisitions and dispositions, see Note 12 to the Consolidated Financial Statements in Item 8 of this report.

We have made, and will continue to make, expenditures to comply with environmental and safety regulations and requirements. These costs are considered a normal recurring cost of our ongoing operations. While we expect current pending legislation or regulations to increase the cost of business, we do not anticipate that we will be required to expend amounts that will have a material adverse effect on our financial position or operations, nor are we aware of any pending regulatory changes that would have a material impact, based on current laws and regulations. However, compliance with new legislation or regulations could increase our costs or adversely affect demand for oil or gas and result in a material adverse effect on our financial position or operations.

Financial Condition

During 2016, our total assets decreased $561.6 million (11%) to $4.7 billion. Most of the decrease related to net oil and gas properties, which declined by $422.1 million. In 2016, $719.1 million of impairments and DD&A of $465.9 million were only partially offset by net additions to oil and gas properties of $716.7 million. The remaining decrease in total assets was primarily related to a decrease of $126.5 million in cash and cash equivalents.

Total liabilities at year-end 2016 were $2.3 billion, down $124.0 million (5%) from $2.4 billion at year-end 2015. During 2016, deferred income taxes declined $225.8 million primarily as a result of our net loss for the year. The decline in deferred income taxes was partially offset by a net increase in current liabilities of $112.3 million.

At December 31, 2016, stockholders' equity totaled $2.4 billion, a decrease of $437.6 million (16%) from $2.8 billion at December 31, 2015. The decrease resulted primarily from our 2016 net loss of $431.0 million.

The 2016 decreases in our total assets, liabilities and stockholders' equity and our net loss for the year resulted primarily from the $719.1 million aggregate impairments of our oil and gas properties. During the first three quarters of 2016, impairments resulted from the continued impact of lower prices on the present value of future cash flows from our proved reserves used in our full cost ceiling limitation calculation. As noted above under ***Operating costs and expenses***, 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 various components of our balance sheet.

Long-Term Debt

Long-term debt at year-end 2016 and 2015 consisted of the following:

	December 31, 2016			December 31, 2015		
(in thousands)	Principal	Unamortized Debt Issuance Costs	Long-term Debt, net	Principal	Unamortized Debt Issuance Costs	Long-term Debt, net
5.875% Senior Notes	$ 750,000	$ (5,691)	$ 744,309	$ 750,000	$ (6,978)	$ 743,022
4.375% Senior Notes	750,000	(6,370)	743,630	750,000	(7,402)	742,598
Total long-term debt	$ 1,500,000	$ (12,061)	$ 1,487,939	$ 1,500,000	$ (14,380)	$ 1,485,620

At each of December 31, 2016 and 2015 we had no bank debt outstanding. All of our long-term debt is senior unsecured debt and is, therefore, *pari passu* with other unsecured debt with respect to the payment of both principal and interest.

Bank Debt

In October 2015, we entered into a new senior unsecured revolving credit facility (Credit Facility) with an initial aggregate commitment from the lenders of $1.0 billion. We have the option to increase the commitment to $1.25 billion at any time. Unlike the prior credit facility, the new Credit Facility is not a borrowing base facility subject to the discretion of the lenders, and is not based on the value of our proved reserves.

At December 31, 2016, we had letters of credit outstanding of $2.5 million under the Credit Facility, leaving an unused borrowing availability of $997.5 million. We did not have any bank debt outstanding during 2016. In 2015, we had average daily bank debt outstanding of $27.4 thousand and the highest amount of bank borrowings outstanding during 2015 was $10.0 million in May.

The Credit Facility contains representations, warranties, covenants and events of default that are customary for investment grade, senior unsecured bank credit agreements, including a financial covenant for the maintenance of a defined total debt-to-capital ratio of no greater than 65%. For further information regarding the terms of the Credit Facility see Note 3 to the Consolidated Financial Statements in Item 8 of this report.

Senior Notes

Our 5.875% senior notes are due May 1, 2022 and our 4.375% senior notes are due June 1, 2024. 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. For further information regarding our senior notes see Note 3 to the Consolidated Financial Statements in Item 8 of this report.

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 receivables and payables related to our operating and E&D activities, changes in our oil and gas well equipment and supplies and changes in the carrying value of our derivative instruments.

At December 31, 2016, we had working capital of $447.0 million, a decrease of $220.9 million (33%) compared to working capital of $667.9 million at December 31, 2015.

Working capital decreases consisted primarily of the following:

- Cash and cash equivalents decreased by $126.5 million.
- Net derivative instrument liability increased $60.1 million.
- Operations-related accounts payable and accrued liabilities increased $37.3 million.

- Accrued liabilities related to our E&D expenditures increased by $25.6 million.

- Oil and gas well equipment and supplies decreased by $21.2 million.

Decreases in working capital were partially offset by the following:

- Operations-related accounts receivable increased $49.2 million

Accounts receivable are a major component of 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 has historically been timely and 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. In February 2016, the quarterly dividend was decreased to $0.08 per share from $0.16 per share. Future dividend payments will depend on our level of earnings, financial requirements and other factors considered relevant by our Board of Directors.

	Years Ended December 31,		
	2016	2015	2014
Dividends declared from Retained earnings (in millions)	$ 7.5	$ 59.3	$ 55.7
Dividends declared from Paid-in capital (in millions)	$ 22.8	$ —	$ —
Dividends per share	$ 0.32	$ 0.64	$ 0.64

See Note 2 to the Consolidated Financial Statements in Item 8 of this report for further information regarding dividends.

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 December 31, 2016, our material off-balance sheet arrangements included operating lease agreements, which are customary in the oil and gas industry.

Contractual Obligations and Material Commitments

At December 31, 2016, we had the following contractual obligations and material commitments.

	Payments Due by Period				
Contractual obligations:	**Total**	**1 Year or Less**	**2 - 3 Years**	**4 - 5 Years**	**More than 5 Years**
(in thousands)					
Long-term debt (1)	$ 1,500,000	$ —	$ —	$ —	$ 1,500,000
Fixed-rate interest payments (1)	478,542	76,876	153,750	153,750	94,166
Operating leases	96,923	9,585	21,208	21,949	44,181
Drilling commitments (2)	157,505	157,505	—	—	—
Asset retirement obligation (3)	154,523	13,753	—	—	—
Other liabilities (4)	177,455	88,793	54,905	6,956	26,801
Firm transportation	26,383	7,655	6,549	4,427	7,752

(1) See Item 7A: Interest Rate Risk for more information regarding fixed and variable rate debt.

(2) We have drilling commitments of $157.5 million, consisting of obligations to finish drilling and completing wells in progress at December 31, 2016.

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

(4) Other includes the estimated value of our commitments associated with our benefit obligations, derivative obligations, and other miscellaneous commitments.

At December 31, 2016, we had firm sales contracts to deliver approximately 46.4 Bcf of natural gas over the next twenty-two months. If this gas is not delivered, our financial commitment would be approximately $164.8 million. This commitment will fluctuate due to price volatility and actual volumes delivered. However, we believe no financial commitment will be due based on our current proved reserves and production levels from which we can fulfill these obligations.

In connection with gas gathering and processing agreements, we have volume commitments over the next ten years. If no gas is delivered, the maximum amount that would be payable under these commitments would be approximately $220.0 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 minimum volume delivery commitments in connection with agreements to reimburse connection costs to various pipelines. The maximum amount that would be payable if no gas is delivered would be approximately $7.9 million. Of this total, we have accrued a liability of $2.1 million. We may have additional liabilities associated with these delivery commitments in the future depending on our production levels and drilling results.

We have other various transportation, delivery, and facilities commitments in the normal course of business, which approximate $35.7 million. We currently anticipate meeting these obligations.

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

Taking into account current commodity prices and anticipated levels of production, we believe that our net cash flow generated from operations and our other capital resources will be adequate to meet future obligations.

2017 Outlook

For 2017, our total production is projected to average 1.06 – 1.11 Bcfe per day, an increase of 13% at the midpoint from 2016 production levels. First quarter 2017 production is expected to average 1.01 – 1.05 Bcfe per day. Oil production in the first quarter is expected to increase approximately 10% from fourth quarter 2016 levels, with natural gas and NGL production expected to increase 4 – 5% sequentially.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Discussion and analysis of our financial condition and results of operation are based on our Consolidated Financial Statements, which have been prepared in accordance with accounting principles generally accepted in the United States of America, or GAAP. The preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. We analyze and base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Changes in facts and circumstances or additional information may result in revised estimates, and actual results may differ from these estimates.

A complete list of our significant accounting policies are described in Note 1 to our Consolidated Financial Statements in Item 8 of this report. We have identified the following policies as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by management.

Oil and Gas Reserves

The process of estimating quantities of oil and gas reserves is complex, requiring significant decisions in the evaluation of all available geological, geophysical, engineering and economic data. The data for a given field may also change substantially over time due to numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. As a result, material revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure that our reserve estimates represent the most accurate assessments possible, subjective decisions and available data for our various fields make these estimates generally less precise than other estimates included in financial statement disclosures.

At year-end 2016, 21% of our total proved reserves are categorized as proved undeveloped reserves, or PUDs. Our reserve engineers review and revise these reserve estimates regularly, as new information becomes available.

We use the units-of-production method to amortize the cost associated with our oil and gas properties. Changes in estimates of reserve quantities and commodity prices will cause corresponding changes in depletion expense, or in some cases, a full cost ceiling impairment charge in the period of the revision. See ***Full Cost Accounting*** below for further information regarding the ceiling limitation calculation. See **SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)** in Item 8 of this report for additional reserve data.

Full Cost Accounting

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

Companies that follow the full cost accounting method are required to make a quarterly ceiling test calculation. This test ensures that total capitalized costs for oil and gas properties (net of accumulated DD&A and deferred income taxes) do not exceed 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. We currently do not have any unproven properties being amortized. Revenue calculations in the reserves are based on the unweighted average first-day-of-the-month commodity price for the prior 12 months. Changes in proved reserve estimates (including those based upon quantity revisions or changes in commodity price) will cause corresponding changes to the full cost ceiling limitation. If net capitalized costs subject to amortization exceed this limit, the excess would be expensed. Any recorded impairment of oil and gas properties is not reversible at a later date.

Quarterly ceiling tests are primarily impacted by commodity prices, changes in estimated reserve quantities, reserves produced, overall exploration and development costs, depletion expense and deferred taxes. For each of the first three quarters of 2016, 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 aggregate impairments of $719.1 million ($456.9 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. At December 31, 2016, the calculated value of the ceiling limitation exceeded the carrying value of our oil and gas properties subject to the test, and no impairment was necessary. However, a decline of 11% or more in the value of the ceiling limitation would have resulted in an impairment. Because the ceiling calculation uses rolling 12-month average commodity prices, the effect of increases and decreases in period-over-period prices can significantly impact the ceiling limitation calculation. See ***Operating costs and expenses*** above for a complete discussion of our 2016 ceiling impairments. See Note 1 to our Consolidated Financial statements in Item 8 of this report for information regarding the effect of a ceiling impairment on our depletion rate.

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 various components of our balance sheet.

Depletion of proved oil and gas properties is computed on the units-of-production method, whereby capitalized costs, including future development costs and asset retirement costs, are amortized over total estimated proved reserves. Changes in our estimate of proved reserve quantities and commodity prices will cause corresponding changes in depletion expense in periods subsequent to these changes. The capitalized costs of unproved properties, including those in wells in progress, are excluded from the costs being amortized. We do not have major development projects that are excluded from costs being amortized. On a quarterly basis, we evaluate excluded costs for inclusion in the costs to be amortized. Significant unproved properties are evaluated individually. Unproved properties that are not considered individually significant are aggregated for evaluation purposes and related costs are transferred to the costs to be amortized quarterly based on the application of historical factors.

Goodwill

Goodwill represents the excess of the purchase price of business combinations over the fair value of the net assets acquired and is tested for impairment at least annually. We first assess qualitative factors to determine whether it is more likely than not (with a greater than 50% threshold) that the fair value of a reporting unit is less than its carrying amount as a basis for determining whether it is necessary to perform the two-step goodwill impairment test. If goodwill is determined to be impaired, then it is written down to a calculated fair value by charging the impairment to expense.

We evaluate our goodwill for impairment in the fourth quarter of each year and whenever events or changes in circumstances indicate the possibility that goodwill may be impaired. Based upon our qualitative assessment at December 31, 2016, goodwill was not impaired. It is possible that goodwill could become impaired in the future if commodity prices or other economic factors become unfavorable.

Contingencies

A provision for contingencies is charged to expense when the loss is probable and the cost can be reasonably estimated. Determining when expenses should be recorded for these contingencies and the appropriate amounts for accrual is a complex estimation process that includes subjective judgment. In many cases, this judgment is based on interpretation of laws and regulations, which can be interpreted differently by regulators and/or courts of law. We closely monitor known and potential legal, environmental, and other contingencies to determine if we should record losses. Actual costs can vary from our estimates for a variety of reasons. See Note 10 to the Consolidated Financial Statements in Item 8 of this report for further information regarding litigation and other commitments and contingencies.

At December 31, 2016, we had not made any material accruals related to environmental remediation costs. However, we may be required to make such estimates in future periods if applicable laws and regulations change or if the interpretation or administration of laws and regulations change. Other factors, such as unanticipated construction problems or identification of areas of contaminated soil or groundwater, could also cause us to accrue for such costs.

Asset Retirement Obligation

Our asset retirement obligation represents the estimated present value of the amount we will incur to retire long-lived assets at the end of their productive lives, in accordance with applicable state laws. Our asset retirement obligation is determined by calculating the present value of estimated cash flows related to the liability. The retirement obligation is recorded as a liability at its estimated present value as of inception with an offsetting increase in the carrying amount of the related long-lived asset. Periodic accretion of discount of the estimated liability is recorded as an expense in the income statement. The cost of the tangible asset, including the asset retirement cost, is depreciated over the useful life of the asset or depleted using the units-of-production method.

Asset retirement liability is determined using significant assumptions including current estimates of plugging and abandonment costs, annual inflation of these costs, the productive lives of assets and our risk-adjusted interest rate. Changes in any of these assumptions can result in significant revisions to the estimated asset retirement obligation. Because of the subjectivity of assumptions, the costs to ultimately retire our wells may vary significantly from prior estimates. See Note 8 to the Consolidated Financial Statements in Item 8 of this report for additional information regarding our asset retirement obligations.

Income Taxes

Our oil and gas exploration and production operations are subject to taxation on income in numerous jurisdictions. We record deferred tax assets and liabilities to account for the expected future tax consequences of events that have been recognized in our financial statements and our tax returns. We routinely assess the realizability of our deferred tax assets. If we conclude that it is more likely than not that some portion or all of the deferred tax assets will not be realized, the tax asset would be reduced by a valuation allowance. Numerous judgments and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions (particularly as related to prevailing oil and gas prices).

The company regularly assesses and, if required, establishes accruals for tax contingencies that could result from assessments of additional tax by taxing jurisdictions where the company operates. See Note 9 to the Consolidated Financial Statements in Item 8 of this report for additional information regarding our income taxes.

Recently Issued Accounting Standards

See Note 1, Basis of Presentation and Summary of Significant Accounting Policies – *Recently Issued Accounting Standards,* to the Consolidated Financial Statements in Item 8 of this report for a discussion of recent accounting pronouncements and their anticipated effect on our business.

ITEM 7A. 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. Oil sales contributed 52% of our total production revenue for 2016. Gas and NGL sales accounted for 32% and 16%, respectively, of our 2016 production revenue. A $1.00 per barrel change in our realized oil price would have resulted in a $16.5 million change in revenues. A $0.10 per Mcf change in our realized gas price would have resulted in a $16.8 million change in our gas revenues. A $1.00 per barrel change in NGL prices would have changed revenues by $14.2 million. See Market Conditions in Item 7 of this report for further information.

We periodically enter into financial derivative contracts to hedge a portion of our price risk associated with our future oil and gas production. At December 31, 2016, we had oil and gas collars covering a portion of our 2017 and 2018 production, which were recorded as short and long-term liabilities. The fair value liability of our oil and gas collars was $29.0 million and $23.0 million, respectively. See Note 4 to the Consolidated Financial Statements in Item 8 of this report for additional information regarding derivative instruments.

While these contracts limit the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. For the oil contracts described above, a hypothetical $1.00 change in the price below or above the forward price used to calculate the fair value would result in a decrease of $4.8 million or an increase of $5.0 million, respectively, to the fair value liability of the derivatives at December 31, 2016. For the gas contracts described above, a hypothetical $0.10 change in the price below or above the forward price used to calculate the fair value would result in a decrease of $5.1 million or an increase of $5.3 million, respectively, to the fair value liability of the derivatives at December 31, 2016.

Interest Rate Risk

At December 31, 2016, 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 outstanding long-term debt is at a fixed rate, we consider our interest rate exposure to be minimal. This sensitivity analysis for interest rate risk excludes accounts receivable, accounts payable and accrued liabilities because of the short-term maturity of such instruments. See Note 3 and Note 5 to the Consolidated Financial Statements in Item 8 of this report for additional information regarding debt.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

CIMAREX ENERGY CO.

INDEX TO FINANCIAL STATEMENTS AND SUPPLEMENTAL SCHEDULES

All other supplemental information and schedules have been omitted because they are not applicable or the information required is shown in the consolidated financial statements or related notes thereto.

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders

Cimarex Energy Co.:

We have audited the accompanying consolidated balance sheets of Cimarex Energy Co. and subsidiaries (the Company) as of December 31, 2016 and 2015, and the related consolidated statements of operations and comprehensive income (loss), stockholders' equity, and cash flows for each of the years in the three year period ended December 31, 2016. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Cimarex Energy Co. and subsidiaries as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the years in the three year period ended December 31, 2016, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Cimarex Energy Co. and subsidiaries' internal control over financial reporting as of December 31, 2016, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 24, 2017 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

KPMG LLP

Denver, Colorado
February 24, 2017

CIMAREX ENERGY CO.

CONSOLIDATED BALANCE SHEETS

(in thousands, except share and per share information)

	December 31, 2016	December 31, 2015
Assets		
Current assets:		
Cash and cash equivalents	$ 652,876	$ 779,382
Accounts receivable:		
Trade, net of allowance	42,287	81,888
Oil and gas sales, net of allowance	217,395	136,537
Gas gathering, processing, and marketing, net of allowance	14,888	6,935
Other	27	38
Oil and gas well equipment and supplies	33,342	54,579
Derivative instruments	—	10,745
Prepaid expenses	7,335	7,036
Other current assets	1,154	790
Total current assets	969,304	1,077,930
Oil and gas properties at cost, using the full cost method of accounting:		
Proved properties	16,225,495	15,546,948
Unproved properties and properties under development, not being amortized	478,277	440,166
	16,703,772	15,987,114
Less—accumulated depreciation, depletion and amortization and impairment	(13,849,701)	(12,710,968)
Net oil and gas properties	2,854,071	3,276,146
Fixed assets, net of accumulated depreciation of $246,901 and $207,173	205,465	230,009
Goodwill	620,232	620,232
Derivative instruments	—	501
Other assets, net	32,621	38,468
	$ 4,681,693	$ 5,243,286
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable:		
Trade	$ 49,163	$ 53,384
Gas gathering, processing, and marketing	25,323	13,431
Accrued liabilities:		
Exploration and development	82,320	56,721
Taxes other than income	18,766	17,545
Other	177,695	173,242
Derivative instruments	49,370	—
Revenue payable	119,715	95,744
Total current liabilities	522,352	410,067
Long-term debt:		
Principal	1,500,000	1,500,000
Less—unamortized debt issuance costs	(12,061)	(14,380)
Long-term debt, net	1,487,939	1,485,620
Deferred income taxes	126,894	352,705
Asset retirement obligation	140,770	153,857
Derivative instruments	2,570	—
Other liabilities	41,104	43,359
Total liabilities	2,321,629	2,445,608
Commitments and contingencies (Note 10)		
Stockholders' equity:		
Preferred stock, $0.01 par value, 15,000,000 shares authorized, no shares issued	—	—
Common stock, $0.01 par value, 200,000,000 shares authorized, 95,123,525 and 94,820,570 shares issued, respectively	951	948
Paid-in capital	2,763,452	2,762,976
Retained earnings (accumulated deficit)	(405,284)	33,313
Accumulated other comprehensive income	945	441
	2,360,064	2,797,678
	$ 4,681,693	$ 5,243,286

The accompanying notes are an integral part of these consolidated financial statements.

CIMAREX ENERGY CO.

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (LOSS)

(in thousands, except per share data)

	Years Ended December 31, 2016	2015	2014
Revenues:			
Oil sales	$ 632,934	$ 809,664	$ 1,308,958
Gas sales	388,786	428,227	687,930
NGL sales	199,498	179,647	375,941
Gas gathering and other	36,033	34,688	49,602
Gas marketing, net of related costs of $122,655, $144,673 and $256,836 respectively	94	393	1,745
	1,257,345	1,452,619	2,424,176
Costs and expenses:			
Impairment of oil and gas properties	719,142	3,716,883	—
Depreciation, depletion and amortization	465,936	778,923	806,021
Asset retirement obligation	7,828	9,121	10,082
Production	232,002	299,374	342,304
Transportation, processing, and other operating	190,725	182,362	195,414
Gas gathering and other	31,785	38,138	35,113
Taxes other than income	61,946	84,764	128,793
General and administrative	73,901	74,688	81,160
Stock compensation	24,523	19,559	15,001
(Gain) loss on derivative instruments, net	55,749	(11,246)	(3,762)
Other operating expense, net	755	856	116
	1,864,292	5,193,422	1,610,242
Operating income (loss)	(606,947)	(3,740,803)	813,934
Other (income) and expense:			
Interest expense	83,272	85,746	72,865
Capitalized interest	(21,248)	(30,589)	(35,925)
Other, net	(10,707)	(13,576)	(28,907)
Income (loss) before income tax	(658,264)	(3,782,384)	805,901
Income tax expense (benefit)	(227,215)	(1,373,436)	298,697
Net income (loss)	$ (431,049)	$ (2,408,948)	$ 507,204
Earnings (loss) per share to common stockholders:			
Basic			
Distributed	$ 0.32	$ 0.64	$ 0.64
Undistributed	(4.94)	(26.56)	5.15
	$ (4.62)	$ (25.92)	$ 5.79
Diluted			
Distributed	$ 0.32	$ 0.64	$ 0.64
Undistributed	(4.94)	(26.56)	5.14
	$ (4.62)	$ (25.92)	$ 5.78
Comprehensive income (loss):			
Net income (loss)	$ (431,049)	$ (2,408,948)	$ 507,204
Other comprehensive income (loss):			
Change in fair value of investments, net of tax	504	(661)	(87)
Total comprehensive income (loss)	$ (430,545)	$ (2,409,609)	$ 507,117

The accompanying notes are an integral part of these consolidated financial statements.

CIMAREX ENERGY CO.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Years Ended December 31,		
	2016	2015	2014
Cash flows from operating activities:			
Net income (loss)	$ (431,049)	$ (2,408,948)	$ 507,204
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Impairments and other valuation losses	719,142	3,716,883	—
Depreciation, depletion and amortization	465,936	778,923	806,021
Asset retirement obligation	7,828	9,121	10,082
Deferred income taxes	(226,100)	(1,388,146)	298,293
Stock compensation	24,523	19,559	15,001
(Gain) loss on derivative instruments, net	55,749	(11,246)	(3,762)
Settlements on derivative instruments	7,437	—	7,641
Changes in non-current assets and liabilities	3,867	23,230	(2,440)
Other, net	1,805	4,206	(3,828)
Changes in operating assets and liabilities:			
Receivables, net	(49,340)	186,699	(35,133)
Other current assets	20,880	37,954	(25,428)
Accounts payable and other current liabilities	(1,453)	(276,735)	45,714
Net cash provided by operating activities	599,225	691,500	1,619,365
Cash flows from investing activities:			
Oil and gas expenditures	(699,558)	(979,044)	(2,108,250)
Sales of oil and gas assets	21,487	39,853	449,981
Sales of other assets	7,889	1,178	8,413
Other capital expenditures	(22,228)	(70,592)	(90,611)
Net cash used by investing activities	(692,410)	(1,008,605)	(1,740,467)
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	(101)	(24,633)	(11,616)
Dividends paid	(38,024)	(58,281)	(53,849)
Proceeds from exercise of stock options and other	4,804	21,439	11,898
Net cash (used) provided by financing activities	(33,321)	690,625	522,433
Net change in cash and cash equivalents	(126,506)	373,520	401,331
Cash and cash equivalents at beginning of period	779,382	405,862	4,531
Cash and cash equivalents at end of period	$ 652,876	$ 779,382	$ 405,862

The accompanying notes are an integral part of these consolidated financial statements.

CIMAREX ENERGY CO.

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

(in thousands)

	Common Stock		Paid-in	Retained Earnings (Accumulated	Accumulated Other Comprehensive	Total Stockholders'
	Shares	Amount	Capital	Deficit)	Income (loss)	Equity
Balance, December 31, 2013	87,152	$ 872	$ 1,970,113	$ 2,050,034	$ 1,189	$ 4,022,208
Dividends	—	—	—	(55,664)	—	(55,664)
Net income	—	—	—	507,204	—	507,204
Unrealized change in fair value of investments, net of tax	—	—	—	—	(87)	(87)
Issuance of restricted stock awards	487	4	(4)	—	—	—
Common stock reacquired and retired	(123)	(1)	(13,559)	—	—	(13,560)
Restricted stock forfeited and retired	(135)	(1)	1	—	—	—
Exercise of stock options	211	2	11,896	—	—	11,898
Stock-based compensation	—	—	28,633	—	—	28,633
Balance, December 31, 2014	87,592	$ 876	$ 1,997,080	$ 2,501,574	$ 1,102	$ 4,500,632
Dividends	—	—	—	(59,313)	—	(59,313)
Net loss	—	—	—	(2,408,948)	—	(2,408,948)
Unrealized change in fair value of investments, net of tax	—	—	—	—	(661)	(661)
Issuance of common stock	6,900	69	729,468	—	—	729,537
Issuance of restricted stock awards	471	5	(5)	—	—	—
Common stock reacquired and retired	(194)	(2)	(21,238)	—	—	(21,240)
Restricted stock forfeited and retired	(90)	(1)	1	—	—	—
Exercise of stock options	142	1	8,450	—	—	8,451
Stock-based compensation	—	—	36,232	—	—	36,232
Stock-based compensation tax benefit	—	—	12,988	—	—	12,988
Balance, December 31, 2015	94,821	$ 948	$ 2,762,976	$ 33,313	$ 441	$ 2,797,678
Dividends	—	—	—	(7,548)	—	(7,548)
Dividends in excess of retained earnings	—	—	(22,803)	—	—	(22,803)
Net loss	—	—	—	(431,049)	—	(431,049)
Unrealized change in fair value of investments, net of tax	—	—	—	—	504	504
Issuance of restricted stock awards	479	5	(5)	—	—	—
Common stock reacquired and retired	(208)	(3)	(26,622)	—	—	(26,625)
Restricted stock forfeited and retired	(32)	—	—	—	—	—
Exercise of stock options	64	1	4,803	—	—	4,804
Stock-based compensation	—	—	45,103	—	—	45,103
Balance, December 31, 2016	95,124	$ 951	$ 2,763,452	$ (405,284)	$ 945	$ 2,360,064

The accompanying notes are an integral part of these consolidated financial statements.

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. BASIS OF PRESENTATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Cimarex Energy Co., a Delaware corporation, is an independent oil and gas exploration and production company. Our operations are mainly located in Texas, Oklahoma and New Mexico.

Basis of Presentation

Our Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in the United States of America, or GAAP. Our significant accounting policies are discussed below. The accounts of Cimarex and its subsidiaries are presented in the accompanying Consolidated Financial Statements. All intercompany accounts and transactions were eliminated in consolidation.

Segment Information

We have determined that our business is comprised of only one segment because our gathering, processing and marketing activities are ancillary to our production operations and are not separately managed.

Use of Estimates

The preparation of our financial statements in conformity with GAAP requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. The more significant areas requiring the use of management's estimates and judgments relate to the estimation of proved oil and gas reserves, the use of these oil and gas reserves in calculating depletion, depreciation and amortization (DD&A), the use of the estimates of future net revenues in computing ceiling test limitations and estimates of future abandonment obligations used in recording asset retirement obligations and the assessment of goodwill.

The process of estimating quantities of oil and gas reserves is complex, requiring significant decisions in the evaluation of all available geological, geophysical, engineering and economic data. The data for a given field may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. As a result, material revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure that our reserve estimates represent the most accurate assessments possible, subjective decisions and available data for our various fields make these estimates generally less precise than other estimates included in financial statement disclosures.

Estimates and judgments are also required in determining the allowance for doubtful accounts, impairments of unproved properties and other assets, purchase price allocation, valuation of deferred tax assets, fair value measurements and commitments and contingencies. We analyze our estimates, including those related to oil, gas and NGL revenues, and base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions.

Cash and Cash Equivalents

Cash and cash equivalents consist of cash in banks and investments readily convertible into cash, which have original maturities of three months or less. Cash equivalents are stated at cost, which approximates market value.

Oil and Gas Well Equipment and Supplies

We carry our inventory at the lower of cost or net realizable value, where net realizable value is estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. We performed an analysis of our oil and gas well equipment and supplies as of December 31, 2016, 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. 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. All costs associated with property acquisition, exploration and development activities are capitalized. Exploration and development costs include dry hole costs, geological and geophysical costs, direct overhead related to exploration and development activities and other costs incurred for the purpose of finding oil and gas reserves. Salaries and benefits paid to employees directly involved in the exploration and development of properties, as well as other internal costs that can be directly identified with acquisition, exploration and development activities, are also capitalized. Under the full cost method of accounting, no gain or loss is recognized upon the disposition of oil and gas properties unless such disposition would significantly alter the relationship between capitalized costs and proved reserves. Expenditures for maintenance and repairs are charged to production expense in the period incurred.

Companies that follow the full cost accounting method are required to make quarterly ceiling test calculations. This test ensures that total capitalized costs for oil and gas properties (net of accumulated DD&A and deferred income taxes) do not exceed 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. We currently do not have any unproven properties that are being amortized. Estimated future net cash flows are determined by commodity prices and proved reserve quantities. Revenue calculations in the reserves are based on the unweighted average first-day-of-the-month prices for the prior 12 months. If net capitalized costs exceed this limit, the excess is charged to expense.

At December 31, 2016, the carrying value of our oil and gas properties subject to the test did not exceed the calculated value of the ceiling limitation and, therefore, we did not recognize an impairment. However, a decline of 11% or more in the value of the ceiling limitation would have resulted in an impairment. We did recognize impairments in the first three quarters of 2016 totaling $719.1 million ($456.9 million, net of tax). For the year ended December 31, 2015, full year impairments totaled $3.7 billion ($2.4 billion, 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 decline, 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 other components of our balance sheet. Any recorded impairment of oil and gas properties is not reversible at a later date.

Depletion of proved oil and gas properties is computed on the units-of-production method, whereby capitalized costs, including future development costs and asset retirement costs, are amortized over total estimated proved reserves. Changes in our estimate of proved reserve quantities, commodity prices and impairment of oil and gas properties will cause corresponding changes in depletion expense in periods subsequent to these changes.

The capitalized costs of unproved properties, including those in wells in progress, are excluded from the costs being amortized. We do not have major development projects that are excluded from costs being amortized. On a quarterly basis, we evaluate excluded costs for inclusion in the costs to be amortized. Significant unproved properties are evaluated individually. Unproved properties that are not considered individually significant are aggregated for evaluation purposes and related costs are transferred to the costs to be amortized quarterly based on the application of historical factors.

Fixed Assets, net

Fixed assets consist primarily of gathering and plant facilities, vehicles, airplanes, office furniture, and computer equipment and software. These items are recorded at cost and are depreciated on the straight-line method based on expected lives of the individual assets, which range from 3 to 30 years.

Goodwill

Goodwill represents the excess of the purchase price of business combinations over the fair value of the net assets acquired and is tested for impairment at least annually. We have one reporting unit for which we first assess qualitative factors to determine whether it is more likely than not (with a greater than 50% threshold) that the fair value of a reporting unit is less than its carrying amount as a basis for determining whether it is necessary to perform the two-step goodwill impairment test. If goodwill is determined to be impaired then it is written down to a calculated fair value by charging the impairment to expense.

We evaluate our goodwill for impairment in the fourth quarter of each year and whenever events or changes in circumstances indicate the possibility that goodwill may be impaired. Based upon our qualitative assessment at December 31, 2016, goodwill was not impaired. It is possible that goodwill could become impaired in the future if commodity prices or other economic factors become less favorable.

Revenue Recognition

Oil, Gas and NGL Sales

Revenue is recorded from the sales of oil, gas and NGLs when the product is delivered at a fixed or determinable price, title has transferred and collectability is reasonably assured. There is a ready market for our products and sales occur soon after production.

Marketing Sales

We market and sell natural gas for working interest owners under short term sales and supply agreements and earn a fee for such services. Revenues are recognized as gas is delivered and are reflected net of gas purchases on the consolidated statements of operations and comprehensive income (loss).

Gas Imbalances

We use the sales method of accounting for gas imbalances. Under this method, revenue is recorded on the basis of gas actually sold. Gas reserves are adjusted to the extent there are sufficient quantities of natural gas to make up an imbalance. A liability is established in situations where there are insufficient proved reserves available to make-up an overproduced imbalance. Imbalances have not been significant in the periods presented.

General and Administrative Expenses

General and administrative expenses are reported net of amounts reimbursed by working interest owners of the oil and gas properties operated by Cimarex and net of amounts capitalized pursuant to the full cost method of accounting.

Derivatives

Our derivative contracts are recorded on the balance sheet at fair value. Our firm sales contracts qualify for the normal purchase and normal sale exception. Contracts that qualify for this treatment do not require mark-to-market accounting treatment. See Note 4 for additional information regarding our derivative instruments.

Income Taxes

We record deferred tax assets and liabilities to account for the expected future tax consequences of events that have been recognized in the financial statements and tax returns. We classify all deferred tax assets and liabilities as noncurrent. We routinely assess the realizability of the deferred tax assets. If we conclude that it is more likely than not that some or all of the deferred tax assets will not be realized, the tax asset is reduced by a valuation allowance. Numerous judgments and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions (particularly as related to prevailing oil and gas prices) and changing tax laws.

We regularly assess and, if required, establish accruals for tax contingencies that could result from assessments of additional tax by taxing jurisdictions where the company operates. See Note 9 for additional information regarding our income taxes.

Contingencies

A provision for contingencies is charged to expense when the loss is probable and the cost can be reasonably estimated. Determining when expenses should be recorded for these contingencies and the appropriate amounts for accrual is a complex estimation process that includes subjective judgment. In many cases, this judgment is based on interpretation of laws and regulations, which can be interpreted differently by regulators and/or courts of law. We closely monitor known and potential legal, environmental and other contingencies and determine when we should record losses for these items based on information available to us. See Note 10 for additional information regarding our contingencies.

Asset Retirement Obligations

We recognize the present value of the fair value of liabilities for retirement obligations associated with tangible long-lived assets in the period in which there is a legal obligation associated with the retirement of such assets and the amount can be reasonably estimated. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. This liability includes costs related to the abandonment of wells, the removal of facilities and equipment, and site restorations. Subsequent to initial measurement, the asset retirement liability is required to be accreted each period. If the fair value of a recorded asset retirement obligation changes, a revision is recorded to both the asset retirement obligation and the asset retirement capitalized cost. Capitalized costs are included as a component of the DD&A calculations. The current portions of the asset retirement obligations are recorded in “Accrued liabilities — Other” in the accompanying consolidated balance sheets and expenditures are classified as cash used in operating activities in the accompanying consolidated statements of cash flows. See Note 8 for additional information regarding our asset retirement obligations.

Stock-based Compensation

We recognize compensation cost related to all stock-based awards in the financial statements based on their estimated grant-date fair value. We grant various types of stock-based awards including stock options, restricted stock (including awards with service-based vesting and market condition-based vesting provisions) and restricted stock units. The fair value of stock option awards is determined using the Black-Scholes option pricing model. Service-based restricted stock and units are valued using the market price of our common stock on the grant date. The fair value of the market condition-based restricted stock is based on the grant-date market value of the award utilizing a statistical analysis. Compensation cost is recognized ratably over the applicable vesting period. To the extent compensation cost relates to employees directly involved in oil and gas acquisition, exploration, and development activities, such amounts are capitalized to oil and gas properties. Amounts not capitalized to oil and gas properties are recognized as stock compensation expense. See Note 6 for additional information regarding our stock-based compensation.

Earnings (loss) per Share

We calculate earnings (loss) per share recognizing that unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents are “participating securities” and, therefore, should be included in computing earnings per share using the two-class earnings allocation method. The two-class method is an earnings allocation formula that determines earnings per share for each class of common stock and participating security according to dividends declared (or accumulated) and participation rights in undistributed earnings. Our unvested share based payment awards, consisting of restricted stock and units, qualify as participating securities. See Note 7 for additional information regarding our earnings per share.

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. The new revenue standard provides a five-step analysis of transactions to determine when and how revenue is recognized. The core principle of the guidance is that a company should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The guidance in this update supersedes the revenue recognition requirements in Topic 605, *Revenue Recognition,* and most industry-specific guidance throughout the Industry Topics of the Codification. Entities can choose to apply the standard using either the full retrospective approach or a modified retrospective approach. We intend to adopt this standard on January 1, 2018, utilizing a modified retrospective approach. Management does not believe the effect of adoption will be material to our financial statements because we follow the sales method of accounting for our oil, gas and NGL production, which is generally consistent with the revenue recognition provisions of the new standard. However, we anticipate the new standard will result in more robust footnote disclosures. We cannot currently determine the extent of the new footnote disclosures as further clarification is needed for certain practices common to the industry.

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842)*. The key provision of this ASU is that a lessee must recognize (i) liabilities to make lease payments and (ii) right-of-use assets on its balance sheet. The ASU permits lessees to make a policy election to not recognize lease assets and liabilities for leases with terms of less than twelve months. Under current GAAP, a determination of whether a lease is a capital or operating lease is made at lease inception and no assets or liabilities are recognized for operating leases. Under this ASU, the determination to be made at the inception of a contract is whether the contract is, or contains, a lease. Leases convey the right to control the use of an identified asset in exchange for consideration. Only the lease components of a contract must be accounted for in accordance with this ASU. Non-lease components, such as activities that transfer a good or service to the customer, shall be accounted for under other applicable Topics. An entity may make a policy election to not separate lease and non-lease components and account for the non-lease components together with the lease components as a single lease component. This ASU retains a distinction between finance and operating leases concerning the recognition and presentation of the expense and payments related to leases in the statements of operations and comprehensive income and cash flows, however, both types of leases require the recognition of assets and liabilities on the balance sheet. This ASU is effective for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years, with early adoption permitted. Upon transition, lessees will be required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. While we are in the process of evaluating the potential impact of adopting this guidance, the primary effect will be to record assets and obligations for contracts currently recognized as operating leases. We do not intend to adopt the standard early.

In March 2016, the FASB issued ASU 2016-09, *Improvements to Employee Share-Based Payment Accounting* (ASU 2016-09). ASU 2016-09 simplifies the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. The amendments in this ASU are effective for fiscal years beginning after December 15, 2016, and interim periods within those fiscal years. The standard contains various amendments, and specifies whether each amendment should be adopted using a retrospective, modified retrospective, or prospective transition method. We will adopt ASU 2016-09 effective January 1, 2017. The amendments within ASU 2016-09 related to the timing of when excess tax benefits and tax benefits on dividends on nonvested equity shares are recognized and accounting for forfeitures will be adopted using a modified retrospective method. In accordance with this method, we expect to record a cumulative-effect adjustment on that date relating to those amendments, representing a decrease to beginning Deferred income taxes of approximately $33 million, a reduction to beginning Accumulated deficit of approximately $31 million and an increase to beginning Paid-in capital of approximately $2 million. The amendments within ASU 2016-09 related to the presentation in the statement of cash flows of excess tax benefits and cash outflows attributable to tax withholdings on the net settlement of equity-classified awards will be adopted using a retrospective method. In accordance with this method, we estimate that Net cash provided by operating activities would have increased and Net cash (used) provided by financing activities would have decreased by approximately $27 million, $34 million and $14 million, for the years ended December 31, 2016, 2015 and 2014, respectively.

In January 2017, the FASB issued ASU 2017-04, *Intangibles—Goodwill and Other (Topic 350)—Simplifying the Test for Goodwill Impairment*. This ASU eliminates step two from the goodwill impairment test. Under current guidance, if the fair value of the reporting unit is less than its carrying amount (step 1 of the goodwill impairment test), entities must complete step two to determine the impairment amount, if any. Under step two, the impairment amount is determined by calculating the implied fair value of goodwill by assigning the fair value of a reporting unit to all of its assets and liabilities as if that reporting unit had been acquired in a business combination, and comparing it to the carrying amount of the goodwill. Under this ASU, the impairment amount is the amount by which the carrying amount of the reporting unit exceeds the reporting unit's fair value, with the amount of impairment not to exceed the carrying amount of the goodwill. This ASU retains the option to qualitatively assess whether it is more likely than not that the fair value of the reporting unit is less than its carrying amount in order to determine if it is necessary to initiate step 1. This ASU is effective for annual or any interim goodwill impairment tests in the fiscal years beginning after December 15, 2019, with early adoption permitted for testing dates after January 1, 2017. The implementation of this ASU will affect the amount of goodwill impairment we record, if any. We adopted this ASU on January 1, 2017, and will apply its provisions in future periods if we determine our goodwill has been impaired.

Subsequent Events

The accompanying financial disclosures include an evaluation of subsequent events through the date of this filing.

2. CAPITAL STOCK

Authorized capital stock consists of 200 million shares of common stock and 15 million shares of preferred stock. At December 31, 2016, there were no shares of preferred stock outstanding. See our Consolidated Statements of Stockholders' Equity for detailed capital stock activity.

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.

Dividends

A cash dividend has been paid to stockholders in every quarter since the first quarter of 2006. In February 2016, the quarterly dividend was decreased to $0.08 per share from $0.16 per share. Dividends declared are recorded as a reduction of retained earnings to the extent retained earnings are available at the close of the period prior to the date of the declared dividend. Dividends in excess of retained earnings are recorded as a reduction of additional paid-in capital. Future dividend payments will depend on our level of earnings, financial requirements, and other factors considered relevant by the Board of Directors.

	Years Ended December 31,		
	2016	2015	2014
Dividends declared from Retained earnings (in millions)	$ 7.5	$ 59.3	$ 55.7
Dividends declared from Paid-in capital (in millions)	$ 22.8	$ —	$ —
Dividends per share	$ 0.32	$ 0.64	$ 0.64

3. LONG-TERM DEBT

A summary of our debt is as follows:

	December 31, 2016			December 31, 2015		
(in thousands)	Principal	Unamortized Debt Issuance Costs	Long-term Debt, net	Principal	Unamortized Debt Issuance Costs	Long-term Debt, net
5.875% Senior Notes	$ 750,000	$ (5,691)	$ 744,309	$ 750,000	$ (6,978)	$ 743,022
4.375% Senior Notes	750,000	(6,370)	743,630	750,000	(7,402)	742,598
Total long-term debt	$ 1,500,000	$ (12,061)	$ 1,487,939	$ 1,500,000	$ (14,380)	$ 1,485,620

At December 31, 2016 and 2015, we had no bank debt outstanding. All of our long-term debt is senior unsecured debt and is, therefore, *pari passu* with respect to the payment of both principal and interest.

Bank Debt

In October 2015, we entered into a new senior unsecured revolving credit facility (Credit Facility) which matures October 16, 2020. The Credit Facility has aggregate commitments of $1.0 billion, with an option to increase aggregate commitments to $1.25 billion at any time. There is no borrowing base subject to the discretion of the lenders based on the value of our proved reserves under the Credit Facility. As of December 31, 2016, we had $2.5 million in letters of credit outstanding under the Credit Facility, leaving an unused borrowing availability of $997.5 million.

At our option, borrowings under the Credit Facility may bear interest at either (a) LIBOR plus 1.125 – 2.0% based on the credit rating for our senior unsecured long-term debt, or (b) a base rate (as defined in the credit agreement) plus 0.125 – 1.0%, based on the credit rating for our senior unsecured long-term debt. Unused borrowings are subject to a commitment fee of 0.125 – 0.35%, based on the credit rating for our senior unsecured long-term debt.

The Credit Facility contains representations, warranties, covenants and events of default that are customary for investment grade, senior unsecured bank credit agreements, including a financial covenant for the maintenance of a defined total debt-to-capital ratio of no greater than 65%. As of December 31, 2016, we were in compliance with all of the financial and non-financial covenants.

At December 31, 2016 and 2015, we had $4.5 million and $5.7 million, respectively, of unamortized debt issuance costs associated with our Credit Facility which were recorded as deferred assets and included in Other assets, net in our balance sheets. The costs are being amortized to interest expense ratably over the life of the Credit Facility.

Senior Notes

In June 2014, we issued $750 million of 4.375% senior notes due 2024 and received net proceeds of $740.9 million, after deducting offering discounts and costs. The net proceeds were used to pay outstanding bank debt and for general corporate purposes. The effective interest rate on the notes, including the debt issuance costs, is 4.50%.

In April 2012, we issued $750 million of 5.875% senior notes due 2022 and received net proceeds of $737.0 million, after deducting underwriting discounts and offering costs. We used a portion of the net proceeds to retire our 7.125% senior notes and the remaining proceeds were used to pay outstanding bank debt and for general corporate purposes. The effective interest rate on the notes, including the debt issuance costs, is 6.04%. These senior notes are callable by us beginning May 1, 2017 at a price of 102.938% of face value declining to 100% of face value on May 1, 2020 and thereafter.

Each of our outstanding 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 December 31, 2016. Interest on each of the senior notes is payable semi-annually.

4. DERIVATIVE INSTRUMENTS/HEDGING

We periodically enter into derivative instruments to mitigate a portion of our potential exposure to a decline in commodity prices and the corresponding negative impact on cash flow available for reinvestment. While the use of these instruments limits the downside risk of adverse price changes, their use may also limit future revenues from favorable price changes. Depending on changes in oil and gas futures markets and management's view of underlying supply and demand trends, we may increase or decrease our hedging positions. We may hedge up to 50% of our oil and natural gas production on a forward five quarter basis.

The following tables summarize our derivative contracts as of December 31, 2016:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Oil Collars:					
2017:					
WTI (1)					
Volume (Bbls)	1,800,000	1,820,000	1,472,000	1,012,000	6,104,000
Wtd Avg Price - Floor	$ 43.08	$ 43.08	$ 45.09	$ 46.27	$ 44.09
Wtd Avg Price - Ceiling	$ 52.90	$ 52.90	$ 55.50	$ 56.98	$ 54.20
2018:					
WTI (1)					
Volume (Bbls)	540,000	—	—	—	540,000
Wtd Avg Price - Floor	$ 47.33	$ —	$ —	$ —	$ 47.33
Wtd Avg Price - Ceiling	$ 59.11	$ —	$ —	$ —	$ 59.11

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

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Gas Collars:					
2017:					
PEPL (1)					
Volume (MMBtu)	9,900,000	10,010,000	8,280,000	5,520,000	33,710,000
Wtd Avg Price - Floor	$ 2.52	$ 2.52	$ 2.61	$ 2.79	$ 2.59
Wtd Avg Price - Ceiling	$ 3.04	$ 3.04	$ 3.12	$ 3.22	$ 3.09
Perm EP (1)					
Volume (MMBtu)	8,100,000	8,190,000	5,520,000	3,680,000	25,490,000
Wtd Avg Price - Floor	$ 2.59	$ 2.59	$ 2.68	$ 2.86	$ 2.65
Wtd Avg Price - Ceiling	$ 3.10	$ 3.10	$ 3.16	$ 3.28	$ 3.14
2018:					
PEPL (1)					
Volume (MMBtu)	2,700,000	—	—	—	2,700,000
Wtd Avg Price - Floor	$ 2.90	$ —	$ —	$ —	$ 2.90
Wtd Avg Price - Ceiling	$ 3.32	$ —	$ —	$ —	$ 3.32
Perm EP (1)					
Volume (MMBtu)	1,800,000	—	—	—	1,800,000
Wtd Avg Price - Floor	$ 3.00	$ —	$ —	$ —	$ 3.00
Wtd Avg Price - Ceiling	$ 3.41	$ —	$ —	$ —	$ 3.41

(1) PEPL refers to the Panhandle Eastern Pipe Line, Tex/OK Mid-Continent Index as quoted in Platt's Inside FERC. Perm EP refers to the El Paso Natural Gas Company, Permian Basin Index as quoted in Platt's Inside FERC.

Under a collar agreement, we receive the difference between the published index price and a floor price if the index price is below the floor. We pay the difference between the ceiling price and the index price if the index price is above the contracted ceiling price. No amounts are paid or received if the index price is between the floor and the ceiling price.

We have elected not to account for our derivatives as cash flow hedges. Therefore, we recognize settlements and changes in the fair value of 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.

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

	Years Ended December 31,		
(in thousands)	2016	2015	2014
(Gain) loss on derivative instruments, net:			
Natural gas contracts	$ 20,995	$ (4,472)	$ 6,751
Oil contracts	34,754	(6,774)	(10,512)
(Gain) loss on derivative instruments, net	$ 55,749	$ (11,246)	$ (3,761)
Settlement (gains) losses:			
Natural gas contracts	$ (6,467)	$ —	$ 4,287
Oil contracts	(970)	—	(11,928)
Settlement (gains) losses	$ (7,437)	$ —	$ (7,641)

Our derivative contracts are carried at their fair value on our balance sheet using Level 2 inputs and are subject to enforceable master netting arrangements, which allow us to offset recognized asset and liability fair value amounts on contracts with the same counterparty. Our policy is to not offset asset and liability positions in our accompanying balance sheets.

The following table presents the amounts and classifications of our derivative assets and liabilities as of December 31, 2016 and 2015, as well as the potential effect of netting arrangements on contracts with the same counterparty.

December 31, 2016: (in thousands)	Balance Sheet Location	Asset	Liability
Oil contracts	Current liabilities — Derivative instruments	$ —	$ 27,892
Natural gas contracts	Current liabilities — Derivative instruments	—	21,478
Oil contracts	Non-current liabilities — Derivative instruments	—	1,059
Natural gas contracts	Non-current liabilities — Derivative instruments	—	1,511
Total gross amounts presented in accompanying balance sheet		—	51,940
Less: gross amounts not offset in the accompanying balance sheet		—	—
Net amount:		$ —	$ 51,940

December 31, 2015: (in thousands)	Balance Sheet Location	Asset	Liability
Oil contracts	Current assets — Derivative instruments	$ 6,774	$ —
Natural gas contracts	Current assets — Derivative instruments	3,971	—
Natural gas contracts	Non-current assets — Derivative instruments	501	—
Total gross amounts presented in accompanying balance sheet		11,246	—
Less: gross amounts not offset in the accompanying balance sheet		—	—
Net amount:		$ 11,246	$ —

We are exposed to financial risks associated with our derivative contracts from non-performance by our counterparties. We mitigate our exposure to any single counterparty by contracting with a number of financial institutions, each of which have a high credit rating and is a member of our bank credit facility. Our member banks do not require us to post collateral for our hedge liability positions. Because some of the member banks have discontinued hedging activities, in the future we may hedge with counterparties outside our bank group to obtain competitive terms and to spread counterparty risk.

5. 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.

The following table provides fair value measurement information for certain assets and liabilities as of December 31, 2016 and 2015.

	December 31, 2016		December 31, 2015	
(in thousands)	**Book Value**	**Fair Value**	**Book Value**	**Fair Value**
Financial Assets (Liabilities):				
5.875% Notes due 2022	$ (750,000)	$ (782,835)	$ (750,000)	$ (723,750)
4.375% Notes due 2024	$ (750,000)	$ (779,453)	$ (750,000)	$ (683,318)
Derivative instruments — assets	$ —	$ —	$ 11,246	$ 11,246
Derivative instruments — liabilities	$ (51,940)	$ (51,940)	$ —	$ —

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

Debt (Level 1)

The fair value of our 4.375% and 5.875% fixed rate notes was based on their last traded value before year end.

Derivative Instruments (Level 2)

The fair value of our derivative instruments was estimated using option pricing models. These models use certain variables including forward price and volatility curves and the strike prices for the instruments. The fair value estimates are adjusted relative to non-performance risk as appropriate. See Note 4 for further information on the fair value of our derivative instruments.

Other Financial Instruments

The carrying amounts of our cash, cash equivalents, accounts receivable, accounts payable, and accrued liabilities approximate fair value because of the short-term maturities and/or liquid nature of these assets and liabilities. Included in "Accrued liabilities — other" at December 31, 2016 and 2015, respectively, are 1) liabilities of approximately $19.3 million and $23.1 million representing the amount by which checks issued, but not yet presented to our banks, exceeded balances in applicable bank accounts; 2) accrued payroll related costs of $43.5 million and $21.5 million; and 3) accrued operating expenses of $53.9 million and $60.4 million.

Our accounts receivable are primarily from either purchasers of our oil, gas, and NGL production (customers) or from exploration and production companies which own interests in properties we operate. This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, because our customers and joint working interest owners may be similarly affected by changes in industry conditions.

We conduct credit analyses prior to making any sales to new customers or increasing credit for existing customers and may require parent company guarantees, letters of credit, or prepayments when deemed necessary.

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 December 31, 2016 and 2015, the allowance for doubtful accounts totaled $1.6 million and $1.8 million, respectively.

Major Customers

Our major customer during 2016 was Sunoco Logistics Partners L.P. (Sunoco), which accounted for 20% of our consolidated revenues. Sunoco and Enterprise Products Partners L.P. (Enterprise) were our major customers in 2015, accounting for 21% and 17%, respectively, of our consolidated revenues that year. During 2014, Sunoco and Enterprise each accounted for 19% of our consolidated revenues and Oneok Partners, L.P. accounted for 10% of our consolidated revenues.

If Sunoco was to stop purchasing our production, we believe there are a number of other purchasers to whom we could sell our production with some delay. If multiple significant customers were to discontinue purchasing our product, we believe there would be challenges initially, but ample markets to handle the disruption.

6. STOCK-BASED AND OTHER COMPENSATION

We have recognized non-cash 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.

	Years Ended December 31,		
(in thousands)	**2016**	**2015**	**2014**
Restricted stock awards			
Performance stock awards	$ 24,183	$ 18,991	$ 12,141
Service-based stock awards	18,391	14,547	13,607
	42,574	33,538	25,748
Stock option awards	2,565	2,803	3,057
	45,139	36,341	28,805
Less amounts capitalized to oil and gas properties	(20,616)	(16,782)	(13,804)
Compensation expense	$ 24,523	$ 19,559	$ 15,001

The increase in 2016 stock compensation is primarily related to performance awards granted in December 2015, a portion of which were amortized during 2016, forfeiture rate adjustments on the service-based stock awards, and the acceleration of expense on a portion of service-based awards for employees who participated in a voluntary early retirement incentive program.

Equity Incentive Plan

Our 2014 Equity Incentive Plan (the 2014 Plan) was approved by stockholders in May 2014 and our previous plan was terminated at that time. Outstanding awards under the previous plan were not impacted. A total of 6.6 million shares of common stock may be issued under the 2014 Plan, including shares available from the previous plan. The 2014 Plan provides for grants of stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance units, dividend equivalents and other stock-based awards.

Restricted Stock

The following table provides information about restricted stock awards granted during the last three years.

	Years Ended December 31,								
	2016			2015			2014		
	Number of Shares		Weighted Average Grant-Date Fair Value	Number of Shares		Weighted Average Grant-Date Fair Value	Number of Shares		Weighted Average Grant-Date Fair Value
Performance stock awards	269,915	$	117.63	263,939	$	87.12	316,441	$	83.22
Service-based stock awards	208,724	$	114.61	207,180	$	114.80	170,402	$	136.72
Total restricted stock awards	478,639	$	116.31	471,119	$	99.29	486,843	$	101.95

Performance awards were granted to eligible executives and are subject to market condition-based vesting determined by our stock price performance relative to a defined peer group's stock price performance. After three years of continued service, an executive will be entitled to vest in 50% to 100% of the award. In accordance with Internal Revenue Code Section 162(m), certain of the amounts awarded may not be deductible for tax purposes. Service-based stock awards granted to other eligible employees and non-employee directors have vesting schedules of three to five years.

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

The following table provides information on restricted stock activity during the year.

	Service-based			Performance (subject to market conditions)		
	Number of Shares		Weighted Average Grant-Date Fair Value	Number of Shares		Weighted Average Grant-Date Fair Value
Outstanding as of January 1, 2016	998,182	$	91.37	829,808	$	82.99
Vested	(243,313)	$	92.37	(287,108)	$	81.53
Granted	208,724	$	114.61	269,915	$	117.63
Canceled	(28,870)	$	110.84	(3,345)	$	87.14
Outstanding as of December 31, 2016	934,723	$	96.57	809,270	$	96.41

The total fair value of restricted stock that vested was $67.9 million in 2016, $52.2 million in 2015, and $34.1 million in 2014.

Unrecognized compensation cost related to unvested restricted stock at December 31, 2016 was $96.0 million. We expect to recognize that cost over a weighted average period of 2.8 years.

Restricted Units

As of December 31, 2016 and 2015, we had 8,838 restricted units outstanding. These represent restricted units held by a non-employee director who has elected to defer payment of common stock represented by the units until termination of his service on the Board of Directors.

Stock Options

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

Compensation cost related to stock options is based on the grant-date fair value of the award, recognized ratably over the applicable vesting period. We estimate the fair value using the Black-Scholes option-pricing model. Expected volatilities are based on the historical volatility of our common stock. We also use historical data to estimate the probability of option exercise, expected years until exercise and potential forfeitures. We use U.S. Treasury bond rates in effect at the grant date for our risk-free interest rates.

The following summarizes the options granted and related information, and the assumptions used to determine the fair value of those options.

	Years Ended December 31,		
	2016	2015	2014
Options granted	89,850	69,000	82,500
Weighted average grant-date fair value	$ 33.38	$ 37.56	$ 41.69
Weighted average exercise price	$ 114.07	$ 115.28	$ 139.02
Total fair value (in thousands)	$ 2,999	$ 2,592	$ 3,439
Expected years until exercise	4.0	5.0	4.0
Expected stock volatility	36.7 %	36.6 %	36.7 %
Dividend yield	0.3 %	0.6 %	0.5 %
Risk-free interest rate	0.96 %	1.6 %	1.8 %

Information about outstanding stock options is summarized below.

	Options	Weighted Average Exercise Price	Weighted Average Remaining Term	Aggregate Intrinsic Value (in thousands)
Outstanding as of January 1, 2016	299,229	$ 93.76		
Exercised	(63,727)	$ 75.37		
Granted	89,850	$ 114.07		
Canceled	(1,997)	$ 139.02		
Forfeited	(15,545)	$ 123.00		
Outstanding as of December 31, 2016	307,810	$ 101.72	4.6 Years	$ 10,846
Exercisable as of December 31, 2016	159,449	$ 86.99	3.4 Years	$ 7,996

The following table provides information regarding options exercised and the grant-date fair value of options vested.

	Years Ended December 31,		
(in thousands)	2016	2015	2014
Number of options exercised	63,727	141,517	211,258
Cash received from option exercises	$ 4,804	$ 8,451	$ 11,898
Tax benefit from option exercises included in paid-in-capital (1)	$ —	$ 4,442	$ —
Intrinsic value of options exercised	$ 2,994	$ 7,467	$ 15,384
Grant-date fair value of options vested	$ 2,486	$ 2,734	$ 4,419

(1) No tax benefit is recorded until the benefit reduces current taxes payable. However, in 2015 we recognized tax benefit on prior period option exercises.

The following summary reflects the status of non-vested stock options as of December 31, 2016 and changes during the year.

	Options	Weighted Average Grant-Date Fair Value	Weighted Average Exercise Price
Non-vested as of January 1, 2016	157,041	$ 34.77	$ 111.58
Vested	(82,985)	$ 29.95	$ 101.46
Granted	89,850	$ 33.38	$ 114.07
Forfeited	(15,545)	$ 19.70	$ 123.00
Non-vested as of December 31, 2016	148,361	$ 35.58	$ 117.55

As of December 31, 2016, there was $3.6 million of unrecognized compensation cost related to non-vested stock options. We expect to recognize that cost on a pro rata basis over a weighted average period of 2.0 years.

Other Compensation

We maintain and sponsor a contributory 401(k) plan for our employees. Annual matching costs related to the plan were $6.7 million, $6.4 million, and $11.0 million for 2016, 2015, and 2014, respectively.

7. EARNINGS (LOSS) PER SHARE

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

	Years Ended December 31,		
(in thousands, except per share data)	**2016**	**2015**	**2014**
Basic:			
Net income (loss)	$ (431,049)	$ (2,408,948)	$ 507,204
Participating securities' share in earnings (1)	—	—	(9,906)
Net income (loss) applicable to common stockholders	$ (431,049)	$ (2,408,948)	$ 497,298
Diluted:			
Net income (loss)	$ (431,049)	$ (2,408,948)	$ 507,204
Participating securities' share in earnings (1)	—	—	(9,891)
Net income (loss) applicable to common stockholders	$ (431,049)	$ (2,408,948)	$ 497,313
Shares:			
Basic shares outstanding	93,379	92,992	85,679
Dilutive effect of stock options	—	—	131
Fully diluted common stock	93,379	92,992	85,810
Excluded (2)	2,061	2,136	94
Earnings (loss) per share to common stockholders (3):			
Basic	$ (4.62)	$ (25.92)	$ 5.79
Diluted	$ (4.62)	$ (25.92)	$ 5.78

(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 is based on actual figures rather than the rounded figures presented.

8. ASSET RETIREMENT OBLIGATIONS

The following table reflects the components of the change in the carrying amount of the asset retirement obligation for the years ended December 31, 2016 and 2015.

(in thousands)	2016	2015
Asset retirement obligation at January 1,	$ 164,105	$ 173,008
Liabilities incurred	3,914	4,114
Liability settlements and disposals	(24,108)	(25,061)
Accretion expense	7,595	7,682
Revisions of estimated liabilities	3,017	4,362
Asset retirement obligation at December 31,	154,523	164,105
Less current obligation	13,753	10,248
Long-term asset retirement obligation	$ 140,770	$ 153,857

During 2016 and 2015, the liability settlements and disposals included $14.9 million and $13.3 million, respectively, related to properties that were sold.

9. INCOME TAXES

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

	Years Ended December 31,		
(in thousands)	2016	2015	2014
Current taxes:			
Federal expense	$ —	$ 14,417	$ —
State (benefit) expense	(1,115)	293	404
	(1,115)	14,710	404
Deferred taxes:			
Federal (benefit) expense	(213,508)	(1,294,194)	282,729
State (benefit) expense	(12,592)	(93,952)	15,564
	(226,100)	(1,388,146)	298,293
	$ (227,215)	$ (1,373,436)	$ 298,697

Federal income tax expense (benefit) for the years presented differs from the amounts that would be provided by applying the U.S. federal income tax rate, primarily due to the effect of state income taxes, non-deductible expenses and revisions. Reconciliations of the income tax expense (benefit) calculated at the federal statutory rate of 35% to the total income tax expense (benefit) are as follows:

	Years Ended December 31,		
(in thousands)	2016	2015	2014
Provision at statutory rate	$ (230,393)	$ (1,323,834)	$ 282,066
Effect of state taxes	(10,780)	(60,634)	15,826
Revision of previous balances	7,181	5,997	—
Other permanent differences	5,296	5,035	805
Change in valuation allowance	1,481	—	—
Income tax expense (benefit)	$ (227,215)	$ (1,373,436)	$ 298,697

The components of net deferred tax liabilities are as follows:

(in thousands)	December 31, 2016	December 31, 2015
Assets:		
Stock compensation and other accrued amounts	$ 58,306	$ 32,084
Net operating loss carryforward, net of valuation allowance	399,912	305,506
Credit carryforward	6,016	6,016
	464,234	343,606
Liabilities:		
Property, plant and equipment	(591,128)	(696,311)
Net deferred tax liabilities	$ (126,894)	$ (352,705)

At December 31, 2016, we had a U.S. net tax operating loss carryforward of approximately $1,182.4 million, which would expire in years 2031 through 2036. We believe that the carryforward will be utilized before it expires. We recorded a $10.4 million increase to the net operating loss carryforward at December 31, 2016, for certain state losses and a corresponding increase in the state net operating loss valuation allowance of $11.9 million. The net decrease in the state net operating losses after reduction for the valuation allowance was $1.5 million. The total valuation allowance on state net operating losses at December 31, 2016, was $82.0 million because it is not more likely than not that these additional state net operating losses will be utilized before they expire. Approximately $90.9 million of the U.S. net tax operating loss carryforward is attributable to deductions taken for employee stock awards on the Company's tax returns in excess of amounts expensed through the Company's income statement. We also had an alternative minimum tax credit carryforward of approximately $6.0 million.

At December 31, 2016 and 2015, we had no unrecognized tax benefits that would impact our effective rate and we have made no provisions for interest or penalties related to uncertain tax positions. The tax years 2013 through 2015 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 tax years 2012 through 2015.

10. COMMITMENTS AND CONTINGENCIES

Lease Commitments

We have various commitments for office space and equipment under operating lease arrangements. Rent expense for the operating leases totaled $12.9 million in 2016. Rent expense was $13.2 million and $14.3 million for 2015 and 2014, respectively.

Shown below are future minimum cash payments required under these leases as of December 31, 2016.

(in thousands)	Operating Leases
2017	$ 9,585
2018	10,531
2019	10,677
2020	10,864
2021	11,085
Later years	44,181
Total future minimum lease payments	$ 96,923

Other Commitments

We have commitments of $157.5 million to finish drilling and completing wells in progress at December 31, 2016.

At December 31, 2016, we had firm sales contracts to deliver approximately 46.4 Bcf of natural gas over the next twenty-two months. If this gas is not delivered, our financial commitment would be approximately $164.8 million. This commitment will fluctuate due to price volatility and actual volumes delivered. However, we believe no financial commitment will be due based on our current proved reserves and production levels from which we can fulfill these obligations.

In connection with gas gathering and processing agreements, we have volume commitments over the next ten years. At December 31, 2016, if no gas is delivered, the maximum amount that would be payable under these commitments would be approximately $220.0 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 minimum volume delivery commitments in connection with agreements to reimburse connection costs to various pipelines. At December 31, 2016, the maximum amount that would be payable if no gas is delivered would be approximately $7.9 million. Of this total, we have accrued a liability of $2.1 million. We may have additional liabilities associated with these delivery commitments in the future depending on our production levels and drilling results.

We have other various transportation, delivery, and facilities commitments in the normal course of business, which approximate $35.7 million at December 31, 2016. We currently anticipate meeting these obligations.

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

Litigation

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

H.B. Krug, et al. v. Helmerich & Payne, Inc.

In 2008, we recorded litigation expense of $119.6 million for the *H.B. Krug, et al. v. Helmerich & Payne, Inc.* trial court verdict, and began accruing additional post-judgment interest and costs for this case.

On December 13, 2013, the Oklahoma Supreme Court reversed the trial court's $119.6 million verdict and affirmed an alternative jury verdict for $3.65 million. The Supreme Court also remanded the case back to the trial court for consideration of potential prejudgment interest, attorney's fees and cost awards. Accordingly, on December 31, 2013 we reduced the previously recognized litigation expense, which included related interest and costs, and the associated long-term liability by $142.8 million.

On April 1, 2014, Cimarex paid the Plaintiffs $15.8 million in satisfaction of the $3.65 million damages award, the post-judgment interest award and the payment in lieu of bond, all of which are now final and not appealable. On June 24, 2014, the trial court ruled the Plaintiffs were not entitled to prejudgment interest but were entitled to attorney's fees and costs, the amount of which will be determined at a subsequent hearing. On November 3, 2015, the Oklahoma Supreme Court affirmed the trial court's denial of prejudgment interest. The only remaining issue is the amount of Plaintiffs' award of attorney's fees, which is subject to future trial and appellate court proceedings and, therefore, cannot be determined at this time.

11. RELATED PARTY TRANSACTIONS

Helmerich & Payne, Inc. (H&P) provides contract drilling services to Cimarex. Drilling costs of approximately $18.3 million were incurred by Cimarex related to such services for 2016. During 2015 and 2014, such costs were $7.9 million and $18.4 million, respectively. Hans Helmerich, a director of Cimarex, is Chairman of the Board of Directors of H&P.

Lisa Stewart, who joined Cimarex's Board of Directors in October 2015, is Chairman, President, Chief Executive Officer, and Chief Investment Officer of Sheridan Production Partners (Sheridan). During 2016, Cimarex paid certain affiliates of Sheridan oil and gas revenues of $177.6 thousand and joint interest billings of $5.2 thousand and received oil and gas revenues of $0.4 thousand and joint interest billings of $73.1 thousand from Sheridan affiliates. During 2015, Cimarex paid certain affiliates of Sheridan oil and gas revenues of $224.2 thousand and joint interest billings of $10.4 thousand and received oil and gas revenues of $4.1 thousand and joint interest billings of $81.5 thousand from Sheridan affiliates.

Jerry Box, a director of Cimarex whose term expired May 2015, was the non-executive Chairman of the Board of Directors of Newpark Resources, Inc. (Newpark) through May 2014. Certain subsidiaries of Newpark provided various drilling services to Cimarex. Costs of such services were $589.2 thousand through May 2014.

12. PROPERTY SALES AND ACQUISITIONS

The following sales and acquisitions were made in the ordinary course of business. All amounts are net of customary purchase price adjustments.

There were no significant sales and acquisitions in 2016 or 2015. We sold interests in various non-core oil and gas properties for $446.1 million during 2014. Most of the proceeds were related to sales of producing gas wells in southwestern Kansas and undeveloped acreage in Reagan County, Texas. During 2014, we made property acquisitions totaling $249.7 million, most of which were in our Cana area in Western Oklahoma.

13. SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

	Years Ended December 31,		
(in thousands)	**2016**	**2015**	**2014**
Cash paid during the period for:			
Interest expense (including capitalized amounts)	$ 79,590	$ 80,785	$ 66,167
Interest capitalized	$ 20,308	$ 28,819	$ 32,623
Income taxes	$ 13	$ 558	$ 354
Cash received for income tax refunds	$ 1,450	$ 1,503	$ 460

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)

Oil and Gas Reserve Information—Proved reserve quantities are based on estimates prepared by Cimarex in accordance with guidelines established by the Securities and Exchange Commission (SEC).

Reserve definitions comply with definitions of Rule 4-10(a) (1)-(32) of Regulation S-X of the SEC. All of our reserve estimates are maintained by our internal Corporate Reservoir Engineering group, which is comprised of reservoir engineers and engineering technicians. The objectives and management of this group are separate from and independent of the exploration and production functions of our company. The technical employee primarily responsible for overseeing the reserve estimation process is our company's Vice President of Corporate Engineering. This individual graduated from the Colorado School of Mines with a Bachelor of Science degree in Engineering and has more than 22 years of practical experience in reserve evaluation. He has been directly involved in the annual reserve reporting process of Cimarex since 2002 and has served in his current role for the past twelve years.

DeGolyer and MacNaughton, an independent petroleum engineering consulting firm, reviewed reserves associated with greater than 80% of the total future net revenue discounted at 10% attributable to the total interests owned by Cimarex as of December 31, 2016. The individual primarily responsible for overseeing the review is a Senior Vice President with DeGolyer and MacNaughton and a Registered Professional Engineer in the State of Texas with over 37 years of experience in oil and gas reservoir studies and evaluations.

Proved reserves are those quantities of oil, NGL, and gas, which, by analysis of geosciences and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

There are numerous uncertainties inherent in estimating quantities of proved reserves and projecting future rates of production and the timing of development expenditures. The estimation of our proved reserves employs one or more of the following: production trend extrapolation, analogy, volumetric assessment, and material balance analysis. Techniques including review of production and pressure histories, analysis of electric logs and fluid tests, and interpretations of geologic and geophysical data also are involved in this estimation process.

The following table summarizes the trailing 12-month index prices used in the reserve estimates for 2016, 2015, and 2014. These prices are prior to adjustments for fixed and determinable amounts under provisions in existing contracts, location, grade and quality.

	December 31,		
	2016	2015	2014
Gas price per Mcf	$ 2.48	$ 2.59	$ 4.35
Oil price per Bbl	$ 42.75	$ 50.28	$ 94.99
NGL price per Bbl	$ 14.37	$ 14.41	$ 30.89

The following reserve data represents estimates only and should not be construed as being exact.

	Gas (MMcf)	Oil (MBbl)	NGL (MBbl)	Total (MMcfe)
Total proved reserves:				
December 31, 2013	1,293,500	108,533	92,044	2,496,964
Revisions of previous estimates	85,533	(1,039)	4,262	104,873
Extensions and discoveries	420,442	29,155	36,424	813,911
Purchases of reserves	88,227	1,383	6,186	133,641
Production	(155,128)	(15,639)	(11,343)	(317,022)
Sales of properties	(65,841)	(3,401)	(2,300)	(100,044)
December 31, 2014	1,666,733	118,992	125,273	3,132,323
Revisions of previous estimates	(154,390)	(14,633)	(5,668)	(276,192)
Extensions and discoveries	183,084	22,859	18,079	428,714
Purchases of reserves	15	1	1	25
Production	(168,987)	(18,663)	(13,063)	(359,343)
Sales of properties	(9,503)	(758)	(345)	(16,120)
December 31, 2015	1,516,952	107,798	124,277	2,909,407
Revisions of previous estimates	5,888	(4,357)	6,670	19,761
Extensions and discoveries	123,175	19,419	14,050	323,987
Purchases of reserves	959	1	—	965
Production	(168,227)	(16,528)	(14,200)	(352,591)
Sales of properties	(7,327)	(455)	(164)	(11,042)
December 31, 2016	1,471,420	105,878	130,633	2,890,487
Proved developed reserves:				
December 31, 2013	1,060,704	86,665	69,089	1,995,233
December 31, 2014	1,263,957	100,050	89,630	2,402,033
December 31, 2015	1,129,490	89,189	87,549	2,189,920
December 31, 2016	1,144,720	92,032	99,176	2,291,966
Proved undeveloped reserves:				
December 31, 2013	232,796	21,868	22,955	501,731
December 31, 2014	402,776	18,942	35,643	730,290
December 31, 2015	387,462	18,609	36,728	719,487
December 31, 2016	326,700	13,846	31,457	598,521

Year-end 2016 proved reserves declined by less than 1% from year-end 2015 proved reserves, to 2.89 Tcfe. Proved natural gas reserves were 1.47 Tcf, proved oil reserves were 0.64 Tcfe, and proved NGL reserves were 0.78 Tcfe. Our reserves in the Mid-Continent accounted for 63% of total proved reserves, with the majority of the remainder in the Permian Basin.

During 2016, we added 324.0 Bcfe of proved reserves through extensions and discoveries, primarily in the Mid-Continent and Permian Basin, where we added 121.6 Bcfe and 198.7 Bcfe, respectively. In addition, we had net positive revisions of 19.8 Bcfe. The revisions included increases of 126.2 Bcfe for net performance revisions and 138.5 Bcfe related to decreases in operating expenses, partially offset by negative revisions of 244.9 Bcfe due to lower commodity prices. The performance revisions resulted primarily from positive adjustments to previously booked PUD reserves (72.3 Bcfe) and better than expected performance from wells with initial production in late 2015.

During 2015, we added 428.7 Bcfe of proved reserves through extensions and discoveries, primarily in the Mid-Continent and Permian Basin, where we added 176.8 Bcfe and 251.1 Bcfe, respectively. During 2015, we had net negative reserve revisions of 276.2 Bcfe. The significant decrease in commodity prices seen in 2015 resulted in negative revisions of 398.8 Bcfe due to prices. In addition, 19.1 Bcfe of negative revisions were due to increases in operating expenses, which shortened the economic lives of properties. These decreases were partially offset by net positive performance revisions of 141.7 Bcfe, which included 47.4 Bcfe for better than expected performance of PUD reserves converted to proved developed reserves during the year and positive adjustments of 95.3 Bcfe to previously booked PUD reserves.

During 2014, we added 813.9 Bcfe of proved reserves through extensions and discoveries, primarily in the Mid-Continent and Permian Basin. In the Mid-Continent, we added 80.4 Bcfe from wells drilled and added 496.6 Bcfe of PUD reserves in our Cana area. In the Permian Basin, development drilling added 234.3 Bcfe.

During 2014, we had net positive reserve revisions of 104.9 Bcfe. Performance revisions were a net positive of approximately 113.4 Bcfe. This net increase was due to better than expected performance of PUD reserves converted to proved developed reserves during the year (124.7 Bcfe) and positive adjustments to previously booked PUD reserves (10.1 Bcfe), offset by 21.4 Bcfe of net negative revisions primarily attributed to Cana area wells impacted by infill drilling. Additionally, there were positive price revisions of 16.1 Bcfe, offset by negative revisions of 24.6 Bcfe due to increases in operating expenses, which shortened the economic lives of properties.

At December 31, 2016, we had PUD reserves of 598.5 Bcfe, down 121.0 Bcfe, or 17%, from 719.5 Bcfe of PUD reserves at December 31, 2015. Changes in our PUD reserves are summarized in the table below (in Bcfe).

PUD reserves at December 31, 2015	719.5
Converted to developed	(104.3)
Additions	35.6
Net revisions	(52.3)
PUD reserves at December 31, 2016	598.5

During 2016, we invested $97.7 million to develop and convert 14% of our 2015 PUD reserves to proved developed reserves. Additionally, in 2016 we invested $11.1 million to develop 2015 PUD reserves that were waiting on completion at year-end and had not yet been converted to proved developed reserves. During 2015, we invested $246.5 million to develop PUD reserves, converting 24% of our 2014 PUD reserves to proved developed reserves. During 2014, we invested $503.5 million to develop PUD reserves, converting 56% of our 2013 PUD reserves to proved developed reserves.

All 35.6 Bcfe of our 2016 PUD reserve additions occurred in our western Oklahoma Cana area. At December 31, 2016, all of our PUD reserves are associated with this area. We have no PUD reserves that have remained undeveloped for five years or more after initial booking and we have no PUD reserves whose scheduled delay to initiation of development is beyond five years of initial booking.

During 2016, we had net negative PUD reserve revisions of 52.3 Bcfe. This included 127.3 Bcfe removed due to lower commodity prices partially offset by positive technical adjustments of 72.3 Bcfe to remaining previously booked PUD reserves. Further, negative additional price revisions of 7.8 Bcfe to remaining PUD reserves were more than offset by 10.5 Bcfe of positive revisions due to lower projected operating expenses.

Costs Incurred—The following table sets forth the capitalized costs incurred in our oil and gas production, exploration, and development activities.

	Years Ended December 31,		
(in thousands)	**2016**	**2015**	**2014**
Costs incurred during the year:			
Acquisition of properties			
Proved	$ 2,678	$ 30	$ 138,508
Unproved	67,961	41,233	277,099
Exploration	5,814	6,902	50,271
Development	672,842	823,830	1,664,877
Oil and gas expenditures	749,295	871,995	2,130,755
Property sales	(24,687)	(41,276)	(446,107)
	724,608	830,719	1,684,648
Asset retirement obligation, net	(7,950)	(4,818)	27,243
	$ 716,658	$ 825,901	$ 1,711,891

Aggregate Capitalized Costs—The table below reflects the aggregate capitalized costs relating to our oil and gas producing activities at December 31, 2016.

(in thousands)		
Proved properties	$	16,225,495
Unproved properties and properties under development, not being amortized		478,277
		16,703,772
Less-accumulated depreciation, depletion, amortization, and impairments		(13,849,701)
Net oil and gas properties	$	2,854,071

Costs Not Being Amortized—The following table summarizes oil and gas property costs not being amortized at December 31, 2016, by year that the costs were incurred.

(in thousands)		
2016	$	234,905
2015		42,808
2014		114,746
2013 and prior		85,818
	$	478,277

Of the costs not being amortized, $173.5 million (36%) relates to unevaluated wells in progress and $48.5 million (10%) is capitalized interest. The remaining $256.3 million (54%) is for land and seismic expenditures, most of which were for costs invested in our Mid-Continent region ($136.9 million) and our Permian Basin region ($91.6 million). On a quarterly basis, we evaluate excluded costs for inclusion in the costs to be amortized. Significant unproved properties are evaluated individually. Unproved properties that are not considered individually significant are aggregated for evaluation purposes and related costs are transferred to the costs to be amortized quarterly based on the application of historical factors. We expect to include these costs in the amortization computation as we continue with our exploration and development plans.

Oil and Gas Operations—The following table contains direct revenue and cost information relating to our oil and gas exploration and production activities for the periods indicated. We have no long-term supply or purchase agreements with governments or authorities in which we act as producer. Income tax expense related to our oil and gas operations is computed using the effective tax rate for the period.

	Years Ended December 31,		
(in thousands, except per Mcfe)	**2016**	**2015**	**2014**
Oil, gas and NGL revenues from production	$ 1,221,218	$ 1,417,538	$ 2,372,829
Less operating costs and income taxes:			
Impairment of oil and gas properties	719,142	3,716,883	—
Depletion	419,591	736,583	773,817
Asset retirement obligation	7,828	9,121	10,082
Production	232,002	299,374	342,304
Transportation, processing and other operating	210,144	183,134	215,246
Taxes other than income	61,946	84,764	128,793
Income tax expense (benefit)	(148,155)	(1,311,634)	334,499
	1,502,498	3,718,225	1,804,741
Results of operations from oil and gas producing activities	$ (281,280)	$ (2,300,687)	$ 568,088
Depletion rate per Mcfe	$ 1.19	$ 2.05	$ 2.44

Standardized Measure of Future Net Cash Flows—The "Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves" (Standardized Measure) is calculated in accordance with guidance provided by the FASB. The Standardized Measure does not purport, nor should it be interpreted, to present the fair value of a company's proved oil and gas reserves. Fair value would require, among other things, consideration of expected future economic and operating conditions, varying price and cost assumptions, and risks inherent in reserve estimates.

Under the Standardized Measure, future cash inflows are based upon the forecasted future production of year-end proved reserves. Future cash inflows are then reduced by estimated future production and development costs to determine net pre-tax cash flow. Future income taxes are computed by applying the statutory tax rate to the excess of pre-tax cash flow over our tax basis in the associated oil and gas properties. Tax credits and permanent differences are also considered in the future income tax calculation. Future net cash flow after income taxes is discounted using a 10% annual discount rate to arrive at the Standardized Measure.

The following summary sets forth our Standardized Measure.

	December 31,		
(in thousands)	**2016**	**2015**	**2014**
Cash inflows	$ 7,576,211	$ 8,839,485	$ 19,892,471
Production costs	(2,970,891)	(3,521,881)	(5,777,710)
Development costs	(794,298)	(1,058,020)	(1,453,860)
Income tax expense	(507,145)	(728,029)	(3,768,780)
Net cash flow	3,303,877	3,531,555	8,892,121
10% annual discount rate	(1,411,259)	(1,597,424)	(4,539,276)
Standardized measure of discounted future net cash flow	$ 1,892,618	$ 1,934,131	$ 4,352,845

The estimates of cash flows and reserve quantities shown above are based upon the unweighted average 12 month first-day-of-the-month benchmark prices. See table above under ***Oil and Gas Reserve Information*** for prices used in determining the Standardized Measure. If future gas sales are covered by contracts at specified prices, the contract prices would be used. Prices are market driven and will fluctuate due to supply and demand factors, seasonality, and geopolitical and economic factors.

The following are the principal sources of change in the Standardized Measure.

	December 31,		
(in thousands)	**2016**	**2015**	**2014**
Standardized Measure, beginning of period	$ 1,934,131	$ 4,352,845	$ 3,598,894
Sales, net of production costs	(717,126)	(850,267)	(1,686,486)
Net change in sales prices, net of production costs	(429,956)	(4,262,261)	(176,200)
Extensions and discoveries, net of future production and development costs	517,702	573,373	1,633,285
Changes in future development costs	167,387	280,163	23,025
Previously estimated development costs incurred during the period	110,945	214,749	442,780
Revision of quantity estimates	15,701	(240,063)	230,673
Accretion of discount	227,904	638,948	520,058
Change in income taxes	115,609	1,691,721	(434,949)
Purchases of reserves in place	429	20	228,539
Sales of properties	(9,440)	(26,225)	(185,326)
Change in production rates and other	(40,668)	(438,872)	158,552
Standardized Measure, end of period	$ 1,892,618	$ 1,934,131	$ 4,352,845

SUPPLEMENTAL QUARTERLY FINANCIAL DATA (UNAUDITED)

2016	**Quarter**			
	First	**Second**	**Third**	**Fourth**
(in thousands, except for per share data)				
Revenues	$ 240,600	$ 298,873	$ 335,717	$ 382,155
Expenses, net (1)	426,731	569,163	348,535	343,965
Net income (loss)	$ (186,131)	$ (270,290)	$ (12,818)	$ 38,190
Earnings (loss) per share to common stockholders:				
Basic:				
Distributed	$ 0.08	$ 0.08	$ 0.08	$ 0.08
Undistributed	(2.08)	(2.99)	(0.22)	0.32
	$ (2.00)	$ (2.91)	$ (0.14)	$ 0.40
Diluted:				
Distributed	$ 0.08	$ 0.08	$ 0.08	$ 0.08
Undistributed	(2.08)	(2.99)	(0.22)	0.32
	$ (2.00)	$ (2.91)	$ (0.14)	$ 0.40

(1) The 2016 quarterly expenses, net include non-cash impairments to our oil and gas properties of $230.1 million (or $1.57 per diluted share), $399.2 million (or $2.73 per diluted share), and $89.8 million (or $0.61 per diluted share) for the first quarter through the third quarter of 2016, respectively, as discussed in Note 1 to the Consolidated Financial Statements under ***Oil and Gas Properties***.

2015	**Quarter**			
	First	**Second**	**Third**	**Fourth**
(in thousands, except for per share data)				
Revenues	$ 361,002	$ 424,283	$ 356,055	$ 311,279
Expenses, net (1)	775,943	1,024,498	1,119,339	941,787
Net loss	$ (414,941)	$ (600,215)	$ (763,284)	$ (630,508)
Earnings (loss) per share to common stockholders:				
Basic:				
Distributed	$ 0.16	$ 0.16	$ 0.16	$ 0.16
Undistributed	(5.00)	(6.63)	(8.37)	(6.94)
	$ (4.84)	$ (6.47)	$ (8.21)	$ (6.78)
Diluted:				
Distributed	$ 0.16	$ 0.16	$ 0.16	$ 0.16
Undistributed	(5.00)	(6.63)	(8.37)	(6.94)
	$ (4.84)	$ (6.47)	$ (8.21)	$ (6.78)

(1) The 2015 quarterly expenses, net include non-cash impairments to our oil and gas properties of $603.6 million (or $4.47 per diluted share), $967.3 million (or $6.62 per diluted share), $1.2 billion (or $8.07 per diluted share) and $965.3 million (or $6.60 per diluted share) for the first quarter through the fourth quarter of 2015, respectively, as discussed in Note 1 to the Consolidated Financial Statements under ***Oil and Gas Properties***.

The sum of the individual quarterly net income per common share amounts does not agree with year-to-date net income per common share because each quarter's computation is based on the number of shares outstanding at the end of the applicable quarter using the two-class method.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

Cimarex's management, under the supervision and with the participation of the Chief Executive Officer (CEO) and Chief Financial Officer (CFO), have evaluated the effectiveness of Cimarex's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the Exchange Act)) as of December 31, 2016. 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 our most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Cimarex's management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act). The company's internal control over financial reporting is a process designed by, or under the supervision of, the CEO and CFO to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements in accordance with generally accepted accounting principles.

Because of the inherent limitations of internal control over financial reporting, misstatements may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

As of December 31, 2016, management assessed the effectiveness of the company's internal control over financial reporting based on the criteria established in "Internal Control-Integrated Framework (2013)," issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that assessment, management concluded that the company's internal control over financial reporting was effective as of December 31, 2016.

Our independent registered public accounting firm has audited, and reported on, the effectiveness of our internal control over financial reporting as of December 31, 2016, which follows this report.

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders

Cimarex Energy Co.:

We have audited Cimarex Energy Co. and subsidiaries' internal control over financial reporting as of December 31, 2016, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Cimarex Energy Co. and subsidiaries' management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on Cimarex Energy Co. and subsidiaries' internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Cimarex Energy Co. and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Cimarex Energy Co. and subsidiaries as of December 31, 2016 and 2015, and the related consolidated statements of operations and comprehensive income (loss), stockholders' equity, and cash flows for each of the years in the three year period ended December 31, 2016, and our report dated February 24, 2016 expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP

Denver, Colorado
February 24, 2017

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information concerning the directors of Cimarex required under this item is incorporated by reference from the Cimarex Energy Co. definitive Proxy Statement for the May 11, 2017 Annual Meeting of Shareholders. The Proxy Statement will be filed with the Securities and Exchange Commission no later than 120 days subsequent to December 31, 2016. The executive officers of Cimarex as of February 24, 2017 were:

Name	Age	Office
Thomas E. Jorden	59	Chairman of the Board, Chief Executive Officer and President
Joseph R. Albi	58	Executive Vice President – Operations, Chief Operating Officer
Stephen P. Bell	62	Executive Vice President – Business Development
G. Mark Burford	49	Vice President and Chief Financial Officer
Francis B. Barron	54	Senior Vice President – General Counsel
John A. Lambuth	54	Senior Vice President – Exploration
Gary R. Abbott	44	Vice President – Corporate Engineering
Krista L. Johnson	46	Vice President – Human Resources, Governmental Relations, and External Affairs
Timothy A. Ficker	49	Vice President – Controller, Chief Accounting Officer, and Assistant Secretary

There are no family relationships by blood, marriage, or adoption among any of the above executive officers. All executive officers are elected annually by the board of directors to serve for one year or until a successor is elected and qualified. There is no arrangement or understanding between any of the officers and any other person pursuant to which he or she was selected as an executive officer.

THOMAS E. JORDEN was elected Chairman of the Board effective August 14, 2012 after being named President and Chief Executive Officer effective September 30, 2011. Since December 8, 2003, Mr. Jorden served as Executive Vice President of Exploration and had served in a similar capacity since September 30, 2002. Prior to September 2002, Mr. Jorden was with Key Production Company, Inc., where he served as Vice President of Exploration (October 1999 to September 2002) and Chief Geophysicist (November 1993 to September 1999). Prior to joining Key, Mr. Jorden was with Union Pacific Resources.

JOSEPH R. ALBI was named Executive Vice President and Chief Operating Officer effective September 30, 2011. Mr. Albi served as Executive Vice President of Operations since March 1, 2005. Since December 8, 2003, Mr. Albi served as Senior Vice President of Corporate Engineering. From September 30, 2002 to December 8, 2003, he served as Vice President of Engineering. From June 1994 to September 2002, Mr. Albi was with Key Production Company, Inc. where he served as Vice President of Engineering and Manager of Engineering.

STEPHEN P. BELL was named Executive Vice President, Business Development effective September 13, 2012. Since September 2002, Mr. Bell served as Senior Vice President of Business Development and Land. Prior to its merger with Cimarex, Mr. Bell was with Key Production Company, Inc. since February 1994. In September 1999, he was appointed Senior Vice President, Business Development and Land. From February 1994 to September 1999, he served as Vice President, Land.

G. MARK BURFORD was named Vice President and Chief Financial Officer in September 2015. He was appointed Vice President, Capital Markets and Planning in December 2010. Mr. Burford joined Cimarex in April 2005 as Director of Capital Markets. Prior to joining Cimarex, he was Director of Investor Relations for Whiting Petroleum and Tom Brown, Inc. His experience also includes equity research with Petrie Parkman & Co., an investment banking firm, and public accounting.

FRANCIS B. BARRON joined Cimarex as Senior Vice President, General Counsel in July 2013. From February 2004 until July 2013, Mr. Barron served in various capacities at Bill Barrett Corporation, a publicly traded, Denver-based oil and gas exploration and development company, including as Executive Vice President, General Counsel and Secretary. He also served as Chief Financial Officer from November 2006 until March 2007. Prior to February 2004, Mr. Barron was a partner at the Denver, Colorado office of the law firm of Patton Boggs LLP as well as a partner at Bearman Talesnick & Clowdus Professional Corporation. Mr. Barron's practice included corporate, securities and business law for publicly traded oil and gas companies.

JOHN LAMBUTH was named Senior Vice President of Exploration in December 2015. Prior to his promotion, he served as the Company's Vice President of Exploration since September 2012 and Chief Geophysicist, a position he held since joining Cimarex in 2004. Mr. Lambuth began his career in 1985 with Shell Oil Co., where he held various positions in exploration and in research and development. Immediately prior to joining Cimarex, he spent three years as onshore Exploration Manager of El Paso Energy Company.

GARY R. ABBOTT was elected Vice President of Corporate Engineering March 1, 2005. Since January 2002, Mr. Abbott served as manager, Corporate Reservoir Engineering. From April 1999 to January 2002, Mr. Abbott was a reservoir engineer with Key Production Company, Inc.

KRISTA L. JOHNSON joined Cimarex as Vice President of Governmental and External Affairs in November 2014. Previously she served at Shell Oil Company since 2006, her last role as Vice President, International Organizations. Prior to joining Shell, she spent eight years with Western Gas Resources, most recently as Director of Government and Media Relations. Her experience also includes private practice in oil and gas law, client based energy advocacy in Washington, work in the Federal Relations Department of the American Petroleum Institute, and in the office of former U.S. Senator Conrad Burns.

TIMOTHY A. FICKER was appointed Vice President, Controller, Chief Accounting Officer, and Assistant Secretary in December 2016 to be effective in February 2017 and previously served as the Company's Controller since September 2016. From February 2015 until September 2016, he served as Chief Financial Officer and Principal of Alcova Management LLC, a start-up oil and gas exploration and production company concentrating on the Powder River Basin of Wyoming. Mr. Ficker served as Chief Financial Officer of Venoco, Inc., and in other capacities from March 2007 to November 2014. From May 2005 to March 2007, he served as Vice President, Chief Financial Officer, Principal Accounting Officer and Secretary of Infinity Energy Resources Inc. Mr. Ficker previously served as an audit partner in KPMG LLP's energy audit practice in Denver and as an audit partner for Arthur Andersen LLP, where he served clients primarily in the energy industry. His energy clients at KPMG and Arthur Andersen were principally domestic exploration and production companies.

ITEM 11. EXECUTIVE COMPENSATION

Information required under this item is incorporated by reference from the Cimarex Energy Co. definitive Proxy Statement for the May 11, 2017 Annual Meeting of Shareholders. The Proxy Statement will be filed with the Securities and Exchange Commission no later than 120 days subsequent to December 31, 2016.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information required under this item is incorporated by reference from the Cimarex Energy Co. definitive Proxy Statement for the May 11, 2017 Annual Meeting of Shareholders. The Proxy Statement will be filed with the Securities and Exchange Commission no later than 120 days subsequent to December 31, 2016.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information required under this item is incorporated by reference from the Cimarex Energy Co. definitive Proxy Statement for the May 11, 2017 Annual Meeting of Shareholders. The Proxy Statement will be filed with the Securities and Exchange Commission no later than 120 days subsequent to December 31, 2016.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information required under this item is incorporated by reference from the Cimarex Energy Co. definitive Proxy Statement for the May 11, 2017 Annual Meeting of Shareholders. The Proxy Statement will be filed with the Securities and Exchange Commission no later than 120 days subsequent to December 31, 2016.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

Exhibits not incorporated by reference to a prior filing are designated by an asterisk (*) and are filed herewith; all exhibits not so designated are incorporated by reference to a prior SEC filing as indicated.

Exhibit	Title
3.1	Amended and Restated Certificate of Incorporation of Cimarex Energy Co. (filed as Exhibit 3.1 to Registrant's Form 8-K (Commission File no. 001-31446) dated June 7, 2005 and incorporated herein by reference).
3.2	Amended and Restated By-laws of Cimarex Energy Co. dated December 11, 2013 (filed on December 16, 2013 (Commission File No. 001-31446) and incorporated herein by reference).
3.3	Amended and Restated By-laws of Cimarex Energy Co. dated November 11, 2015 (filed as Exhibits 3.1 and 3.2 to the Current Report on Form 8-K filed on November 12, 2015 (Commission File No. 001-31446) and incorporated herein by reference).
4.1	Specimen Certificate of Cimarex Energy Co. common stock (filed as Exhibit 4.3 to Registration Statement on Form S-3 filed September 17, 2012 (Registration No. 333-183939) and incorporated herein by reference).
4.2	Debt Securities Indenture dated as of April 5, 2012, by and among Cimarex Energy Co. and U.S. Bank National Association, as trustee included as Exhibit 4.1 to Registrant's Current Report on Form 8-K filed on April 5, 2012 and incorporated herein by reference.
4.3	First Supplemental Indenture dated as of April 5, 2012, by and among Cimarex Energy Co., the Subsidiary Guarantors party thereto and U.S. Bank National Association, as trustee included as Exhibit 4.2 to Registrant's Current Report on Form 8-K filed on April 5, 2012 and incorporated herein by reference.
4.4	Form of 5.875% Senior Notes due 2022 included in Exhibit 4.3 to the Registrant's Current Report on Form 8-K filed on April 5, 2012 and incorporated herein by reference.
4.5	Indenture dated as of June 4, 2014, by and between Cimarex Energy Co. and U.S. Bank National Association, as trustee included as Exhibit 4.1 to Registrant's Current Report on Form 8-K filed on June 4, 2014 and incorporated herein by reference.
4.6	First Supplemental Indenture dated as of June 4, 2014, by and among Cimarex Energy Co., the Subsidiary Guarantors party thereto and U.S. Bank National Association, as trustee included as Exhibit 4.2 to Registrant's Current Report on Form 8-K filed on June 4, 2014 and incorporated herein by reference.

4.7 Form of 4.375% Senior Notes due 2024 included in Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed on June 4, 2014 and incorporated herein by reference.

4.8 Form of Indenture by and among Cimarex Energy Co. and U.S. Bank National Association, as trustee (filed as Exhibit 4.7 to Registration Statement on Form S-3 filed September 21, 2015 (Registration No. 333-183939) and incorporated herein by reference).

10.1 Credit Agreement dated as of July 14, 2011, among Cimarex, the Administrative Agent, the Co-Syndication Agents, the Co-Documentation Agents and the Lenders filed on July 18, 2011 as Exhibit 10.l to the Registrant's Current Report on Form 8-K and incorporated herein by reference.

10.2 First Amendment to Credit Agreement dated as of July 19, 2012, among Cimarex, the Guarantors, the Administrative Agent, and the Lenders filed on May 5, 2014 as Exhibit 10.1 to the Registrant's Current Report on Form 8-K and incorporated herein by reference.

10.3 Second Amendment to Credit Agreement dated as of May 1, 2014, among Cimarex, the Guarantors, the Administrative Agent, and the Lenders filed on May 5, 2014 as Exhibit 10.2 to the Registrant's Current Report on Form 8-K and incorporated herein by reference.

10.4 Employment Agreement, dated September 7, 1999, by and between Paul Korus and Key Production Company, Inc. (filed as Exhibit 10.6 to the Registration Statement on Form S-4 dated May 9, 2002 (Registration No. 333-87948) and incorporated herein by reference).

10.5 Amendment to Employment Agreement effective January 1, 2009 between Cimarex Energy Co. and Paul Korus (filed as Exhibit 10.9 to the Annual Report on Form 10-K for the year ended December 31, 2008 filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

10.6 Employment Agreement, dated October 25, 1993, by and between Thomas E. Jorden and Key Production Company, Inc. (filed as Exhibit 10.7 to the Registration Statement on Form S-4 dated May 9, 2002 (Registration No. 333-87948) and incorporated herein by reference).

10.7 Amendment to Employment Agreement effective January 1, 2009 between Cimarex Energy Co. and Thomas E. Jorden (filed as Exhibit 10.11 to the Annual Report on Form 10-K for the year ended December 31, 2008 filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

10.8 Employment Agreement, dated February 2, 1994, by and between Stephen P. Bell and Key Production Company, Inc. (filed as Exhibit 10.8 to the Registration Statement on Form S-4 dated May 9, 2002 (Registration No. 333-87948) and incorporated herein by reference).

10.9 Amendment to Employment Agreement effective January 1, 2009 between Cimarex Energy Co. and Stephen P. Bell (filed as Exhibit 10.13 to the Annual Report on Form 10-K for the year ended December 31, 2008 filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

10.10 Employment Agreement, dated March 11, 1994, by and between Joseph R. Albi and Key Production Company, Inc. (filed as Exhibit 10.9 to the Registration Statement on Form S-4 dated May 9, 2002 (Registration No. 333-87948) and incorporated herein by reference).

10.11 Amendment to Employment Agreement effective January 1, 2009 between Cimarex Energy Co. and Joseph R. Albi (filed as Exhibit 10.15 to the Annual Report on Form 10-K for the year ended December 31, 2008 filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

10.12 Amended and Restated 2002 Stock Incentive Plan of Cimarex Energy Co. effective January 1, 2009 (filed as Exhibit 10.16 to the Annual Report on Form 10-K for the year ended December 31, 2008 filed on February 27, 2009 (Commission File No. 001- 31446) and incorporated herein by reference).

10.13 2011 Equity Incentive Plan adopted May 18, 2011 (filed as Appendix A to the Definitive Proxy Statement 14-A filed on March 23, 2011 (Commission File No. 001-31446) and incorporated herein by reference).

10.14 Form of Notice of Grant of Award of Performance Stock and Award Agreement (filed as Exhibit 10.2 to Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011 filed on August 4, 2011 (Commission File no. 001-31446) and incorporated herein by reference).

10.15 Form of Notice of Grant of Restricted Stock and Award Agreement (filed as Exhibit 10.3 to Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011 filed on August 4, 2011 (Commission File no. 001-31446) and incorporated herein by reference).

10.16 Form of Notice of Grant of Nonqualified Stock Option and Award Agreement (filed as Exhibit 10.4 to Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011 filed on August 4, 2011 (Commission File no. 001-31446) and incorporated herein by reference).

10.17 Form of Notice of Grant and Award Agreement (Other Stock Award with performance conditions) (filed as Exhibit 10.15 to the Annual Report on Form 10-K for the year ended December 31, 2013 filed on February 26, 2014 (Commission File No. 001-31446) and incorporated herein by reference).

10.18 2014 Equity Incentive Plan adopted May 15, 2014 (filed as Appendix A to the Definitive Proxy Statement 14-A filed on April 1, 2014 (Commission File No. 001-31446) and incorporated herein by reference.

10.19 Form of Notice of Grant of Restricted Stock (Director) and Award Agreement (filed as Exhibit 10.1 to Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2014 filed on August 6, 2014 (Commission File No. 001-31446) and incorporated herein by reference).

10.20 Form of Notice of Grant of Nonqualified Stock Option and Award Agreement (filed as Exhibit 10.2 to Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2014 filed on August 6, 2014 (Commission File No. 001-31446) and incorporated herein by reference).

10.21 Form of Notice of Grant of Restricted Stock and Award Agreement (filed as Exhibit 10.3 to Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2014 filed on August 6, 2014 (Commission File No. 001-31446) and incorporated herein by reference).

10.22 Form of Notice of Grant of Restricted Stock and Award Agreement (Performance Award) (filed as Exhibit 10.4 to Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2014 filed on August 6, 2014 (Commission File No. 001-31446) and incorporated herein by reference).

10.23 Form of Notice of Grant of Restricted Stock and Award Agreement (Performance Award) (filed as Exhibit 10.23 to the Annual Report on Form 10-K for the year ended December 31, 2014 filed on February 25, 2015 (Commission File No. 001-31446) and incorporated herein by reference).

10.24 Deferred Compensation Plan for Nonemployee Directors adopted May 19, 2004, as amended and restated effective January 1, 2009 (filed as Exhibit 10.18 to the Annual Report on Form 10-K for the year ended December 31, 2008 filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

10.25 Cimarex Energy Co. Supplemental Savings Plan (amended and restated, effective January 1, 2009) (filed as Exhibit 10.19 to the Annual Report on Form 10-K for the year ended December 31, 2008 filed on February 27, 2009 (Commission File No. 001- 31446) and incorporated herein by reference).

10.26 Cimarex Energy Co. Change in Control Severance Plan dated effective April 1, 2005, amended and restated effective January 1, 2009 (filed as Exhibit 10.20 to the Annual Report on Form 10-K for the year ended December 31, 2008 filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

10.27 Amendment to Cimarex Energy Co. Change in Control Severance Plan dated effective March 19, 2013 (filed as Exhibit 10.1 to the Current Report on Form 8-K filed on March 20, 2013 (Commission File No. 001-31446) and incorporated herein by reference).

10.28 Form of Indemnification Agreement between Cimarex Energy Co. and each of its executive officers and directors (filed as Exhibit 10.20 to the Annual Report on Form 10-K for the year ended December 31, 2012 filed on February 26, 2013 (Commission File No. 001-31446) and incorporated herein by reference).

10.29 Retention Agreement dated June 9, 2010 (filed as Exhibit 10.21 to the Annual Report on Form 10-K for the year ended December 31, 2013 filed on February 26, 2014 (Commission File No. 001-31446) and incorporated herein by reference).

10.30 Credit Agreement Dated as of October 16, 2015, by and among Cimarex, the Administrative Agent, the Syndication Agent, the Documentation Agents and the Lenders (filed on October 19, 2015 as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Commission File No. 001-31446) and incorporated herein by reference).

10.31 Form of Notice of Grant of Restricted Stock (Director) and Award Agreement (filed as Exhibit 10.2 to Registrant's Form 8-K (Commission File No. 001-31446) dated November 2, 2015 and incorporated herein by reference).

10.32 Succession Agreement dated August 17, 2015 (filed as Exhibit 10.2 to Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2015 filed on November 4, 2015 (Commission File No. 001-31446) and incorporated herein by reference).

14.1 Code of Ethics for Chief Executive Officer and Senior Financial Officers (filed as Exhibit 14.1 to the Annual Report on Form 10-K for the year ended December 31, 2003 filed on March 11, 2004 (Commission File No. 001-31446) and incorporated herein by reference).

14.2 Revised Code of Business Conduct and Ethics for Directors, Officers and Employees dated August 30, 2016 (filed as Exhibit 14.1 and 14.2 to the Current Report on Form 8-K filed September 1, 2016 (Commission File No. 001-31446) and incorporated herein by reference).

21.1 Significant Subsidiaries of the Registrant.*

23.1 Consent of KPMG LLP.*

23.2 Consent of DeGolyer and MacNaughton.*

24.1 Power of Attorney of directors of the Registrant.*

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 G. Mark Burford, 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.*

32.2	Certification of G. Mark Burford, Chief Financial Officer of Cimarex Energy Co., pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.*
99.1	Letter dated January 16, 2017 from DeGolyer and MacNaughton, independent petroleum engineering consulting firm, reporting the results of its audit of Cimarex reserves as of December 31, 2016 of certain selected properties.*
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. *

ITEM 16. FORM 10-K SUMMARY

None.

SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) 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.

Date: February 24, 2017

CIMAREX ENERGY CO.

By: /s/ Thomas E. Jorden

Thomas E. Jorden

Chairman of the Board, Chief Executive Officer, and President

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Thomas E. Jorden Thomas E. Jorden	Chairman of the Board, Director, Chief Executive Officer, and President (Principal Executive Officer)	February 24, 2017
* *Attorney-in-Fact* Joseph R. Albi	Director, Executive Vice President – Operations, Chief Operating Officer	February 24, 2017
/s/ G. Mark Burford G. Mark Burford	Vice President and Chief Financial Officer (Principal Financial Officer)	February 24, 2017
/s/ Timothy A. Ficker Timothy A. Ficker	Vice President, Controller, Chief Accounting Officer (Principal Accounting Officer)	February 24, 2017
* *Attorney-in-Fact* Hans Helmerich	Director	February 24, 2017
* *Attorney-in-Fact* David A. Hentschel	Director	February 24, 2017
* *Attorney-in-Fact* Harold R. Logan, Jr.	Director	February 24, 2017
* *Attorney-in-Fact* Floyd R. Price	Director	February 24, 2017
* *Attorney-in-Fact* Monroe W. Robertson	Director	February 24, 2017

* *Attorney-in-Fact* Lisa A. Stewart	Director	February 24, 2017
* *Attorney-in-Fact* Michael J. Sullivan	Director	February 24, 2017
* *Attorney-in-Fact* L. Paul Teague	Director	February 24, 2017
*By: /s/ G. Mark Burford G. Mark Burford *Attorney-in-Fact*	Vice President and Chief Financial Officer (Principal Financial Officer)	February 24, 2017

CORPORATE INFORMATION

Cimarex Energy Co. common stock trades on the New York Stock Exchange under the symbol XEC.

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Website
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Stock Transfer Agent
Continental Stock Transfer & Trust Company
17 Battery Place, 8th Floor
New York, New York 10004
Tel: (888) 509-5580

Communications regarding transfers, lost certificates, duplicate mailings or changes of address should be directed to our transfer agent.

Independent Registered Public Accounting Firm
KPMG LLP

Independent Reservoir Engineers
DeGolyer and MacNaughton

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