CIMAREX ENERGY CO
Form 10-K/A
March 09, 2015
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D C 20549

Form 10-K/A

Amendment No. 1

(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, 2014
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 including ZIP code)

(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 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, 2014 was approximately $12.3 billion.

Number of shares of Cimarex Energy Co. common stock outstanding as of February 13, 2015 was 87,597,134.
Documents Incorporated by Reference: Portions of the Registrant's Proxy Statement for its 2015 Annual Meeting of Stockholders are incorporated by reference into Part III of this Form 10-K.

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EXPLANATORY NOTE

We are filing this Amendment No. 1 (this “Amendment”) to our Annual Report on Form 10-K for the year ended December 31, 2014 to include a graph in Item 5 of this report comparing the cumulative five year total return attained by stockholders on Cimarex Energy Co.’s common stock to certain indexes. The graph was inadvertently excluded from the original filing. The associated data related to the graph was included in the original filing.

Our consolidated financial results have not changed from those presented in our original Form 10-K and no other items or disclosures in our Form 10-K have been amended. For ease of reference, we are filing the annual report in its entirety. This Amendment does not reflect events occurring after February 25, 2015, the original filing date of our Form 10 K.

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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

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PART I

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, we are providing "2015 Outlook," which contains projections for certain 2015 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 and gas production;
- Timing and amount of future production of oil and natural gas;
- Reductions in the quantity of oil and gas 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;
- Reserve estimates;
- Cash flow and anticipated liquidity;
- Amount, nature and timing of capital expenditures;
- Access to capital markets;
- Legislation 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;
- Estimates of proved reserves, exploitation potential or exploration prospect size;
- 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 and gas. These risks include, but are not limited to, commodity price volatility, inflation, lack of availability of goods and services,

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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.

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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.

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 of non-core assets. Key elements to our approach include:

- Maintaining a strong financial position
- Investment in a diversified portfolio of drilling opportunities with varying geologic characteristics, in different geographic areas and with assorted exposure to oil, natural gas and NGLs
- Detailed evaluation and ranking of investment decisions based on rate of return
- 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 by efficiently operating our properties

Conservative use of leverage has long been the key to our financial strategy. We believe that low leverage mitigates financial risk, which enables us to withstand volatility in commodity prices and provide competitive returns to shareholders. Cimarex looks to enhance shareholder returns through quarterly dividends which have increased 100% over the last five years. In June 2014, Cimarex was added to the S&P 500. 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 2010-2014.

Proved Oil and Gas Reserves

In 2014, our total proved reserves grew 25% to 3.1 Tcfe. Proved undeveloped reserves as a percentage of total proved reserves increased to 23% from 20% a year ago. We added 814 Bcfe of new reserves through extensions and discoveries and had upward revisions of 105 Bcfe. Organic growth, as represented by our reserve replacement ratio (excluding reserve purchases and sales) was 2.9 times. The change in our proved reserves is as follows (in Bcfe):

Proved Reserves at December 31, 2013	2,497.0
Revisions of previous estimates	104.8
Extensions and discoveries	813.9
Purchases of reserves	133.6
Production	(317.0)
Sales of reserves	(100.0)
Proved Reserves at December 31, 2014	3,132.3

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

	Years Ended December 31,		
	2014	2013	2012
Total Proved Reserves:			
Gas (Bcf)	1,666.7	1,293.5	1,251.9
Oil (MMBbls)	119.0	108.5	77.9
NGL (MMBbls)	125.3	92.0	89.9
Equivalent (Bcfe)	3,132.3	2,497.0	2,258.8
% Developed	77	80	80

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

Production volumes totaled 869 MMcfe of natural gas equivalent per day, a 25% increase over 2013. Production volumes are comprised of 49% natural gas, 30% oil and 21% NGLs. The following tables show our production volumes by region, the average commodity prices received and production cost per unit of production (Mcfe). Separate data also is included for our Cana-Woodford project, which is part of our Mid-Continent region and is part of our largest producing field.

	Production Volumes				Net Average Daily Volumes			
	Gas	Oil	NGL	Equivalent	Gas	Oil	NGL	Equivalent
Years Ended December 31,	(MMcf)	(MBbls)	(MBbls)	(MMcfe)	(MMcf)	(MBbls)	(MBbls)	(MMcfe)
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-Woodford	76,915	1,903	5,937	123,952	210.7	5.2	16.3	339.6
2013								
Permian Basin	35,414	10,739	2,823	116,783	97.0	29.4	7.7	320.0
Mid-Continent	84,779	2,171	4,757	126,345	232.3	5.9	13.0	346.1
Other	5,055	470	296	9,659	13.8	1.4	0.9	26.5
Total Company	125,248	13,380	7,876	252,787	343.1	36.7	21.6	692.6
Cana-Woodford	50,919	1,150	3,863	81,000	139.5	3.2	10.6	221.9
2012								
Permian Basin	29,135	8,750	2,480	96,517	79.6	23.9	6.8	263.7
Mid-Continent	80,998	2,210	3,962	118,029	221.3	6.1	10.8	322.5
Other	8,362	556	510	14,754	22.9	1.5	1.4	40.3
Total Company	118,495	11,516	6,952	229,300	323.8	31.5	19.0	626.5
Cana-Woodford	43,222	898	2,830	65,593	118.1	2.5	7.7	179.2

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Years Ended December 31,	Average Realized Price Gas (per Mcf)	Oil (per Bbl)	NGL (per Bbl)	Production Cost (per Mcfe)
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-Woodford	$ 4.32	$ 88.21	$ 34.89	$ 0.24
2013				
Permian Basin	$ 3.91	$ 93.02	$ 26.13	$ 1.48
Mid-Continent	$ 3.70	$ 93.48	$ 31.25	$ 0.76
Other	$ 3.74	$ 102.67	$ 29.81	$ 1.85
Total Company	$ 3.76	$ 93.44	$ 29.36	$ 1.13
Cana-Woodford	$ 3.57	$ 94.33	$ 30.64	$ 0.27
2012				
Permian Basin	$ 2.93	$ 87.93	$ 30.78	$ 1.50
Mid-Continent	$ 2.86	$ 90.41	$ 29.91	$ 0.77
Other	$ 2.88	$ 105.37	$ 35.95	$ 1.55
Total Company	$ 2.88	$ 89.25	$ 30.66	$ 1.13
Cana-Woodford	$ 2.69	$ 90.64	$ 29.67	$ 0.25

Acquisitions and Divestitures

In 2014 we made property acquisitions totaling $250 million, including a $238 million acquisition of properties in our Cana-Woodford shale play where enhanced completion techniques along with new workover designs were used to increase returns. In addition, we sold interests in various non-core oil and gas properties for $446 million, including non-strategic, high-value acreage in Reagan County, Texas, for $242 million, and other producing properties in southwestern Kansas.

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Exploration and Production 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 2014, E&D investment totaled $1.88 billion. Of that, 73% was invested in the Permian Basin and 25% in the Mid-Continent region.

In 2014, Cimarex drilled or participated in 312 gross (174.6 net) wells, of which we operated 185 gross (144.5 net) wells. At year-end, we were in the process of drilling or participating in 8 gross (4.0 net) wells and there were 54 gross (31.9 net) wells waiting on completion. A summary of our 2014 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	$ 1,377	171	117	99
Mid-Continent	463	139	57	100
Other	41	2	1	50
	$ 1,881	312	175	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 2014, we focused on drilling horizontal wells that yielded oil and liquids-rich gas from the Wolfcamp shale, the Bone Spring formation, and the Avalon shale. Cimarex saw improved results in its Wolfcamp shale wells, as measured by production and reserves, with the implementation of long laterals and in the Bone Spring wells via upsized well completions.

The Permian region produced 399 MMcfe per day in 2014, which was 46% of our total company production. Because of strong oil prices in the first nine months, the Permian was our most active drilling region in 2014. Oil production in the Permian Basin in 2014 averaged a record 34,390 barrels per day, a 17% increase over 2013.

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Our Mid-Continent region consists of Oklahoma and the Texas Panhandle. Our activity in 2014 in the Mid-Continent was focused in the Cana-Woodford shale in Oklahoma. Returns increased significantly in this play during 2014 as we implemented well completion techniques in this area that were highly successful in our Delaware Basin Wolfcamp Shale wells in 2013. These improved results, combined with a favorable average product price mix, led to the Mid-Continent region posting the company’s strongest returns in 2014. Cimarex also had success in a new zone, the Meramec, which sits above the Woodford Shale. Cimarex is working to delineate the size and potential of the Meramec play.

The Mid-Continent region is our largest producing area. During 2014, production averaged 451.2 MMcfe per day, or 52% of total company production. Production from the region increased 30% in 2014 versus 2013. New completion designs and improved workover technology both contributed to higher production from the region.

Wells Drilled

We drilled the following exploratory and developmental wells in 2014:

	Wells Drilled					
	2014		2013		2012	
	Gross	Net	Gross	Net	Gross	Net
Exploratory						
Productive	1	0.4	1	1.0	8	6.3
Dry	1	0.5	3	2.4	5	2.6
Total	2	0.9	4	3.4	13	8.9
Developmental						
Productive	309	173.6	359	181.0	328	177.0
Dry	1	0.1	2	1.0	11	6.1
Total	310	173.7	361	182.0	339	183.1

We have working interests in the following productive wells by region as of December 31, 2014:

	Gas		Oil	
	Gross	Net	Gross	Net
Mid-Continent	3,757	1,447	490	166
Permian Basin	1,002	511	4,968	991
Other	295	86	108	39
	5,054	2,044	5,566	1,196

Significant Properties

All of our oil and gas assets (proved reserves and undeveloped acreage) are located in the United States. We have varying levels of ownership interests in our properties consisting of working, royalty and overriding royalty interests.

We operate the wells that comprise 74% of our proved reserves. In 2014, proved reserves in the Watonga-Chickasha field were approximately 54% of the company's total proved reserves. The Cana-Woodford shale makes up the majority of this field. No other field had reserves in excess of 15% of our total proved reserves.

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At December 31, 2014, 63% of our total proved reserves were located in the Mid-Continent region and 36% were in the Permian Basin. We owned an interest in 10,620 gross (3,240 net) productive oil and gas wells. The following table summarizes our estimated proved oil and gas reserves by region as of December 31, 2014.

	Gas (Bcf)	Oil (MMBbl)	NGL (MMBbl)	Equivalent (Bcfe)	% of Total Proved Reserves
Mid-Continent	1,280.2	27.8	89.6	1,984.7	63
Permian Basin	370.7	90.1	35.3	1,122.7	36
Other	15.8	1.1	0.4	24.9	1
	1,666.7	119.0	125.3	3,132.3	100

At December 31, 2014, our ten largest producing fields held 80% 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	54.0	46.4	13,000'	Woodford
Ford, West	Permian Basin	5.3	59.9	9,500'	Wolfcamp
Lusk	Permian Basin	5.0	55.4	9,500'	Bone Spring
Dixieland	Permian Basin	3.1	98.3	11,000'	Wolfcamp
Two Georges	Permian Basin	2.5	92.7	11,500'	Bone Spring
Cottonwood Draw	Permian Basin	2.4	72.5	3,000'-10,000'	Delaware/Wolfcamp
Red Hills	Permian Basin	2.4	64.3	8,800'	Bone Spring/Wolfcamp
Phantom	Permian Basin	2.3	58.9	11,500'	Bone Spring
Sandbar	Permian Basin	1.9	58.1	7,500'	Bone Spring
Benson	Permian Basin	1.1	83.8	9,500'	Bone Spring
		79.9			

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Acreage

The following table sets forth the gross and net acres of both developed and undeveloped leases held by Cimarex as of December 31, 2014. 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	103,907	80,314	700,703	290,550	804,610	370,864
Texas	28,577	18,314	134,207	58,148	162,784	76,462
	150,715	116,819	834,910	348,698	985,625	465,517
Permian Basin						
New Mexico	83,091	58,017	198,185	138,291	281,276	196,308
Texas	149,724	125,275	186,686	138,684	336,410	263,959
	232,815	183,292	384,871	276,975	617,686	460,267
Other						
Arizona	2,098,481	2,098,481	17,207	—	2,115,688	2,098,481
California	380,782	380,782	—	—	380,782	380,782
Colorado	67,892	44,408	36,414	2,127	104,306	46,535
Gulf of Mexico	25,000	13,000	58,388	13,443	83,388	26,443
Louisiana	5,362	1,601	11,842	3,040	17,204	4,641
Michigan	31,794	31,716	1,183	1,183	32,977	32,899
Montana	35,258	10,379	8,248	1,875	43,506	12,254
Nevada	1,196,299	1,196,299	440	1	1,196,739	1,196,300
New Mexico	1,635,750	1,629,343	18,412	2,578	1,654,162	1,631,921
Texas	36,464	11,976	96,729	36,137	133,193	48,113
Utah	86,068	59,433	26,211	1,575	112,279	61,008
Wyoming	98,801	13,865	43,118	4,796	141,919	18,661
Other	161,978	146,193	9,512	3,486	171,490	149,679
	5,859,929	5,637,476	327,704	70,241	6,187,633	5,707,717
Total	6,243,459	5,937,587	1,547,485	695,914	7,790,944	6,633,501

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									
	2015		2016		2017		2018		2019	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Mid-Continent	10,174	9,865	22,293	20,600	15,859	15,859	325	325	—	—

Permian Basin	27,976	25,659	43,196	42,711	11,066	11,051	19,297	18,309	3,983	3,983
Other	20,754	20,754	200,352	200,175	52,641	52,641	31,412	31,412	67,448	67,448
	58,904	56,278	265,841	263,486	79,566	79,551	51,034	50,046	71,431	71,431
% of undeveloped	0.9	0.9	4.3	4.4	1.3	1.3	0.8	0.8	1.1	1.2

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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 customers during 2014 were Enterprise Products Partners L.P. (Enterprise), Sunoco Logistics Partners L.P. (Sunoco) and Oneok Partners, L.P. (Oneok). Enterprise and Sunoco each accounted for 19% of our consolidated revenues in 2014. Oneok accounted for 10% of our 2014 consolidated revenues.

Enterprise is a significant oil purchaser in Oklahoma and West Texas. Sunoco is a significant purchaser of our oil in Southeast New Mexico and Canadian County, Oklahoma. If either of these entities 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 both parties were to discontinue purchasing our product, there would be challenges initially, but ample markets to handle the disruption.

Oneok primarily purchases our NGLs and provides gathering, compression and processing services for the majority of our Mid-Continent region gas production. In the event Oneok ceased buying our NGLs, a minimal impact would occur as these products are piped to various processing and storage market areas where we could sell to a different purchaser. In the event Oneok ceased gathering, compressing, and processing our gas, there would be challenges initially, but several other entities exist to fill in the gap.

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, 2014, and 2013, Cimarex had 991 and 908 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. 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 and gas 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 Rules 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

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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 greater than 80% of the total future net revenue discounted at 10% attributable to the total interests owned by Cimarex as of December 31, 2014. 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 40 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 20 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 ten 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.

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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 to 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 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 these 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), 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 undisclosed impact on our capital expenditures, earnings or competitive position.

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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. 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 also may impact our abilities to borrow under our revolving credit facility and to raise additional debt or equity capital to fund acquisitions.

If prices stay at recent lower levels or 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.

As of December 31, 2014, the calculated value of the ceiling limitation exceeded the carrying value of our oil and gas properties subject to a ceiling test and no impairment was necessary. However, a decline of 8% or more in the value of the ceiling limitation would have resulted in an impairment. If commodity prices stay at the current early 2015 levels or decline further, we will incur full cost ceiling impairments in future quarters. Because the ceiling calculation uses rolling 12-month average commodity prices, the effect of lower quarter-over-quarter prices in 2015 compared to 2014 is a lower ceiling value each quarter. This will result in ongoing impairments each quarter until prices stabilize or improve. Impairment charges would not affect cash flow from operating activities, but would adversely affect our net income and stockholders’ equity.

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.

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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. See “Forward-Looking Statement” in 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.

At December 31, 2014, 23% of our total proved reserves are categorized as proved undeveloped.

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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, 2014.

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.

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. During 2014, we had hedges covering 28% of our oil production and 32% of our gas production. We currently do not have any hedges in place for 2015 or later periods. 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 end-user exception to the clearing requirement and intend to continue to engage in derivative transactions. However, the CFTC is still finalizing rules that will have an impact on our hedging counterparties and possibly end-users as well. 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.

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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 write down 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.

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 Culberson County, Texas area where we have significant development activities. The lack of availability or capacity in these facilities or the loss of the these facilities due to 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.

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 may be subject to information technology system failures, network disruptions and breaches in data security.

Information system failures, network disruptions and breaches in data security 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. Such system failures could result in the unanticipated disruption of our operations, the processing of transactions, the failure to meet regulatory standards and the reporting of our financial results. While management has taken steps to address these concerns by implementing network security and internal control measures, there can be no assurance that a system failure or data security breach will not have a material adverse effect on our financial condition and results of operations.

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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.

Failing to comply with any of the applicable laws and regulations 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.

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 a permit 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, 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 U.S. Environmental Protection Agency (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

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where hazardous substances may have been released or disposed. The most significant of these environmental laws is 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 are presently 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

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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. We could encounter similar issues if the greater sage grouse is listed as a threatened or endangered species because its habitat includes our areas of operation. A listing decision is anticipated in 2015.

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.

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, in October 2011, the EPA announced its plan to propose federal pre-treatment standards for wastewater generated during the hydraulic fracturing process. Hydraulic fracturing requires the use of a significant volume of water with some resulting "flowback water," as well as "produced water." If adopted, the new pretreatment rules will require shale gas operations to pretreat wastewater before transferring it to treatment facilities. Moreover, the EPA has indicated that it may develop and issue regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing; however, to date, it has taken no action to do so. In addition to the use of water, hydraulic fracturing fluid contains chemicals or additives designed to optimize production. Many states already require companies to disclose the components of this fluid, and additional states and municipalities, as well as the federal government, may follow with additional regulations regarding disclosure and other issues concerning hydraulic fracturing. Indeed, in May 2013, the BLM published a supplemental notice of proposed rulemaking governing hydraulic fracturing on federal and Indian lands that replaces a prior draft of proposed rulemaking issued by the agency in May 2012. The revised proposed rule would continue to require public disclosure of chemicals used in hydraulic fracturing on federal and Indian lands, confirmation that wells used in fracturing operations meet appropriate construction standards, and development of appropriate plans for managing flowback water that returns to the

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surface. A final rule is expected to be published in 2015. In May 2013, the Texas Railroad Commission adopted new rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. Many additional regulations also are being considered by federal, state and municipal governments and agencies, including limiting water withdrawals and usage, water disposal, restricting which additives may be used, implementing local or state-wide hydraulic fracturing moratoriums and temporary or permanent bans in certain environmentally sensitive and other areas. Public sentiment against hydraulic fracturing and shale gas production has become more vocal, which could lead to permitting and compliance requirements becoming more stringent. Consequences of these actions could increase our capital, compliance, and operating costs significantly, as well as delay or halt our ability to develop our oil and gas reserves.

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

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 current administration intends to promulgate proposed climate change rulemaking this summer aimed at reducing GHG emissions by 45% by 2025 compared to 2012 levels. The current administration intends to finalize proposed climate change rulemaking by 2016. It is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business. Any such future laws and 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, and such requirements also could adversely affect demand for the oil and natural gas that we produce.

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

Other companies operate approximately 23% 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, 2014, 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, 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.

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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 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:

- pay dividends on, redeem or repurchase our capital stock or redeem or repurchase our subordinated debt;
- make loans to others;
- make investments;
- incur additional indebtedness or issue preferred stock;
- create certain liens;
- sell assets;
- enter into agreements that restrict dividends or other payments from our restricted subsidiaries to us;
- consolidate, merge or transfer all, or substantially all, of our assets and our restricted subsidiaries;
- engage in transactions with affiliates;
- enter into hedging contracts;
- create unrestricted subsidiaries; and
- enter into sale and leaseback transactions.

In addition, our revolving credit agreement requires us to maintain a debt to EBITDA ratio (as defined in the credit agreement) of not more than 3.5 and a current ratio (defined to include undrawn borrowings) of greater than 1.0. Also, the indenture, under which we issued our senior unsecured notes, restricts us from incurring additional indebtedness, subject to certain exceptions, unless our fixed charge coverage ratio (as defined in the indenture) is at least 2.25. The

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additional indebtedness limitation does not prohibit us from borrowing under our revolving credit facility. See Note 2 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 6.7% of our total net undeveloped acreage at December 31, 2014. At that date, we had leases representing 56,278 net acres expiring in 2015, 263,486 net acres expiring in 2016, and 79,551 net acres expiring in 2017. 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.

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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 grow 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.

The refining industry may be unable to absorb rising U.S. oil and condensate production; in such a case, the resulting surplus could depress prices and restrict the availability of markets.

The export of oil and certain condensates is restricted under U.S. law. Absent a change in this law or an expansion of U.S. refining capacity, rising U.S. production of oil and condensate could result in a surplus of these products, which could cause prices for these commodities to fall and markets to constrict. If this occurs, our returns on our capital projects would decline, which could make some of our drilling plans uneconomic and which could require us to shut in some of our production. This could have a material adverse effect on our cash flow and profitability.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

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ITEM 3. LEGAL PROCEEDINGS

The information set forth under the heading "Litigation" in Note 11 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.

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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 2014. 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 Common Stock on the NYSE and the quarterly dividends paid per share.

2014	High	Low	Dividends Paid Per Share
First Quarter	$ 121.71	$ 92.38	$ 0.14
Second Quarter	$ 143.75	$ 111.49	$ 0.16
Third Quarter	$ 150.71	$ 125.25	$ 0.16
Fourth Quarter	$ 129.12	$ 96.02	$ 0.16

2013	High	Low	Dividends Paid Per Share
First Quarter	$ 79.69	$ 56.96	$ 0.12
Second Quarter	$ 76.61	$ 62.98	$ 0.14
Third Quarter	$ 97.60	$ 65.17	$ 0.14
Fourth Quarter	$ 113.03	$ 94.11	$ 0.14

The closing price of Cimarex stock as reported on the New York Stock Exchange on February 13, 2015, was $112.01. At December 31, 2014, Cimarex's 87,592,535 shares of outstanding common stock were held by approximately 2,148 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, 2014:

	(a) Number of securities	(b)	(c) Number of securities remaining available for future issuance

Plan Category	to be issued upon exercise of outstanding options, warrants, and rights	Weighted-average exercise price of outstanding options, warrants, and rights	under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders	384,082	$ 78.19	5,331,312
Equity compensation plans not approved by security holders	—	—	—
Total	384,082	$ 78.19	5,331,312

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In June 2014, Cimarex was added to the S&P 500. 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, 2009 to December 31, 2014.

	12/2009	12/2010	12/2011	12/2012	12/2013	12/2014
Cimarex Energy Co.	$ 100.00	$ 167.87	$ 117.94	$ 110.80	$ 202.75	$ 205.90
S&P 500	$ 100.00	$ 115.06	$ 117.49	$ 136.30	$ 180.44	$ 205.14
Dow Jones US Exploration & Production	$ 100.00	$ 116.74	$ 111.85	$ 118.36	$ 156.05	$ 139.24
S&P Oil & Gas Exploration & Production	$ 100.00	$ 109.28	$ 102.25	$ 105.98	$ 135.11	$ 120.81

The stock price performance included in this graph is not necessarily indicative of future stock price performance.

Stock Repurchases. In December 2005, the Board of Directors authorized the repurchase of up to four million shares of our common stock. The authorization expired on December 31, 2011. Through December 31, 2007, we had repurchased and cancelled a total of 1,364,300 shares at an overall average price of $39.05. No shares have been repurchased since the quarter ended September 30, 2007.

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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.

	For the Years Ended December 31, 2014	2013	2012	2011	2010
	(in millions, except per share and proved reserves amounts)				
Operating Results:					
Oil, gas and NGL sales	$ 2,373	$ 1,953	$ 1,582	$ 1,704	$ 1,559
Total Revenues	$ 2,424	$ 1,998	$ 1,624	$ 1,758	$ 1,614
Net income (loss)	$ 507	$ 565	$ 354	$ 530	$ 575
Earnings (loss) per share to common Stockholders:					
Basic	$ 5.79	$ 6.48	$ 4.08	$ 6.17	$ 6.74
Diluted	$ 5.78	$ 6.47	$ 4.07	$ 6.15	$ 6.70
Cash dividends declared per share	$ 0.64	$ 0.56	$ 0.48	$ 0.40	$ 0.32
Balance sheet data:					
Cash and Cash Equivalents	$ 406	$ 5	$ 70	$ 2	$ 114
Oil and Gas Properties, net	$ 6,904	$ 5,966	$ 5,005	$ 4,126	$ 2,922
Goodwill	$ 620	$ 620	$ 620	$ 620	$ 620
Total assets	$ 8,725	$ 7,253	$ 6,305	$ 5,358	$ 4,287
Long-term Obligations					
Long-term debt	$ 1,500	$ 924	$ 750	$ 405	$ 350
Deferred Income Taxes	$ 1,755	$ 1,460	$ 1,121	$ 904	$ 548
Other	$ 194	$ 164	$ 313	$ 302	$ 267
Stockholders' equity	$ 4,501	$ 4,022	$ 3,475	$ 3,131	$ 2,610
Cash flow data:					
Net cash flow provided by operating activities	$ 1,619	$ 1,324	$ 1,193	$ 1,292	$ 1,130
Net cash used in investing activities	$ (1,740)	$ (1,531)	$ (1,415)	$ (1,429)	$ (978)
Net cash provided by (used in) financing activities	$ 522	$ 142	$ 289	$ 25	$ (41)
Proved Reserves:					
Oil (MBbls)	118,992	108,533	77,921	72,322	63,656
Gas (Bcf)	1,667	1,294	1,252	1,216	1,254
NGL (MBbls)	125,273	92,044	89,909	65,815	41,310
Total equivalent (Bcfe)	3,132	2,497	2,259	2,045	1,884

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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. Please 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. Our operations currently are focused in two main areas: the Permian Basin and the Mid-Continent region. Our Permian Basin region encompasses west Texas and southeast New Mexico. Our Mid-Continent region 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 diversified drilling portfolio. Our strategy centers on maximizing cash flow from producing properties and profitably reinvesting that cash flow in exploration and development. We consider property acquisitions, dispositions and occasional mergers to enhance our competitive position.

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

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

2014 Summary of Operating and Financial Results

- Average daily production increased by 25% to 868.6 MMcfe/d.
- Proved reserves increased 25% to 3.1 Tcfe.
- We added 813.9 Bcfe of proved reserves from extensions and discoveries, replacing 257% of production.
- Exploration and development expenditures totaled $1.9 billion.
- Revenues reached $2.4 billion, up 21% from 2013.
- Cash flow provided by operating activities totaled $1.6 billion.
- Net income was $507.2 million, or $5.78 per diluted share.

During 2014, our drilling activities were focused almost exclusively in our Permian Basin and Mid-Continent regions. We participated in the drilling and completion of 312 gross (175 net) wells, 185 of which we operated.

Total debt at December 31, 2014 was $1.5 billion comprised entirely of long-term senior notes. Cash on hand was $405.9 million. Our stockholders' equity grew to $4.5 billion from $4.0 billion a year earlier.

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Proved Reserves

	Year Ended December 31, 2014			
	Gas (MMcf)	Oil (MBbl)	NGL (MBbl)	Total Gas Equivalents (MMcfe)
Permian Basin	370,729	90,081	35,253	1,122,734
Mid-Continent	1,280,234	27,791	89,621	1,984,709
Other	15,770	1,120	399	24,880
Total	1,666,733	118,992	125,273	3,132,323

	Year Ended December 31, 2013			
	Gas (MMcf)	Oil (MBbl)	NGL (MBbl)	Total Gas Equivalents (MMcfe)
Permian Basin	336,016	85,532	26,157	1,006,152
Mid-Continent	939,224	21,656	65,335	1,461,170
Other	18,260	1,345	552	29,642
Total	1,293,500	108,533	92,044	2,496,964

Year-end 2014 proved reserves grew 25% to 3.1 Tcfe, up from 2.5 Tcfe at year-end 2013. Proved natural gas reserves were 1.7 Tcfe, and both oil and NGLs contributed 0.7 Tcfe each. Increases in the Mid-Continent's proved reserves accounted for 82% of the year-over-year increase and the region now represents 63% of the company's total proved reserves. The remainder of the increase was from the Permian Basin, where most of the rest of our proved reserves are located.

Reserves added from extensions and discoveries totaled 813.9 Bcfe, of which 52% was from natural gas. During 2014, we had net positive reserve revisions of 104.9 Bcfe. This included positive revisions of 16.1 Bcfe due to prices offset by negative revisions of 24.6 Bcfe due to increases in operating expenses, which shortened the economic lives of properties. Performance revisions were a net positive 113.4 Bcfe. This net increase was primarily due to better than expected performance of PUD reserves converted to proved developed reserves during the year.

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. 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, contractual arrangements 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. See "Supplemental Oil and Gas Information" in Item 8 of this report for further discussion regarding our proved reserves.

Revenues

Almost all of our revenues are derived from sales of 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. Commodity prices are market driven and future prices will continue to fluctuate due to supply and demand factors, seasonality and geopolitical and economic factors.

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Oil sales contributed 55% of our total production revenue for 2014. Gas sales accounted for 29% and NGL sales contributed 16%. A $1.00 per barrel change in our realized oil price would have resulted in a $15.6 million change in revenues. A $0.10 per Mcf change in our realized gas price would have resulted in a $15.5 million change in our gas revenues. A $1.00 per barrel change in NGL prices would have changed revenues by $11.3 million.

The following table presents our average realized commodity prices. Realized prices do not include settlements of commodity hedging contracts.

	Years Ended December 31,		
	2014	2013	2012
Oil Prices:			
Average realized sales price ($/Bbl)	$ 83.70	$ 93.44	$ 89.25
Average WTI Midland price ($/Bbl)	$ 86.18	$ 95.33	$ 91.24
Average WTI Cushing price ($/Bbl)	$ 93.01	$ 97.97	$ 94.20
Gas Prices:			
Average realized sales price ($/Mcf)	$ 4.43	$ 3.76	$ 2.88
Average Henry Hub price ($/Mcf)	$ 4.43	$ 3.65	$ 2.79
NGL Prices:			
Average realized sales price ($/Bbl)	$ 33.14	$ 29.36	$ 30.66

In the fourth quarter of 2014, and through the date of this report, domestic prices for oil, gas and NGLs have declined precipitously. It is likely that prices will continue to fluctuate in the future.

Approximately 80% of our 2014 oil production was in the Permian Basin, the sale of which is tied to the WTI Midland benchmark price. Due to greater industry-wide production in this area, west Texas oil prices have declined relative to the Cushing benchmark. In 2014, the average Midland index price was $6.83 per barrel lower than the average Cushing index price. In 2013, the average Midland price was only $2.64 per barrel lower than the average Cushing price. The overall decline in realized average oil prices together with the decline in the Midland benchmark price resulted in our lower realized oil prices in 2014.

Prior to 2014, our average realized prices for gas and NGLs were net of certain processing fees. Beginning in 2014, these fees are no longer netted against realized prices. The resulting positive impact on gas prices for 2014 was $0.07 per Mcf. The positive impact on NGL prices was $3.54 per barrel. These positive impacts to prices were equally offset by increased transportation, processing and other operating costs. See RESULTS OF OPERATIONS below and Note 1, Basis of Presentation – Oil, Gas and NGL Sales, to the Consolidated Financial Statements in Item 8 of this report for additional information regarding these processing fees.

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

Production and other operating expenses

Costs associated with producing oil, gas and NGLs 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 2014, we owned interests in 10,620 gross wells.

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

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

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

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

At December 31, 2014, the calculated value of the ceiling limitation exceeded the carrying value of our oil and gas properties subject to the test, and no impairment was necessary. However, a decline of 8% or more in the value of the ceiling limitation would have resulted in an impairment.

If commodity prices stay at current early 2015 levels or decline further, we will incur full cost ceiling impairments in future quarters. Because the ceiling calculation uses rolling 12-month average commodity prices, the effect of lower quarter-over-quarter prices in 2015 compared to 2014 is a lower ceiling value each quarter. This will result in ongoing impairments each quarter until prices stabilize or improve. Impairment charges would not affect cash flow from operating activities, but would adversely affect our net income and stockholders' equity.

General and administrative (G&A) expenses consist primarily of salaries and related benefits, office rent, legal fees, consultants, systems costs and other administrative costs incurred in our offices and not directly associated with exploration, development or production activities. Our G&A expense is reported net of amounts reimbursed to us by working interest owners of the oil and gas properties we operate and net of amounts capitalized pursuant to the full cost method of accounting.

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

RESULTS OF OPERATIONS

2014 compared to 2013

Net income for the year ended December 31, 2014 was $507.2 million ($5.78 per diluted share), down 10% from $564.7 million ($6.47 per diluted share) for the previous year. In 2014, higher revenues from increased production volumes and higher realized prices received for gas and NGL production were offset by lower realized oil prices and increased operating expenses, primarily for DD&A and other operating, net expenses. In 2013, other operating, net included a significant reduction in our estimated exposure to certain litigation expense which had been accruing since 2008. Changes in our net income are discussed further in the analysis that follows.

Production Revenue (in thousands or as indicated)	Years Ended December 31, 2014	2013	Percent Change Between 2014 / 2013	Price / Volume Change Price	Volume	Total
Oil sales	$ 1,308,958	$ 1,250,212	5 %	$ (152,324)	$ 211,070	$ 58,746
Gas sales	687,930	471,045	46 %	103,936	112,949	216,885
NGL sales	375,941	231,248	63 %	42,877	101,816	144,693
Total production revenue	$ 2,372,829	$ 1,952,505	22 %	$ (5,511)	$ 425,835	$ 420,324
Total oil volume — thousand barrels	15,639	13,380	17 %			
Oil volume — Bbl/d	42,846	36,659	17 %			
Average oil price — per barrel	$ 83.70	$ 93.44	(10) %			
Total gas volume — MMcf	155,128	125,248	24 %			
Gas volume — MMcf/d	425.0	343.1	24 %			
Average gas price — per Mcf	$ 4.43	$ 3.76	18 %			
Total NGL volume — thousand barrels	11,343	7,876	44 %			
NGL volume — Bbl/d	31,078	21,578	44 %			
Average NGL price — per barrel	$ 33.14	$ 29.36	13 %			
Total equivalent production volumes — MMcfe/d	868.6	692.6	25 %			

As reflected in the table above, our 2014 production revenue was 22% higher than that of 2013. Increased revenue from greater production volumes and higher realized prices for gas and NGL sales were partially offset by lower realized oil prices. See Revenues above, for a discussion regarding realized prices.

Our 2014 aggregate production volumes were 317.0 Bcfe, comprised of 49% natural gas, 30% oil and 21% NGL. This compares to 2013 aggregate production volumes of 252.8 Bcfe, made up of 50% natural gas, 32% oil and 18% NGL. The 25% year-over-year growth was primarily due to our successful drilling programs in the Permian Basin and Mid-Continent region. See Items 1 and 2 of this report for a discussion of 2014 activity in these regions.

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

	Years Ended December 31, 2014	2013
Gas Gathering and Marketing (in thousands):		
Gas gathering and other revenues	$ 49,602	$ 45,441
Gas gathering and other costs	(35,113)	(25,876)
Gas gathering and other margin	$ 14,489	$ 19,565
Gas marketing revenues, net of related costs	$ 1,745	$ 105

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

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Our total operating costs and expenses (not including gas gathering and marketing costs, or income tax expense) in 2014 were $1.58 billion, an increase of 46% compared to $1.08 billion for the prior year. In 2013 we recorded a $142.8 million reduction in our estimated exposure to litigation expense, which had been accruing since 2008. Excluding the effect of the litigation expense estimate reduction, 2013 operating costs and expenses would have been $1.22 billion and the year-over-year increase would have been 29%. Analyses of the year-over-year differences are discussed below.

	Years Ended December 31,		Variance Between 2014 /	Per Mcfe	
	2014	2013	2013	2014	2013
Operating costs and expenses (in thousands):					
DD&A	$ 806,021	$ 615,874	$ 190,147	$ 2.54	$ 2.44
Asset retirement obligation	10,082	7,989	2,093	$ 0.03	$ 0.03
Production	342,304	286,742	55,562	$ 1.08	$ 1.13
Transportation, processing and other operating	195,414	93,580	101,834	$ 0.62	$ 0.37
Taxes other than income	128,793	112,732	16,061	$ 0.41	$ 0.45
General and administrative	81,160	77,466	3,694	$ 0.26	$ 0.31
Stock compensation	15,001	14,279	722	$ 0.05	$ 0.06
(Gain) loss on derivative instruments, net	(3,762)	209	(3,971)	N/A	N/A
Other operating (income) expense, net	116	(132,334)	132,450	N/A	N/A
	$ 1,575,129	$ 1,076,537	$ 498,592		

Our 2014 DD&A expense increased 31% and accounted for 53% of the aggregate increase in operating costs and expenses, excluding the effect of the 2013 litigation expense estimate reversal. About 78% of the 2014 increase in DD&A was attributable to our higher production volumes. On a per Mcfe basis, 2014 DD&A increased by 4%. Our DD&A rate has increased because the per unit cost of adding new proved reserves has exceeded the net remaining book basis of proved reserves added in prior years.

We expect our 2015 average DD&A rate to fluctuate depending on average realized prices in 2015. Continued lower realized prices during 2015 will cause the value of our oil and gas reserves to decrease and will result in impairments of our oil and gas properties during 2015. In quarters subsequent to an impairment, our DD&A rate will be lower than it is currently and will continue to decline after each subsequent impairment. If 2015 realized prices rebound, we would expect our DD&A rates in subsequent periods to increase moderately each quarter.

Asset retirement obligation expense increased by 26% compared to 2013. Most of the increase resulted from higher plugging and abandonment costs incurred than had previously been estimated.

Our production costs consist of lease operating expense and workover expense as follows:

(in thousands)	Years Ended December 31, 2014	2013	Variance Between 2014 / 2013	Per Mcfe 2014	2013
Lease operating expense	$ 276,395	$ 226,730	$ 49,665	$ 0.87	$ 0.90
Workover expense	65,909	60,012	5,897	$ 0.21	$ 0.23
	$ 342,304	$ 286,742	$ 55,562	$ 1.08	$ 1.13

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Lease operating expense in 2014 increased 22% compared to 2013. Increased costs associated with putting new wells on production in 2014 accounted for approximately 65% of the $49.7 million year-over-year increase. Most of these costs were for salt water disposal, rental equipment, and chemicals and treating. We also experienced year-over-year increases for labor, and site maintenance and restoration. These increased expenditures were partially offset by decreased costs resulting from property divestitures during the year. The lower rate per Mcfe was primarily a function of increased production volumes in 2014.

Workover expense increased by 10% from 2013 to 2014. Generally, these costs will fluctuate based on the amount of maintenance and remedial activity planned and/or required during the period.

Our year-over-year transportation, processing and other operating costs increased significantly during 2014. These costs will vary by product type and region. During 2014, approximately half of the increase in costs resulted from increases in sales and processing volumes, contractual fees, compression charges and fuel costs. The remaining increase relates to the inclusion of certain processing fees that in previous years were treated as a reduction in realized sales prices for residue gas and NGLs. These costs accounted for approximately $0.16 per Mcfe for 2014. See Note 1, Basis of Presentation – Oil, Gas and NGL Sales, to the Consolidated Financial Statements in this report for additional information.

Taxes other than income are assessed by state and local taxing authorities on production, revenues or the value of properties. Revenue based severance taxes comprise approximately 85% of these taxes. The 2014 year-over-year increase results primarily from higher severance taxes on greater oil, gas and NGL production volumes. While the aggregate tax amount increased by 14%, the rate per Mcfe declined 9% due to the increase in production volumes.

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

	Years Ended December 31,		Variance Between 2014 / 2013
(in thousands)	2014	2013	
G&A capitalized to oil and gas properties	$ 76,636	$ 74,691	$ 1,945
G&A expense	81,160	77,466	3,694
	$ 157,796	$ 152,157	$ 5,639
G&A expense per Mcfe	$ 0.26	$ 0.31	$ (0.05)

Our 2014 overall G&A cost increased modestly (4%) compared to 2013. In 2014, we experienced increased costs for salaries and benefits, consulting fees and higher rent related to new office facilities, which were partially offset by lower charitable contributions. The 16% decline in G&A expense per Mcfe is due to increased production volumes in 2014.

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

	Years Ended December 31,		Variance Between
(in thousands)	2014	2013	2014 / 2013
Performance restricted stock awards	$ 12,141	$ 11,105	$ 1,036
Service-based restricted stock awards	13,607	12,018	1,589
Restricted stock	25,748	23,123	2,625
Stock option awards	3,057	3,145	(88)
Total stock compensation	28,805	26,268	2,537
Less amounts capitalized to oil and gas properties	(13,804)	(11,989)	(1,815)
Stock compensation	$ 15,001	$ 14,279	$ 722

Expense associated with stock compensation will fluctuate based on the grant-date market value of the award and the number of shares granted. See Note 7 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 of the instruments. Since 2009, 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 summarizes the net (gains) and losses from settlements and changes in fair value of our derivative contracts. All of our derivative contracts were settled as of December 31, 2014, and we have not entered into any new contracts through the date of this report. See Note 5 to the Consolidated Financial Statements in Item 8 of this report for further details regarding our derivative instruments.