CIMAREX ENERGY CO
Form 10-K
February 26, 2014

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D C 20549

Form 10-K

(Mark One)

ý **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2013

OR

o **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 1800, 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 ý NO o

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 o NO ý

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 ý NO o

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 ý NO o

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. ý

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). YES o NO ý

Aggregate market value of the voting stock held by non-affiliates of Cimarex Energy Co. as of June 30, 2013 was approximately $5.5 billion.

Number of shares of Cimarex Energy Co. common stock outstanding as of February 14, 2014 was 87,012,034. Documents Incorporated by Reference: Portions of the Registrant's Proxy Statement for its 2014 Annual Meeting of Stockholders are incorporated by reference into Part III of this Form 10-K.

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DESCRIPTION

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GLOSSARY

Bbl/d Barrels (of oil or natural gas liquids) per day

Bbls Barrels (of oil or natural gas liquids)

Bcf Billion cubic feet

Bcfe Billion cubic feet equivalent

Btu British thermal unit

MBbls Thousand barrels

Mcf Thousand cubic feet (of natural gas)

Mcfe Thousand cubic feet equivalent

MMBbl/MMBbls Million barrels

MMBtu Million British thermal units

MMcf Million cubic feet

MMcf/d Million cubic feet per day

MMcfe Million cubic feet equivalent

MMcfe/d Million cubic feet equivalent per day

Net Acres Gross acreage multiplied by working interest percentage

Net Production Gross production multiplied by net revenue interest

NGL or NGLs Natural gas liquids

Tcf Trillion cubic feet

Tcfe Trillion cubic feet equivalent

One barrel of oil or NGL is the energy equivalent of six Mcf of natural gas

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 "*2014 Outlook,"* which contains projections for certain 2014 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;
- Amount, nature and timing of capital expenditures;
- 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;
- Reserve estimates;
- Cash flow and anticipated liquidity;
- Estimates of proved reserves, exploitation potential or exploration prospect size;
- Legislation and regulatory changes;
- Increased financing costs due to a significant increase in interest rates;

Access to capital markets.

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, 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

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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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ITEM 1. BUSINESS

General

Cimarex Energy Co., a Delaware corporation formed in 2002, is an independent oil and gas exploration and production company. Our operations are mainly located in Oklahoma, Texas and New Mexico. Our website address is www.cimarex.com. There you will find our news releases, annual reports, proxy statements, Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, insider (Section 16) filings (Forms 3, 4, and 5) and all other Securities and Exchange Commission (SEC) filings. We have also posted our Code of Ethics, Code of Business Conduct, Corporate Governance Guidelines, Audit Committee Charter and Compensation and Governance Committee Charter. Copies of these documents are available in print upon a written or telephonic request to our Corporate Secretary. Throughout this Form 10-K we use the terms "Cimarex," "company," "we," "our," and "us" to refer to Cimarex Energy Co. and its subsidiaries.

Proved oil and gas reserves as of year-end 2013 totaled 2.5 Tcfe, consisting of 1.3 Tcf of natural gas, 108,533 MBbls of oil and 92,044 MBbls of NGLs. Of total proved reserves, 80% are classified as proved developed.

Our 2013 production averaged 692.6 MMcfe per day, comprised of 343.1 MMcf of gas, 36,659 barrels of oil and 21,578 barrels of NGL. The wells we operate account for 75% of total proved reserves and approximately 77% of production.

Our corporate headquarters are located at 1700 Lincoln Street, Suite 1800, Denver, Colorado 80203 and our main telephone number at that location is (303) 295-3995.

2013 Financial and Operating Highlights

During 2013, we accomplished the following:

- Invested $1.6 billion in exploration and development
- Delineated and expanded our Delaware Basin acreage position uncovering several long-term future drilling projects
- Generated a record $2.0 billion of revenues
- Grew production 11% to a record 692.6 MMcfe/d
- Increased proved reserves 11% to 2.5 Tcfe; 26% of which are oil
- Added 727 Bcfe of proved reserves from extensions and discoveries
- Realized net income of $564.7 million, or $6.47 per diluted share, which benefited from a reduction in our estimated exposure to litigation expense of $90.3 million (after tax), that had been accruing since 2008
- Generated $1.3 billion of cash flow from operating activities

Business Strategy

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. While our primary focus is drilling, we occasionally consider acquisition and merger opportunities that allow us to either enhance our competitive position in existing core areas or to add new areas. Key elements to our approach include:

Maintaining a diversified portfolio of drilling opportunities, with varying geologic characteristics, in different geographic areas and commodity type exposure

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Detailed evaluation of drilling decisions based on risk-adjusted discounted cash flow rate of return on investment

Tracking predicted and actual results in a centralized exploration management system that provides feedback to improve results

Attracting quality employees and maintaining integrated teams of geoscientists, landmen and engineers

Maximizing profitability by efficiently operating our properties

Maintaining a strong financial structure

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. Further, our diversified portfolio and limited long-term capital commitments provide the flexibility to respond quickly to industry volatility.

Our drilling portfolio is principally split between the Permian Basin and Mid-Continent regions. Exploration and development (E&D) capital expenditures for 2013 totaled $1.57 billion. Of total expenditures, 65% were invested in the Permian Basin and 31% in the Mid-Continent area. Our Permian Basin efforts generated our best rates of return in 2013 and are focused on drilling horizontal oil and liquids-rich gas wells in the Bone Spring formations in Texas and New Mexico and to the Wolfcamp shale formation in Texas. In the Mid-Continent, our activity has been focused in the liquids-rich gas portion of the Cana-Woodford shale.

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. At year-end 2013, we had $924 million of long-term debt and $4.02 billion of stockholders equity.

Business Segments

Cimarex has one reportable segment (exploration and production).

Exploration and Production Overview

Our exploration and production (E&P) activities are conducted primarily in two main areas: the Permian Basin and the Mid-Continent region. The Permian Basin encompasses west Texas and southeast New Mexico. The Mid-Continent region consists of Oklahoma, the Texas Panhandle and southwest Kansas.

A summary of our 2013 exploration and development activity by region is as follows.

	Exploration and Development Capital (in millions)	Gross Wells Drilled	Net Wells Drilled	Completion Rate	12/31/13 Proved Reserves (Bcfe)
Permian Basin	$ 1,019	175	115	99%	1,006
Mid-Continent	480	183	65	100%	1,461
Other	66	7	5	43%	30
	$ 1,565	365	185	99%	2,497

Permian Basin

Our Permian Basin operations cover west Texas and southeast New Mexico. In total, Cimarex drilled 175 gross (115 net) wells in this area during 2013, completing 174 gross (114 net) as producers. Capital investment in this area totaled $1,019 million, or 65% of total 2013 capital.

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Drilling principally occurred in the Delaware Basin portion of New Mexico and West Texas, mainly targeting the Bone Spring and Wolfcamp formations. Cimarex drilled and completed 73 gross (40 net) New Mexico Bone Spring wells in 2013. Texas Third Bone Spring drilling totaled 39 gross (28 net) wells.

In addition, Cimarex drilled and completed 26 gross (21 net) horizontal Wolfcamp shale wells in Culberson and Reeves Counties, Texas in 2013. The company now has over 180,000 net acres prospective for the Wolfcamp shale formation in the Delaware Basin.

Cimarex also successfully tested an oil window in the Avalon shale interval on our acreage in Lea County, New Mexico. We completed five gross (five net) wells during 2013.

Mid-Continent

Our Mid-Continent region encompasses operations in Oklahoma, southwest Kansas and the Texas Panhandle. We drilled 183 gross (65 net) Mid-Continent wells during 2013, completing all as producers. The bulk of this drilling activity was in the Anadarko Basin of western Oklahoma, where we drilled 149 gross (54 net) wells which were primarily infill development wells. At year-end there were 54 gross (22 net) wells waiting on completion. Capital investment in this region in 2013 totaled $480 million, or 31% of total E&D capital.

Our largest investment area was in the Cana-Woodford shale play. We have approximately 75,000 net acres in the core of the play.

Production, Pricing and Production Cost Information

The following tables set forth certain information regarding the company's production volumes by region, the average commodity prices received and production cost per unit of production (Mcfe). This data is also included for our Cana-Woodford project, which is part of our Mid-Continent region. In 2013, proved reserves of Cana-Woodford were approximately 43% of the company's total proved reserves. No other field had reserves in excess of 15% of our total proved reserves.

	Production Volumes				Net Average Daily Volumes			
Years Ending December 31,	**Gas (MMcf)**	**Oil (MBbls)**	**NGL (MBbls)**	**Equivalent (MMcfe)**	**Gas (MMcf)**	**Oil (MBbls)**	**NGL (MBbls)**	**Equivalent (MMcfe)**
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
2011								
Permian Basin	26,848	6,121	1,228	70,944	73.6	16.8	3.4	194.4
Mid-Continent	74,078	2,078	3,378	106,811	203.0	5.7	9.3	292.6
Other	19,187	1,579	1,630	38,443	52.5	4.3	4.4	105.3
Total company	120,113	9,778	6,236	216,198	329.1	26.8	17.1	592.3
Cana-Woodford	30,187	630	2,194	47,130	82.7	1.7	6.0	129.1

	Average Sales Price			Production
Years Ending December 31,	Gas (per MCF)	Oil (per Bbl)	NGL (per Bbl)	Cost (per Mcfe)
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
2011				
Permian Basin	$ 4.94	$ 90.81	$ 44.70	$ 1.88
Mid-Continent	$ 4.26	$ 91.62	$ 38.73	$ 0.80
Other	$ 4.27	$ 103.31	$ 47.91	$ 0.79
Total company	$ 4.42	$ 93.00	$ 42.31	$ 1.14
Cana-Woodford	$ 3.92	$ 91.71	$ 38.38	$ 0.18

Our largest producing area is the Mid-Continent region. During 2013, Mid-Continent production averaged 346.1 MMcfe/d, or 50% of total production. Infill development drilling activity in the Cana-Woodford shale play resulted in Mid-Continent production increasing 7% in 2013.

The Permian Basin contributed 320.0 MMcfe/d in 2013, which was 46% of our total production. It was our most active drilling area in 2013 as higher oil prices led to strong returns on investment. Most of the activity was focused in the Bone Spring and Wolfcamp formations. Oil production in the Permian Basin was a record 29,421 Bbl/d, a 23% increase over 2012.

Acquisitions and Divestitures

In 2013, we sold interests in non-core oil and gas assets for $61.5 million. During the second quarter of 2013, we also sold a 50% interest in our Culberson County, Texas Triple Crown gas gathering and processing system for approximately $31 million. Total property acquisitions during 2013 were $37.1 million, mostly for undeveloped acreage in Reeves County, Texas.

During 2012, we sold interests in non-core oil and gas assets for $306 million. Of this total, $290 million was related to non-core oil and gas assets located in Texas. We had property acquisitions of $33.5 million during 2012, most of which were undeveloped acreage in the Permian Basin.

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 pricing mechanisms related to either monthly index prices on pipelines where we deliver our gas or the daily spot market.

We sell our oil and gas to a broad portfolio of customers. Our major customers during 2013 were Enterprise Products Partners L.P. (Enterprise) and Sunoco Logistics Partners L.P. (Sunoco). Enterprise and Sunoco accounted for 24% and 22%, respectively, of our consolidated revenues in 2013. Enterprise is our primary oil purchaser in Oklahoma and West Texas. Sunoco is a significant purchaser of our oil in Southeast New Mexico. If either of these entities were to stop purchasing our production, there are a number of other purchasers to whom we could sell our production with little delay. If both parties were to discontinue purchasing our product, there would be challenges initially, but ample markets to handle the disruption. We regularly monitor the credit worthiness of all our customers and may require parental guarantees, letters of credit or prepayments when deemed necessary.

Employees

Cimarex had 908 employees on December 31, 2013. 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.

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

Environmental Regulation. Various federal, state and local laws regulating the discharge of materials into the environment, or otherwise relating to the protection of the environment, directly impact oil and gas exploration, development and production operations, which consequently impact our operations and costs. These laws and regulations govern, among other things, emissions 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.

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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.

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, state legislatures, state agencies 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 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, geopolitical instability, the actions of the Organization of Petroleum Exporting Countries, the level of domestic and global oil and gas exploration and production activity, weather conditions, technological advances affecting energy consumption, governmental regulations and taxes, and advancement of alternative fuels.

Our proved oil and gas reserves and production volumes will decrease unless such 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 credit facility, and proceeds from the sale of senior notes. Low prices reduce 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 bank credit facility and to raise additional debt or equity capital to fund acquisitions.

If prices decrease, we may 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. Even moderate future price declines could cause us to incur impairment charges, which could have a material adverse effect on the results of our operations in the period taken.

As of December 31, 2013, 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 3% or more in the value of the ceiling limitation would have resulted in an impairment. If prices decline, or if there is a negative impact on one or more of the other components of the calculation, we may incur a full cost ceiling impairment related to our oil and gas properties in future quarters.

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 commercially could negatively affect our financial results and future rate of growth.

In order to replace the reserves depleted by production and to maintain or grow 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 can require significant capital expenditures and can impose reinvestment risk for our company, 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 dry holes, but also from 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, 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;
- operating costs;
- property, severance, excise and other taxes incidental to oil and gas operations;
- workover and remediation costs; and
- Federal and state income taxes.

Our proved oil and gas reserve estimates are prepared by Cimarex engineers in accordance with SEC guidelines. 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, 2013.

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The cash flow amounts referred to 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 (i) the unweighted average of the previous twelve months' first day of the month prices and (ii) current costs as of the date of the estimate; actual future prices and costs, however, 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. For 2014, we have currently hedged approximately 28% of our anticipated oil production and 37% of our anticipated gas production. These 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 all of our derivative contracts are accounted for under mark-to-market accounting, 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.

At this time, we believe we have satisfied the requirements for the commercial end-user clearing and collateral exemption and 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.

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.

Our oil and natural gas production depends in large part on the proximity and capacity of pipeline systems and transportation facilities. 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 recently begun development activities. The lack of availability or capacity in these facilities for an extended period of time could negatively affect our revenues.

Federal and state regulation of oil and natural gas, 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.

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 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.

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 and human health and safety. 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. 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.

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Environmental matters and costs can be significant.

As an owner, lessee, or operator of oil and gas properties, we are subject to various complex 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 petroleum hydrocarbons or other substances into the air, soil or water.

Liabilities under environmental law can be joint and several and may in some cases be imposed regardless of fault on our part. We could be held liable for damages or remediating facilities that were previously owned or operated by others. 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 hydraulic fracturing activities are subject to risks that could negatively impact our operations and profitability.

We use hydraulic fracturing for 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.

In addition to water, hydraulic fracturing fluid contains chemicals or additives designed to optimize production. Many states require companies to disclose the components of this fluid. Additional states, as well as the Federal government, may follow with similar or conflicting requirements or may restrict the use of certain additives, resulting in more costly or less effective development of wells.

Efforts to regulate hydraulic fracturing by local municipalities, states and at the federal level are increasing. Many new regulations are being considered, including limiting water withdrawals and usage, water disposition, 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, may be impacting the earth's climate. Methane, a primary component of natural gas, and carbon dioxide, a by-product of the burning of oil and natural gas, are examples of greenhouse gases. 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 greenhouse gases. In December 2009, the Environmental Protection Agency (EPA) issued findings that methane and carbon dioxide present a health and safety issue such that they should be regulated under the Clean Air Act. Restrictions resulting from federal or state legislation or regulations may have an effect on our ability to produce oil and gas, as well as the demand for our products. Such changes may result in additional compliance obligations with respect to the release, capture and use of carbon dioxide that could have an adverse effect on our operations and financial results.

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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, 2013, our long-term debt consisted of $750 million of 5.875% senior notes and $174 million of bank debt. 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 senior revolving credit facility bears interest at floating rates.

We may not generate sufficient cash flow from operations. Without sufficient cash flow, there may not be adequate future sources of capital to enable us to service our indebtedness or to fund our other liquidity

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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 additional indebtedness limitation does not prohibit us from borrowing under our revolving credit facility. See Note 5 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 producing properties requires an assessment of several factors, including:

- geological risks and recoverable reserves;
- future oil and gas prices and their appropriate 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 that 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.

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.

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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 natural gas and oil exploration and development, and any such change could have an adverse effect on our financial position.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Oil and Gas Reserves

All of our 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 75% of our proved reserves. All information in this Form 10-K relating to oil and gas reserves is net to our interest unless stated otherwise. See Note 15 to the Consolidated Financial Statements for further information. The following table sets forth the present value and estimated volume of our oil and gas proved reserves:

	Years Ending December 31,		
	2013	**2012**	**2011**
Total Proved Reserves:			
Gas (MMcf)	1,293,500	1,251,863	1,216,441
Oil (MBbls)	108,533	77,921	72,322
NGL (MBbls)	92,044	89,909	65,815
Equivalent (MMcfe)	2,496,964	2,258,844	2,045,265
Standardized measure of discounted future net cash flow after-tax, discounted at 10% (in millions)	$ 3,598.9	$ 2,908.7	$ 3,139.8
Average price used in calculation of future net cash flow:			
Gas ($/Mcf)	$ 3.01	$ 2.27	$ 3.79
Oil ($/Bbl)	$ 92.74	$ 88.91	$ 89.64
NGL ($/Bbl)	$ 28.42	$ 29.12	$ 41.70

Proved oil and gas reserve quantities are based on estimates prepared by Cimarex in accordance with the SEC's modernized rules for reporting oil and gas reserves. Reserve definitions comply 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 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.

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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 will also 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, 2013. 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 thirty-nine 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 nineteen 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 nine years.

Significant Properties

As of December 31, 2013, 59% of our total proved reserves were located in our Mid-Continent region and 40% were in the Permian Basin. In total we owned an interest in 12,079 gross (4,160 net) productive oil and gas wells.

The following table summarizes our estimated proved oil and gas reserves by region as of December 31, 2013.

	Gas (Bcf)	Oil (MBbl)	NGL (MBbl)	Equivalent (Bcfe)	Percent of Proved Reserves
Mid-Continent	939.2	21,656	65,335	1,461.1	59%
Permian Basin	336.0	85,532	26,157	1,006.2	40%
Other	18.3	1,345	552	29.7	1%
	1,293.5	108,533	92,044	2,497.0	100%

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Our ten largest producing fields hold 69% of total proved reserves. We are the principal operator of our production in each of these fields. The table below summarizes certain key statistics about these properties.

Field	Region	% of Total Proved Reserves	Average Working Interest %	Approximate Average Depth (feet)	Primary Formation
Watonga-Chickasha (Cana)	Mid-Continent	43.0	38.1	13,000'	Woodford
Lusk	Permian Basin	6.8	60.7	9,500'	Bone Spring
Two Georges	Permian Basin	3.4	93.1	11,500'	Bone Spring
Phantom	Permian Basin	2.8	57.7	11,500'	Bone Spring
Ford, West	Permian Basin	5.0	62.3	9,500'	Wolfcamp
Caprock	Permian Basin	1.2	74.2	9,000'	Abo
Sandbar	Permian Basin	2.2	64.1	7,500'	Bone Spring
Quail Ridge	Permian Basin	1.4	57.5	8,000' - 13,000'	Bone Spring/Morrow
Cottonwood Draw	Permian Basin	2.1	75.2	3,000' - 10,000'	Delaware/Wolfcamp
Benson	Permian Basin	1.4	95.0	9,500'	Bone Spring
		69.3			

Acreage

The following table sets forth the gross and net acres of both developed and undeveloped leases held by Cimarex as of December 31, 2013. 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	19,293	19,184	118,271	86,768	137,564	105,952
Oklahoma	104,708	81,216	523,576	273,651	628,284	354,867
Texas	57,975	47,332	220,032	144,538	278,007	191,870
	181,976	147,732	861,879	504,957	1,043,855	652,689
Permian Basin						
New Mexico	97,024	70,264	192,962	135,693	289,986	205,957
Texas	159,884	133,591	167,881	123,722	327,765	257,313
	256,908	203,855	360,843	259,415	617,751	463,270
Other						
Arizona	2,107,906	2,107,906	17,207		2,125,113	2,107,906
California	381,422	381,422	364	364	381,786	381,786
Colorado	68,188	44,408	36,246	2,127	104,434	46,535
Gulf of Mexico	25,000	13,000	53,388	12,693	78,388	25,693
Louisiana	5,362	1,601	11,853	3,045	17,215	4,646
Michigan	31,794	31,716	1,183	1,183	32,977	32,899
Montana	35,067	10,311	8,439	1,943	43,506	12,254
Nevada	1,196,299	1,196,299	440	1	1,196,739	1,196,300

New Mexico	1,643,251	1,629,406	19,065	2,518	1,662,316	1,631,924
Texas	47,469	21,698	103,367	35,623	150,836	57,321
Utah	86,068	59,433	26,171	1,572	112,239	61,005
Wyoming	104,364	14,663	44,689	5,135	149,053	19,798
Other	95,200	79,249	8,663	3,232	103,863	82,481
	5,827,390	5,591,112	331,075	69,436	6,158,465	5,660,548
Total	6,266,274	5,942,699	1,553,797	833,808	7,820,071	6,776,507

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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.

	Undeveloped Acres Expiring									
	2014		2015		2016		2017		2018	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Mid-Continent	23,255	22,991	10,586	10,505	16,913	16,904	21	21		
Permian Basin	12,552	12,071	48,237	45,480	27,128	26,522	4,761	4,749	8,153	7,833
Other	14,051	13,671	19,847	19,847	201,227	201,227	52,722	52,715	31,884	31,884
	49,858	48,733	78,670	75,832	245,268	244,653	57,504	57,485	40,037	39,717
Percent of undeveloped	0.8%	0.8%	1.3%	1.3%	3.9%	4.1%	0.9%	1.0%	0.6%	0.7%

Gross Wells Drilled

We participated in drilling the following number of gross wells during calendar years 2013, 2012, and 2011:

	Exploratory			Developmental		
	Productive	Dry	Total	Productive	Dry	Total
Year ended December 31, 2013	1	3	4	359	2	361
Year ended December 31, 2012	8	5	13	328	11	339
Year ended December 31, 2011	3	7	10	314	7	321

We were in the process of drilling 29 gross (18.7 net) wells at December 31, 2013, and there were 82 gross (36.7 net) wells waiting on completion.

Net Wells Drilled

The number of net wells drilled during calendar years 2013, 2012, and 2011 are shown below:

	Exploratory			Developmental		
	Productive	Dry	Total	Productive	Dry	Total
Year ended December 31, 2013	1.0	2.4	3.4	181.0	1.0	182.0
Year ended December 31, 2012	6.3	2.6	8.9	177.0	6.1	183.1
Year ended December 31, 2011	2.5	6.2	8.7	158.9	5.9	164.8

Productive Wells

We have working interests in the following productive wells as of December 31, 2013:

	Gas		Oil	
	Gross	Net	Gross	Net
Mid-Continent	4,523	2,271	947	271
Permian Basin	1,049	523	4,331	945
Other	379	103	850	47
	5,951	2,897	6,128	1,263

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ITEM 3. LEGAL PROCEEDINGS

In January 2009, the Tulsa County District Court issued a judgment totaling $119.6 million in the *H.B. Krug, et al. versus Helmerich & Payne, Inc.* (H&P) case. This lawsuit originally was filed in 1998 and addressed H&P's conduct pertaining to a 1989 take-or-pay settlement, along with potential drainage and other related issues. Pursuant to the 2002 spin-off transaction to stockholders of H&P, Cimarex assumed the assets and liabilities of H&P's exploration and production business, including this lawsuit. In 2008, we recorded litigation expense of $119.6 million for this lawsuit and began accruing additional post-judgment interest and costs. On August 18, 2011, the Oklahoma Court of Appeals issued an Opinion regarding the *Krug* litigation. The Oklahoma Court of Appeals reversed and remanded the $112.7 million disgorgement of profits award, holding the District Court erred in failing to make the required findings of fact and conclusions of law. In all other respects, the Court of Appeals affirmed the judgment, including damages of $6.845 million. On February 13, 2012, the Oklahoma Supreme Court granted Cimarex's Petition for Certiorari, which requested a review of the affirmed portion of the judgment. On December 10, 2013, the Oklahoma Supreme Court reversed the trial court's original judgment of $119.6 million and affirmed an alternative jury verdict for $3.65 million. In light of the Oklahoma Supreme Court's ruling, on December 31, 2013, we reduced previously recognized litigation expense and the associated long-term liability by $142.8 million. A portion of our anticipated remaining liability includes estimates for amounts yet to be adjudicated. These estimates are likely to change. On December 30, 2013, the Plaintiffs filed a Petition for Rehearing with the Oklahoma Supreme Court. On February 24, 2014, the Oklahoma Supreme Court denied the Plaintiffs' Petition for Rehearing. Our assessments and estimates likely will change in the future as a result of legal proceedings that cannot be predicted at this time.

On December 11, 2012, Cimarex entered into a preliminary resolution of the *Hitch Enterprises, Inc., et al. v. Cimarex Energy Co., et al.* (*Hitch*) litigation matter for $16.4 million. *Hitch* is a statewide royalty class action pending in the Federal District Court in Oklahoma City, Oklahoma. The settlement was reached at a mediation, which occurred after the parties began to exchange information, including damage analyses, on November 16, 2012. On July 2, 2013, the Court entered a judgment approving the parties' settlement. The judgment became final and unappealable on August 2, 2013. Cimarex distributed the settlement proceeds pursuant to the Court's order in September 2013 and the administration of the settlement is ongoing.

Additional information regarding these and other litigation is included in Note 13 to the Consolidated Financial Statements included in Item 8 of this report.

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 2013. 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.

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

2012	High	Low	Dividends Paid Per Share
First Quarter	$ 87.85	$ 55.87	$ 0.10
Second Quarter	$ 76.74	$ 46.19	$ 0.12
Third Quarter	$ 63.91	$ 50.03	$ 0.12
Fourth Quarter	$ 64.26	$ 55.74	$ 0.12

The closing price of Cimarex stock as reported on the New York Stock Exchange on February 14, 2014, was $109.26. At December 31, 2013, Cimarex's 87,152,197 shares of outstanding common stock were held by approximately 2,193 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, 2013:

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants, and rights	(b) Weighted-average exercise price of outstanding options, warrants, and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column(a))
Equity compensation plans approved by security holders	531,016	$ 59.78	1,809,228
Equity compensation plans not approved by security holders			
Total	531,016	$ 59.78	1,809,228

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 and the Dow Jones US Exploration & Production index. The graph tracks the performance of a $100 investment in our

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common stock and in each of the indexes (with the reinvestment of all dividends) from December 31, 2008 to December 31, 2013.

	12/08	12/09	12/10	12/11	12/12	12/13
Cimarex Energy Co.	$ 100.00	$ 199.28	$ 334.53	$ 235.04	$ 220.81	$ 404.04
S&P 500	$ 100.00	$ 126.46	$ 145.51	$ 148.59	$ 172.37	$ 228.19
Dow Jones US Exploration & Production	$ 100.00	$ 140.56	$ 164.09	$ 157.22	$ 166.37	$ 219.35

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,				
	2013	2012	2011	2010	2009
	(in millions, except per share amounts)				
Operating results:					
Gas, oil and NGL sales	$ 1,953	$ 1,582	$ 1,704	$ 1,559	$ 962
Total Revenues	1,998	1,624	1,758	1,614	1,010
Net income (loss)	565	354	530	575	(312)
Earnings (loss) per share to common Stockholders:					
Basic	$ 6.48	$ 4.08	$ 6.17	$ 6.74	$ (3.82)
Diluted	$ 6.47	$ 4.07	$ 6.15	$ 6.70	$ (3.82)
Cash dividends declared per share	$ 0.56	$ 0.48	$ 0.40	$ 0.32	$ 0.24
Balance sheet data:					
Total assets	$ 7,253	$ 6,305	$ 5,358	$ 4,287	$ 3,374
Total debt	$ 924	$ 750	$ 405	$ 350	$ 393
Stockholders' equity	$ 4,022	$ 3,475	$ 3,131	$ 2,610	$ 2,038
Cash flow data:					
Net cash provided by operating activities	$ 1,324	$ 1,193	$ 1,292	$ 1,130	$ 675
Net cash used in investing activities	$ (1,531)	$ (1,415)	$ (1,429)	$ (978)	$ (444)
Net cash provided by (used in) financing activities	$ 142	$ 289	$ 25	$ (41)	$ (230)
Proved Reserves:					
Gas (Bcf)	1,294	1,252	1,216	1,254	1,187
Oil (MBbls)	108,533	77,921	72,322	63,656	56,764
NGL (MBbls)	92,044	89,909	65,815	41,310	1,253
Total equivalent (Bcfe)	2,497	2,259	2,045	1,884	1,535

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 *"Certain Risks"* in Item 1A of this report. Certain amounts in prior years' financial statements have been reclassified to conform to the 2013 financial statement presentation. 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 principal business objective is to profitably grow proved reserves and production for the long-term benefit of our stockholders through a diversified drilling portfolio. Our strategy centers on maximizing cash flow from producing properties and profitably reinvesting that cash flow in exploration and development. We occasionally consider property acquisitions and mergers to enhance our competitive position.

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In order to achieve a consistent rate of growth and mitigate risk, we have historically maintained a portfolio of exploration and development projects targeting both oil and gas. We seek geologic and geographic diversification by operating in multiple basins. In recent years, we have shifted our capital expenditures to oil and liquids-rich gas projects because of strong oil prices relative to gas prices. We deal with volatility in commodity prices by maintaining flexibility in our capital investment program. In addition, we periodically hedge a portion of our oil and/or gas production to mitigate our potential exposure to price declines and the corresponding negative impact on cash flow available for investment.

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

Growth is generally funded with cash flow provided by operating activities together with bank borrowings, sales of non-strategic assets and occasional public financing. Conservative use of leverage and maintaining a strong balance sheet have long been a part of our financial strategy. We have a long track record of profitable growth.

2013 Summary

- Average daily production increased by 11% to a record 692.6 MMcfe/d.
- Our oil production grew 17% and gas production was up by 6%.
- Revenues reached a record $2.0 billion, up 23% from 2012.
- Proved reserves increased 11% to 2.5 Tcfe; proved oil reserves grew 39%.
- We added 727 Bcfe of proved reserves from extensions and discoveries.
- Exploration and development expenditures totaled $1.6 billion.
- Cash flow provided by operating activities totaled $1.3 billion.
- Net income was $564.7 million, or $6.47 per diluted share. Our net income benefited from a reduction in our estimated exposure to litigation expense of $90.3 million (after tax), which had been accruing since 2008.

Our drilling activities were focused almost exclusively in the Permian Basin and Mid-Continent regions. During 2013, we drilled and completed 365 gross (185 net) wells. Of total wells drilled, 175 gross (115 net) were in the Permian Basin and 183 gross (65 net) were in the Mid-Continent.

At December 31, 2013, long-term debt totaled $924 million and was comprised of $750 million of senior notes and $174 million of borrowings under our senior unsecured revolving credit facility. In April 2013, the borrowing base on our credit facility was increased from $2 billion to $2.25 billion.

Proved Reserves

	2013				2012			
	Gas (MMcf)	Oil (MBbl)	NGL (MBbl)	Total Gas Equivalents (MMcfe)	Gas (MMcf)	Oil (MBbl)	NGL (MBbl)	Total Gas Equivalents (MMcfe)
Total proved reserves:								

Permian Basin	336,016	85,532	26,157	1,006,152	233,236	58,623	18,634	696,782
Mid-Continent	939,224	21,656	65,335	1,461,170	996,747	17,984	70,615	1,528,341
Other	18,260	1,345	552	29,642	21,880	1,314	660	33,721
Total	1,293,500	108,533	92,044	2,496,964	1,251,863	77,921	89,909	2,258,844

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Year-end 2013 proved reserves grew 11% to 2.5 Tcfe, up from 2.3 Tcfe at year-end 2012. Proved oil reserves increased by 39% from 77.9 MMBbl to 108.5 MMBbl. Total proved reserves were 80% developed and 52% gas. Approximately 59% of 2013 proved reserves were in our Mid-Continent region and 40% in the Permian Basin.

Permian Basin proved reserves increased 44% and the region now represents 40% of the company's total proved reserves. Proved reserves in the Mid-Continent region decreased 4% due to revisions and lower proved undeveloped reserves.

Reserves added from extensions and discoveries totaled 727 Bcfe. Oil accounted for 40% of total reserve additions with natural gas representing 39% and growth in NGL volumes comprising 21%. The Permian region accounts for 67% of the 2013 reserve additions.

During 2013, we had net negative reserve revisions of 216 Bcfe. Approximately 208 Bcfe of the negative revisions relates to performance of certain wells drilled in our Cana-Woodford shale development project.

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 Note 15 to the Consolidated Financial Statements of this report for further discussion regarding our proved reserves.

Revenues

Most of our revenues are derived from sales of oil, gas and NGL production. Our revenue, profitability and future growth are highly dependent on the commodity prices we receive. Compared to 2012, our 2013 average realized gas price increased by 31%. Our average realized oil price increased by 5%. Our average realized NGL price decreased 4%. Prices we receive are determined by prevailing market conditions. Regional and worldwide economic and geopolitical activity, weather and other factors influence market conditions, which often result in significant volatility in commodity prices.

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

	Years Ended December 31,		
	2013	**2012**	**2011**
Gas Prices:			
Average Henry Hub price ($/Mcf)	$ 3.65	$ 2.79	$ 4.04
Average realized sales price ($/Mcf)	$ 3.76	$ 2.88	$ 4.42
Oil Prices:			
Average WTI Cushing price ($/Bbl)	$ 97.97	$ 94.20	$ 95.14
Average realized sales price ($/Bbl)	$ 93.44	$ 89.25	$ 93.00
NGL Prices:			
Average realized sales price ($/Bbl)	$ 29.36	$ 30.66	$ 42.31

On an energy equivalent basis, 50% of our 2013 aggregate production was natural gas. A $0.10 per Mcf change in our average realized gas sales price would have resulted in a $12.5 million change in our gas revenues. Similarly, 50% of our production was crude oil and NGLs. A $1.00 per barrel change in our average realized sales prices would have resulted in a $21.3 million change in our oil and NGL revenues.

See **RESULTS OF OPERATIONS** below for a discussion of the impact changes in realized prices had on our 2013 revenues.

Production and other operating expenses

Costs associated with finding and producing oil and gas are substantial. Some of these costs vary with commodity prices, some trend with the type and volume of production and others are a function of the number of wells we own. At the end of 2013, we owned interests in 12,079 gross wells.

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

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

Depreciation, depletion and amortization (DD&A) of our producing properties is computed using the units-of-production method. The economic life of each producing well depends upon the estimated proved reserves for that well, which in turn depend upon the assumed price for future sales of production. Therefore, fluctuations in oil and gas prices will impact the level of proved reserves used in the calculation. Higher prices generally have the effect of increasing reserves which reduces depletion expense. Conversely, lower prices generally have the effect of decreasing reserves, which increases depletion expense. The cost of replacing production also impacts our DD&A rate. In addition, changes in estimates of reserve quantities, estimates of operating and future development costs, and reclassifications of properties from unproved to proved will impact depletion expense.

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

At December 31, 2013, 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 3% or more in the value of the ceiling limitation would have resulted in an impairment. If pricing conditions decline, or if there is a negative impact on one or more of the other components of the calculation, we may incur a full cost ceiling impairment related to our oil and gas properties in future quarters. An impairment charge would have no effect on liquidity or our capital resources, but it would adversely affect our results of operations in the period incurred.

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

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See **RESULTS OF OPERATIONS** below for a discussion of changes in production and other operating expenses.

Derivative Instruments/Hedging

We periodically enter into derivative instruments to mitigate a portion of our potential exposure to a decline in oil and/or gas prices and the corresponding negative impact on cash flow available for reinvestment. While the use of these instruments limits the downside risk of adverse price changes, their use may also limit future revenues that would have resulted from favorable price changes.

During 2013, we had hedges covering 30% of our 2013 oil production and 13% of our gas production. For contracts that have settled through December 31, 2013, we paid net cash settlements of $6.3 million on oil contracts and received $2.2 million of cash settlements on our gas contracts.

In 2012, we hedged about 41% of our oil production and none of our gas production. All of the oil contracts expired during 2012 without any cash settlements. During 2011, we had 45% of our oil production and 6% of gas production hedged. Those contracts were settled in 2011 for a net gain of $6.7 million.

The following tables summarize our outstanding hedging contracts as of December 31, 2013:

Oil Contracts

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

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

Gas Contracts

				Weighted Average Price	
Period	**Type**	**Volume/Day**	**Index(1)**	**Floor**	**Ceiling**
Jan 14 - Dec 14	Collars	80,000 MMBtu	PEPL	$ 3.51	$ 4.57
Jan 14 - Dec 14	Collars	20,000 MMBtu	Perm EP	$ 3.65	$ 4.50
Feb 14 - Dec 14	Collars	10,000 MMBtu	Perm EP	$ 3.65	$ 4.50

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

Subsequent to December 31, 2013 we entered into the following gas hedges:

				Weighted Average Price	
Period	**Type**	**Volume/Day**	**Index(1)**	**Floor**	**Ceiling**
Feb 14 - Dec 14	Collars	30,000 MMBtu	Perm EP	$ 3.58	$ 4.50

(1) Perm EP refers to El Paso Natural Gas Company, Permian Basin Index as quoted in Platt's Inside FERC.

Depending on changes in oil and gas futures markets and management's view of underlying supply and demand trends, we may increase or decrease our hedging positions.

Since 2009, we have chosen not to apply hedge accounting treatment to our derivative contracts. As a result, any settlements on the contracts are shown as a component of operating costs and expenses as either a net gain or loss on derivative instruments. See the discussion of our net gains/losses on hedging activities below, in **RESULTS OF OPERATIONS.** Also, see Item 7A and Note 2 to the Consolidated Financial Statements of this report for additional information regarding our derivative instruments.

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RESULTS OF OPERATIONS

2013 compared to 2012

Net income for the year ended December 31, 2013, was $564.7 million ($6.47 per diluted share), up 60% from $353.8 million ($4.07 per diluted share) for the previous year. The increase in 2013 net income was primarily the result of higher revenues from increased production volumes and higher realized prices received for oil and gas production. Net income in 2013 also benefited from a reduction in our estimated exposure to certain litigation expense which had been accruing since 2008. The increases to 2013 net income were partially offset by increased DD&A, other oil and gas operational expenses and income taxes compared to 2012. These changes are discussed further in the analysis that follows.

Production Revenue	For the Years Ended December 31, 2013	2012	Percent Change Between 2013/2012	Price / Volume Change Price	Volume	Total
(in thousands or as indicated)						
Gas sales	$ 471,045	$ 340,744	38%	$ 110,218	$ 20,083	$ 130,301
Oil sales	1,250,212	1,027,757	22%	56,062	166,393	222,455
NGL sales	231,248	213,149	8%	(10,239)	28,338	18,099
Total production revenue	$ 1,952,505	$ 1,581,650	23%	$ 156,041	$ 214,814	$ 370,855
Total gas volume MMcf	125,248	118,495	6%			
Gas volume MMcf/d	343.1	323.8	6%			
Average gas price per Mcf	$ 3.76	$ 2.88	31%			
Total oil volume thousand barrels	13,380	11,516	16%			
Oil volume Bbl/d	36,659	31,463	17%			
Average oil price per barrel	$ 93.44	$ 89.25	5%			
Total NGL volume thousand barrels	7,876	6,952	13%			
NGL volume Bbl/d	21,578	18,994	14%			
Average NGL price per barrel	$ 29.36	$ 30.66	-4%			
Total equivalent production volumes MMcfe/d	692.6	626.5	11%			

Revenue from our production totaled a record $2.0 billion in 2013, compared to $1.6 billion last year. Increased production volumes together with higher realized prices for oil and gas sales accounted for the year-over-year improvement.

In 2013, our aggregate production volumes reached a record 692.6 MMcfe/d, up 11% from 626.5 Mcfe/d in 2012. The growth in production resulted from our successful drilling programs in the Permian Basin and Mid-Continent region.

Gas production in 2013 averaged 343.1 MMcf/d, compared to 323.8 MMcf/d for 2012. The 6% year-over-year increase resulted in additional revenue of $20.1 million.

Oil production for 2013 averaged 36,659 Bbl/d, up 17% from 31,463 Bbl/d in 2012. The growth in 2013 volume provided an additional $166.4 million of oil revenue.

During 2013, our average NGL production volumes of 21,578 Bbl/d were 14% greater than 18,994 Bbl/d for 2012, and contributed an additional $28.3 million of revenue.

Our average realized gas price for 2013 improved by 31%, to $3.76 per Mcf, compared to $2.88 per Mcf in 2012. The 2013 increase in price provided additional revenue of $110.2 million for the year.

Realized oil prices during 2013 averaged $93.44 per barrel, an increase of 5% from the average price received in 2012 of $89.25 per barrel. The higher price in 2013 contributed $56.1 million of additional oil revenue for the year.

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In 2013, our realized price for NGLs averaged $29.36 per barrel, which was 4% lower than the average realized price of $30.66 per barrel received in 2012. The lower price resulted in $10.2 million less revenue in 2013.

The changes in realized commodity prices were the result of overall market conditions.

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

	For the Years Ended December 31,	
	2013	2012
Gas Gathering, Processing and Marketing (in thousands):		
Gas gathering, processing and other revenues	$ 45,441	$ 43,042
Gas gathering and processing costs	(25,876)	(21,965)
Gas gathering and processing margin	$ 19,565	$ 21,077
Gas marketing revenues, net of related costs	$ 105	$ (754)

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

In 2013, our total operating costs and expenses of $1.077 billion (not including gas gathering, processing and marketing costs, or income tax expense) benefited from a $142.8 million reduction in our estimated exposure to litigation expense which had been accruing since 2008. Excluding the effect of the litigation reduction, our total operating costs and expenses would have been $1.219 billion, or $188 million (18%) higher than 2012 costs and expenses of $1.031 billion. Analyses of the year-over-year differences are discussed below:

	For the Years Ended December 31,		Variance Between	Per Mcfe	
	2013	2012	2013/2012	2013	2012
Operating costs and expenses (in thousands):					
Depreciation, depletion and amortization (DD&A)	$ 615,874	$ 513,916	$ 101,958	$ 2.44	$ 2.24
Asset retirement obligation	7,989	13,019	(5,030)	$ 0.03	$ 0.06
Production	286,742	258,584	28,158	$ 1.13	$ 1.13
Transportation and other operating	93,580	57,354	36,226	$ 0.37	$ 0.25
Taxes other than income	112,732	86,994	25,738	$ 0.45	$ 0.38
General and administrative	77,466	54,428	23,038	$ 0.31	$ 0.24
Stock compensation	14,279	21,919	(7,640)	$ 0.06	$ 0.10
(Gain)/Loss on derivative instruments, net	209	(245)	454	N/A	N/A
Other operating (income) expense, net	(132,334)	24,961	(157,295)	N/A	N/A
	$ 1,076,537	$ 1,030,930	$ 45,607		

Our 2013 DD&A expense increased 20% to $615.9 million, compared to $513.9 million in 2012. The $102.0 million increase accounted for 54% of the aggregate increase in operating costs and expenses, excluding the effect of the litigation reversal. On a per Mcfe basis, 2013 DD&A increased by 9% to $2.44 compared to $2.24 for 2012. About half of the 2013 increase in DD&A was attributable to our higher production volumes. The rest of the increase was a result of a higher DD&A rate. 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 average DD&A rate to increase modestly during 2014.

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Asset retirement obligation expense declined by 39% to $8.0 million in 2013, compared to $13.0 million in 2012. Half of the decrease resulted from property sales in the latter half of 2012, which lowered our retirement obligation expense during 2013. This decrease was partially offset by increased expense related to newly drilled wells. The remaining decrease was due to higher plugging and abandonment costs in the Permian Basin and Gulf of Mexico during 2012.

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

(in thousands)	For the Years Ended December 31, 2013	2012	Variance Between 2013/2012	Per Mcfe 2013	2012
Lease operating expense	$ 226,730	$ 217,891	$ 8,839	$ 0.90	$ 0.95
Workover expense	60,012	40,693	19,319	$ 0.23	$ 0.18
	$ 286,742	$ 258,584	$ 28,158	$ 1.13	$ 1.13

Lease operating expense in 2013 increased by 4% compared to 2012. In 2013, as we continued to put new wells on production, we had increased costs for compression, rental equipment, fuel and overhead. We also had year-over-year increased costs for equipment & maintenance, roads & location, and environmental expenditures. These increases were partially offset by lower salt water disposal costs and decreased year-over-year costs resulting from property divestitures which occurred in the latter half of 2012. The lower rate per Mcfe was primarily a function of increased production volumes and efficiencies of horizontal well operations in 2013 compared to 2012.

Workover expense increased by 47% from 2012 to 2013. Generally, these costs will fluctuate based on the amount of maintenance and remedial activity planned and/or required during the period. About 60% of the 2013 increase was incurred in the Permian Basin region and the remainder was primarily in the Mid-Continent region.

Our year-over-year transportation and other operating costs increased by 63% during 2013. Transportation costs will vary by product type and area. Increases or decreases in sales volumes, compression charges and fuel costs also have an impact. The increase in these costs is primarily from the growth of our oil and NGL production in the Permian Basin and western Oklahoma.

Taxes other than income are assessed by state and local taxing authorities on production, revenues or the value of properties. Revenue based severance taxes are the largest component of these taxes. Our 2013 taxes increased by 30% compared to 2012. The increase is primarily due to increased severance taxes on higher production volumes. In addition, our 2012 taxes were lower due to a refund for taxes paid in prior years.

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

(in thousands)	For the Years Ended December 31, 2013	2012	Variance Between 2013/2012
G&A capitalized to oil and gas properties	$ 74,691	$ 66,611	$ 8,080
G&A expense	77,466	54,428	23,038
	$ 152,157	$ 121,039	$ 31,118

G&A expense per Mcfe	$ 0.31	$ 0.24	$ 0.07

Our 2013 overall G&A cost increased 26% compared to 2012. In 2013, we experienced increased costs for salaries and benefits as well as higher rent related to new office facilities. In addition, our 2013 expenditures included $7 million for university endowments established in honor of our former Chairman, F.H. Merelli, and $1 million of contributions for tornado relief in Oklahoma.

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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. In accordance with our stock incentive plan, such grants are periodically made to non-employee directors, officers and other eligible employees. We have recognized non-cash stock-based compensation cost as follows:

(in thousands)	For the Years Ended December 31, 2013	2012	Variance Between 2013/2012
Performance restricted stock awards	$ 11,105	$ 19,066	$ (7,961)
Service-based restricted stock awards	12,018	12,231	(213)
Restricted stock	23,123	31,297	(8,174)
Stock option awards	3,145	2,889	256
Total stock compensation	26,268	34,186	(7,918)
Less amounts capitalized to oil and gas properties	(11,989)	(12,267)	278
Stock compensation	$ 14,279	$ 21,919	$ (7,640)

Expense associated with stock compensation will fluctuate based on the grant-date market value of the award and the number of shares granted. The 2012 cost for the performance awards includes $3.9 million of accelerated compensation expense related to the death of former Chairman, F.H. Merelli. In addition, the 2013 cost for performance awards is approximately $4.3 million lower than 2012 cost due to the timing of awards granted. Almost all of the performance awards granted in 2013 were awarded in mid-December. Awards granted in January of 2010 were fully amortized in early January of 2013, resulting in 2013 having less cost amortized during the year.

See Note 8 to the Consolidated Financial Statements of this report for further discussion regarding our stock-based compensation.

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

Gains and losses on our derivative contracts are a function of fluctuations in the underlying commodity prices and the monthly settlement of the instruments. See Item 7A and Note 2 to the Consolidated Financial Statements of this report for further details regarding our derivative instruments.

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

(in thousands)	For the Years Ended December 31, 2013	2012
(Gain) loss on derivative instruments, net:		
Natural gas contracts	$ (4,651)	$
Oil contracts	4,860	(245)
(Gain) loss on derivative instruments, net	$ 209	$ (245)
Settlement (gains) losses:		

Natural gas contracts	$	(2,187)	$
Oil contracts		6,275	
Settlement (gains) losses	$	4,088	$

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Other operating (income) expense, net consists of costs related to various legal matters, most of which pertain to litigation and contract settlements, and title and royalty issues. For 2013, we have income of $132.3 million versus expense of $25.0 million for 2012. In December 2013, based on a ruling from the Oklahoma Supreme Court, we reduced our estimated exposure to litigation expense that had been accruing since 2008 by $142.8 million. See Item 3 and Note 13 to the Consolidated Financial Statements of this report for further information regarding litigation matters.

Other (income) and expense

(in thousands)	For the Years Ended December 31, 2013	2012	Variance Between 2013/2012
Interest expense	$ 54,973	$ 49,317	$ 5,656
Capitalized interest	(31,517)	(35,174)	3,657
Loss on early extinguishment of debt		16,214	(16,214)
Other, net	(21,518)	(19,864)	(1,654)
	$ 1,938	$ 10,493	$ (8,555)

Our interest expense includes interest on debt, amortization of financing costs and miscellaneous interest expense. Most of the 11% year-over-year increase of $5.7 million relates to our 5.875% senior notes being outstanding for all of 2013, whereas they were only outstanding for eight months during 2012. See ***Long-Term Debt*** below for further information regarding our senior notes.

We capitalize interest on non-producing leasehold costs, the costs of drilling and completing wells and constructing qualified assets. The 10% decline in 2013 capitalized interest compared to amounts capitalized in 2012 resulted because both the average rate of interest and the amount of costs on which interest is calculated declined in 2013.

In connection with the retirement of our 7.125% senior notes in 2012, we recognized a $16.2 million loss on early extinguishment of debt.

Components of other, net consist of miscellaneous income and expense items that will vary from period to period, including gain or loss on the sale or value of oil and gas well equipment, income and expense associated with other non-operating activities, miscellaneous asset sales and interest income. The 8% increase in 2013 income compared to 2012 was mainly due to net gains on asset sales which were partially offset by lower income from non-operating activities.

Income Tax Expense

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

(in thousands)	For the Years Ended December 31, 2013	2012
Current benefit	$ (689)	$ (1,489)
Deferred taxes	329,700	208,216
	$ 329,011	$ 206,727
Combined Federal and state effective income tax rate	36.8%	36.9%

Our income tax expense (benefit) differs from the statutory rate of 35% due to the effects of state income taxes, the Domestic Production Activities allowance and other permanent differences. See Note 6 to the Consolidated Financial Statements of this report for further information regarding our income taxes.

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RESULTS OF OPERATIONS

2012 compared to 2011

Net income for the year ended December 31, 2012, was $353.8 million, or $4.07 per diluted share. For 2011, we had net income of $529.9 million, or $6.15 per diluted share. Decreased revenues from lower realized commodity prices and higher DD&A expense were the primary factors for the decrease in 2012 net income. These changes are discussed further in the analysis that follows.

Commodity Sales	For the Years Ended December 31, 2012	2011	Percent Change Between 2012/2011	Price / Volume Change Price	Volume	Total
(in thousands or as indicated)						
Gas sales	$ 340,744	$ 530,334	-36%	$ (182,482)	$ (7,108)	$ (189,590)
Oil sales	1,027,757	909,344	13%	(43,185)	161,598	118,413
NGL sales	213,149	263,842	-19%	(80,991)	30,298	(50,693)
Total commodity sales	$ 1,581,650	$ 1,703,520	-7%	$ (306,658)	$ 184,788	$ (121,870)

	2012	2011	Percent Change
Total gas volume MMcf	118,495	120,113	-1%
Gas volume MMcf/d	323.8	329.1	-2%
Average gas price per Mcf	$ 2.88	$ 4.42	-35%
Total oil volume thousand barrels	11,516	9,778	18%
Oil volume Bbl/d	31,463	26,789	17%
Average oil price per barrel	$ 89.25	$ 93.00	-4%
Total NGL volume thousand barrels	6,952	6,236	11%
NGL volume Bbl/d	18,994	17,086	11%
Average NGL price per barrel	$ 30.66	$ 42.31	-28%
Total equivalent production volumes MMcfe/d	626.5	592.3	6%

Commodity sales totaled $1.6 billion in 2012, compared to $1.7 billion in 2011. The 7% year-over-year decline was attributable to a $307 million decrease from lower prices, which was partially offset by $185 million from higher oil and NGL production.

In 2012, our aggregate production volumes were 626.5 MMcfe/d, up 6% from 592.3 Mcfe/d in 2011. The year-over-year increase in volume was a result of our successful drilling programs in the Permian Basin and Mid-Continent region.

Our 2012 gas production averaged 323.8 MMcf/d, compared to 329.1 MMcf/d for 2011. The 1% decline in gas production resulted in decreased revenues of $7.1 million.

Oil production for 2012 averaged 31,463 Bbl/d, up 18% from 26,789 Bbl/d for in 2011. The increase in 2012 production provided an additional $161.6 million of oil revenue.

In 2012, our average daily NGL production volume was 18,994 Bbl/d compared to 17,086 Bbl/d for 2011. The 11% higher volumes contributed $30.3 million of additional revenue.

The increases in our 2012 oil and NGL production reflect our continued focus on drilling oil and liquids-rich gas wells in the Permian Basin and the Cana-Woodford shale.

Our average realized gas price for 2012 fell to $2.88 per Mcf, compared to $4.42 per Mcf in 2011. The 35% decrease in gas prices resulted in $182.5 million lower revenues compared to 2011.

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Realized oil prices during 2012 averaged $89.25 per barrel, a decrease of 4% from the average price received in 2011 of $93.00 per barrel. This decrease resulted in lower oil revenue of $43.2 million compared to 2011.

During 2012 our average realized price for NGLs was $30.66 per barrel, which was 28% lower than the average realized price of $42.31 per barrel received in 2011. The decrease in realized price resulted in lower NGL sales in 2012 of $81.0 million.

The changes in realized commodity prices were the result of overall market conditions.

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

	For the Years Ended December 31,	
	2012	2011
Gas Gathering, Processing and Marketing (in thousands):		
Gas gathering, processing and other revenues	$ 43,042	$ 53,640
Gas gathering and processing costs	(21,965)	(23,327)
Gas gathering and processing margin	$ 21,077	$ 30,313
Gas marketing revenues, net of related costs	$ (754)	$ 729

The lower net margins from gas gathering and processing and gas marketing activities are primarily the result of lower volumes and prices associated with third-party gas in 2012 versus 2011.

In 2012, our total operating costs and expenses (not including gas gathering, processing and marketing and processing costs, or income tax expense) increased to $1.031 billion compared to $896 million in 2011. Analyses of the year-over-year differences are discussed below:

	For the Years Ended December 31,		Variance Between	Per Mcfe	
	2012	2011	2012/2011	2012	2011
Operating costs and expenses (in thousands):					
Depreciation, depletion and amortization (DD&A)	$ 513,916	$ 390,461	$ 123,455	$ 2.24	$ 1.81
Asset retirement obligation	13,019	11,451	1,568	$ 0.06	$ 0.05
Production	258,584	247,048	11,536	$ 1.13	$ 1.14
Transportation and other operating	57,354	56,711	643	$ 0.25	$ 0.26
Taxes other than income	86,994	126,468	(39,474)	$ 0.38	$ 0.59
General and administrative	54,428	45,256	9,172	$ 0.24	$ 0.21
Stock compensation	21,919	18,949	2,970	$ 0.10	$ 0.09
Gain on derivative instruments, net	(245)	(10,322)	10,077	N/A	N/A
Other operating, net	24,961	10,263	14,698	N/A	N/A
	$ 1,030,930	$ 896,285	$ 134,645		

Our 2012 DD&A expense increased 32% to $513.9 million, compared to $390.5 million in 2011. The $123.5 million increase accounted for 92% of the aggregate increase in operating costs and expenses. DD&A per Mcfe increased by 24% to $2.24 from $1.81. The higher DD&A rate is primarily from increasing costs of reserves added and the effect of lower prices resulting in negative reserve revisions. We expect the average DD&A rate to increase modestly during 2013.

Asset retirement obligation expense increased by 14% to $13.0 million in 2012. The increase resulted from higher estimated plugging and abandonment costs in the Permian Basin and Gulf of Mexico.

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

(in thousands)	For the Years Ended December 31, 2012	2011	Variance Between 2012/2011	Per Mcfe 2012	2011
Lease operating expense	$ 217,891	$ 208,097	$ 9,794	$ 0.95	$ 0.96
Workover expense	40,693	38,951	1,742	$ 0.18	$ 0.18
	$ 258,584	$ 247,048	$ 11,536	$ 1.13	$ 1.14

Lease operating expense in 2012 increased by 5% compared to 2011. Higher costs were associated with compressor rentals and field employees. The lower rate per Mcfe was primarily a function of increased production volumes and efficiencies of horizontal well operations for 2012 compared to 2011.

Workover expense for 2012 was slightly higher than 2011. Such costs will fluctuate based on the amount of maintenance and remedial activity planned and/or required during the period.

Our 2012 transportation and other operating costs were relatively flat compared to 2011. Transportation costs will vary based on increases or decreases in sales volumes, compression charges and fuel cost.

Taxes other than income are assessed by state and local taxing authorities on production, revenues or the value of properties. Revenue based severance taxes are the largest component of these taxes. Our 2012 taxes decreased due to lower gas and NGL prices, a reduced tax rate on Oklahoma horizontal deep wells and a refund for taxes in prior years.

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

(in thousands)	For the Years Ended December 31, 2012	2011	Variance Between 2012/2011
G&A capitalized to oil and gas properties	$ 66,611	$ 51,836	$ 14,775
G&A expense	54,428	45,256	9,172
	$ 121,039	$ 97,092	$ 23,947
G&A expense per Mcfe	$ 0.24	$ 0.21	$ 0.03

Our 2012 overall G&A cost increased 25% compared to 2011 primarily due to higher employee compensation and benefits. The increase in G&A expense includes $3.6 million of death benefits paid to the estate of former Chairman, F.H. Merelli, as per his employment contract.

Stock compensation expense consists of non-cash charges resulting from the issuance of restricted stock, restricted stock units and stock option awards, net of amounts capitalized. In accordance with our

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stock incentive plan, such grants are periodically made to non-employee directors, officers and other eligible employees. We have recognized non-cash stock-based compensation cost as follows:

(in thousands)	For the Years Ended December 31, 2012	2011	Variance Between 2012/2011
Performance restricted stock awards	$ 19,066	$ 16,268	$ 2,798
Service-based restricted stock awards	12,231	11,300	931
Restricted unit awards		34	(34)
Restricted stock and units	31,297	27,602	3,695
Stock option awards	2,889	3,518	(629)
Total stock compensation	34,186	31,120	3,066
Less amounts capitalized to oil and gas properties	(12,267)	(12,171)	(96)
Stock compensation	$ 21,919	$ 18,949	$ 2,970

Expense associated with stock compensation will fluctuate based on the grant-date market value of the award and the number of shares granted. The 2012 cost for the performance awards includes $3.9 million of accelerated compensation expense related to the death of former Chairman, F.H. Merelli. See Note 8 to the Consolidated Financial Statements of this report for further discussion regarding our stock-based compensation.

We have not elected hedge accounting treatment for our derivative instruments. Therefore, we recognize settlements and changes in the assets or liabilities relating to our open derivative contracts in earnings. Cash settlements of our contracts are included in cash flows from operating activities in our statements of cash flows. See Item 7A and Note 2 to the Consolidated Financial Statements for further details regarding our derivative instruments.

The following table summarizes the net (gains) and losses from settlements and changes in fair value of our derivative contracts as presented in our accompanying financial statements:

(in thousands)	For the Years Ended December 31, 2012	2011
(Gain) loss on derivative instruments, net:		
Natural gas contracts	$	$ (2,754)
Oil contracts	(245)	(7,568)
(Gain) loss on derivative instruments, net	$ (245)	$ (10,322)
Settlement (gains) losses:		
Natural gas contracts	$	$ (8,485)
Oil contracts		1,774
Settlement (gains) losses	$	$ (6,711)

Other operating expense consists of costs related to various legal matters, most of which pertain to litigation and contract settlements and title and royalty issues. The $14.7 million increase in expense during 2012 resulted primarily from a fourth-quarter $16.4 million accrual for a mediated royalty litigation settlement. See Note 13 to the Consolidated Financial Statements of this report for further information regarding litigation matters.

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Other (income) and expense

(in thousands)	**For the Years Ended December 31, 2012**	**2011**	**Variance Between 2012/2011**
Interest expense	$ 49,317	$ 35,611	$ 13,706
Capitalized interest	(35,174)	(29,057)	(6,117)
Loss on early extinguishment of debt	16,214		16,214
Other, net	(19,864)	(9,758)	(10,106)
	$ 10,493	$ (3,204)	$ 13,697

Our interest expense includes interest on debt and amortization of financing costs. During 2012, debt outstanding increased to $750 million from $405 million.

We capitalize interest primarily on the cost of drilling and completing wells and constructing qualified assets. The higher capitalized interest in 2012 was due to higher costs on which interest was calculated.

In connection with the retirement of our 7.125% senior notes, we recognized a $16.2 million loss on early extinguishment of debt in the second quarter of 2012. The retirement of our 7.125% notes and the issuance of our 5.875% senior notes are described in more detail under ***Long-Term Debt*** below.

Components of other, net consist of miscellaneous income and expense items that will vary from period to period, including gain or loss on the sale or value of oil and gas well equipment, income and expense associated with other non-operating activities, miscellaneous asset sales and interest income. The $10.1 million increase in 2012 was mainly due to increased income from non-operating activities.

Income Tax Expense

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

(in thousands)	**For the Years Ended December 31, 2012**	**2011**
Current benefit	$ (1,489)	$ (46,073)
Deferred taxes	208,216	357,622
	$ 206,727	$ 311,549
Combined Federal and state effective income tax rate	36.9%	37.0%

Our income tax expense (benefit) differs from the statutory rate of 35% due to the effects of state income taxes, the Domestic Production Activities allowance and other permanent differences. See Note 6 to the Consolidated Financial Statements of this report for further information regarding our income taxes.

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LIQUIDITY AND CAPITAL RESOURCES

Overview

Our liquidity is highly dependent on the prices we receive for the oil, gas and NGLs we produce. Prices received for production heavily influence our revenue, cash flow, profitability, access to capital and future rate of growth.

During 2013, we saw an improvement in our realized natural gas prices compared to the prior two years. Oil and NGL prices continued to fluctuate during 2013 due to supply and demand factors, seasonality and other geopolitical and economic factors. It is likely that commodity prices will continue to fluctuate in the future. See ***Revenues*** above for more information about our realized commodity prices.

We deal with volatility in commodity prices by maintaining flexibility in our capital investment program. In addition, we periodically hedge a portion of our oil and/or gas production to mitigate our potential exposure to price declines and the corresponding negative impact on cash flow available for investment.

During 2013, our exploration and development (E&D) expenditures of $1.6 billion were largely funded by cash flow provided by operating activities (operating cash flow). Based on current economic conditions, our 2014 E&D capital expenditures are estimated to be $1.8 billion, which we expect to be funded primarily by operating cash flow and long-term debt. Occasional sales of non-core assets may also be used to supplement funding of capital expenditures. The timing of capital expenditures and the receipt of cash flows do not necessarily match, causing us to borrow and repay funds under our bank credit facility throughout the year.

We consider acquisition opportunities that play to our strengths and that have drilling upside. However, the timing and size of potential acquisitions is unpredictable.

At December 31, 2013, our long-term debt totaled $924 million and consisted of $750 million of 5.875% senior notes and $174 million of borrowings under our senior unsecured revolving credit facility. We also had letters of credit outstanding under our credit facility of $2.5 million, leaving an unused borrowing availability of $823.5 million. Our debt to total capitalization at December 31, 2013 was 19%. The reconciliation of debt to total capitalization, which is a non-GAAP measure, is long-term debt ($924 million) divided by long-term debt plus stockholders' equity ($4,022 million). Management believes that this non-GAAP measure is useful information as it is a common statistic used in the investment community.

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

Sources and Uses of Cash

Our primary sources of liquidity and capital resources are operating cash flow, borrowings under our bank credit facility, asset sales and public offerings of debt securities. Our primary uses of funds are expenditures for exploration, development, leasehold and property acquisitions, other capital expenditures, debt service and common stock dividends.

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The following table presents our sources and uses of cash and cash equivalents from 2011 to 2013. Capital expenditures are presented on a cash basis. These amounts differ from capital expenditures (including accruals) that are referred to elsewhere in this report.

	For the Years Ended December 31,		
(in thousands)	**2013**	**2012**	**2011**
Sources of cash and cash equivalents:			
Operating cash flow	$ 1,324,348	$ 1,192,764	$ 1,292,275
Sales of oil and gas and other assets	93,164	312,622	229,355
Net increase in bank debt	174,000		55,000
Increase in other long-term debt		750,000	
Issuance of common stock and other	14,494	11,433	10,411
Total sources of cash and cash equivalents	1,606,006	2,266,819	1,587,041
Uses of cash and cash equivalents:			
Oil and gas capital expenditures	(1,572,288)	(1,662,707)	(1,562,159)
Other capital expenditures	(51,913)	(64,987)	(96,642)
Net decrease in bank debt		(55,000)	
Decrease in other long-term debt		(363,595)	
Financing costs incurred	(100)	(13,821)	(7,379)
Dividends paid	(46,712)	(39,577)	(32,581)
Total uses of cash and cash equivalents	(1,671,013)	(2,199,687)	(1,698,761)
Net increase (decrease) in cash and cash equivalents	$ (65,007)	$ 67,132	$ (111,720)
Cash and cash equivalents at end of year	$ 4,531	$ 69,538	$ 2,406

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

Cash flow provided by operating activities for 2013 was $1.3 billion compared to $1.2 billion for 2012 and $1.3 billion for 2011. The increase from 2012 to 2013 was primarily a result of increased revenue from higher realized commodity prices and increased production volumes, which was partially offset by higher production related operating expenses. The decrease in 2012 compared to 2011was mostly due to lower realized commodity prices, which were only partially offset by higher oil and NGL sales volumes.

In 2013, cash flow used in investing activities was $1.5 billion, compared to $1.4 billion for both 2012 and 2011. In 2013, we had E&D and other capital expenditures of $1.6 billion, which were partially offset by proceeds from asset sales of $93 million. Our 2012 E&D and other capital expenditures were $1.7 billion, which were partially offset by asset sales of $313 million. For 2011, our E&D and other capital expenditures of $1.6 billion were partially offset by asset sales of $229 million.

Net cash flow provided by financing activities in 2013 was $141.7 million compared to $289.4 million in 2012 and $25.5 million in 2011. In 2013, we had cash inflows from net bank borrowings of $174.0 million together with net proceeds from the issuance of common stock and other of $14.4 million, which were partially offset by $46.7 million of dividend payments. During 2012, cash proceeds from issuance of $750.0 million of long-term debt and $11.4 million of common stock were offset by debt payments of $418.6 million, financing costs of $13.8 million and dividend payments of $39.6 million. Our 2011 net cash inflow came from net bank borrowing of $55.0 million plus

$10.4 million from the issuance of common stock, less $32.6 million of dividend payments and $7.3 million of financing costs.

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Reconciliation of Adjusted Cash Flow from Operations

	For the Year Ended December 31,		
(in thousands)	**2013**	**2012**	**2011**
Net cash provided by operating activities	$ 1,324,348	$ 1,192,764	$ 1,292,275
Change in operating assets and liabilities	63,840	(58,049)	22,686
Adjusted cash flow from operations	$ 1,388,188	$ 1,134,715	$ 1,314,961

Management believes that the non-GAAP measure of adjusted cash flow from operations is useful information for investors. It is accepted by the investment community as a means of measuring the company's ability to fund its capital program without reflecting fluctuations caused by changes in current assets and liabilities (which are included in the GAAP measure of cash flow from operating activities). It is also used by professional research analysts in providing investment recommendations pertaining to companies in the oil and gas exploration and production industry.

Capital Expenditures

The following table sets forth certain historical information regarding capitalized expenditures for oil and gas acquisitions, exploration and development activities and property sales:

	For Years Ended December 31,	
(in thousands)	**2013**	**2012**
Acquisitions:		
Proved	$ 682	$ 2,645
Unproved	36,396	30,870
	37,078	33,515
Exploration and development:		
Land & seismic	165,107	121,960
Exploration	46,290	74,034
Development	1,354,098	1,426,918
	1,565,495	1,622,912
Property sales	(61,503)	(305,862)
	$ 1,541,070	$ 1,350,565

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

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During 2013 and 2012, our E&D expenditures have been largely focused on the Delaware Basin of our Permian region and Cana-Woodford shale of our Mid-Continent region. The following table reflects wells drilled by region:

	For the Years Ended December 31,	
	2013	**2012**
Gross wells		
Permian Basin	175	182
Mid-Continent	183	167
Other	7	3
	365	352
Net wells		
Permian Basin	115	122
Mid-Continent	65	69
Other	5	1
	185	192
% Gross wells completed as producers	99%	95%

Our 2014 E&D capital expenditures are expected to be approximately $1.8 billion, most of which will again be directed towards drilling oil and liquids-rich gas wells in the Permian Basin and Mid-Continent regions.

We actively evaluate acquisitions, particularly in our core area of operations. We also evaluate our non-core property holdings for potential divestitures. For further information on our property acquisitions and dispositions, see Note 14 to the Consolidated Financial Statements of this report.

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

Our 2013 drilling program is discussed in more detail in *Exploration and Production Overview* under Item 1 of this report.

Financial Condition

Future cash flows and the availability of financing are subject to a number of variables including success in finding and producing new reserves, production from existing wells and realized commodity prices. To meet capital and liquidity requirements, we rely on certain resources, including cash flows from operating activities, bank borrowings and access to capital markets. We routinely use our bank credit facility to finance our working capital needs.

During 2013, our total assets increased $948 million to $7.2 billion, up from $6.3 billion at December 31, 2012. The increase was primarily due to a $961 million increase in net oil and gas properties.

Total liabilities at year-end 2013 increased to $3.2 billion, up $401 million from $2.8 billion at year-end 2012. This was mainly due to an increase of $174 million in long-term debt and a $338 million increase in deferred income taxes, which were partially offset by a $142 million decrease in other long-term liabilities.

On December 31, 2013, stockholders' equity totaled $4.0 billion, up $547 million from $3.5 billion at December 31, 2012. The increase primarily resulted from our 2013 net income of $565 million.

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Dividends

A quarterly cash dividend has been paid to stockholders every quarter since the first quarter of 2006. In February 2013, the quarterly dividend was increased to $0.14 per share from $0.12 per share. Future dividend payments will depend on our level of earnings, financial requirements and other factors considered relevant by the Board of Directors.

	2013	2012	2011
Dividend declared (in millions)	$ 48.4	$ 41.3	$ 34.3
Dividend per share	$ 0.56	$ 0.48	$ 0.40

Working Capital Analysis

Our working capital fluctuates primarily as a result of our exploration and development activities, realized commodity prices and changes related to our operating activities.

Working capital decreased $38.3 million from a deficit of $175.7 million at December 31, 2012, to a deficit of $214.0 million at December 31, 2013.

The decrease in working capital was a result of the following:

- Cash and cash equivalents decreased by $65.0 million.
- Net accounts payable and accrued liabilities related to non-E&D expenditures increased by $18.6 million.
- Accrued liabilities related to our E&D expenditures increased by $18.3 million.

Working capital decreases were partially offset by:

- An increase in operations-related accounts receivable of $64.7 million.

Accounts receivable are a major component of working capital and include a diverse group of companies comprised of major energy companies, pipeline companies, local distribution companies and other end-users. The collection of receivables during the periods presented has been timely. Historically, losses associated with uncollectible receivables have not been significant.

Long-Term Debt

Long-term debt at December 31, 2013, and December 31, 2012, consisted of the following:

(in thousands)	2013	2012
Bank debt	$ 174,000	$
5.875% Senior Notes due 2022	750,000	750,000
Total long-term debt	$ 924,000	$ 750,000

Bank Debt

We have a five-year senior unsecured revolving credit facility (Credit Facility) that matures July 14, 2016. Under our Credit Facility, the borrowing base is determined at the discretion of the lenders based on the value of our proved reserves. In April 2013, our borrowing base was increased from $2 billion to $2.25 billion. Our aggregate commitments remain unchanged at $1 billion. The next regular annual redetermination date is scheduled for April 15, 2014.

As of December 31, 2013, we had $174 million of bank debt outstanding at a weighted average interest rate of 2.15%. We also had letters of credit outstanding of $2.5 million, leaving an unused borrowing

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availability of $823.5 million. During 2013, we had average daily bank debt outstanding of $159.3 million, compared to $96.3 million in 2012. Our highest amount of bank borrowings outstanding during 2013 was $300 million in December. During 2012, the highest amount of outstanding bank borrowings was $296 million in December.

At our option, borrowings under the Credit Facility may bear interest at either (a) LIBOR plus 1.75-2.5%, based on our leverage ratio; or (b) the higher of (i) a prime rate, (ii) the federal funds effective rate plus 0.50%, or (iii) adjusted one-month LIBOR plus 1.0% plus, in each case, an additional 0.75-1.5%, based on our leverage ratio.

The Credit Facility has a number of financial and non-financial covenants. We were in compliance with all these covenants at December 31, 2013. For further information see Note 5 to the Consolidated Financial Statements of this report.

5.875% Notes due 2022

In April 2012, we issued $750 million of 5.875% senior notes due May 1, 2022, with interest payable semiannually in May and November. The notes were sold to the public at par. The notes are governed by an indenture containing certain covenants, events of default and other restrictive provisions. We may redeem the notes in whole or in part, at any time on or after May 1, 2017, at redemption prices of 102.938% of the principal amount as of May 1, 2017, declining to 100% on May 1, 2020 and thereafter.

7.125% Notes due 2017

In May 2007, we issued $350 million of 7.125% senior unsecured notes at par that were scheduled to mature May 1, 2017. In March 2012, we commenced a cash tender offer (Tender Offer) to purchase all of the outstanding 7.125% senior notes. The Tender Offer was completed in the second quarter of 2012. We recognized a $16.2 million loss on early extinguishment of debt in connection with this transaction.

Off-Balance Sheet Arrangements

We may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. As of December 31, 2013, our material off-balance sheet arrangements included operating lease agreements which are customary in the oil and gas industry.

Contractual Obligations and Material Commitments

At December 31, 2013, we had contractual obligations and material commitments as follows:

		Payments Due by Period			
Contractual obligations:	**Total**	**1 Year or Less**	**2 - 3 Years**	**4 - 5 Years**	**More than 5 Years**
(in thousands)					
Long-term debt(1)	$ 924,000	$	$ 174,000	$	$ 750,000
Fixed-Rate interest payments(1)	374,531	44,063	88,125	88,125	154,218
Operating leases	127,763	8,354	21,492	20,623	77,294
Drilling commitments(2)	170,595	170,595			
Gathering facilities and pipelines(3)	1,827	1,827			
Asset retirement obligation	154,026	27,058	(4)	(4)	(4)
Other(5)	68,389	16,644	31,144	3,050	17,551
Firm Transportation	645	502	143		

(1) These amounts do not include interest on the $174 million of bank debt outstanding at December 31, 2013. See Item 7A: Interest Rate Risk for more information regarding fixed and variable rate debt.

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(2) Our drilling commitments consist of obligations to finish drilling and completing wells in progress at December 31, 2013.

(3) We have projects in New Mexico and Texas where we are constructing gathering facilities and pipelines. At December 31, 2013, we had commitments of $1.8 million relating to this construction.

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

(5) Other includes the estimated value of our commitment associated with our benefit obligations and other miscellaneous commitments.

At December 31, 2013, we had firm sales contracts to deliver approximately 19.4 Bcf of natural gas over the next 10 months. In total, our financial exposure would be approximately $68.6 million should this gas not be delivered. Our exposure will fluctuate with price volatility and actual volumes delivered, however, we believe Cimarex has no financial exposure from these contracts based on our current proved reserves and production levels. In the normal course of business we have various other delivery commitments which are not material individually or in the aggregate. All of the noted commitments were routine and were made in the normal course of our business.

Based on current commodity prices and anticipated levels of production, we believe that estimated net cash generated from operations and amounts available under our existing bank Credit Facility will be adequate to meet future obligations.

2014 Outlook

Our 2014 E&D capital investment is presently expected to be $1.8 billion, with the majority of the capital allocated to projects in the Permian Basin. The remainder will be spent in our Mid-Continent region, mainly drilling Cana-Woodford shale wells.

Total company production volumes are projected to average 760-800 MMcfe/d in 2014, a midpoint increase of 13% over 2013. Oil production is expected to grow 17-19% in 2014. As has been our historical practice, we regularly review capital expenditures throughout the year and will adjust our investments based on changes in commodity prices, service costs and drilling success. We have the flexibility to adjust our capital expenditures based upon market conditions.

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CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

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

Oil and Gas Reserves

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

At year-end 2013, 20% of our total proved reserves are categorized as proved undeveloped reserves, or PUDs. Our reserve engineers review and revise these reserve estimates regularly, as new information becomes available.

We use the units-of-production method to amortize the cost associated with our oil and gas properties. Changes in estimates of reserve quantities and commodity prices will cause corresponding changes in depletion expense, or in some cases, a full cost ceiling limitation charge in the period of the revision.

See Note 15 to the Consolidated Financial Statements for additional reserve data.

Full Cost Accounting

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

Companies that follow the full cost accounting method are required to make a quarterly ceiling test calculation. This test ensures that total capitalized costs for oil and gas properties (net of accumulated DD&A and deferred income taxes) do not exceed the sum of the present value discounted at 10% of estimated future net cash flows from proved reserves, the cost of properties not being amortized, the lower of cost or estimated fair value of unproven properties included in the costs being amortized and all related tax effects. We currently do not have any unproven properties being amortized. Revenue calculations in

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the reserves are based on the unweighted average first-day-of-the-month commodity price for the prior twelve months. Changes in proved reserve estimates (whether based upon quantity revisions or commodity price) will cause corresponding changes to the full cost ceiling limitation. If net capitalized costs subject to amortization exceed this limit, the excess would be expensed. Recorded impairment of oil and gas properties is not reversible.

Quarterly and annual ceiling tests are primarily impacted by commodity prices, reserve quantities added and produced, overall exploration and development costs, depletion expense and deferred taxes. As of December 31, 2013, 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 3% or more in the value of the ceiling limitation would have resulted in an impairment. If pricing conditions decline, or if there is a negative impact on one or more of the other components of the calculation, we may incur a full cost ceiling impairment related to our oil and gas properties in future quarters. An impairment charge would have no effect on liquidity or our capital resources, but could adversely affect our results of operations in the period incurred.

Depletion of proved oil and gas properties is computed on the units-of-production method, whereby capitalized costs, including future development costs and asset retirement obligations, are amortized over total estimated proved reserves. Changes in our estimate of proved reserve quantities and commodity prices will cause corresponding changes in depletion expense in periods subsequent to these changes. The capitalized costs of unproved properties, including those in wells in progress, are excluded from the costs being amortized. We do not have major development projects that are excluded from costs being amortized. On a quarterly basis, we evaluate excluded costs for inclusion in the costs to be amortized resulting from the determination of proved reserves or impairments. To the extent that the evaluation indicates these properties are impaired, the amount of the impairment is added to the capitalized costs to be amortized. Expenditures for maintenance and repairs are charged to production expense in the period incurred.

Goodwill

Goodwill represents the excess of the purchase price of business combinations over the fair value of the net assets acquired and is tested for impairment at least annually. In 2012, we adopted the Financial Accounting Standards Board (FASB) Accounting Standards Update No. 2011-08: *Intangibles Goodwill and Other (Topic 350): Testing Goodwill for Impairment* (ASU 2011-08). ASU 2011-08 allows an entity to first assess qualitative factors to determine whether it is more likely than not (with a greater than 50% threshold) that the fair value of a reporting unit is less than its carrying amount as a basis for determining whether it is necessary to perform the two-step goodwill impairment test. If goodwill is determined to be impaired, then it is written down to a calculated fair value by charging the impairment to expense.

We evaluate our goodwill for impairment in the fourth quarter of each year or whenever events or changes in circumstances indicate the possibility that goodwill may be impaired. Based upon our qualitative assessment at December 31, 2013, goodwill was not impaired. It is possible that goodwill could become impaired in the future if commodity prices or other economic factors become less favorable.

Contingencies

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

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At December 31, 2013, we have not made any accruals related to environmental remediation costs. However, we may be required to make such estimates in future periods if applicable laws and regulations change or if the interpretation or administration of laws and regulations change. Other factors, such as unanticipated construction problems or identification of areas of contaminated soil or groundwater, could also cause us to accrue for such costs.

Hitch Enterprises, Inc. et al. v. Cimarex Energy Co. et al.

On December 11, 2012, Cimarex entered into a preliminary resolution of the *Hitch Enterprises, Inc., et al. v. Cimarex Energy Co., et al.* (*Hitch*) litigation matter for $16.4 million. *Hitch* is a statewide royalty class action pending in the Federal District Court in Oklahoma City, Oklahoma. The settlement was reached at a mediation, which occurred after the parties began to exchange information, including damage analyses, on November 16, 2012. On July 2, 2013, the Court entered a judgment approving the parties' settlement. The judgment became final and unappealable on August 2, 2013. Cimarex distributed the settlement proceeds pursuant to the Court's order in September 2013 and the administration of the settlement is ongoing. In the fourth quarter of 2012, we accrued $16.4 million for this matter.

H.B. Krug, et al. versus H&P

In January 2009, the Tulsa County District Court issued a judgment totaling $119.6 million in the *H.B. Krug, et al. versus Helmerich & Payne, Inc.* (H&P) case. This lawsuit originally was filed in 1998 and addressed H&P's conduct pertaining to a 1989 take-or-pay settlement, along with potential drainage and other related issues. Pursuant to the 2002 spin-off of Cimarex to stockholders of H&P, Cimarex assumed the assets and liabilities of H&P's exploration and production business, including this lawsuit. In 2008, we recorded litigation expense of $119.6 million for this lawsuit and began accruing additional post-judgment interest and costs.

On August 18, 2011, the Oklahoma Court of Appeals issued an Opinion regarding the *Krug* litigation. The Oklahoma Court of Appeals reversed and remanded the $112.7 million disgorgement of profits award, holding the District Court erred in failing to make the required findings of fact and conclusions of law. In all other respects, the Court of Appeals affirmed the judgment, including damages of $6.845 million. On February 13, 2012, the Oklahoma Supreme Court granted Cimarex's Petition for Certiorari, which requested a review of the affirmed portion of the judgment.

On December 10, 2013, the Oklahoma Supreme Court reversed the trial court's original judgment of $119.6 million and affirmed an alternative jury verdict for $3.65 million. In light of the Oklahoma Supreme Court's ruling, on December 31, 2013, we reduced previously recognized litigation expense and the associated long-term liability by $142.8 million. A portion of our anticipated remaining liability includes estimates for amounts yet to be adjudicated. These estimates are likely to change.

On December 30, 2013, the Plaintiffs filed a Petition for Rehearing with the Oklahoma Supreme Court. On February 24, 2014, the Oklahoma Supreme Court denied the Plaintiffs' Petition for Rehearing. Our assessments and estimates likely will change in the future as a result of legal proceedings that cannot be predicted at this time.

In the normal course of business, we have various litigation matters. We assess the probability of estimable amounts related to litigation matters in accordance with guidance established by the FASB and adjust our accruals accordingly. Though some of the related claims may be significant, the resolution of them we believe, individually or in the aggregate, would not have a material adverse effect on our financial condition or results of operations. See Note 13 to the Consolidated Financial Statements for additional information regarding our contingencies.

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Asset Retirement Obligation

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

Asset retirement liability is determined using significant assumptions including current estimates of plugging and abandonment costs, annual inflation of these costs, the productive lives of assets and our risk-adjusted interest rate. Changes in any of these assumptions can result in significant revisions to the estimated asset retirement obligation. Because of the subjectivity of assumptions, the costs to ultimately retire our wells may vary significantly from prior estimates. See Note 4 to the Consolidated Financial Statements of this report for additional information regarding our asset retirement obligations.

Recently Issued Accounting Standards

No significant accounting standards applicable to Cimarex have been issued during the year ended December 31, 2013.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market risk refers to the risk of loss arising from adverse changes in commodity prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses but rather indicators of reasonably possible losses.

Price Fluctuations

Our major market risk is pricing applicable to our oil and gas production. The prices we receive for our production are based on prevailing market conditions and are influenced by many factors that are beyond our control. Pricing for oil and gas production has been volatile and unpredictable.

We periodically enter into financial derivative contracts to hedge a portion of our price risk associated with our future oil and gas production.

The following tables detail the financial derivative contracts we have in place as of December 31, 2013:

Oil Contracts

				Weighted Average Price		
Period	**Type**	**Volume/Day**	**Index(1)**	**Floor**	**Ceiling**	**Fair Value (in thousands)**
Jan 14 - Dec 14	Collars	12,000 Bbls	WTI	$ 85.00	$ 103.47	$ 1,416

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

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Gas Contracts

Period	Type	Volume/Day	Index(1)	Weighted Average Price Floor	Weighted Average Price Ceiling	Fair Value (in thousands)
Jan 14 - Dec 14	Collars	80,000 MMBtu	PEPL	$ 3.51	$ 4.57	$ 2,329
Jan 14 - Dec 14	Collars	20,000 MMBtu	Perm EP	$ 3.65	$ 4.50	$ 90
Feb 14 - Dec 14	Collars	10,000 MMBtu	Perm EP	$ 3.65	$ 4.50	$ 44

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

While these contracts limit the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. For the oil contracts listed above, a hypothetical $1.00 change in the price below or above the contracted price applied to the notional amounts would cause a change in our gain (loss) on mark-to-market derivatives in 2013 of $4.4 million. For the gas contracts listed above, a hypothetical $0.10 change in the price below or above the contracted price applied to the notional amounts would cause a change in our gain (loss) on mark-to-market derivatives in 2013 of $4.0 million.

Subsequent to December 31, 2013, we entered into gas collars. See Note 2 to the Consolidated Financial Statements of this report for additional information regarding our derivative instruments.

Counterparty credit risk did not have a significant effect on our cash flow calculations and commodity derivative valuations. This is primarily because we have mitigated our exposure to any single counterparty by contracting with numerous counterparties and because our derivative contracts are held with "investment grade" counterparties that are a part of our credit facility. See Note 2 to the Consolidated Financial Statements of this report for additional information regarding our derivative instruments.

Interest Rate Risk

At December 31, 2013, our debt was comprised of the following:

(in thousands)	Fixed Rate Debt	Variable Rate Debt
Bank debt	$	$ 174,000
5.875% Notes due 2022	750,000	
Total long-term debt	$ 750,000	$ 174,000

As of December 31, 2013, the amounts outstanding under our five-year senior unsecured revolving credit facility bears interest at either (a) LIBOR plus 1.75-2.5%, based on our leverage ratio, or (b) the higher of (i) a prime rate, (ii) the federal funds effective rate plus 0.50%, or (iii) adjusted one-month LIBOR plus 1.0% plus, in each case, an additional 0.75-1.5%, based on our leverage ratio. Our senior unsecured notes bear interest at a fixed rate of 5.875% and will mature on May 1, 2022.

We consider our interest rate exposure to be minimal because approximately 81% of our long-term debt obligations were at fixed rates. An increase of 100 basis points in the interest rate of our variable rate debt would increase our annual interest expense by $1.7 million. This sensitivity analysis for interest rate risk excludes accounts receivable, accounts payable and accrued liabilities because of the short-term maturity of such instruments. See Note 3 and Note 5 to the Consolidated Financial Statements in this report for additional information regarding debt.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

CIMAREX ENERGY CO.

INDEX TO FINANCIAL STATEMENTS AND SUPPLEMENTAL SCHEDULES

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

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Cimarex Energy Co.:

We have audited the accompanying consolidated balance sheets of Cimarex Energy Co. and subsidiaries (the Company) as of December 31, 2013 and 2012, and the related consolidated statements of income and comprehensive income, stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2013. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Cimarex Energy Co. and subsidiaries as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2013, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control Integrated Framework* (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 26, 2014 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

KPMG LLP

Denver, Colorado
February 26, 2014

CIMAREX ENERGY CO.

CONSOLIDATED BALANCE SHEETS

(in thousands, except share and per share information)

	December 31, 2013	December 31, 2012
Assets		
Current assets:		
Cash and cash equivalents	$ 4,531	$ 69,538
Restricted cash	818	
Accounts receivable:		
Trade, net of allowance	83,070	55,528
Oil and gas sales, net of allowance	265,050	239,106
Gas gathering, processing, and marketing, net of allowance	19,102	7,901
Other	532	439
Oil and gas well equipment and supplies	66,772	81,029
Deferred income taxes	16,854	8,477
Derivative instruments	4,268	
Prepaid Expenses	7,867	7,420
Other current assets	275	699
Total current assets	469,139	470,137
Oil and gas properties at cost, using the full cost method of accounting:		
Proved properties	12,863,961	11,258,748
Unproved properties and properties under development, not being amortized	585,361	645,078
	13,449,322	11,903,826
Less accumulated depreciation, depletion and amortization	(7,483,685)	(6,899,057)
Net oil and gas properties	5,965,637	5,004,769
Fixed assets, less accumulated depreciation of $167,675 and $145,130	146,918	152,605
Goodwill	620,232	620,232
Other assets, net	51,209	57,409
	$ 7,253,135	$ 6,305,152
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable:		
Trade	$ 80,918	$ 88,168
Gas gathering, processing, and marketing	35,192	15,485
Accrued liabilities:		
Exploration and development	173,298	155,002

Taxes other than income	27,509	29,179
Other	211,688	208,728
Derivative instruments	389	
Revenue payable	154,173	149,300
Total current liabilities	683,167	645,862
Long-term debt	924,000	750,000
Deferred income taxes	1,459,841	1,121,353
Asset retirement obligation	126,968	133,991
Other liabilities	36,951	179,210
Total liabilities	3,230,927	2,830,416
Commitments and contingencies		
Stockholders' equity:		
Preferred stock, $0.01 par value, 15,000,000 shares authorized, no shares issued		
Common stock, $0.01 par value, 200,000,000 shares authorized, 87,152,197 and 86,595,976 shares issued, respectively	872	866
Paid-in capital	1,970,113	1,939,628
Retained earnings	2,050,034	1,533,768
Accumulated other comprehensive income	1,189	474
	4,022,208	3,474,736
	$ 7,253,135	$ 6,305,152

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

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CIMAREX ENERGY CO.

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

(in thousands, except per share data)

	For the Years Ended December 31,		
	2013	**2012**	**2011**
Revenues:			
Gas sales	$ 471,045	$ 340,744	$ 530,334
Oil sales	1,250,212	1,027,757	909,344
NGL Sales	231,248	213,149	263,842
Gas gathering, processing and other	45,441	43,042	53,640
Gas marketing, net of related costs of $187,772, $86,813 and $119,725 respectively	105	(754)	729
	1,998,051	1,623,938	1,757,889
Costs and expenses:			
Depreciation, depletion and amortization	615,874	513,916	390,461
Asset retirement obligation	7,989	13,019	11,451
Production	286,742	258,584	247,048
Transportation and other operating	93,580	57,354	56,711
Gas gathering and processing	25,876	21,965	23,327
Taxes other than income	112,732	86,994	126,468
General and administrative	77,466	54,428	45,256
Stock compensation	14,279	21,919	18,949
(Gain) loss on derivative instruments, net	209	(245)	(10,322)
Other operating (income) expense, net	(132,334)	24,961	10,263
	1,102,413	1,052,895	919,612
Operating income	895,638	571,043	838,277
Other (income) and expense:			
Interest expense	54,973	49,317	35,611
Capitalized interest	(31,517)	(35,174)	(29,057)
Loss on early extinguishment of debt		16,214	
Other, net	(21,518)	(19,864)	(9,758)
Income before income tax	893,700	560,550	841,481
Income tax expense	329,011	206,727	311,549
Net income	$ 564,689	$ 353,823	$ 529,932

Earnings per share to common shareholders:						
Basic						
Distributed	$	0.56	$	0.48	$	0.40
Undistributed		5.92		3.60		5.77
	$	6.48	$	4.08	$	6.17
Diluted						
Distributed	$	0.56	$	0.48	$	0.40
Undistributed		5.91		3.59		5.75
	$	6.47	$	4.07	$	6.15
Comprehensive income:						
Net income	$	564,689	$	353,823	$	529,932
Other comprehensive income:						
Change in fair value of investments, net of tax		715		488		(278)
Total comprehensive income	$	565,404	$	354,311	$	529,654

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

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CIMAREX ENERGY CO.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Years Ended December 31,		
	2013	2012	2011
Cash flows from operating activities:			
Net income	$ 564,689	$ 353,823	$ 529,932
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	615,874	513,916	390,461
Asset retirement obligation	7,989	13,019	11,451
Deferred income taxes	329,700	208,216	357,622
Stock compensation	14,279	21,919	18,949
(Gain) loss on derivative instruments	209	(245)	(10,322)
Settlements on derivative instruments	(4,088)		6,711
Loss on early extinguishment of debt		16,214	
Changes in non-current assets and liabilities	(141,215)	3,125	4,418
Other, net	751	4,728	5,739
Changes in operating assets and liabilities:			
Receivables, net	(64,780)	56,435	(48,632)
Other current assets	14,234	4,209	32,593
Accounts payable and other current liabilities	(13,294)	(2,595)	(6,647)
Net cash provided by operating activities	1,324,348	1,192,764	1,292,275
Cash flows from investing activities:			
Oil and gas expenditures	(1,572,288)	(1,662,707)	(1,562,159)
Sales of oil and gas assets	61,503	311,562	117,344
Sales of other assets	31,661	1,060	112,011
Other capital expenditures	(51,913)	(64,987)	(96,642)
Net cash used by investing activities	(1,531,037)	(1,415,072)	(1,429,446)
Cash flows from financing activities:			
Net bank debt borrowings	174,000	(55,000)	55,000
Proceeds from other long-term debt		750,000	
Other long-term debt payments		(363,595)	
Financing costs incurred	(100)	(13,821)	(7,379)
Dividends paid	(46,712)	(39,577)	(32,581)
Issuance of common stock and other	14,494	11,433	10,411
Net cash provided by financing activities	141,682	289,440	25,451
Net change in cash and cash equivalents	(65,007)	67,132	(111,720)
Cash and cash equivalents at beginning of period	69,538	2,406	114,126

Cash and cash equivalents at end of period	$ 4,531	$ 69,538	$ 2,406

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

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CIMAREX ENERGY CO.

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

(in thousands)

	Common Stock Shares	Common Stock Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (loss)	Treasury Stock	Total Stockholders' Equity
Balance, December 31, 2010	85,235	$ 852	$ 1,883,065	$ 725,651	$ 264	$	$ 2,609,832
Dividends				(34,320)			(34,320)
Net Income				529,932			529,932
Unrealized change in fair value of investments, net of tax					(278)		(278)
Issuance of restricted stock awards	655	7	(7)				
Common stock reacquired and retired	(192)	(2)	(16,064)				(16,066)
Restricted stock forfeited and retired	(37)						
Exercise of stock options	78	1	3,192				3,193
Vesting of restricted stock units	35						
Stock-based compensation			31,102				31,102
Stock-based compensation tax benefit			7,218				7,218
Balance, December 31, 2011	85,774	$ 858	$ 1,908,506	$ 1,221,263	$ (14)	$	$ 3,130,613
Dividends				(41,318)			(41,318)
Net Income				353,823			353,823
Unrealized change in fair value of investments, net of tax					488		488
Issuance of restricted stock awards	562	5	(5)				
Common stock reacquired and retired	(184)	(2)	(11,015)				(11,017)
Restricted stock forfeited and retired	(141)	(1)	1				
Exercise of stock options	559	6	11,427				11,433
Vesting of restricted stock units	26						
Stock-based compensation			34,085				34,085
Stock-based compensation tax benefit			(3,371)				(3,371)
Balance, December 31, 2012	86,596	$ 866	$ 1,939,628	$ 1,533,768	$ 474	$	$ 3,474,736
Dividends				(48,423)			(48,423)
Net Income				564,689			564,689
Unrealized change in fair value of investments, net of tax					715		715
Issuance of restricted stock awards	579	6	(6)				
Common stock reacquired and retired	(153)	(1)	(10,100)				(10,101)
Restricted stock forfeited and retired	(171)	(2)	2				
Exercise of stock options	276	3	14,491				14,494
Vesting of restricted stock units	25						
Stock-based compensation			26,098				26,098
Balance, December 31, 2013	87,152	$ 872	$ 1,970,113	$ 2,050,034	$ 1,189	$	$ 4,022,208

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

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CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. BASIS OF PRESENTATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

Basis of presentation

Our Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in the United States of America, or GAAP. Our significant accounting policies are discussed below. The accounts of Cimarex and its subsidiaries are presented in the accompanying Consolidated Financial Statements. All intercompany accounts and transactions were eliminated in consolidation. Certain amounts in prior years' financial statements have been reclassified to conform to the 2013 financial statement presentation.

Use of estimates

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

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

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

Cash, Cash Equivalents and Restricted Cash

Cash and cash equivalents consist of cash in banks and investments readily convertible into cash, which have original maturities of three months or less. Cash equivalents are stated at cost, which approximates market value. At December 31, 2012, we had restricted cash of $811 thousand included in our "non-current other assets." This consisted of monies from third parties being held by Cimarex pending resolution of ownership disputes. As of December 31, 2013, the ownership disputes were resolved and we have transferred the restricted cash and the related liability from non-current to current.

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CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

1. BASIS OF PRESENTATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Oil and Gas Well Equipment and Supplies

Our oil and gas well equipment and supplies are valued at the lower of cost or market using weighted average cost.

Oil and Gas Properties

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

Companies that follow the full cost accounting method are required to make quarterly ceiling test calculations. This test ensures that total capitalized costs for oil and gas properties (net of accumulated DD&A and deferred income taxes) do not exceed the sum of the present value discounted at 10% of estimated future net cash flows from proved reserves, the cost of properties not being amortized, the lower of cost or estimated fair value of unproven properties included in the costs being amortized, and all related tax effects. We currently do not have any unproven properties that are being amortized. Revenue calculations in the reserves are based on the unweighted average first-day-of-the-month prices for the prior twelve months. Changes in proved reserve estimates (whether based upon quantity revisions or commodity prices) will cause corresponding changes to the full cost ceiling limitation. If net capitalized costs subject to amortization exceed this limit, the excess would be charged to expense. Any recorded impairment of oil and gas properties is not reversible at a later date.

Our quarterly and annual ceiling tests are primarily impacted by commodity prices, reserve quantities added and produced, overall exploration and development costs and depletion expense. As of December 31, 2013, 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 3% or more in the value of the ceiling limitation would have resulted in an impairment. If pricing conditions decline, or if there is a negative impact on one or more of the other components of the calculation, we may incur a full cost ceiling impairment related to our oil and gas properties in future quarters. An impairment charge would have no effect on liquidity or our capital resources, but it would adversely affect our results of operations in the period incurred.

Depletion of proved oil and gas properties is computed on the units-of-production method, whereby capitalized costs, including future development costs and asset retirement obligations, are amortized over total estimated proved reserves. Changes in our estimate of proved reserve quantities and commodity prices will cause corresponding changes in depletion expense in periods subsequent to these changes. The capitalized costs of unproved properties, including those in wells in progress, are excluded from the costs being amortized. We do not have major development projects that are excluded from costs being amortized. On a quarterly basis, we evaluate excluded costs for inclusion in the costs to be amortized resulting from the determination of proved reserves or impairments. To the extent that the evaluation

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

1. BASIS OF PRESENTATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

indicates these properties are impaired, the amount of the impairment is added to the capitalized costs to be amortized. Expenditures for maintenance and repairs are charged to production expense in the period incurred.

Goodwill

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

We evaluate our goodwill for impairment in the fourth quarter of each year or whenever events or changes in circumstances indicate the possibility that goodwill may be impaired. Based upon our qualitative assessment at December 31, 2013, goodwill was not impaired. It is possible that goodwill could become impaired in the future if commodity prices or other economic factors become less favorable.

Revenue Recognition

Oil, Gas and NGL Sales

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

Marketing Sales

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

Gas Imbalances

We use the sales method of accounting for gas imbalances. Under this method, revenue is recorded on the basis of gas actually sold. Gas reserves are adjusted to the extent there are sufficient quantities of natural gas to make up an imbalance. A liability is established in situations where there are insufficient proved reserves available to make-up an overproduced imbalance. The natural gas imbalance liability at December 31, 2013 and 2012 was $4.9 million and $5.4 million, respectively. At December 31, 2013 and 2012, we were also in an under-produced position relative to certain other third parties.

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

1. BASIS OF PRESENTATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

General and Administrative Expenses

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

Derivatives

Our derivative contracts are recorded on the balance sheet at fair value. Our firm sales contracts qualify for the normal purchase and normal sale exception. Contracts that qualify for this treatment do not require mark-to-market accounting treatment. See Note 2 for additional information regarding our derivative instruments.

Income Taxes

Deferred income taxes are computed using the liability method. Deferred income taxes are provided on all temporary differences between the financial basis and the tax basis of assets and liabilities. Valuation allowances are established to reduce deferred tax assets to an amount that more likely than not will be realized. See Note 6 for additional information regarding our income taxes.

Contingencies

A provision for contingencies is charged to expense when the loss is probable and the cost can be reasonably estimated. Determining when expenses should be recorded for these contingencies and the appropriate amounts for accrual is a complex estimation process that includes subjective judgment. In many cases, this judgment is based on interpretation of laws and regulations, which can be interpreted differently by regulators and/or courts of law. We closely monitor known and potential legal, environmental, and other contingencies and periodically determine when we should record losses for these items based on information available to us. See Note 13 for additional information regarding our contingencies.

Asset Retirement Obligations

We recognize the fair value of liabilities for retirement obligations associated with tangible long-lived assets in the period in which there is a legal obligation associated with the retirement of such assets and the amount can be reasonably estimated. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. This liability includes costs related to the abandonment of wells, the removal of facilities and equipment, and site restorations. Subsequent to initial measurement, the asset retirement liability is required to be accreted each period. If the fair value of a recorded asset retirement obligation changes, a revision is recorded to both the asset retirement obligation and the asset retirement capitalized cost. Capitalized costs are included as a component of the DD&A calculations.

Stock-based Compensation

We recognize compensation related to all stock-based awards, including stock options, in the financial statements based on their estimated grant-date fair value. We grant various types of stock-based awards including stock options, restricted stock (including awards with service-based vesting and market

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

1. BASIS OF PRESENTATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

condition-based vesting provisions) and restricted stock units. The fair value of stock option awards is determined using the Black-Scholes option pricing model. Service-based restricted stock and units are valued using the market price of our common stock on the grant date. The fair value of the market condition-based restricted stock is based on the grant-date market value of the award utilizing a statistical analysis. Compensation cost is recognized ratably over the applicable vesting period. To the extent compensation cost relates to employees directly involved in oil and gas acquisition, exploration and development activities, such amounts are capitalized to oil and gas properties. Amounts not capitalized to oil and gas properties are recognized as stock compensation expense. See Note 8 for additional information regarding our stock-based compensation.

Earnings per Share

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

Segment Information

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

Recently Issued Accounting Standards

No significant accounting standards applicable to Cimarex have been issued during the year ended December 31, 2013.

Subsequent Events

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

2. DERIVATIVE INSTRUMENTS/HEDGING

We periodically enter into derivative instruments to mitigate a portion of our potential exposure to a decline in commodity prices and the corresponding negative impact on cash flow available for reinvestment. While the use of these instruments limits the downside risk of adverse price changes, their use may also limit future revenues from favorable price changes.

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2. DERIVATIVE INSTRUMENTS/HEDGING (Continued)

The following tables summarize our outstanding hedging contracts as of December 31, 2013:

Oil Contracts

Period	Type	Volume/Day	Index(1)	Weighted Average Price Floor	Weighted Average Price Ceiling	Fair Value (in thousands)
Jan 14 - Dec 14	Collars	12,000 Bbls	WTI	$ 85.00	$ 103.47	$ 1,416

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

Gas Contracts

Period	Type	Volume/Day	Index(1)	Weighted Average Price Floor	Weighted Average Price Ceiling	Fair Value (in thousands)
Jan 14 - Dec 14	Collars	80,000 MMBtu	PEPL	$ 3.51	$ 4.57	$ 2,329
Jan 14 - Dec 14	Collars	20,000 MMBtu	Perm EP	$ 3.65	$ 4.50	$ 90
Feb 14 - Dec 14	Collars	10,000 MMBtu	Perm EP	$ 3.65	$ 4.50	$ 44

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

Subsequent to December 31, 2013 we entered into the following gas hedges:

Period	Type	Volume/Day	Index(1)	Weighted Average Price Floor	Weighted Average Price Ceiling
Feb 14 - Dec 14	Collars	30,000 MMBtu	Perm EP	$ 3.58	$ 4.50

(1) Perm EP refers to El Paso Natural Gas Company, Permian Basin Index as quoted in Platt's Inside FERC.

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

Depending on changes in oil and gas futures markets and management's view of underlying supply and demand trends, we may increase or decrease our hedging positions.

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

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CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2. DERIVATIVE INSTRUMENTS/HEDGING (Continued)

The following table summarizes the net gains and (losses) from settlements and changes in fair value of our derivative contracts as presented in our accompanying financial statements:

(in thousands)	2013	2012	2011
Gain (loss) on derivative instruments, net:			
Natural gas contracts	$ 4,651	$	$ 2,754
Oil contracts	(4,860)	245	7,568
Gain (loss) on derivative instruments, net	$ (209)	$ 245	$ 10,322
Gains (losses) from settlement of derivative instruments:			
Natural gas contracts	$ 2,187	$	$ 8,485
Oil contracts	(6,275)		(1,774)
Settlement gains (losses)	$ (4,088)	$	$ 6,711

Our derivative contracts are carried at their fair value on our balance sheet using Level 2 inputs. We estimate the fair value with internal risk-adjusted discounted cash flow calculations. Cash flows are based on published forward commodity price curves for the underlying commodity as of the date of the estimate. For collars, we estimate the option value of the contract floors and ceilings using an option pricing model which takes into account market volatility, market prices, and contract terms.

The fair value of our derivative instruments in an asset position includes a measure of counterparty credit risk and the fair value of instruments in a liability position includes a measure of our own non-performance risk. These credit risks are based on current published credit default swap rates.

Due to the volatility of commodity prices, the estimated fair value of our derivative instruments is subject to fluctuation from period to period, which could result in significant differences between the current estimated fair value and the ultimate settlement price.

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

The following table presents the amounts and classifications of our derivative assets and liabilities as of December 31, 2013, as well as the potential effect of netting arrangements on contracts with the same counterparty. At December 31, 2012, we had no outstanding derivative contracts.

December 31, 2013: (in thousands)	Balance Sheet Location		Asset	Liability
Oil contracts	Current assets	Derivative instruments	$ 1,805	$
Natural gas contracts	Current assets	Derivative instruments	2,463	

Oil contracts	Current liabilities	Derivative instruments		389
Total gross amounts presented in accompanying balance sheet			4,268	389
Less: gross amounts not offset in the accompanying balance sheet			(389)	(389)
Net amount:			$ 3,879	$

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CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2. DERIVATIVE INSTRUMENTS/HEDGING (Continued)

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

3. FAIR VALUE MEASUREMENTS

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The FASB has established a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. This hierarchy consists of three broad levels. Level 1 inputs are the highest priority and consist of unadjusted quoted prices in active markets for identical assets and liabilities. Level 2 are inputs other than quoted prices that are observable for the asset or liability, either directly or indirectly. Level 3 are unobservable inputs for an asset or liability.

The following tables provide fair value measurement information for certain liabilities as of December 31, 2013 and 2012 (in thousands):

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

December 31, 2012: **(in thousands)**	**Carrying Amount**	**Fair Value**
Financial (Liabilities):		
5.875% Notes due 2022	$ (750,000)	$ (825,750)

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

Debt (Level 1)

The fair value of our bank debt at December 31, 2013 was estimated to approximate the carrying amount because the floating rate interest paid on such debt was set for periods of three months or less.

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

Derivative Instruments (Level 2)

The fair value of our derivative instruments was estimated using internal discounted cash flow calculations. Cash flows are based on the stated contract prices and current and published forward commodity price curves, adjusted for volatility. The cash flows are risk adjusted relative to non-performance for both our counterparties and our liability positions. Please see Note 2 for further information on the fair value of our derivative instruments.

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CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

3. FAIR VALUE MEASUREMENTS (Continued)

Other Financial Instruments

The carrying amounts of our cash, cash equivalents, restricted cash, accounts receivable, accounts payable, and accrued liabilities approximate fair value because of the short-term maturities and/or liquid nature of these assets and liabilities. Included in "accrued liabilities, other" at December 31, 2013 and 2012, respectively, are liabilities of approximately $43.7 million and $36.9 million representing the amount by which checks issued, but not yet presented to our banks for collection, exceeded balances in applicable bank accounts. Also included in "accrued liabilities, other" at December 31, 2013 and 2012, respectively, are accrued payroll related general and administrative expenses of $41.9 million and $31.3 million.

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

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

We routinely assess the recoverability of all material accounts receivable to determine their collectability. We accrue a reserve to the allowance for doubtful accounts when it is probable that a receivable will not be collected and the amount of the reserve may be reasonably estimated. At December 31, 2013, the allowance for doubtful accounts totaled $6 million. At December 31, 2012, the allowance for doubtful accounts was $6.5 million.

Major Customers

Our major customers during 2013 were Enterprise Products Partners L.P. (Enterprise) and Sunoco Logistics Partners L.P. (Sunoco). Enterprise and Sunoco accounted for 24% and 22%, respectively, of our consolidated revenues in 2013. During 2012, Sunoco and Enterprise were also our major customers and accounted for 22% and 21% of our consolidated revenues, respectively. Enterprise is our primary oil purchaser in Oklahoma and West Texas. Sunoco is a significant purchaser of our oil in Southeast New Mexico. If either of these purchasers were to stop purchasing our production, there are a number of other purchasers to whom we could sell our production with little delay. If both parties were to discontinue purchasing our product, there would be challenges initially, but ample markets to handle the disruption.

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CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. ASSET RETIREMENT OBLIGATIONS

The following table reflects the components of the change in the carrying amount of the asset retirement obligation for the years ended December 31, 2013 and 2012:

(in thousands)	2013	2012
Asset retirement obligation at January 1,	$ 185,138	$ 183,361
Liabilities incurred	5,547	22,355
Liability settlements and disposals	(47,842)	(42,958)
Accretion expense	7,871	10,318
Revisions of estimated liabilities	3,312	12,062
Asset retirement obligation at December 31,	154,026	185,138
Less current obligation	27,058	51,147
Long-term asset retirement obligation	$ 126,968	$ 133,991

5. LONG-TERM DEBT

A summary of our debt is as follows:

(in thousands)	December 31, 2013	December 31, 2012
Bank debt	$ 174,000	$
5.875% Senior Notes due 2022	750,000	750,000
Total long-term debt	$ 924,000	$ 750,000

Bank Debt

We have a five-year senior unsecured revolving credit facility (Credit Facility), which matures July 14, 2016. Under our Credit Facility, the borrowing base is determined at the discretion of the lenders based on the value of our proved reserves. In April 2013, our borrowing base was increased from $2 billion to $2.250 billion. Our aggregate commitments remain unchanged at $1 billion. The next regular annual redetermination date is scheduled for April 15, 2014.

As of December 31, 2013, we had $174 million of bank debt outstanding at a weighted average interest rate of 2.15%. We also had letters of credit outstanding under the Credit Facility of $2.5 million, leaving an unused borrowing availability of $823.5 million.

At our option, borrowings under the Credit Facility may bear interest at either (a) LIBOR plus 1.75-2.5%, based on our leverage ratio, or (b) the higher of (i) a prime rate, (ii) the federal funds effective rate plus 0.50%, or (iii) adjusted one-month LIBOR plus 1.0% plus, in each case, an additional 0.75-1.5%, based on our leverage ratio.

The Credit Facility also has financial covenants that include the maintenance of current assets (including unused bank commitments) to current liabilities at a ratio of greater than 1.0. We also must maintain a leverage ratio of total debt to earnings before interest expense, income taxes and non-cash items (such as depreciation, depletion and amortization expense, unrealized gains and losses on commodity derivatives, ceiling test write-downs, and goodwill impairments) of not more than 3.5. Other covenants could limit our ability to incur additional indebtedness, pay dividends, repurchase our common

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CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. LONG-TERM DEBT (Continued)

stock, or sell assets. As of December 31, 2013, we were in compliance with all of the financial and non-financial covenants.

5.875% Notes due 2022

In April 2012, we issued $750 million of 5.875% senior notes due May 1, 2022, with interest payable semiannually in May and November. The notes were sold to the public at par. The notes are governed by an indenture containing certain covenants, events of default and other restrictive provisions. We may redeem the notes in whole or in part, at any time on or after May 1, 2017, at redemption prices of 102.938% of the principal amount as of May 1, 2017, declining to 100% on May 1, 2020 and thereafter.

7.125% Notes due 2017

In May 2007, we issued $350 million of 7.125% senior unsecured notes at par that were scheduled to mature May 1, 2017. On March 22, 2012, we commenced a cash tender offer (Tender Offer) to purchase all of the outstanding 7.125% senior notes. The Tender Offer was completed in the second quarter of 2012. We recognized a $16.2 million loss on early extinguishment of debt during the second quarter of 2012.

6. INCOME TAXES

Federal income tax expense (benefit) for the years presented differs from the amounts that would be provided by applying the U.S. Federal income tax rate, due to the effect of state income taxes, and the Domestic Production Activities allowance. The components of the provision for income taxes are as follows:

	Years Ended December 31,		
(in thousands)	**2013**	**2012**	**2011**
Current Taxes:			
Federal (benefit)	$ (381)	$ (1,629)	$ (45,404)
State (benefit)	(308)	140	(669)
	(689)	(1,489)	(46,073)
Deferred taxes:			
Federal	315,165	199,459	345,397
State	14,535	8,757	12,225
	329,700	208,216	357,622
	$ 329,011	$ 206,727	$ 311,549

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CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

6. INCOME TAXES (Continued)

Reconciliations of the income tax (benefit) expense calculated at the federal statutory rate of 35% to the total income tax (benefit) expense are as follows:

	Years Ended December 31,		
(in thousands)	**2013**	**2012**	**2011**
Provision at statutory rate	$ 312,795	$ 196,192	$ 294,518
Effect of state taxes	14,226	8,902	11,445
Domestic Production Activities allowance		567	2,343
Other permanent differences	1,990	1,066	3,243
Income tax expense	$ 329,011	$ 206,727	$ 311,549

The components of Cimarex's net deferred tax liabilities are as follows:

	December 31,	
(in thousands)	**2013**	**2012**
Long-term:		
Assets:		
Stock compensation and other accrued amounts	$ 24,815	$ 97,972
Net operating loss carryforward	207,282	161,308
Credit carryforward	4,068	4,449
	236,165	263,729
Liabilities:		
Property, plant and equipment	(1,696,006)	(1,385,082)
Net, long-term deferred tax liability	(1,459,841)	(1,121,353)
Current:		
Assets:		
Other accrued amounts	16,854	8,477
	16,854	8,477
Net deferred tax liabilities	$ (1,442,987)	$ (1,112,876)

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

At December 31, 2013 and 2012, we had no unrecognized tax benefits that would impact our effective rate and we have made no provisions for interest or penalties related to uncertain tax positions. The tax years 2009 - 2012 remain open to examination by the Internal Revenue Service of the United States. We file tax returns with various state taxing authorities which remain open for examination for tax years 2009 - 2012.

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

7. CAPITAL STOCK

Authorized capital stock consists of 200 million shares of common stock and 15 million shares of preferred stock. At December 31, 2013, there were no shares of preferred stock outstanding. A summary of our issued and outstanding common stock activity follows:

(in thousands)	
December 31, 2010	85,235
Restricted shares issued under compensation plans, net of reacquired stock and cancellations	461
Option exercises, net of cancellations	78
December 31, 2011	85,774
Restricted shares issued under compensation plans, net of reacquired stock and cancellations	263
Option exercises, net of cancellations	559
December 31, 2012	86,596
Restricted shares issued under compensation plans, net of reacquired stock and cancellations	280
Option exercises, net of cancellations	276
December 31, 2013	87,152

Dividends

A cash dividend has been paid to stockholders in every quarter since the first quarter of 2006. In February 2013, the quarterly dividend was increased to $0.14 per share from $0.12 per share. Future dividend payments will depend on our level of earnings, financial requirements and other factors considered relevant by the Board of Directors.

	2013	2012	2011
Dividend declared (in millions)	$ 48.4	$ 41.3	$ 34.3
Dividend per share	$ 0.56	$ 0.48	$ 0.40

8. STOCK-BASED COMPENSATION

Our 2011 Equity Incentive Plan (the 2011 Plan) was approved by stockholders in May 2011 and our previous plan was terminated. Outstanding awards under the previous plan were not impacted. The 2011 Plan provides for grants of stock options, restricted stock, restricted stock units, performance stock and performance stock units. A total of 5.3 million shares of common stock may be issued under the 2011 Plan.

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

	Year Ended December 31,		
(in thousands)	2013	2012	2011
Restricted stock and units	$ 23,123	$ 31,297	$ 27,602
Stock options	3,145	2,889	3,518

		26,268		34,186		31,120
Less amounts capitalized to oil and gas properties		(11,989)		(12,267)		(12,171)
Compensation expense	$	14,279	$	21,919	$	18,949

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CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. STOCK-BASED COMPENSATION (Continued)

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

Restricted Stock and Units

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

	Year Ended December 31,					
	2013		2012		2011	
	Number of Shares	Weighted Average Grant-Date Fair Value	Number of Shares	Weighted Average Grant-Date Fair Value	Number of Shares	Weighted Average Grant-Date Fair Value
Performance stock awards	298,000	$ 77.75	262,770	$ 43.22	363,758	$ 73.01
Service-based stock awards	281,236	$ 72.89	299,499	$ 54.17	291,053	$ 89.47
Total restricted stock awards	579,236	$ 75.39	562,269	$ 49.05	654,811	$ 80.33

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

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

The following table reflects the non-cash compensation cost related to our restricted stock and units:

	Year Ended December 31,		
(in thousands)	2013	2012	2011
Performance stock awards	$ 11,105	$ 19,066	$ 16,268
Service-based stock awards	12,018	12,231	11,300
Restricted unit awards			34
	23,123	31,297	27,602
Less amounts capitalized to oil and gas properties	(10,741)	(11,132)	(10,241)
Restricted stock and units compensation expense	$ 12,382	$ 20,165	$ 17,361

The 2012 compensation cost for the performance awards includes $3.9 million of accelerated vesting related to the death of former Chairman, F.H. Merelli. In addition, the 2013 cost for performance awards is approximately $4.3 million lower than 2012 costs due to the timing of awards granted. Almost all of the performance awards granted in 2013 were awarded in mid-December. Awards granted in early January of 2010 were fully amortized in January of 2013, resulting in 2013 having less costs amortized during the year.

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CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. STOCK-BASED COMPENSATION (Continued)

Unrecognized compensation cost related to unvested restricted shares and units at December 31, 2013 was $67.2 million. We expect to recognize that cost over a weighted average period of 2.3 years.

The following table provides information on restricted stock and unit activity during the last three years. A restricted unit held by an employee represents a right to an unrestricted share of common stock upon completion of defined vesting and holding periods. A restricted unit held by a non-employee director represents an election to defer payment of director fees until the time specified by the director in his deferred compensation agreement. The remaining outstanding restricted units as of December 31, 2013 shown below represent restricted units held by a non-employee director who has elected to defer payment of common stock represented by the units until termination of his service on the Board of Directors.

	Year Ended December 31,		
	2013	**2012**	**2011**
Restricted Stock:			
Outstanding beginning of period	1,838,736	2,019,552	1,899,511
Vested	(383,608)	(602,372)	(497,720)
Granted	579,236	562,269	654,811
Canceled	(170,530)	(140,713)	(37,050)
Outstanding end of period	1,863,834	1,838,736	2,019,552
Restricted Stock Units:			
Outstanding beginning of period	33,838	59,470	94,807
Converted to Stock	(25,000)	(25,632)	(35,337)
Outstanding end of period	8,838	33,838	59,470
Vested included in outstanding	8,838	33,838	59,470

Stock Options

The following table provides information about stock options granted during the last three years:

Year Ended December 31,								
2013			**2012**			**2011**		
Options	**Weighted Average**	**Weighted Average**	**Options**	**Weighted Average**	**Weighted Average**	**Options**	**Weighted Average**	**Weighted Average**

		Grant-Date Fair Value	Exercise Price		Grant-Date Fair Value	Exercise Price		Grant-Date Fair Value	Exercise Price
Granted to certain executive officers		$	$		$	$	90,000	$ 19.17	$ 55.96
Granted to other employees	144,400	$ 21.64	$ 72.25	152,800	$ 20.55	$ 51.92	91,300	$ 34.20	$ 86.01
	144,400			152,800			181,300		

Options granted under our 2011 and previous plans expire seven to ten years from the grant date and have service-based vesting schedules of three to five years. The plans provide that all grants have an exercise price of the average of the high and low prices of our common stock as reported by the New York Stock Exchange on the date of grant.

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CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. STOCK-BASED COMPENSATION (Continued)

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

The following summarizes the options granted, the weighted average grant-date fair value, the total fair value of the options, and the assumptions used to determine the fair value of those options:

	Year Ended December 31,		
	2013	2012	2011
Options granted	144,400	152,800	181,300
Weighted average grant-date fair value	$ 21.64	$ 20.55	$ 26.74
Total Fair Value (in thousands)	$ 3,125	$ 3,140	$ 4,848
Expected years until exercise	4.0	5.3	4.3
Expected stock volatility	38.6%	47.4%	48.7%
Dividend yield	0.8%	0.9%	0.6%
Risk-free interest rate	1.4%	0.6%	0.9%

Non-cash compensation cost related to our stock options is reflected in the following table:

	Year Ended December 31,		
(in thousands)	**2013**	**2012**	**2011**
Stock option awards	$ 3,145	$ 2,889	$ 3,518
Less amounts capitalized to oil and gas properties	(1,248)	(1,135)	(1,930)
Stock option compensation expense	$ 1,897	$ 1,754	$ 1,588

As of December 31, 2013, there was $4.3 million of unrecognized compensation cost related to non-vested stock options. We expect to recognize that cost on a pro rata basis over a weighted average period of 1.7 years.

Information about outstanding stock options is summarized below:

	Options	Weighted Average Exercise Price	Weighted Average Remaining Term	Aggregate Intrinsic Value (in thousands)
Outstanding as of January 1, 2013	687,459	$ 54.51		
Exercised	(276,069)	$ 52.50		
Granted	144,400	$ 72.25		
Canceled	(2,663)	$ 86.00		
Forfeited	(22,111)	$ 65.09		
Outstanding as of December 31, 2013	531,016	$ 59.78	5.3 Years	$ 23,201

Exercisable as of December 31, 2013	188,002	$ 52.43	4.7 Years	$	9,596

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. STOCK-BASED COMPENSATION (Continued)

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

	Year Ended December 31,		
(in thousands)	**2013**	**2012**	**2011**
Number of options exercised	276,069	558,419	78,661
Cash received from option exercises	$ 14,494	$ 11,433	$ 3,193
Tax benefit from option exercises included in paid-in-capital	$ (1)	$ 76	$ 1,407
Intrinsic value of options exercised	$ 10,109	$ 22,482	$ 3,856
Grant-date fair value of options vested	$ 2,521	$ 2,560	$ 4,128

(1) No tax benefit is recorded until the benefit reduces current taxes payable.

The following summary reflects the status of non-vested stock options as of December 31, 2013 and changes during the year:

	Options	**Weighted Average Grant-Date Fair Value**	**Weighted Average Exercise Price**
Non-vested as of January 1, 2013	317,062	$ 23.22	$ 60.58
Vested	(96,337)	$ 26.17	$ 65.54
Granted	144,400	$ 21.64	$ 72.25
Forfeited	(22,111)	$ 24.52	$ 65.09
Non-vested as of December 31, 2013	343,014	$ 21.64	$ 63.81

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CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

9. EARNINGS PER SHARE

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

	Year Ended December 31,		
(in thousands, except per share data)	**2013**	**2012**	**2011**
Basic:			
Net income	$ 564,689	$ 353,823	$ 529,932
Participating securities' share in earnings	(11,091)	(6,753)	(12,005)
Net income applicable to common stockholders	$ 553,598	$ 347,070	$ 517,927
Diluted:			
Net income	$ 564,689	$ 353,823	$ 529,932
Participating securities' share in earnings	(11,076)	(6,732)	(11,950)
Net income applicable to common stockholders	$ 553,613	$ 347,091	$ 517,982
Shares:			
Basic shares outstanding	85,288	84,757	83,755
Incremental shares from assumed exercise of stock options	121	277	398
Fully diluted common stock	85,409	85,034	84,153
Excluded(1)	251	414	273
Earnings per share to common stockholders:(2)			
Basic	$ 6.48	$ 4.08	$ 6.17
Diluted	$ 6.47	$ 4.07	$ 6.15

(1) Inclusion of certain outstanding stock options would have an anti-dilutive effect.

(2) Earnings per share are based on actual figures rather than the rounded figures presented.

10. EMPLOYEE BENEFIT PLANS

We maintain and sponsor a contributory 401(k) plan for our employees. Annual costs related to the plan were $9.0 million for 2013. During 2012 and 2011, such costs were $8.2 million and $8.9 million, respectively.

11. RELATED PARTY TRANSACTIONS

Helmerich & Payne, Inc. (H&P) provides contract drilling services to Cimarex. Drilling costs of approximately $17.0 million were incurred by Cimarex related to such services for 2013. During 2012 and 2011, such costs were $20.8 million and $37.4 million, respectively. At December 31, 2013 and 2012, we had no minimum expenditure commitments to secure the use of H&P's drilling rigs. We had minimum expenditure commitments of $3.5 million at December 31, 2011. Hans Helmerich, a director of Cimarex, is Chairman of the Board of Directors of H&P.

Certain subsidiaries of Newpark Resources, Inc. have provided various drilling services to Cimarex. Costs of such services were $3.5 million in 2013. During 2012 and 2011, such costs were $4.1 million and $7.3 million, respectively. Jerry Box, a director of Cimarex, is the non-executive Chairman of the Board of Newpark.

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

12. SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

	For the Years Ended December 31,		
(in thousands)	**2013**	**2012**	**2011**
Cash paid during the period for:			
Interest expense (including capitalized amounts)	$ 50,754	$ 42,420	$ 29,650
Interest capitalized	$ 29,098	$ 30,255	$ 24,193
Income taxes	$ 205	$ 377	$ 1,753
Cash received for income taxes	$ 966	$ 49,754	$ 59,109

13. COMMITMENTS AND CONTINGENCIES

Lease Commitments

We have various commitments for office space and equipment under operating lease arrangements. Rental expense for the operating leases totaled $13.2 million in 2013. They were $5.7 million and $5.3 million for 2012 and 2011, respectively. The increase in 2013 rent expense compared to the prior periods was due to additional costs associated with office relocations and entering into new lease arrangements.

Shown below are future minimum cash payments required under these leases as of December 31, 2013:

(in thousands)	**Operating Leases**
2014	$ 8,354
2015	10,634
2016	10,858
2017	10,435
2018	10,188
Later years	77,294
Total future minimum lease payments	$ 127,763

Other Commitments

We have commitments of $170.6 million to finish drilling and completing wells in progress at December 31, 2013.

In New Mexico and Texas, we are constructing gathering facilities and pipelines. At December 31, 2013, we had commitments of $1.8 million relating to these construction projects.

At December 31, 2013, we had firm sales contracts to deliver approximately 19.4 Bcf of natural gas over the next 10 months. If this gas is not delivered, our financial commitment would be approximately $68.6 million. This commitment will fluctuate due to price volatility and actual volumes delivered. However, we believe no financial commitment will be due based on our current proved reserves and production levels.

We have other various transportation and delivery commitments in the normal course of business, which approximate $4.8 million over the next four years.

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CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

13. COMMITMENTS AND CONTINGENCIES (Continued)

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

Litigation

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

Hitch Enterprises, Inc. et al. v. Cimarex Energy Co. et al.

On December 11, 2012, Cimarex entered into a preliminary resolution of the *Hitch Enterprises, Inc., et al. v. Cimarex Energy Co., et al.* (*Hitch*) litigation matter for $16.4 million. *Hitch* is a statewide royalty class action pending in the Federal District Court in Oklahoma City, Oklahoma. The settlement was reached at a mediation, which occurred after the parties began to exchange information, including damage analyses, on November 16, 2012. On July 2, 2013, the Court entered a judgment approving the parties' settlement. The judgment became final and unappealable on August 2, 2013. Cimarex distributed the settlement proceeds pursuant to the Court's order in September 2013 and the administration of the settlement is ongoing. In the fourth quarter of 2012, we accrued $16.4 million for this matter.

H.B. Krug, et al. versus H&P

In January 2009, the Tulsa County District Court issued a judgment totaling $119.6 million in the *H.B. Krug, et al. versus Helmerich & Payne, Inc.* (H&P) case. This lawsuit originally was filed in 1998 and addressed H&P's conduct pertaining to a 1989 take-or-pay settlement, along with potential drainage and other related issues. Pursuant to the 2002 spin-off of Cimarex to stockholders of H&P, Cimarex assumed the assets and liabilities of H&P's exploration and production business, including this lawsuit. In 2008, we recorded litigation expense of $119.6 million for this lawsuit and began accruing additional post-judgment interest and costs.

On August 18, 2011, the Oklahoma Court of Appeals issued an Opinion regarding the *Krug* litigation. The Oklahoma Court of Appeals reversed and remanded the $112.7 million disgorgement of profits award, holding the District Court erred in failing to make the required findings of fact and conclusions of law. In all other respects, the Court of Appeals affirmed the judgment, including damages of $6.845 million. On February 13, 2012, the Oklahoma Supreme Court granted Cimarex's Petition for Certiorari, which requested a review of the affirmed portion of the judgment.

On December 10, 2013, the Oklahoma Supreme Court reversed the trial court's original judgment of $119.6 million and affirmed an alternative jury verdict for $3.65 million. In light of the Oklahoma Supreme Court's ruling, on December 31, 2013, we reduced previously recognized litigation expense and the associated long-term liability by $142.8 million. A portion of our anticipated remaining liability includes estimates for amounts yet to be adjudicated. These estimates are likely to change.

On December 30, 2013, the Plaintiffs filed a Petition for Rehearing with the Oklahoma Supreme Court. On February 24, 2014, the Oklahoma Supreme Court denied the Plaintiffs' Petition for Rehearing. Our assessments and estimates likely will change in the future as a result of legal proceedings that cannot be predicted at this time.

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CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

14. PROPERTY SALES AND ACQUISITIONS

In 2013, we sold interests in non-core oil and gas assets for $61.5 million. During the second quarter of 2013, we also sold a 50% interest in our Culberson County, Texas Triple Crown gas gathering and processing system for approximately $31 million. Total property acquisitions during 2013 were $37.1 million, mostly for undeveloped acreage in Reeves County, Texas.

During 2012, we sold interests in non-core oil and gas assets for $306 million. Of this total, $290 million was related to non-core oil and gas assets located in Texas. We had property acquisitions of $33.5 million during 2012, most of which were undeveloped acreage in the Permian Basin.

In 2011, we sold all of our interests in assets located in Sublette County, Wyoming for $195.5 million (after purchase price adjustments). The assets sold principally consisted of a gas processing plant under construction and related assets ($111.4 million) and 210 Bcf of proved undeveloped gas reserves ($84.1 million). Total property acquisitions during 2011 were approximately $45.4 million. Of our total acquisitions, $42.2 million was in our western Oklahoma Cana-Woodford shale play.

15. UNAUDITED SUPPLEMENTAL OIL AND GAS DISCLOSURES

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

	Years Ended December 31,		
(in thousands, except per Mcfe)	**2013**	**2012**	**2011**
Oil, gas and NGL revenues from production	$ 1,952,505	$ 1,581,650	$ 1,703,520
Less operating costs and income taxes:			
Depletion	584,628	484,529	367,509
Asset retirement obligation	7,989	13,019	11,451
Production	286,742	258,584	247,048
Transportation and other operating	93,580	57,354	56,711
Taxes other than income	112,732	86,994	126,468
Income tax expense	319,082	251,215	331,082
	1,404,753	1,151,695	1,140,269
Results of operations from oil and gas producing activities	$ 547,752	$ 429,955	$ 563,251
Depletion rate per Mcfe	$ 2.31	$ 2.11	$ 1.70

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

15. UNAUDITED SUPPLEMENTAL OIL AND GAS DISCLOSURES (Continued)

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

	Years Ended December 31,		
(in thousands)	**2013**	**2012**	**2011**
Costs incurred during the year:			
Acquisition of properties			
Proved	$ 682	$ 2,645	$ 23,071
Unproved	195,121	117,695	168,238
Exploration	52,672	109,169	82,531
Development	1,354,098	1,426,918	1,351,617
Oil and gas expenditures	1,602,573	1,656,427	1,625,457
Property sales	(61,503)	(305,862)	(117,344)
	1,541,070	1,350,565	1,508,113
Asset retirement obligation, net	4,426	12,525	63,246
	$ 1,545,496	$ 1,363,090	$ 1,571,359

Aggregate Capitalized Costs The table below reflects the aggregate capitalized costs relating to our oil and gas producing activities at December 31, 2013:

(in thousands)	
Proved properties	$ 12,863,961
Unproved properties and properties under development, not being amortized	585,361
	13,449,322
Less-accumulated depreciation, depletion and amortization	(7,483,685)
Net oil and gas properties	$ 5,965,637

Costs Not Being Amortized The following table summarizes oil and gas property costs not being amortized at December 31, 2013, by year that the costs were incurred:

(in thousands)

2013	$ 250,263
2012	98,889
2011	128,601
2010 and prior	107,608
	$ 585,361

Costs not being amortized include the costs of unevaluated wells in progress and other properties. On a quarterly basis, such costs are evaluated for inclusion in the costs to be amortized resulting from the determination of proved reserves, impairments, or reductions in value. To the extent that the evaluation indicates these properties are impaired, the amount of the impairment is added to the capitalized costs to

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CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

15. UNAUDITED SUPPLEMENTAL OIL AND GAS DISCLOSURES (Continued)

be amortized. Abandonments of unproved properties are accounted for as an adjustment to capitalized costs related to proved oil and gas properties, with no losses recognized.

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

Reserve definitions comply with definitions of 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 our company. The technical employee primarily responsible for overseeing the reserve estimation process is our company's Vice President of Corporate Engineering. This individual graduated from the Colorado School of Mines with a Bachelor of Science degree in Engineering and has more than nineteen years of practical experience in reserve evaluation. He has been directly involved in the annual reserve reporting process of Cimarex since 2002 and has served in his current role for the past nine years.

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, 2013. 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 thirty-nine years of experience in oil and gas reservoir studies and evaluations.

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

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

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CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

15. UNAUDITED SUPPLEMENTAL OIL AND GAS DISCLOSURES (Continued)

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

	Gas (MMcf)	Oil (MBbl)	NGL (MBbl)	Total Gas Equivalents (MMcfe)
Total proved reserves:				
December 31, 2010	1,254,166	63,656	41,310	1,883,957
Revisions of previous estimates	(35,981)	(2,062)	6,865	(7,160)
Extensions and discoveries	321,419	21,253	23,019	587,049
Purchases of reserves	13,480	308	1,430	23,910
Production	(120,113)	(9,778)	(6,236)	(216,198)
Sales of properties	(216,530)	(1,055)	(573)	(226,293)
December 31, 2011	1,216,441	72,322	65,815	2,045,265
Revisions of previous estimates	(211,401)	(3,154)	(4,492)	(257,276)
Extensions and discoveries	372,459	27,817	36,324	757,307
Purchases of reserves	50	14	2	145
Production	(118,495)	(11,516)	(6,952)	(229,299)
Sales of properties	(7,191)	(7,562)	(788)	(57,298)
December 31, 2012	1,251,863	77,921	89,909	2,258,844
Revisions of previous estimates	(101,235)	(2,942)	(16,197)	(216,068)
Extensions and discoveries	280,619	48,010	26,431	727,267
Purchases of reserves	263	27	9	479
Production	(125,248)	(13,380)	(7,876)	(252,787)
Sales of properties	(12,762)	(1,103)	(232)	(20,771)
December 31, 2013	1,293,500	108,533	92,044	2,496,964
Proved developed reserves:				
December 31, 2010	911,898	60,231	31,051	1,459,590
December 31, 2011	989,511	68,250	44,755	1,667,541
December 31, 2012	985,352	73,524	63,757	1,809,037
December 31, 2013	1,060,704	86,665	69,089	1,995,233
Proved undeveloped reserves:				
December 31, 2010	342,268	3,425	10,259	424,367
December 31, 2011	226,930	4,072	21,060	377,724
December 31, 2012	266,511	4,397	26,152	449,807
December 31, 2013	232,796	21,868	22,955	501,731

During 2013, we added 727.3 Bcfe of proved reserves through extensions and discoveries, primarily in the Permian Basin and Cana-Woodford area. We added 489.4 Bcfe in the Permian Basin (288.2 Bcfe development drilling and 201.2 Bcfe in proved undeveloped reserves). Of this amount, 52% consisted of oil. In our western Oklahoma Cana-Woodford shale area, we added 44.9 Bcfe from wells drilled and 179.9 Bcfe of proved undeveloped (PUD) reserves.

During 2013, we had net negative reserve revisions of 216 Bcfe. Approximately 208 Bcfe of the net negative revisions relates to performance of certain wells drilled in our Cana-Woodford shale development project. Negative revisions resulted from poorer than expected production performance of PUD reserves

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

15. UNAUDITED SUPPLEMENTAL OIL AND GAS DISCLOSURES (Continued)

converted to proved developed reserves during the year (72 Bcfe); wells adversely impacted by infill drilling and/or exhibiting poorer than expected performance (60 Bcfe); the removal of PUD locations due to altered future drilling plans (40 Bcfe); and adjustments to previously booked PUD reserves based on actual results observed in 2013 (36 Bcfe). The remainder of net negative revisions relates to offsetting increases and decreases primarily associated with higher commodity prices and increased operating expenses.

In 2012, we added 757.3 Bcfe of proved reserves through extensions and discoveries. In our western Oklahoma Cana-Woodford shale area, we added 202.5 Bcfe from infill wells drilled and 315.9 Bcfe of PUD reserves. Development drilling in the Permian Basin added 229.2 Bcfe.

Approximately 72 Bcfe of the 257.3 Bcfe net negative revisions during 2012 related to production performance of certain wells drilled in our Cana-Woodford shale project. The remainder of the net negative revisions primarily resulted from decreases in prices (91 Bcfe), increases in operating expenses (21 Bcfe) which shortened the economic lives, adjustments to previously booked PUD reserves (25 Bcfe) and the removal of PUD locations due to altered future drilling plans (42 Bcfe).

During 2011, we added 587.0 Bcfe of proved reserves through extensions and discoveries. These additions were also primarily due to wells drilled and PUD reserves added in our Cana-Woodford shale area and in the Permian Basin. Net negative revisions during 2011 were negligible.

At December 31, 2013, we had PUD reserves of 502 Bcfe, up 52 Bcfe from 450 Bcfe of PUDs at December 31, 2012. Changes in our PUD reserves are summarized in the table below (in Bcfe):

PUDs at December 31, 2012	449.8
Converted to developed	(253.5)
Additions	381.1
Net revisions	(75.7)
PUDs at December 31, 2013	501.7

During 2013, we invested $255.5 million to develop and convert certain 2012 PUD reserves to proved developed reserves. A portion of the development costs were on wells that are expected to be converted to developed in subsequent periods. During 2012 and 2011, we invested $164.4 million and $21.6 million, respectively, for conversion of PUD reserves to proved developed reserves.

The 381 Bcfe of PUD additions consist of 201 Bcfe in the Permian Basin and 180 Bcfe in our western Oklahoma, Cana Woodford shale play. All of our PUD reserves are associated with these two areas. We have no PUD reserves that have remained undeveloped for five years or more after initial disclosure. We have no PUD reserves whose scheduled delay to initiation of development is beyond five years of initial booking.

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

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

15. UNAUDITED SUPPLEMENTAL OIL AND GAS DISCLOSURES (Continued)

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

The following summary sets forth our Standardized Measure:

	December 31,		
(in thousands)	**2013**	**2012**	**2011**
Cash inflows	$ 16,565,980	$ 12,384,251	$ 13,824,129
Production costs	(5,000,004)	(3,684,875)	(3,999,352)
Development costs	(1,113,743)	(562,994)	(555,963)
Income tax expense	(3,099,304)	(2,368,115)	(2,938,590)
Net cash flow	7,352,929	5,768,267	6,330,224
10% annual discount rate	(3,754,035)	(2,859,566)	(3,190,474)
Standardized measure of discounted future net cash flow	$ 3,598,894	$ 2,908,701	$ 3,139,750

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

	December 31,		
(in thousands)	**2013**	**2012**	**2011**
Standardized Measure, beginning of period	$ 2,908,701	$ 3,139,750	$ 2,515,277
Sales, net of production costs	(1,459,451)	(1,178,718)	(1,268,175)
Net change in sales prices, net of production costs	371,563	(957,606)	448,727
Extensions and discoveries, net of future production and development costs	1,901,786	1,707,024	1,662,706
Changes in future development costs	121,347	146,808	(57,847)
Previously estimated development costs incurred during the period	253,047	148,976	42,492
Revision of quantity estimates	(436,856)	(457,013)	(16,269)
Accretion of discount	416,594	459,490	361,662
Change in income taxes	(344,447)	197,916	(353,804)
Purchases of reserves in place	1,552	572	41,854
Sales of properties	(38,080)	(214,746)	(123,870)
Change in production rates and other	(96,862)	(83,752)	(113,003)
Standardized Measure, end of period	$ 3,598,894	$ 2,908,701	$ 3,139,750

Impact of Pricing The estimates of cash flows and reserve quantities shown above are based upon the unweighted average first-day-of-the-month prices. If future gas sales are covered by contracts at specified

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CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

15. UNAUDITED SUPPLEMENTAL OIL AND GAS DISCLOSURES (Continued)

prices, the contract prices would be used. Fluctuations in prices are due to supply and demand and are beyond our control.

The following average prices were used in determining the Standardized Measure as of:

	December 31,		
	2013	2012	2011
Gas price per Mcf	$ 3.01	$ 2.27	$ 3.79
Oil price per Bbl	$ 92.74	$ 88.91	$ 89.64
NGL price per Bbl	$ 28.42	$ 29.12	$ 41.70

Companies that follow the full cost accounting method are required to make quarterly ceiling test calculations. This test ensures that total capitalized costs for oil and gas properties (net of accumulated DD&A and deferred income taxes) do not exceed the sum of the present value discounted at 10% of estimated future net cash flows from proved reserves, the cost of properties not being amortized, the lower of cost or estimated fair value of unproven properties included in the costs being amortized, and all related tax effects. We currently do not have any unproven properties that are being amortized. We calculate the projected income tax effect using the "year-by-year" method for purposes of the supplemental oil and gas disclosures and use the "short-cut" method for the ceiling test calculation. Application of these rules during periods of relatively low commodity prices, even if of short-term duration, may result in write-downs.

16. UNAUDITED SUPPLEMENTAL QUARTERLY FINANCIAL DATA

2013	First	Second	Third	Fourth
(in thousands, except for per share data)				
Revenues	$ 426,356	$ 493,757	$ 561,336	$ 516,602
Expenses, net	336,429	364,192	422,966	309,775
Net income	$ 89,927	$ 129,565	$ 138,370	$ 206,827
Earnings per share to common stockholders:				
Basic:				
Distributed	$ 0.14	$ 0.14	$ 0.14	$ 0.14
Undistributed	0.90	1.36	1.45	2.23
	$ 1.04	$ 1.50	$ 1.59	$ 2.37
Diluted:				
Distributed	$ 0.14	$ 0.14	$ 0.14	$ 0.14
Undistributed	0.90	1.35	1.45	2.23
	$ 1.04	$ 1.49	$ 1.59	$ 2.37

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CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

16. UNAUDITED SUPPLEMENTAL QUARTERLY FINANCIAL DATA (Continued)

2012	**First**	**Second**	**Third**	**Fourth**
(in thousands, except for per share data)				
Revenues	$ 423,036	$ 353,122	$ 406,912	$ 440,868
Expenses, net	316,929	288,820	322,650	341,716
Net income	$ 106,107	$ 64,302	$ 84,262	$ 99,152
Earnings per share to common stockholders:				
Basic:				
Distributed	$ 0.12	$ 0.12	$ 0.12	$ 0.12
Undistributed	1.12	0.63	0.85	1.02
	$ 1.24	$ 0.75	$ 0.97	$ 1.14
Diluted:				
Distributed	$ 0.12	$ 0.12	$ 0.12	$ 0.12
Undistributed	1.11	0.62	0.85	1.02
	$ 1.23	$ 0.74	$ 0.97	$ 1.14

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

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

Cimarex's management, under the supervision and with the participation of the Chief Executive Officer (CEO) and Chief Financial Officer (CFO), have evaluated the effectiveness of Cimarex's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the Exchange Act)) as of December 31, 2013. Based on that evaluation, the CEO and CFO concluded that the disclosure controls and procedures are effective in providing reasonable assurance that information required to be disclosed in reports filed with the SEC is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. The disclosure controls and procedures are designed to provide reasonable assurance that such information is accumulated and communicated to our management, including the CEO and CFO, as appropriate, to allow such persons to make timely decisions regarding required disclosures.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There was no change in our internal control over financial reporting that occurred during our most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

As of December 31, 2013, management assessed the effectiveness of the company's internal control over financial reporting based on the criteria established in "Internal Control Integrated Framework," issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 Framework). Based on that assessment, management concluded that the company's internal control over financial reporting was effective as of December 31, 2013.

Our independent registered public accounting firm has audited, and reported on, the effectiveness of our internal controls over financial reporting as of December 31, 2013, which follows this report.

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Cimarex Energy Co.:

We have audited Cimarex Energy Co. and subsidiaries (the Company) internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control Integrated Framework* (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Cimarex Energy Co.'s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, Cimarex Energy Co. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control Integrated Framework* (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of the Company as of December 31, 2013 and 2012, and the related consolidated statements of income and comprehensive income, stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2013, and our report dated February 26, 2014 expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP

Denver, Colorado
February 26, 2014

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ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information concerning the directors of Cimarex required under this item is incorporated by reference from the Cimarex Energy Co. definitive Proxy Statement for the May 15, 2014 Annual Meeting of Stockholders. The Proxy Statement will be filed with the Securities and Exchange Commission no later than April 30, 2014. The executive officers of Cimarex as of February 26, 2014 were:

Name	Age	Office
Thomas E. Jorden	56	Chairman of the Board, President and Chief Executive Officer
Joseph R. Albi	55	Executive Vice President and Chief Operating Officer
Stephen P. Bell	59	Executive Vice President, Business Development
Paul Korus	57	Senior Vice President and Chief Financial Officer
Francis B. Barron	51	Senior Vice President, General Counsel
Gary R. Abbott	41	Vice President, Corporate Engineering
Richard S. Dinkins	69	Vice President, Human Resources
John Lambuth	51	Vice President, Exploration
James H. Shonsey	62	Vice President, Chief Accounting Officer, and Controller

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

THOMAS E. JORDEN was elected chairman of the board effective August 14, 2012 after being named president and chief executive officer effective September 30, 2011. Since December 8, 2003, Mr. Jorden served as executive vice president of exploration and had served in a similar capacity since September 30, 2002. Prior to September 2002, Mr. Jorden was with Key Production Company, Inc., where he served as vice president of exploration (October 1999 to September 2002) and chief geophysicist (November 1993 to September 1999). Prior to joining Key, Mr. Jorden was with Union Pacific Resources.

JOSEPH R. ALBI was named executive vice president and chief operating officer effective September 30, 2011. Mr. Albi served as executive vice president of operations since March 1, 2005. Since December 8, 2003, Mr. Albi served as senior vice president of corporate engineering. From September 30, 2002 to December 8, 2003, he served as vice president of engineering. From October 1999 to September, 2002, Mr. Albi was with Key Production Company, Inc. where he served as vice president of engineering and manager of engineering.

STEPHEN P. BELL was named executive vice president, business development effective September 13, 2012. Since September, 2002, Mr. Bell served as senior vice president of business development and land. Prior to its merger with Cimarex, Mr. Bell was with Key Production Company, Inc. since February 1994. In September 1999, he was appointed senior vice president, business development and land. From February 1994 to September 1999, he served as vice president, land.

PAUL KORUS was named senior vice president in December 2010 and has served as chief financial officer of Cimarex since September 2002. From June 1999 to September 2002, Mr. Korus was vice president and chief financial officer of Key Production Company. Prior to Key, he was an equity research analyst with an energy investment banking firm from 1995 to 1999 and was with Apache Corporation from 1982 to 1995.

FRANCIS B. BARRON joined Cimarex in July 2013 as senior vice president, general counsel. Mr. Barron served as executive vice president, general counsel of Bill Barrett Corporation, a Denver-based oil and gas exploration and development company, from February 2009 until July 2013 and as secretary from March 2004 until July 2013. He served as their senior vice president, general counsel from March 2004 until

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February 2009 and as chief financial officer from November 2006 until March 2007. Previously, Mr. Barron was a partner at the Denver, Colorado office of the law firm of Patton Boggs LLP as well as a partner at Bearman Talesnick & Clowdus Professional Corporation. Mr. Barron's practice included corporate, securities and business law for publicly traded oil and gas companies.

GARY R. ABBOTT was elected vice president of corporate engineering March 1, 2005. Since January 2002, Mr. Abbott served as manager, corporate reservoir engineering. From April 1999 to January 2002, Mr. Abbott was a reservoir engineer with Key Production Company, Inc.

RICHARD S. DINKINS was named vice president of human resources on December 8, 2003. Mr. Dinkins joined Key Production Company, Inc. in March 2002 as its director of human resources and continued in that position with Cimarex commencing in September 2002. Prior to joining Key, Mr. Dinkins was with Sprint and before that, served as Vice President of Human Resources for Terra Resources, Inc. and Pacific Enterprises Oil Company.

JOHN LAMBUTH was named vice president of exploration in September 2012. Prior to his promotion, he served as the company's chief geophysicist, a position he held since joining Cimarex in 2004. Mr. Lambuth began his career in 1985 with Shell Oil Co., where he held various positions in exploration and in research and development. Immediately prior to joining Cimarex, he spent three years as onshore exploration manager of El Paso Energy Company. Mr. Lambuth holds a Bachelors' Degree in Geophysical Engineering from the Colorado School of Mines.

JAMES H. SHONSEY was named vice president in April 2006. Mr. Shonsey was elected chief accounting officer and controller on May 28, 2003. From 2001 to May 2003, Mr. Shonsey was chief financial officer of The Meridian Resource Corporation; and from 1997 to 2001, he served as the chief financial officer of Westport Resources Corporation.

ITEM 11. EXECUTIVE COMPENSATION

Information required under this item is incorporated by reference from the Cimarex Energy Co. definitive Proxy Statement for the May 15, 2014 Annual Meeting of Stockholders. The Proxy Statement will be filed with the Securities and Exchange Commission no later than April 30, 2014.

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

Information required under this item is incorporated by reference from the Cimarex Energy Co. definitive Proxy Statement for the May 15, 2014 Annual Meeting of Stockholders. The Proxy Statement will be filed with the Securities and Exchange Commission no later than April 30, 2014.

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

Information required under this item is incorporated by reference from the Cimarex Energy Co. definitive Proxy Statement for the May 15, 2014 Annual Meeting of Stockholders. The Proxy Statement will be filed with the Securities and Exchange Commission no later than April 30, 2014.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information required under this item is incorporated by reference from the Cimarex Energy Co. definitive Proxy Statement for the May 15, 2014 Annual Meeting of Stockholders. The Proxy Statement will be filed with the Securities and Exchange Commission no later than April 30, 2014.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

		Page
(a) (1)	The following financial statements are included in Item 8 to this 10-K:	
	Consolidated balance sheets as of December 31, 2013 and 2012.	56
	Consolidated statements of income and comprehensive income for the years ended December 31, 2013, 2012, and 2011	57
	Consolidated statements of cash flows for the years ended December 31, 2013, 2012, and 2011	58
	Consolidated statements of stockholders' equity for the years ended December 31, 2013, 2012, and 2011	59
	Notes to consolidated financial statement	60
(2)	Financial statement schedules None	
(3)	Exhibits:	

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

Exhibit	Title
3.1	Amended and Restated Certificate of Incorporation of Cimarex Energy Co. (filed as Exhibit 3.1 to Registrant's Form 8-K (Commission File no. 001-31446) dated June 7, 2005 and incorporated herein by reference).
3.2	Amended and Restated By-laws of Cimarex Energy Co. dated December 11, 2013 (filed on December 16, 2013 (Commission File No. 001-31446) and incorporated herein by reference).
4.1	Specimen Certificate of Cimarex Energy Co. common stock (filed as Exhibit 4.3 to Registration Statement on Form S-3 filed September 17, 2012 (Registration No. 333-183939) and incorporated herein by reference).
4.2	Debt Securities Indenture dated as of April 5, 2012, by and among Cimarex Energy Co. and U.S. Bank National Association, as trustee included as Exhibit 4.1 to Registrant's Current Report on Form 8-K filed on April 5, 2012 and incorporated herein by reference.
4.3	First Supplemental Indenture dated as of April 5, 2012, by and among Cimarex Energy Co., the Subsidiary Guarantors party thereto and U.S. Bank National Association, as trustee included as Exhibit 4.2 to Registrant's Current Report on Form 8-K filed on April 5, 2012 and incorporated herein by reference.
4.4	Form of 5.875% Senior Notes due 2022 included in Exhibit 4.3 to the Registrant's Current Report on Form 8-K filed on April 5, 2012 and incorporated herein by reference.
10.1	Credit Agreement dated as of July 14, 2011, among Cimarex, the Administrative Agent, the Co-Syndication Agents, the Co-Documentation Agents and the Lenders filed on July 18, 2011 as Exhibit 10.l to the Registrant's Current Report on Form 8-K and incorporated herein by reference.
10.2	Employment Agreement, dated September 7, 1999, by and between Paul Korus and Key Production Company, Inc. (filed as Exhibit 10.6 to the Registration Statement on Form S-4 dated May 9, 2002 (Registration No. 333-87948) and incorporated herein by reference).
10.3	Amendment to Employment Agreement effective January 1, 2009 between Cimarex Energy Co. and Paul Korus (filed as Exhibit 10.9 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

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Exhibit	Title
10.4	Employment Agreement, dated October 25, 1993, by and between Thomas E. Jorden and Key Production Company, Inc. (filed as Exhibit 10.7 to the Registration Statement on Form S-4 dated May 9, 2002 (Registration No. 333-87948) and incorporated herein by reference).
10.5	Amendment to Employment Agreement effective January 1, 2009 between Cimarex Energy Co. and Thomas E. Jorden (filed as Exhibit 10.11 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).
10.6	Employment Agreement, dated February 2, 1994, by and between Stephen P. Bell and Key Production Company, Inc. (filed as Exhibit 10.8 to the Registration Statement on Form S-4 dated May 9, 2002 (Registration No. 333-87948) and incorporated herein by reference).
10.7	Amendment to Employment Agreement effective January 1, 2009 between Cimarex Energy Co. and Stephen P. Bell (filed as Exhibit 10.13 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).
10.8	Employment Agreement, dated March 11, 1994, by and between Joseph R. Albi and Key Production Company, Inc. (filed as Exhibit 10.9 to the Registration Statement on Form S-4 dated May 9, 2002 (Registration No. 333-87948) and incorporated herein by reference).
10.9	Amendment to Employment Agreement effective January 1, 2009 between Cimarex Energy Co. and Joseph R. Albi (filed as Exhibit 10.15 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).
10.10	Amended and Restated 2002 Stock Incentive Plan of Cimarex Energy Co. effective January 1, 2009 (filed as Exhibit 10.16 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).
10.11	2011 Equity Incentive Plan adopted May 18, 2011 (filed as Appendix A to the Definitive Proxy Statement 14-A filed on March 23, 2011 (Commission File No. 001-31446) and incorporated herein by reference).
10.12	Form of Notice of Grant of Award of Performance Stock and Award Agreement (filed as Exhibit 10.2 to Registrant's Quarterly Report on Form 10-Q filed on August 4, 2011 (Commission File no. 001-31446) and incorporated herein by reference).
10.13	Form of Notice of Grant of Restricted Stock and Award Agreement (filed as Exhibit 10.3 to Registrant's Quarterly Report on Form 10-Q filed on August 4, 2011 (Commission File no. 001-31446) and incorporated herein by reference).
10.14	Form of Notice of Grant of Nonqualified Stock Option and Award Agreement (filed as Exhibit 10.4 to Registrant's Quarterly Report on Form 10-Q filed on August 4, 2011 (Commission File no. 001-31446) and incorporated herein by reference).
10.15	Form of Notice of Grant and Award Agreement (Other Stock Award with performance conditions).*
10.16	Deferred Compensation Plan for Nonemployee Directors adopted May 19, 2004, as amended and restated effective January 1, 2009 (filed as Exhibit 10.18 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

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Exhibit	Title
10.17	Cimarex Energy Co. Supplemental Savings Plan (amended and restated, effective January 1, 2009) (filed as Exhibit 10.19 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).
10.18	Cimarex Energy Co. Change in Control Severance Plan dated effective April 1, 2005, amended and restated effective January 1, 2009 (filed as Exhibit 10.20 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).
10.19	Amendment to Cimarex Energy Co. Change in Control Severance Plan dated effective March 19, 2013 (filed as Exhibit 10.1 to the Current Report on Form 8-K filed on March 20, 2013 (Commission File No. 001-31446) and incorporated herein by reference).
10.20	Form of Indemnification Agreement between Cimarex Energy Co. and each of its executive officers and directors (filed as Exhibit 10.20 to the Annual Report on Form 10-K for the year ended December 31, 2012 (Commission File No. 001-31446) and incorporated herein by reference).
10.21	Retention Agreement dated June 9, 2010.*
14.1	Code of Ethics for Chief Executive Officer and Senior Financial Officers (filed as Exhibit 14.1 to the Annual Report on Form 10-K for the year ended December 31, 2003 (Commission File No. 001-31446) and incorporated herein by reference).
21.1	Significant Subsidiaries of the Registrant.*
23.1	Consent of KPMG LLP.*
23.2	Consent of DeGolyer and MacNaughton*
24.1	Power of Attorney of directors of the Registrant. *
31.1	Certification of Thomas E. Jorden, Chief Executive Officer of Cimarex Energy Co., pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.*
31.2	Certification of Paul Korus, Chief Financial Officer of Cimarex Energy Co., pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.*
32.1	Certification of Thomas E. Jorden, Chief Executive Officer of Cimarex Energy Co., pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.*
32.2	Certification of Paul Korus, Chief Financial Officer of Cimarex Energy Co., pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.*
99.1	Letter dated January 22, 2014 from DeGolyer and MacNaughton, independent petroleum engineering consulting firm, reporting the results of its audit of Cimarex reserves as of December 31, 2013 of certain selected properties.*
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document

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SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

Date: February 26, 2014

CIMAREX ENERGY CO.

By: /s/ THOMAS E. JORDEN

Thomas E. Jorden
Chairman, President and Chief Executive Officer

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

Signature	Title	Date
/s/ THOMAS E. JORDEN Thomas E. Jorden	Chairman of the Board and Director, President and Chief Executive Officer (Principal Executive Officer)	February 26, 2014
* *Attorney-in-Fact* Joseph R. Albi	Director, Executive Vice President and Chief Operating Officer	February 26, 2014
/s/ PAUL KORUS Paul Korus	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 26, 2014
/s/ JAMES H. SHONSEY James H. Shonsey	Vice President, Chief Accounting Officer and Controller (Principal Accounting Officer)	February 26, 2014
* *Attorney-in-Fact* Jerry Box	Director	February 26, 2014
* *Attorney-in-Fact* Hans Helmerich	Director	February 26, 2014

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Signature	Title	Date
* *Attorney-in-Fact* David A. Hentschel	Director	February 26, 2014
* *Attorney-in-Fact* Harold R. Logan, Jr.	Director	February 26, 2014
* *Attorney-in-Fact* Floyd R. Price	Director	February 26, 2014
* *Attorney-in-Fact* Monroe W. Robertson	Director	February 26, 2014
* *Attorney-in-Fact* Michael J. Sullivan	Director	February 26, 2014
* *Attorney-in-Fact* L. Paul Teague	Director	February 26, 2014
*By: /s/ PAUL KORUS Paul Korus *Attorney-in-Fact*	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 26, 2014