CIMAREX ENERGY CO
Form 10-K
February 26, 2013

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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, 2012

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. o

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, 2012 was approximately $4.6 billion.

Number of shares of Cimarex Energy Co. common stock outstanding as of February 15, 2013 was 86,406,418. Documents Incorporated by Reference: Portions of the Registrant's Proxy Statement for its 2013 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

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

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PART I

Forward-Looking Statements

Throughout this Form 10-K, we make statements that may be deemed "forward-looking" statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. 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:

- Amount, nature and timing of capital expenditures;
- Drilling of wells;
- Reserve estimates;
- Timing and amount of future production of oil and natural gas;
- Operating costs and other expenses;
- Cash flow and anticipated liquidity;
- Estimates of proved reserves, exploitation potential or exploration prospect size;
- Marketing of oil and natural gas;
- Legislation and regulatory changes;
- 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 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, New Mexico and Kansas. Our website address is *www.cimarex.com*. There you will find our news releases, annual reports, proxy statements, 10-Ks, 10-Qs, 8-Ks, insider (Section 16) filings 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 2012 totaled 2.3 Tcfe, consisting of 1.3 Tcf of gas and 168 million barrels of oil and natural gas liquids (liquids). Of total proved reserves, 45% are liquids and 80% are classified as proved developed.

Our 2012 production averaged 626.5 MMcfe/d, comprised of 323.8 MMcf of gas and 50,457 barrels of liquids. The wells we operate account for 68% of total proved reserves and approximately 80% 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.

2012 Summary Highlights

During 2012 we accomplished the following:

- grew production 6% to a record 626.5 MMcfe/d; combined Permian Basin and Mid-Continent production increased 20% to an all-time high of 586 MMcfe/d;
- increased proved reserves 10% to 2.3 Tcfe; adjusted for property sales, reserves increased 13%;
- added 757 Bcfe of proved reserves from extensions and discoveries replacing 330% of production;
- realized net income of $353.8 million, or $4.07 per diluted share;
- generated cash flow from operating activities of $1.2 billion;
- sold $306 million of non-strategic assets which will be reinvested in core area exploration and development activities;
- evaluated, de-risked and expanded our acreage position in several key long-term future drilling projects;
- ended the year with debt to total capitalization of 18%.

Business Strategy

Our principal business objective is to profitably grow proved reserves and production for the long-term benefit of our shareholders 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:

generating and 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 which provides feedback to improve results;
- attracting quality employees and maintaining integrated teams of geoscientists, landmen and engineers;
- maximizing profitability by efficiently operating our properties; and
- 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 2012 totaled $1.6 billion. Of total expenditures, 55% were invested in the Permian Basin and 41% in the Mid-Continent area. Our Permian Basin efforts are focused on horizontal oil and liquids-rich gas drilling, where the Bone Spring oil formation both in Texas and New Mexico has been one of our most economic investments areas. In the Mid-Continent, our activity has been focused in the liquids-rich gas portion of the Cana-Woodford shale. With oil prices relatively stronger than gas prices, we shifted essentially all of our capital to oil and liquids-rich gas drilling in 2012.

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 2012, we had $750 million of long-term debt and debt to total capitalization was 18%.

2013 Outlook

Our 2013 E&D capital investment is presently expected to be in the range of $1.4-1.5 billion. We expect nearly all of our 2013 capital to be directed towards oil and liquids-rich gas drilling in the Permian Basin and Cana-Woodford shale play.

Total company production volumes are projected to average 675-705 MMcfe/d in 2013, an increase of 8-13%. Liquids are projected to account for 51% of total equivalent production, up from 48% in 2012. Combined Mid-Continent and Permian 2013 production volumes are projected to grow 11-15%, averaging between 652-673 MMcfe/d. Gulf Coast volumes are projected to average 23-32 MMcfe/d, or 4% of total estimated company volumes.

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.

Business Segments

Cimarex has one reportable segment (exploration and production).

Exploration and Production Overview

Our exploration and production (E&P) activities have been 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. Our Gulf Coast operations are conducted in southeast Texas.

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A summary of our 2012 exploration and development activity by region is as follows.

	Exploration and Development Capital (in millions)	Gross Wells Drilled	Net Wells Drilled	Completion Rate	12/31/12 Proved Reserves (Bcfe)
Permian Basin	$ 889	182	122	94%	697
Mid-Continent	673	167	69	98%	1,528
Gulf Coast/Other	61	3	1	33%	34
	$ 1,623	352	192	95%	2,259

Permian Basin

Our Permian Basin operations cover west Texas and southeast New Mexico. Drilling principally occurred in the Delaware Basin portion of New Mexico and West Texas, mainly targeting the Bone Spring and Wolfcamp formations. In total, we drilled 182 gross (122 net) wells in this area during 2012 completing 171 gross (113 net) as producers. Full-year 2012 investment in this area totaled $889 million, or 55% of total capital.

Cimarex drilled and completed 64 gross (34 net) New Mexico Bone Spring wells in 2012. Per-well 30-day gross production from these wells averaged over 640 Boe/d (90% oil). Texas Third Bone Spring drilling totaled 43 gross (26 net) wells, which had per-well 30-day average gross production rates of over 1,000 Boe/d (85% oil).

We are also evaluating multiple shale intervals in the Delaware Basin, including the Wolfcamp, Avalon and Cisco/Canyon formations. The majority of drilling to date has been in the Wolfcamp. The Wolfcamp formation is a shale interval that varies in thickness from 600-700 feet at depths of 8,000-10,000 feet throughout our acreage.

We drilled and completed 15 gross (14 net) horizontal Wolfcamp shale wells in southern Eddy County, New Mexico and Culberson County, Texas, in 2012. Since commencing the play in 2010, we have drilled a total of 33 gross (31 net) Wolfcamp wells. Thirty-day average initial production on these wells was 6.4 MMcfe/d, comprised of 44% gas, 26% oil and 30% NGL. We have over 100,000 net acres prospective for the Wolfcamp in this area.

Mid-Continent

Our Mid-Continent region encompasses operations in Oklahoma, southwest Kansas and the Texas Panhandle. We drilled 167 gross (69 net) Mid-Continent wells during 2012, completing 98% as producers. The bulk of this drilling activity was in the Anadarko Basin of western Oklahoma, where we drilled 149 gross (61 net) wells which were primarily infill development wells. At year-end there were 46 gross (21 net) wells waiting on completion. Full-year 2012 investment in this area was $673 million, or 41% of total E&D capital.

In the Anadarko Basin of western Oklahoma, our largest investment was in the Cana-Woodford shale play. The Cana-Woodford formation is a shale interval that varies in thickness from 120-280 feet at depths of 11,000-16,000 feet throughout our acreage. We have approximately 141,000 net acres in the play.

Gulf Coast

Our Gulf Coast region is focused on exploration in southeast Texas. This effort is generally characterized by reliance on three-dimensional (3-D) seismic information for prospect generation. Compared to other core areas, we often experience larger potential reserves per well, greater drilling depths and lower success rates in the Gulf Coast. During 2012, several new seismic shoots were being obtained and processed and drilling was limited. Full-year 2012 investment in the Gulf Coast area was $46 million, or 3% of total E&D capital. We drilled 3 gross (1 net) Gulf Coast wells in 2012, realizing a 33% success rate.

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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 2012, proved reserves of Cana-Woodford were approximately 50% 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)**
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
Gulf Coast/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
Gulf Coast/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
2010								
Permian Basin	26,104	5,097	615	60,374	71.5	14.0	1.7	165.4
Mid-Continent	70,865	1,708	2,014	93,198	194.1	4.7	5.5	255.4
Gulf Coast/Other	35,844	3,039	1,643	63,937	98.3	8.3	4.5	175.1
Total company	132,813	9,844	4,272	217,509	363.9	27.0	11.7	595.9
Cana-Woodford	18,669	358	1,480	29,697	51.1	1.0	4.1	81.4

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	Avearge Sales Price			Production
Year Ending December 31,	Gas (per MCF)	Oil (per Bbl)	NGL (per Bbl)	Cost (per Mcfe)
2012				
Permian Basin	$ 2.93	$ 87.93	$ 30.78	$ 1.50
Mid-Continent	$ 2.86	$ 90.41	$ 29.91	$ 0.77
Gulf Coast/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
Gulf Coast/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
2010				
Permian Basin	$ 5.01	$ 76.10	$ 33.36	$ 1.53
Mid-Continent	$ 4.71	$ 75.54	$ 33.68	$ 0.73
Gulf Coast/Other	$ 5.27	$ 78.55	$ 37.00	$ 0.56
Total company	$ 4.92	$ 76.76	$ 34.91	$ 0.89
Cana-Woodford	$ 4.34	$ 76.76	$ 33.84	$ 0.10

Our largest producing area is the Mid-Continent region. During 2012, Mid-Continent production averaged 322.5 MMcfe/d, or 51% of total production. Infill development drilling activity in the Cana-Woodford shale play resulted in Mid-Continent production increasing 10% in 2012.

The Permian Basin contributed 263.7 MMcfe/d in 2012, which was 42% of our total production. It was our most active drilling area in 2012 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 was a record 23,908 Bbl/d, a 43% increase over 2011.

Gulf Coast production averaged 40.3 MMcfe/d during 2012, a 62% decrease from 2011. These volumes represented 6% of total production. Gulf Coast volumes can fluctuate significantly depending on timing of exploration success relative to natural production declines.

Acquisitions and Divestitures

Over the last two years we made property acquisitions totaling approximately $78.9 million. We bought $33.5 million of properties in 2012, the largest of which was a $21 million purchase of properties in Culberson County, Texas. In 2011, we acquired additional oil and gas properties for a total of $45.4 million of which $42.2 million was in our Cana-Woodford shale play.

We regularly evaluate our asset base for potential divestiture. Over the last two years we sold $535 million of properties. In 2012, we sold $306 million of properties, the most significant of which was the year-end sale of $294 million of non-core assets in Texas. These properties had production of approximately 2,550 Boe/d (75% oil) and proved reserves of 9.1 million barrels.

In August 2011, we sold all of our interests in Sublette County, Wyoming for $195.5 million. These assets principally consisted of a gas processing plant under construction and 210 Bcf of proved undeveloped gas reserves. In 2011, we also sold interests in certain other non-strategic oil and gas properties with proved reserves of 16.3 Bcfe for $33.3 million, including assets located in south Texas and southeast New Mexico.

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Marketing

Our oil and gas production is sold under short-term arrangements at market-responsive prices. We sell our oil at prices tied directly or indirectly to field postings. Our gas is sold under 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 2012 were Sunoco Logistics Partners L.P. (Sunoco) and Enterprise Products Partners L.P. (Enterprise) and accounted for 22% and 21% of our consolidated revenues in 2012, respectively. Sunoco is a significant purchaser of our oil in New Mexico and Beaumont, Texas areas. Enterprise is our primary oil purchaser in Oklahoma and Ward/Culberson Counties in Texas. 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 employed 851 people on December 31, 2012. 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.

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

Cimarex is committed to environmental protection and believes we are in 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

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anticipate that there will be any undisclosed impact on our capital expenditures, earnings or competitive position.

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 not presently known to us or that we currently deem immaterial may also 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 very 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 global supply and demand for oil and gas, geopolitical instability, the actions of the Organization of Petroleum Exporting Countries, the level of 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 in quantity unless we successfully replace the reserves we produce 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. 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, our ability to borrow under our bank credit facility and to raise additional debt or equity capital to fund acquisitions may also be impacted.

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 price declines in the future could cause us to incur impairment charges in the future, which could have a material adverse effect on our results of operations in the period taken.

As of December 31, 2012, 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, the amount of the excess has declined approximately 87% since December 31, 2011. As of December 31, 2012, a decline of 3% or more in the value of the ceiling limitation would have resulted in an impairment. If negative trends continue, we may incur impairment charges in the future, which could have a material adverse effect on our financial results.

Global financial markets may impact our business and financial condition.

Recurrence of a credit crisis or other turmoil in the global financial system may have an 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 an impact on our lenders, purchasers of our oil and gas production and working interest owners in properties we operate, causing them to fail to meet their obligations to us.

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

In order to replace the reserves depleted by production and to maintain or grow our total proved reserves and overall production levels, we must locate and develop new oil and gas reserves both in existing as well as new areas of development 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 may from time to time seek to acquire proved reserves, our main business strategy is to grow through drilling. Without successful exploration and development, our reserves, production and revenues could decline rapidly, which would negatively impact our results of operations.

Exploration and development involves numerous risks, including new regulations or legislation and the risk that no commercially productive oil or gas reservoirs will be discovered. It can also be unprofitable, not only from dry wells, but also from productive wells that do not produce sufficient reserves to return a profit or from declines in commodity prices.

Our drilling operations may be curtailed, delayed or canceled as a result of several factors, including unforeseen poor drilling conditions, title problems, unexpected pressure or irregularities in formations. In addition, 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 may also 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 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;
- future oil, gas and NGL prices;
- effects of governmental regulation;
- future operating costs;
- future property, severance, excise and other taxes incidental to oil and gas operations;

workover and remediation costs; and

Federal and state income taxes.

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At December 31, 2012, 20% of our total proved reserves are categorized as proved undeveloped. All of these proved undeveloped reserves are in the Cana-Woodford shale play.

Our proved oil and gas reserve estimates are prepared by Cimarex engineers in accordance with guidelines established by the SEC. DeGolyer and MacNaughton, independent petroleum engineers, reviewed our reserve estimates for properties that comprised at least 80% of the discounted future net cash flows before income taxes, using a 10% discount rate, as of December 31, 2012.

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

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

To manage our exposure to price risk, we enter hedging agreements from time to time. We use commodity derivatives with respect to a significant portion of our future production. For 2013, we have hedged approximately 35% of our anticipated oil production. The goal of these hedges is to lock in prices so as to limit volatility and increase the predictability of cash flow. These transactions limit our potential gains if oil and gas prices rise above the price 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 futures contracts fail to perform under the contracts;
- a sudden unexpected event materially impacts oil and natural gas prices;
- our production is less than expected; 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 the provisions of the Dodd-Frank Act. The 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 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 exemption and continue to engage in derivative transactions. However, the CFTC is still finalizing rules which 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, reporting or disclosure obligations.

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We have been an early entrant into new or emerging resource development projects. 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 development projects have limited or no production history. Consequently, in those areas we may not have past drilling results to help predict our future drilling results. Therefore, our cost of drilling, completing and operating wells in these areas may be higher than initially expected. The value of our undeveloped acreage may decline if drilling results are unsuccessful. Furthermore, if drilling results are unsuccessful, we may be required to write down the carrying value of our undeveloped acreage in new or emerging plays.

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 transportation facilities, some of which are owned by others.

Our oil and natural gas production depends in large part on the availability, proximity and capacity of pipeline systems and transportation facilities. The lack of available capacity on these systems and facilities (or the lack of such systems and facilities in proximity to our wells) could result in the curtailment of production or the delay or discontinuance of drilling plans. The lack of availability of these facilities for an extended period of time could negatively affect our revenues.

Federal and state regulation of oil and natural gas production and transportation, 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, gather and transport 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 than Cimarex. These companies 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 sophisticated 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 operation results.

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

Exploration, production and the sale of oil and gas are subject to extensive laws and regulations, including laws and regulations protecting the environment and human health and safety. Federal and state regulatory agencies frequently require permitting and impose conditions on our activities. During the permitting process, these regulatory authorities often exercise considerable discretion in both the timing and ultimate scope of the permits. The requirements or conditions imposed by these authorities can be costly, possibly resulting in delays in the commencement of our operations. Further, if the required permits are not issued or if the current requirements become more burdensome, costs could materially increase and operations could be significantly restricted.

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 penalties. Such liabilities and costs could have a material adverse effect on both our financial condition and operations.

Environmental matters and costs can be significant.

As an owner, lessee or operator of oil and gas properties, we are subject to various complex 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, waste materials, 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 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. The fluid used in this process is primarily water. In developing plays where hydraulic fracturing is necessary for the 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. Certain states are requiring 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 state-wide hydraulic fracturing moratoriums and temporary or permanent bans in certain environmentally sensitive areas. Public sentiment against hydraulic fracturing and shale gas production has become more vocal, which could render permitting and compliance requirements to become more stringent. Consequences of these actions could potentially 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.

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 20% 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 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, 2012, our long-term debt consisted of $750 million of 5.875% senior notes. 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.

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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 may also be impacted by changes in prevailing interest rates, as borrowing under our existing senior revolving credit facility bears interest at floating rates.

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

- reducing or delaying capital expenditures;
- seeking additional debt financing or equity capital;
- selling non-strategic 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 credit agreement contain various restrictive covenants that may limit management's discretion in certain respects. In particular, these agreements limit Cimarex 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 the assets of us and our restricted subsidiaries taken as a whole;

- 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 less than 3.5 to 1 and a current ratio (defined to include undrawn borrowings) of greater than 1 to 1. 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 to 1. The additional indebtedness limitation does not prohibit us from borrowing under our revolving credit facility. See Note 5, Long-term Debt, in Notes to 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. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the 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 January 2009, the Tulsa County District Court issued a judgment totaling $119.6 million in the "Krug v. Helmerich & Payne, Inc." case. See Note 13, Commitments and Contingencies in this report for more detailed information.

Because this case is subject to further appeal and despite the fact that the ultimate outcome currently is unknown, we have accrued for the District Court's original judgment in our financial statements. If the District Court's original judgment is ultimately affirmed in its entirety, the $119.6 million plus the then determined amount of post-judgment interest and costs would become payable. This could have an adverse effect on our liquidity.

In the normal course of business, we have other various lawsuits and related disputed claims. Although we currently believe the resolution of these lawsuits and claims, individually or in the aggregate,

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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 which are not in accord with our evaluation of the possible liability or outcome of such litigation or 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.

The Fiscal Year 2013 Budget proposed by President Obama recommends elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. Legislation has been introduced in Congress which would implement many of these proposals. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; and (iii) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear, however, whether any such changes will be enacted or how soon such changes could be effective.

The passage of this legislation or any other similar change in U.S. federal income tax law could eliminate or postpone certain tax deductions that are currently available with respect to 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 68% 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, Unaudited Supplemental Oil and Gas Disclosures, in Notes to 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,		
	2012	**2011**	**2010**
Total Proved Reserves			
Gas (MMcf)	1,251,863	1,216,441	1,254,166
Oil (MBbls)	77,921	72,322	63,656
NGL (MBbls)	89,909	65,815	41,310
Equivalent (MMcfe)	2,258,844	2,045,265	1,883,957
Standardized measure of discounted future net cash flow after-tax, discounted at 10% (in millions)	$ 2,908.7	$ 3,139.8	$ 2,515.3
Average price used in calculation of future net cash flow			
Gas ($/Mcf)	$ 2.27	$ 3.79	$ 4.12
Oil ($/Bbl)	$ 88.91	$ 89.64	$ 75.35
NGL ($/Bbl)	$ 29.12	$ 41.70	$ 33.89

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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.

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 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, 2012. 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-eight 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 eighteen 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 eight years.

Significant Properties

As of December 31, 2012, 99% of our total proved reserves were located in the Mid-Continent and Permian Basin regions. In total we owned an interest in 13,127 gross (4,953 net) productive oil and gas wells.

The following table summarizes our estimated proved oil and gas reserves by region as of December 31, 2012.

	Gas (Bcf)	Oil (MBbl)	NGL (MBbl)	Equivalent (Bcfe)	Percent of Proved Reserves
Mid-Continent	996.8	17,984	70,615	1,528.3	68%
Permian Basin	233.2	58,623	18,634	696.8	31%
Gulf Coast/Other	21.9	1,314	660	33.7	1%
	1,251.9	77,921	89,909	2,258.8	100%

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Our ten largest producing fields hold 70% 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	50.1	35.8	13,000'	Woodford
Lusk	Permian	3.4	43.7	9,500'	Bone Spring
Triple Crown Wolfcamp	Permian	2.9	100.0	9,500'	Wolfcamp
Two Georges	Permian	2.9	88.8	11,500'	Bone Spring
Phantom	Permian	2.6	55.0	11,500'	Bone Spring
Eola-Robberson	Mid-Continent	2.1	90.0	5,500' - 11,000'	Bromide/McLish/Oil Creek
Cottonwood Draw	Permian	1.6	85.6	3,000' - 10,000'	Delaware/Wolfcamp
Caprock	Permian	1.5	72.8	9,000'	Abo
Quail Ridge	Permian	1.5	69.4	8,000' - 13,000'	Bone Spring/Morrow
Benson	Permian	1.0	85.5	9,500'	Bone Spring
		69.6			

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Acreage

The following table sets forth the gross and net acres of both developed and undeveloped leases held by Cimarex as of December 31, 2012. Gross acres are the total number of acres in which we own a working interest. Net acres are the gross acres multiplied by our working interest.

	Acreage					
	Undeveloped		Developed		Total	
	Gross	Net	Gross	Net	Gross	Net
Mid-Continent						
Kansas	18,973	18,864	118,111	86,454	137,084	105,318
Oklahoma	152,524	122,115	544,173	280,060	696,697	402,175
Texas	139,977	126,053	197,418	119,662	337,395	245,715
	311,474	267,032	859,702	486,176	1,171,176	753,208
Permian Basin						
New Mexico	100,695	75,727	187,316	131,922	288,011	207,649
Texas	134,930	112,010	162,498	118,034	297,428	230,044
	235,625	187,737	349,814	249,956	585,439	437,693
Gulf Coast						
Louisiana	5,968	1,657	12,259	3,195	18,227	4,852
Texas	129,621	103,959	102,063	36,961	231,684	140,920
Offshore	25,762	13,000	72,350	17,308	98,112	30,308
	161,351	118,616	186,672	57,464	348,023	176,080
Western/Other						
Arizona	2,111,139	2,111,139	17,207		2,128,346	2,111,139
California	382,124	382,124	364	364	382,488	382,488
Colorado	90,320	62,719	36,758	2,203	127,078	64,922
Michigan	53,603	53,525	1,183	1,183	54,786	54,708
Montana	36,095	10,590	7,319	1,698	43,414	12,288
Nevada	1,196,299	1,196,299	440	1	1,196,739	1,196,300
New Mexico	1,643,240	1,629,395	19,722	2,518	1,662,962	1,631,913
Utah	87,932	59,373	28,290	1,632	116,222	61,005
Wyoming	108,218	15,809	45,290	5,292	153,508	21,101
Other	66,555	47,616	8,198	3,222	74,753	50,838
	5,775,525	5,568,589	164,771	18,113	5,940,296	5,586,702
Total	6,483,975	6,141,974	1,560,959	811,709	8,044,934	6,953,683

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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									
	2013		2014		2015		2016		2017	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Mid-Continent	59,308	50,735	23,538	23,245	12,084	12,039	11,239	11,239	21	21
Permian Basin	37,737	37,039	17,206	16,405	46,931	39,343	6,096	6,072	991	991
Gulf Coast	85,116	84,211	7,816	7,735	879	879	1	1		
Western/Other	45,704	45,704	7,602	7,562	17,954	17,954	198,369	198,369	56,120	56,120
	227,865	217,689	56,162	54,947	77,848	70,215	215,705	215,681	57,132	57,132
Percent of undeveloped	3.5	3.5	0.9	0.9	1.2	1.1	3.3	3.5	0.9	0.9

Gross Wells Drilled

We participated in drilling the following number of gross wells during calendar years 2012, 2011, and 2010:

	Exploratory			Developmental		
	Productive	Dry	Total	Productive	Dry	Total
Year ended December 31, 2012	8	5	13	328	11	339
Year ended December 31, 2011	3	7	10	314	7	321
Year ended December 31, 2010	10	3	13	199	7	206

We were in the process of drilling 37 gross (14.9 net) wells at December 31, 2012, and there were 64 gross (29.8 net) wells waiting on completion.

Net Wells Drilled

The number of net wells drilled during calendar years 2012, 2011, and 2010 are shown below:

	Exploratory			Developmental		
	Productive	Dry	Total	Productive	Dry	Total
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
Year ended December 31, 2010	9.4	3.0	12.4	111.4	5.2	116.6

Productive Wells

We have working interests in the following productive wells as of December 31, 2012:

	Gas		Oil	
	Gross	Net	Gross	Net
Mid-Continent	4,394	2,220	1,295	577
Permian	1,142	603	5,066	1,392
Gulf Coast / Other	393	111	837	50
	5,929	2,934	7,198	2,019

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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* (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 shareholders of H&P, by which Cimarex became a publicly-traded entity, Cimarex assumed the assets and liabilities of H&P's exploration and production business, including this lawsuit. In 2008 we recorded a litigation expense of $119.6 million for this lawsuit. We have accrued additional post-judgment interest and costs during the appeal of the District Court's judgment.

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* was filed as a statewide royalty putative class action 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. The Court has entered an order preliminarily approving the parties' settlement. The deadline for putative class members to opt out of the settlement class was February 15, 2013, and less than $^1/_2$% of the class members opted out. The Court will hold the settlement fairness hearing on March 22, 2013. In the fourth quarter of 2012, we accrued $16.4 million for this matter.

Additional information regarding these and other litigation is included in Note 13, Commitments and Contingencies, of the notes to our consolidated financial statements included in Item 8 of this report.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

ITEM 4A. EXECUTIVE OFFICERS

The executive officers of Cimarex as of February 26, 2013 were:

Name	Age	Office
Thomas E. Jorden	55	Chairman of the Board, President and Chief Executive Officer
Joseph R. Albi	54	Executive Vice President and Chief Operating Officer
Stephen P. Bell	58	Executive Vice President, Business Development
Paul Korus	56	Senior Vice President and Chief Financial Officer
Gary R. Abbott	40	Vice President, Corporate Engineering
Richard S. Dinkins	68	Vice President, Human Resources
John Lambuth	50	Vice President, Exploration
Thomas A. Richardson	67	Vice President, General Counsel
James H. Shonsey	61	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.

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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.

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.

THOMAS A. RICHARDSON joined Cimarex in August 2008 and was elected vice president and general counsel on September 20, 2008. Mr. Richardson retired as a senior partner of Holme Roberts & Owen LLP, a Denver law firm, in December 2007. Mr. Richardson joined Holme Roberts in June 1970 and served as a partner of the firm from 1975 to his retirement. His specialties at the firm included corporate, securities and merger and acquisition law.

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.

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PART II

ITEM 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

Our $0.01 par value common stock trades on the New York Stock Exchange under the symbol XEC. A cash dividend was paid to shareholders in each quarter of 2012. 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.

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

2011	**High**	**Low**	**Dividends Paid Per Share**
First Quarter	$ 117.95	$ 87.60	$ 0.08
Second Quarter	$ 117.94	$ 81.65	$ 0.10
Third Quarter	$ 93.24	$ 55.29	$ 0.10
Fourth Quarter	$ 71.22	$ 50.80	$ 0.10

The closing price of Cimarex stock as reported on the New York Stock Exchange on February 15, 2013, was $64.95. At December 31, 2012, Cimarex's 86,595,976 shares of outstanding common stock were held by approximately 2,356 stockholders of record.

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The following graph compares the cumulative 5-year total return attained by shareholders 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 common stock and in each of the indexes (with the reinvestment of all dividends) from December 31, 2007 to December 31, 2012.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*

*

$100 invested on 12/31/07 in stock or index, including reinvestment of dividends.

Fiscal year ending December 31.

	12/07	12/08	12/09	12/10	12/11	12/12
Cimarex Energy Co.	100.00	63.31	126.16	211.78	148.80	139.79
S&P 500	100.00	63.00	79.67	91.67	93.61	108.59
Dow Jones US Exploration & Production	100.00	59.88	84.17	98.26	94.14	99.62

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

ITEM 5C. 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,				
	2012	2011	2010	2009	2008
	(in millions, except per share amounts)				
Operating results:					
Gas, oil and NGL sales	$ 1,582	$ 1,704	$ 1,559	$ 962	$ 1,881
Total Revenues	1,624	1,758	1,614	1,010	1,970
Net income (loss)	354	530	575	(312)	(915)
Earnings (loss) per share to common Stockholders:					
Basic	$ 4.08	$ 6.17	$ 6.74	$ (3.82)	$ (11.22)
Diluted	$ 4.07	$ 6.15	$ 6.70	$ (3.82)	$ (11.22)
Cash dividends declared per share	$ 0.48	$ 0.40	$ 0.32	$ 0.24	$ 0.24
Balance sheet data:					
Total assets	$ 6,305	$ 5,358	$ 4,287	$ 3,374	$ 4,094
Total debt	$ 750	$ 405	$ 350	$ 393	$ 588
Stockholders' equity	$ 3,475	$ 3,131	$ 2,610	$ 2,038	$ 2,352
Cash flow data:					
Net cash provided by operating activities	$ 1,193	$ 1,292	$ 1,130	$ 675	$ 1,367
Net cash used in investing activities	$ (1,415)	$ (1,429)	$ (978)	$ (444)	$ (1,597)
Net cash provided by (used in) financing activities	$ 289	$ 25	$ (41)	$ (230)	$ 107
Proved Reserves:					
Gas (Bcf)	1,252	1,216	1,254	1,187	1,067
Oil (MBbls)	77,921	72,322	63,656	56,764	44,286
NGL (MBbls)	89,909	65,815	41,310	1,253	916
Total equivalent (Bcfe)	2,259	2,045	1,884	1,535	1,339

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

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 2012 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, New Mexico, and Kansas.

Our principal business objective is to profitably grow proved reserves and production for the long-term benefit of our shareholders 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 blended portfolio of low, moderate, and higher risk exploration and development projects. 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.

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

Growth is generally funded with cash flow provided by operating activities together with bank borrowings, sale 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.

Our revenue, profitability, and future growth are highly dependent on the commodity prices we receive. Prices impact the amount of cash flow available for capital expenditures, our ability to raise additional capital and the fair market value of our assets. We use the full cost method of accounting for oil and gas activities. An extended decline in oil and/or gas prices could have an adverse effect on our financial position and results of operations, including the determination of full cost accounting ceiling test writedowns.

The preparation of our financial statements in conformity with generally accepted accounting principles requires us to make estimates and assumptions that impact reported results of operations and the amount of reported assets, liabilities, equity and proved reserves.

2012 Summary:

- Average daily production increased by 6% to 627 MMcfe/d compared to 592 MMcfe/d in 2011.
- Our combined Permian Basin and Mid-Continent production grew 20% to an all-time high of 586 MMcfe/d, compared to 487 MMcfe/d in 2011.
- We added 757.3 Bcfe of proved reserves from extensions and discoveries, replacing 330% of production.
- Proved reserves increased 10% to 2.26 Tcfe. Adjusted for property sales, proved reserves increased 13%.
- Exploration and development expenditures totaled $1.6 billion.
- Cash flow provided by operating activities totaled $1.2 billion.
- Net income was $353.8 million, or $4.07 per diluted share. This compares to 2011 net income of $529.9 million, or $6.15 per diluted share.
- We issued $750 million of 5.875% senior notes at par and retired our 7.125% senior notes.
- Total debt increased by $345 million to $750 million compared to $405 million at year-end 2011.
- We sold $305.9 million of non-strategic assets and used the proceeds for general corporate purposes, including repayment of outstanding bank debt.

Drilling activities were focused almost exclusively in the Permian Basin and Mid-Continent regions. During 2012, we drilled and completed 352 gross (192 net) wells. Of total wells drilled, 182 gross (122 net) were in the Permian Basin and 167 gross (69 net) were in the Mid-Continent.

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We continue to evaluate and expand our acreage position in key long-term future drilling projects. During 2012, we invested $152.8 million in land and seismic.

In July 2012, aggregate commitments on our senior unsecured revolving credit facility were increased from $800 million to $1 billion. The credit facility provides for a borrowing base of $2 billion and will mature on July 14, 2016. We did not have any bank debt outstanding at December 31, 2012. At December 31, 2011, our outstanding bank debt was $55 million.

Proved Reserves

Year-end 2012 proved reserves grew 10% to 2.26 Tcfe, up from 2.05 Tcfe at year-end 2011. The increase in 2012 proved reserves is net of production of 229.3 Bcfe and sales of 57.3 Bcfe. Proved reserves were 80% developed at year-end 2012 compared to 82% at year-end 2011. Overall, approximately 68% of proved reserves were in our Mid-Continent region and 31% in the Permian Basin.

Reserves added from extensions and discoveries totaled 757.3 Bcfe, replacing 330% of production. In our western Oklahoma Cana-Woodford shale area, we added 202.5 Bcfe from infill wells drilled and 315.9 Bcfe of proved undeveloped (PUD) reserves. Development drilling in the Permian Basin added 229.2 Bcfe. In total, reserve additions were comprised of 51% oil and NGLs and 49% gas. With continued focus on oil and liquids-rich gas projects, the amount of proved reserves comprised of oil and NGLs increased to 45% as compared to 41% at year-end 2011.

Approximately 72 Bcfe of the 257.3 Bcfe net negative revisions during 2012 relate to production performance of certain wells recently drilled in our Cana-Woodford shale project. PUD reserve additions in extensions and discoveries for 2012 now reflect revised expectations of future production performance. The remainder of the net negative revision 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).

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. While revenues are a function of both production and prices, wide swings in commodity prices have had the greatest impact on our results of operations. Compared to 2011, our 2012 average realized gas price decreased by 35% and our average realized NGL price decreased by 28%. Our average oil price decreased 4%. Prices we receive are determined by prevailing market conditions. Regional and worldwide economic and geopolitical activity, weather and other variable factors influence market conditions, which often result in significant volatility in commodity prices.

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

	Years Ended December 31,		
	2012	2011	2010
Gas Prices:			
Average Henry Hub price ($/Mcf)	$ 2.79	$ 4.04	$ 4.39
Average realized sales price ($/Mcf)	$ 2.88	$ 4.42	$ 4.92
Oil Prices:			
Average WTI Cushing price ($/Bbl)	$ 94.20	$ 95.14	$ 79.54
Average realized sales price ($/Bbl)	$ 89.25	$ 93.00	$ 76.76
NGL Prices:			
Average realized sales price ($/Bbl)	$ 30.66	$ 42.31	$ 34.91

On an energy equivalent basis, 52% of our 2012 aggregate production was natural gas. A $0.10 per Mcf change in our average realized gas sales price would have resulted in a $12 million change in our gas revenues. Similarly, 48% of our production was crude oil and NGLs. A $1.00 per barrel change in our average realized sales prices would have resulted in an $18 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 2012 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 2012, we owned interests in 13,127 gross wells.

Production expense generally consists of the cost of water disposal, power and fuel, direct labor, third-party field services, compression and certain maintenance activity (workovers) necessary to produce oil and gas from existing wells.

Transportation expense is comprised of costs paid to move oil and gas from the wellhead to a specified sales point. In some cases we receive a payment from purchasers which is net of transportation costs, and in other instances we pay separately for transportation. If costs are netted in the proceeds received, both the gross revenues and gross costs are shown in sales and expenses, respectively.

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 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. Lower prices generally have the effect of decreasing reserves which increases depletion expense. The costs of replacing production also impact our DD&A rate. In addition, changes in estimates of reserve quantities, estimates of operating and future development costs, and reclassifications from unproved properties to proved properties will impact depletion expense.

We use the full cost method of accounting for our oil and gas operations. Accounting rules require us to perform a quarterly "ceiling test" calculation to test our oil and gas properties for possible impairment. The primary components impacting this analysis are commodity prices, reserve quantities added and produced, overall exploration and development costs, and depletion expense. 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 the present value discounted at 10% of estimated future net cash flows from proved reserves, the cost of properties not being amortized,

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the lower of cost or estimated fair value of unproven properties included in the costs being amortized, and all related tax effects.

At December 31, 2012, 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, the amount of the excess has declined approximately 87% since December 31, 2011. As of December 31, 2012, a decline of 3% or more in the value of the ceiling limitation would have resulted in an impairment. If negative trends continue we may incur impairment charges in the future, which could have a material adverse effect on our results of operations in the period taken.

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 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.

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 from favorable price changes.

For 2012, we hedged about half of our anticipated oil production. We did not hedge any of our gas or NGL production. All of the oil contracts expired during 2012 without any cash settlements.

In 2011 we had approximately 40 to 45% of our anticipated oil production and 5 to 6% of projected gas production hedged. Those contracts were settled in 2011 for a net gain of $6.7 million. During 2010 we had approximately 40% of our anticipated 2010 oil and gas production hedged. Those contracts settled in 2010 for a net gain of $52.1 million.

As of December 31, 2012, we did not have any hedges in place. Subsequent to December 31, 2012 we entered into oil contracts as follows:

				Weighted Average Price		
Period	**Type**	**Volume/Day**	**Index(1)**	**Floor**	**Ceiling**	**Swap**
Feb 13 - Dec 13	Collars	6,000 Bbls	WTI	$ 85.00	$ 102.31	
Feb 13 - Dec 13	Swaps	6,000 Bbls	WTI			$ 96.13

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

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 chosen not to apply hedge accounting treatment to any of the derivative contracts we have entered into since 2009. Therefore, settlements on our derivative contracts do not impact our realized commodity prices during the periods they cover. Instead, 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 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

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

Commodity sales totaled $1.6 billion in 2012, compared to $1.7 billion last year. 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 per day, up 6% from 592.3 Mcfe per day in 2011. In the fourth quarter of 2012, our production volumes averaged a record 676.7 MMcfe per day, or 13% above 601.4 MMcfe per day in the fourth quarter 2011. The period-over-period increases in volumes were a result of our successful drilling programs in the Permian Basin and Mid-Continent region.

Our 2012 gas production averaged 323.8 MMcf per day, compared to 329.1 MMcf per day for 2011. The 1% decline in year-over-year gas production resulted in a decrease in revenue of $7.1 million. During the fourth quarter of 2012, our daily gas production averaged 333.4 MMcf per day, down slightly from 334.2 MMcf per day, for the same period of 2011. The decline in fourth quarter 2012 gas production resulted in $0.5 million less revenue in the fourth quarter of 2012 compared to the same period of 2011.

Oil production for 2012 averaged 31,463 barrels per day, up 18% from 26,789 barrels per day for in 2011. The increase in 2012 production provided an additional $161.6 million of oil revenue. Our fourth quarter 2012 oil production averaged 35,099 barrels per day, an increase of 28% compared to 27,431 barrels per day for the fourth quarter 2011. The higher production in the fourth quarter of 2012 increased oil sales by $65.4 million.

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In 2012, our average daily NGL production volume was 18,994 barrels per day compared to 17,086 barrels per day for 2011. The 11% higher volumes contributed $30.3 million of additional revenue. During the fourth quarter of 2012, our average NGL production was 22,118 barrels per day, up 29% from 17,107 barrels per day during the fourth quarter 2011. Higher production provided an additional $18.6 million of revenue in the fourth quarter.

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. During the fourth quarter of 2012, our average realized gas price decreased by 14% to $3.35 per Mcf. For the same period of 2011 we realized an average price of $3.90 per Mcf. The decrease in realized prices in the fourth quarter caused our gas sales to be $16.9 million lower than the same period of 2011.

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. For the fourth quarter of 2012 our average realized oil price was $83.04 per barrel versus $92.76 per barrel received in the fourth quarter of 2011. The decrease in fourth quarter 2012 oil sales due to the 10% decrease in oil prices totaled $31.4 million.

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. In the fourth quarter of 2012 our average realized price for NGLs was $28.99 per barrel compared to an average realized price of $40.29 per barrel received in the fourth quarter of 2011. The 28% decrease in the fourth quarter 2012 NGL realized price resulted in lower NGL sales of $23.0 million compared to the 2011 fourth quarter.

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.

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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	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.

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

	For the Years Ended December 31,		Variance Between	Per Mcfe	
(in thousands)	2012	2011	2012/2011	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 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.

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

(in thousands)	For the Years Ended December 31, 2012	For the Years Ended December 31, 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 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	For the Years Ended December 31, 2011	Variance Between 2012/2011
Performance-based 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-based 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.

Net gain or loss on derivative instruments includes both realized gains and losses on settlements of derivative contracts and unrealized gains and losses stemming from changes in the fair value of outstanding derivative instruments. We have not elected hedge accounting treatment for derivative contracts. Therefore, we recognize all realized settlements and unrealized changes in fair value in operating costs and expenses.

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The following table reflects our net realized and unrealized gains on derivative instruments:

	For the Years Ended December 31,		Variance Between
(In thousands)	**2012**	**2011**	**2012/2011**
Realized gain on settlement of derivative instruments	$	$ 6,711	$ 6,711
Unrealized gain from changes to the fair value of the derivative instruments	245	3,611	3,366
Gain on derivative instruments, net	$ 245	$ 10,322	$ 10,077

Realized and unrealized gains or losses on 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 additional information regarding our derivative instruments.

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.

Other (income) and expense

	For the Years Ended December 31,		Variance Between
(in thousands)	**2012**	**2011**	**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.

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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.

RESULTS OF OPERATIONS

2011 compared to 2010

Net income for the year-ended December 31, 2011was $529.9 million, or $6.15 per diluted share. For 2010 we had net income of $574.8 million, or $6.70 per diluted share. In 2011, increased revenues from higher realized oil and NGL prices were more than offset by higher DD&A and production expenses compared to 2010. These changes are discussed further in the analysis that follows.

Commodity Sales	For the Years Ended December 31, 2011	2010	Percent Change Between 2011/2010	Price / Volume Change Price	Volume	Total
(in thousands or as indicated)						
Gas sales	$ 530,334	$ 653,793	-19%	$ (60,057)	$ (63,402)	$ (123,459)
Oil sales	909,344	755,618	20%	158,795	(5,069)	153,726
NGL sales	263,842	149,151	77%	46,146	68,545	114,691
Total commodity sales	$ 1,703,520	$ 1,558,562	9%	$ 144,884	$ 74	$ 144,958
Total gas volume MMcf	120,113	132,813	-10%			
Gas volume MMcf per day	329.1	363.9				
Average gas price per Mcf	$ 4.42	$ 4.92	-10%			
Total oil volume thousand barrels	9,778	9,844	-1%			
Oil volume barrels per day	26,789	26,969				
Average oil price per barrel	$ 93.00	$ 76.76	21%			
Total NGL volume thousand barrels	6,236	4,272	46%			
NGL volume barrels per day	17,086	11,705				
Average NGL price per barrel	$ 42.31	$ 34.91	21%			
Total equivalent production volumes MMcfe per day	592.3	595.9	-1%			

Commodity sales during 2011 totaled $1.7 billion, compared to $1.6 billion in 2010. The increase was a result of higher realized prices for oil and NGLs.

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In 2011, our aggregate production volumes were 592.3 MMcfe per day, down 1% from 595.9 Mcfe per day in 2010. Aggregate daily production volumes for the fourth quarter of 2011 were 601.4 MMcfe, also down 1% from 604.5 MMcfe for the same period of 2010. Our Permian Basin and Mid-Continent production volumes continue to increase as a result of our successful drilling programs. However, these increases are being offset by decreased Gulf Coast production. The lower output from the Gulf Coast is a result of natural declines in the highly-productive wells previously drilled near Beaumont, Texas combined with a lack of exploration success from our 2011 Gulf Coast drilling program.

Our 2011 gas production averaged 329.1 MMcf per day, compared to 363.9 MMcf per day for 2010. The 10% decline in year over year gas production resulted in a decrease in revenue of $63.4 million. During the fourth quarter of 2011 our daily gas production averaged 334.2 MMcf per day, down 2% from 341.5 MMcf per day, for the same period of 2010. The decline in fourth quarter 2011 gas production resulted in $2.8 million less revenue compared to the fourth quarter of 2010.

Oil production for 2011 averaged 26,789 barrels per day, down slightly from production of 26,969 barrels per day in 2010. The decrease in 2011 production resulted in $5.1 million lower oil revenue for all of 2011. Our fourth quarter 2011 oil production averaged 27,431 barrels per day, or a slight increase compared to daily oil production of 27,137 barrels for the fourth quarter of 2010. The higher production in the fourth quarter of 2011 increased oil sales by $2.2 million.

In 2011 our average daily NGL production volume was 17,086 barrels per day compared to 11,705 barrels per day for 2010. The 46% higher NGL production volumes in 2011 contributed $68.5 million of additional revenue for 2011. During the fourth quarter of 2011 our average daily NGL production was 17,107 barrels per day, up from 16,702 barrels per day during the fourth quarter of 2010. This 2% increase in NGL production provided an additional $1.4 million of revenue in the fourth quarter of 2011. The increases in our 2011 NGL production reflect our continued focus on drilling in more liquids-rich gas basins that produce more attractively priced NGL liquids such as ethane, propane and butane, rather than in gas basins that produce dry gas alone.

Our average realized gas price for 2011 fell to $4.42 per Mcf, compared to $4.92 per Mcf in 2010. The 10% decrease in prices received during 2011 resulted in lower gas sales of $60.1 million in 2011 compared to 2010 gas revenue. During the fourth quarter of 2011 our average realized gas price decreased by 7% to $3.90 per Mcf. For the same period of 2010, we realized an average price per Mcf of $4.18. The decrease in prices received in the fourth quarter of 2011 resulted in $8.6 million less in gas sales compared to the same period of 2010.

Realized oil prices during 2011 averaged $93.00 per barrel, an increase of 21% over the average price received for oil in 2010 of $76.76 per barrel. This increase resulted in an additional $158.8 million of oil sales in 2011. For the fourth quarter of 2011 our average realized oil price was $92.76 per barrel versus $82.33 per barrel received in the fourth quarter of 2010. The increase in fourth quarter 2011 oil sales due to the 13% increase in oil prices totaled $26.3 million.

During 2011 our average realized price for NGLs was $42.31 per barrel, which was 21% higher than the average realized price of $34.91 per barrel received in 2010. The increase in realized price resulted in an additional $46.1 million for NGL sales in 2011. In the fourth quarter of 2011 our average realized price for NGLs was $40.29 per barrel compared to an average realized price of $37.59 per barrel received in the

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fourth quarter of 2010. The 7% increase in the fourth quarter 2011 NGL realized price contributed $4.3 million of additional revenue.

	For the Years Ended December 31,	
	2011	2010
Gas Gathering, Processing and Marketing (in thousands):		
Gas gathering, processing and other revenues	$ 53,640	$ 54,662
Gas gathering and processing costs	(23,327)	(26,148)
Gas gathering and processing margin	$ 30,313	$ 28,514
Gas marketing revenues, net of related costs	$ 729	$ 459

We sometimes transport, process and market third-party gas that is associated with our gas. In 2011, third-party gas gathering, processing and other contributed $30.3 million of pre-tax cash operating margin (revenues less direct expenses) versus $28.5 million in 2010. Our gas marketing margin (revenues less purchases) increased to $729 thousand in 2011 up from $459 thousand in 2010. Changes in net margins from gas gathering, processing, marketing and other activities are the direct result of volumetric changes and overall market conditions.

	For the Years Ended December 31,		Variance Between	Per Mcfe	
	2011	2010	2011/2010	2011	2010
Operating costs and expenses (in thousands):					
Depreciation, depletion and amortization (DD&A)	$ 390,461	$ 304,222	$ 86,239	$ 1.81	$ 1.40
Asset retirement obligation	11,451	7,322	4,129	$ 0.05	$ 0.03
Production	247,048	194,015	53,033	$ 1.14	$ 0.89
Transportation	56,711	45,982	10,729	$ 0.26	$ 0.21
Taxes other than income	126,468	121,781	4,687	$ 0.59	$ 0.56
General and administrative	45,256	48,620	(3,364)	$ 0.21	$ 0.22
Stock compensation	18,949	12,353	6,596	$ 0.09	$ 0.06
(Gain) loss on derivative instruments, net	(10,322)	(62,696)	52,374	N/A	N/A
Other operating, net	10,263	4,575	5,688	N/A	N/A
	$ 896,285	$ 676,174	$ 220,111		

Total operating costs and expenses (not including gas gathering, marketing and processing costs, or income tax expense) increased to $901.4 million in 2011 compared to $680.2 million in 2010. Analyses of the year over year differences are discussed below.

For 2011 DD&A was $390.4 million, compared to $304.2 million in 2010. The $86.2 million increase in expense represents 39% of the total 2011 increase in operating costs and expenses. On a unit of production basis, the DD&A rate for 2011 was $1.81 per Mcfe, up 29% from $1.40 per Mcfe for 2010. The DD&A rate in 2010 was lower as a result of impairments to the carrying value of our oil and gas properties recorded during the last half of 2008 and the first quarter of 2009.

Asset retirement obligation expense increased from $7.3 million in 2010 to $11.5 million in 2011. The increase was primarily due to unforeseen modifications and/or problems that occurred at the time of actual abandonment and site restoration, which resulted in our actual costs exceeding our estimated asset retirement obligation.

In 2011 our production costs were $247 million ($1.14 per Mcfe) up from $194 million ($0.89 per Mcfe) during 2010. The $53.0 million increase accounted for 24% of our total increase in operating costs and expenses.

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

	For the Years Ended December 31,		Variance Between	Per Mcfe	
(in thousands)	2011	2010	2011/2010	2011	2010
Lease operating expense	$ 208,097	$ 164,968	$ 43,129	$ 0.96	$ 0.76
Workover expense	38,951	29,047	9,904	0.18	0.13
	$ 247,048	$ 194,015	$ 53,033	$ 1.14	$ 0.89

About half of the $43.1 million increase in our lease operating expense resulted from higher water disposal costs associated with wells coming on line from our successful Permian Basin and Mid-Continent drilling programs. Increased costs for equipment maintenance, rentals, labor, power and fuel also contributed to the increase in year over year lease operating expense. Workover expense for 2011 was $9.9 million higher than 2010, primarily as a result of more activity being necessary in 2011.

Transportation costs rose to $56.7 million ($0.26 per Mcfe) for 2011 from $46.0 million ($0.21 per Mcfe) in 2010. Transportation costs will fluctuate based on increases or decreases in sales volumes, compression charges and fluctuation in the price of the fuel cost component. Also, in the latter part of 2010 and continuing throughout 2011, our Mid-Continent and Permian Basin wells have experienced increases in transportation rates due to higher contractual rates associated with new wells coming online and contracts for existing wells being renewed.

Taxes other than income increased $4.7 million from $121.8 million in 2010 to $126.5 million in 2011. The $4.7 million increase in taxes resulted primarily from higher realized oil and NGL prices in 2011.

General and administrative costs were as follows:

	For the Years Ended December 31,		Variance Between
(in thousands)	2011	2010	2011/2010
G&A capitalized to oil and gas properties	$ 51,836	$ 72,252	$ (20,416)
G&A expense	45,256	48,620	(3,364)
	$ 97,092	$ 120,872	$ (23,780)
G&A expense per Mcfe	$ 0.21	$ 0.22	$ (0.01)

The decrease in G&A was mostly due to lower bonus expense in 2011.

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

(in thousands)	For the Years Ended December 31, 2011	2010	Variance Between 2011/2010
Performance-based restricted stock awards	$ 16,268	$ 9,604	$ 6,664
Service-based restricted stock awards	11,300	8,228	3,072
Restricted unit awards	34	33	1
Restricted stock and units	27,602	17,865	9,737
Stock option awards	3,518	3,826	(308)
Total stock compensation	31,120	21,691	9,429
Less amounts capitalized to oil and gas properties	(12,171)	(9,338)	(2,833)
Stock compensation	$ 18,949	$ 12,353	$ 6,596

Expense associated with stock compensation will fluctuate based on the grant-date market value of the award and the number of awards granted. The $6.6 million increase in total 2011 stock compensation compared to the 2010 total expense resulted primarily from the increased price per share of our common stock on the date of grants in 2011 compared to the grant date value of previous awards. See Note 8 to the Consolidated Financial Statements of this report for a detailed discussion regarding our stock-based compensation.

Our net (gain) or loss on derivative instruments includes both realized gains and losses on settlements of our derivative contracts and unrealized gains and losses stemming from changes in the fair value of our outstanding derivative instruments.

We estimate the fair values of these instruments 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 include a measure of counterparty credit risk, and the fair value of instruments in a liability position include a measure of our own nonperformance risk. These credit risks are based on current published credit default swap rates.

We did not elect hedge accounting treatment for derivative contracts outstanding in 2011 and 2010. Therefore we recognized all realized settlements and unrealized changes in fair value in our operating costs and expenses. The following table reflects our net realized and unrealized (gains) and losses on derivative instruments:

(In thousands)	For the Years Ended December 31, 2011	2010	Variance Between 2011/2010
Realized (gain) on settlement of derivative instruments	$ (6,711)	$ (52,098)	$ 45,387
Unrealized (gain) from changes to the fair value of the derivative instruments	(3,611)	(10,598)	6,987
(Gain) on derivative instruments, net	$ (10,322)	$ (62,696)	$ 52,374

Realized and unrealized gains or losses on derivative contracts are a function of fluctuations in the underlying commodity prices and the monthly settlement of the instruments. In 2011 we recorded $52.4 million lower gains on our derivative instruments than in 2010, primarily due to lower realized gas prices in 2011. The $52.4 million of lower gains accounted for 24% of our total increase in operating costs and expenses. See Note 2 to the Consolidated Financial Statements in this report for a complete discussion of our derivative instruments.

Other operating, net expense consists of costs related to various legal matters, most of which pertain to litigation and contract settlements and title and royalty issues. Other operating, net increased from $4.6 million in 2010 to $10.3 million for 2011. Expenses for 2010 were significantly lower than in 2011 due to the favorable resolution of items in 2010 that had been accrued in prior years. See Note 13, Commitments and Contingencies, in this report for further information regarding litigation matters.

Other (income) and expense

	For the Years Ended December 31,		Variance Between
(In thousands)	**2011**	**2010**	**2011/2010**
Interest expense	$ 35,611	$ 36,613	$ (1,002)
Capitalized interest	(29,057)	(29,215)	158
Loss on early extinguishment of debt		(3,776)	3,776
Other, net	(9,758)	(5,992)	(3,766)
	$ (3,204)	$ (2,370)	$ (834)

Our interest expense includes interest on outstanding borrowings, amortization of financing costs and miscellaneous interest expense. Our 7.125% senior notes accounted for 70% and 68% of our 2011 and 2010 interest expense, respectively. Capitalized interest remained relatively flat for both 2011 and 2010.

On July 1, 2010, certain holders of our floating rate convertible notes elected to convert their notes. The holders received $20.5 million and 408,450 shares of common stock. We recorded a gain of $3.8 million on the settlement of the notes.

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, other miscellaneous asset sales, income and expense from other non-operating activities and interest income. The $3.8 million increase in 2011 was mainly due to sales of oil and gas well equipment and supplies.

Income Tax Expense

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

	For the Years Ended December 31,	
(In thousands)	**2011**	**2010**
Current taxes (benefit)	$ (46,073)	$ 46,337
Deferred taxes	357,622	292,612
	$ 311,549	$ 338,949
Combined Federal and state effective income tax rate	37.0%	37.1%

The effective tax rate of 37% for 2011 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, Income Taxes, in this report for further information.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Our liquidity is highly dependent on the commodity price we receive for the oil, gas and NGLs we produce. Commodity prices are market driven, have been very volatile and therefore, we cannot predict future commodity prices. Prices received for production heavily influence our revenue, cash flow, profitability, access to capital and future rate of growth.

Natural gas prices have been in decline since year-end 2011, the result of increasing supply coupled with lower demand caused by exceptionally mild winters. Oil and NGL prices have fluctuated during 2012 due to supply and demand factors, seasonality and other geopolitical and economic factors. It is likely that future prices for these commodities will continue to fluctuate.

We deal with volatility in commodity prices by maintaining flexibility in our capital investment program. Based on current commodity prices, our 2013 E&D capital expenditures are expected to range from $1.4 - 1.5 billion. Nearly all the capital is directed towards oil and liquids-rich gas opportunities in the Permian Basin and Cana-Woodford shale play. Actual amounts invested will depend on our calculated rates of return.

Our E&D expenditures have generally been funded by cash flow provided by operating activities (operating cash flow). During 2012, E&D expenditures of $1.6 billion were largely funded by operating cash flow and the sale of $306 million of non-strategic assets. We expect our 2013 E&D capital expenditures to be funded by operating cash flow and long-term debt. We have hedged a portion of our 2013 oil production to protect our operating cash flow for reinvestment.

From time to time we consider acquisition opportunities, however, the timing and size of acquisitions is unpredictable.

At December 31, 2012, our long-term debt consisted of $750 million of 5.875% senior notes. Debt to total capitalization was 18%. The reconciliation of debt to total capitalization, which is a non-GAAP measure, is long-term debt ($750 million) divided by long-term debt plus stockholders' equity ($4.224 billion). 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 2013 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 exploration, development, leasehold and property acquisition, debt service and common stock dividends.

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The following table presents our sources and uses of cash and cash equivalents from 2010 to 2012. 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)	**2012**	**2011**	**2010**
Sources of cash and cash equivalents:			
Operating cash flow	$ 1,192,764	$ 1,292,275	$ 1,130,432
Sales of oil and gas and other assets	312,622	229,355	34,075
Net increase in bank debt		55,000	
Increase in other long-term debt	750,000		
Issuance of common stock and other	11,433	10,411	28,758
Total sources of cash and cash equivalents	2,266,819	1,587,041	1,193,265
Uses of cash and cash equivalents:			
Oil and gas expenditures	(1,662,707)	(1,562,159)	(959,751)
Other capital expenditures	(64,987)	(96,642)	(51,882)
Net decrease in bank debt	(55,000)		(25,000)
Decrease in other long-term debt	(363,595)		(19,450)
Financing costs incurred	(13,821)	(7,379)	(101)
Dividends paid	(39,577)	(32,581)	(25,499)
Total uses of cash and cash equivalents	(2,199,687)	(1,698,761)	(1,081,683)
Net increase (decrease) in cash and cash equivalents	$ 67,132	$ (111,720)	$ 111,582
Cash and cash equivalents at end of year	$ 69,538	$ 2,406	$ 114,126

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

Cash flow provided by operating activities for 2012 was $1.2 billion compared to $1.3 billion for 2011 and $1.1 billion for 2010. Lower commodity prices were responsible for most of the decrease in 2012 and resulted in $307 million less revenue. This was partially offset by a $185 million increase from higher oil and NGLs production in 2012. The increase in 2011 over 2010 was due to higher realized prices for oil and NGLs.

Cash flow used in investing activities for both 2012 and 2011 was $1.4 billion. For 2010, cash flow used in investing activities was $978 million. Changes in cash flow used in investing activities generally result from changes in our capital expenditures and acquisitions net of asset sales. In 2012, we had E&D and other capital expenditures of $1.7 billion which were partially offset by proceeds from asset sales of $313 million. For 2011, E&D expenditures and other capital expenditures were $1.7 billion with proceeds from asset sales of $229 million. In 2010, E&D and other capital expenditures were $1.0 billion which were partially offset by asset sales of $34 million.

During 2012, net cash flow provided by financing activities was $289 million compared to $25 million in 2011. Other long-term debt increased $750 million and we received proceeds of $11.4 million from issuance of common stock. These increases were offset by debt payments of $419 million, $40 million of dividends paid, and financing costs of $14 million. We issued $750 million of 5.875% senior notes in 2012 and used the proceeds to retire the $350 million 7.125% senior notes outstanding and pay down bank debt. In 2011, our net cash inflow was the result of net bank borrowing of $55 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. Net cash used in financing activities was $41 million in 2010. Cash inflows of $29 million from the issuance of common stock were more than offset by debt repayments of $44 million and dividend payments of $25 million during the year.

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Reconciliation of Adjusted Cash Flow from Operations

	For the Year Ended December 31,		
(in thousands)	**2012**	**2011**	**2010**
Net cash provided by operating activities	$ 1,192,764	$ 1,292,275	$ 1,130,432
Change in operating assets and liabilities	(58,049)	22,686	57,699
Adjusted cash flow from operations	$ 1,134,715	$ 1,314,961	$ 1,188,131

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)	**2012**	**2011**	**2010**
Acquisitions:			
Proved	$ 2,645	$ 23,071	$ 15,220
Unproved	30,870	22,327	24,552
	33,515	45,398	39,772
Exploration and development:			
Land & seismic	121,960	164,285	128,283
Exploration	74,034	64,157	103,671
Development	1,426,918	1,351,617	766,980
	1,622,912	1,580,059	998,934
Property sales	(305,862)	(117,344)	(28,235)
	$ 1,350,565	$ 1,508,113	$ 1,010,471

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

In 2012, our E&D expenditures were $1.62 billion compared to $1.58 billion in 2011 and $1.0 billion in 2010.

Of total 2012 expenditures, 55% were for projects in the Permian Basin primarily in the Delaware Basin of southeast New Mexico and West Texas and approximately 41% were in the Mid-Continent region, mostly in the Cana-Woodford shale play.

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The following table reflects wells drilled by region:

	For the Years Ended December 31,	
	2012	2011
Gross wells		
Permian Basin	182	140
Mid-Continent	167	180
Gulf Coast / Other	3	11
	352	331
Net wells		
Permian Basin	122	100
Mid-Continent	69	64
Gulf Coast / Other	1	10
	192	174
% Gross wells completed as producers	95%	96%

Full year 2013 E&D capital expenditures are expected to range from $1.4 - 1.5 billion, most of which will be directed towards drilling oil and liquids-rich gas wells in the Permian Basin and Cana-Woodford shale play. We expect our 2013 E&D capital expenditures to be funded from cash flow and long-term debt. The timing of capital expenditures and the receipt of cash flows do not necessarily match causing us to borrow and repay funds under our credit arrangement throughout the year.

As has been our historical practice, we regularly review our 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.

We made property acquisitions of $33.5 million during 2012, most of which were in the Permian Basin. Property acquisitions totaled approximately $45.4 million in 2011and $39.8 in 2010 which were used to purchase additional interests in the Cana-Woodford shale play.

In 2012, we sold interests in non-core oil and gas assets for $306 million. Of this total, $290 million, which occurred in the fourth quarter, was related to non-core oil and gas assets located in Texas.

In August 2011, we sold all of our interests in assets located in Sublette County, Wyoming for $195.5 million (including purchase price adjustments). The assets sold principally consisted of a gas processing plant under construction and 210 Bcf of proved undeveloped gas reserves. No gain or loss was recognized on the sale of proved reserves as the disposition did not significantly alter the relationship between capitalized costs and proved reserves. During 2011, we also sold $33.3 million of various non-core interests including assets in Lea County, New Mexico and Willacy County, Texas. Various interests in oil and gas properties were sold during 2010 for $28.2 million, most of which were non-core Mississippi assets.

We intend to continue to actively evaluate acquisitions and dispositions relative to our property holdings, particularly in our core areas of operation.

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 2012 exploration and development drilling program is discussed in more detail in *Exploration and Development Activity Overview* under Item 1 of this report.

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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 periodically use our credit facility to finance our working capital needs.

During 2012, our total assets increased $948 million to $6.3 billion, up from $5.4 billion at December 31, 2011. The increase was primarily due to a $879 million increase in net oil and gas properties.

Total liabilities at year-end 2012 increased to $2.8 billion, up $604 million from the $2.2 billion reported at year-end 2011. This was mainly due to an increase of $345 million in long-term debt and a $218 million increase in deferred income taxes.

On December 31, 2012, stockholders' equity totaled $3.5 billion, up $400 million from December 31, 2011. The increase is mostly related to our 2012 net income.

Dividends

A quarterly cash dividend has been paid to shareholders every quarter since the first quarter of 2006. In February 2012, the quarterly dividend was increased to $0.12 per share from $0.10 per share. Future dividend payments will depend on our level of earnings, financial requirements and other factors considered relevant by the Board of Directors.

	2012	2011	2010
Dividend declared (in millions)	$ 41.3	$ 34.3	$ 27.2
Dividend per share	$ 0.48	$ 0.40	$ 0.32

Working Capital Analysis

Our working capital fluctuates primarily as a result of our exploration and development activities, realized commodity prices and our operating activities. Working capital is also impacted by income tax receivables or payables, property sales, accrued G&A and changes in inventory balances.

Working capital decreased $17.3 million from a deficit of $158.4 million at December 31, 2011, to a deficit of $175.7 million at December 31, 2012.

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

- A $47.2 million decrease in our income tax receivable.
- Operations-related accounts payable and accrued liabilities increased by $48.3 million.
- Operations related accounts receivable decreased by $9.2 million.

Working capital decreases were partially offset by:

- An increase in cash and cash equivalents of $67.1 million, primarily the result of property sales which closed in December 2012.
- A decrease of $18.5million in accrued liabilities related to our E&D expenditures.

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.

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Long-Term Debt

Debt at December 31, 2012, and December 31, 2011, consisted of the following:

(in thousands)	2012	2011
Bank debt	$	$ 55,000
7.125% Senior Notes due 2017		350,000
5.875% Senior Notes due 2022	750,000	
Total long-term debt	$ 750,000	$ 405,000

Bank Debt

We have a five-year senior unsecured revolving credit facility (Credit Facility) that matures July 14, 2016. The Credit Facility provides for a borrowing base of $2 billion. Aggregate commitments from our lenders increased from $800 million to $1.0 billion in July 2012.

Under our Credit Facility, the borrowing base is determined at the discretion of lenders based on the value of our proved reserves. The next regular annual redetermination is April 15, 2013.

As of December 31, 2012, we had no bank debt outstanding. We had letters of credit outstanding of $2.5 million leaving an unused borrowing availability of $997.5 million. During 2012, we had average daily bank debt outstanding of $96.3 million, compared to $17.8 million in 2011. Our highest amount of bank borrowings outstanding during 2012 was $296 million in December. During 2011, the highest amount of outstanding bank borrowings was $149 million in July.

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 of greater than 1.0 to 1.0. We also must maintain a leverage ratio of total debt to earnings before interest expense, income taxes and noncash items (such as DD&A expense, unrealized gains and losses on commodity derivatives, ceiling test writedowns and goodwill impairments) of not more than 3.5 to 1.0. Other covenants could limit our ability to incur additional indebtedness, pay dividends, repurchase our common stock or sell assets. As of December 31, 2012, we were in compliance with all of the financial and nonfinancial 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. These 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 a redemption price of 102.938% of the principal amount as of May 1, 2017, declining to 100% on May 1, 2020 and thereafter.

Net proceeds from the offering approximated $737 million, after underwriting discounts and offering costs. We used a portion of the net proceeds to retire our 7.125% senior notes. The remaining proceeds were used for general corporate purposes including repayment of $232 million outstanding under our Credit Facility.

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7.125% Notes due 2017

In May 2007, we issued $350 million of 7.125% senior unsecured notes at par which 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.

Under the terms of the Tender Offer, holders who tendered their notes on or prior to April 4, 2012, received $1,035.63 per $1,000.00 in principal amount of notes tendered plus a consent payment of $3.75 per $1,000.00 in principal amount of notes tendered. As of April 18, 2012, a total of $300,163,000 of notes had been redeemed. In May 2012, the remaining notes were redeemed at 103.563% of the principal amount. We recognized a $16.2 million loss on early extinguishment of debt during the second quarter of 2012.

In conjunction with the Tender Offer, holders who tendered their notes were deemed to consent to proposed amendments to eliminate or modify certain covenants and events of default and other provisions contained in the indenture governing the 7.125% senior notes.

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, 2012, 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, 2012, we had contractual obligations and material commitments as follows:

		Payments Due by Period			
Contractual obligations:	**Total**	**Less than 1 Year**	**1 - 3 Years**	**4 - 5 Years**	**More than 5 Years**
(in thousands)					
Long-term debt(1)	$ 750,000	$	$	$	$ 750,000
Fixed-Rate interest payments(1)	418,594	44,063	88,125	88,125	198,281
Operating leases	131,571	13,486	17,890	19,431	80,764
Drilling commitments(2)	212,762	212,762			
Gathering facilities and pipelines(3)	1,708	1,708			
Asset retirement obligation	185,138	51,147	(4)	(4)	(4)
Other liabilities(5)	59,420	15,368	28,384		15,668
Firm Transportation	1,620	986	599	35	

(1) See Item 3: Interest Rate Risk for more information regarding fixed and variable rate debt.

(2) We have drilling commitments of approximately $206.1 million consisting of obligations to finish drilling and completing wells in progress at December 31, 2012. We also have various commitments for drilling rigs as well as certain service contracts. The total minimum expenditure commitments under these agreements are $6.6 million.

(3) We have projects in Oklahoma, New Mexico, and Texas where we are constructing gathering facilities and pipelines. At December 31, 2012, we had commitments of $1.7 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 liabilities include the fair value of our liabilities associated with our benefit obligations and other miscellaneous commitments.

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At December 31, 2012, we had firm sales contracts to deliver approximately 26.8 Bcf of natural gas over the next 16 months. In total, our financial exposure would be approximately $86.4 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 liquidity needs.

2013 Outlook

Our 2013 E&D capital investment is presently expected to be in the range of $1.4-1.5 billion. Nearly all of this capital will be used for drilling oil and liquids-rich gas wells in the Permian Basin and Cana-Woodford shale play. We have a large inventory of drilling opportunities, limited lease expirations and few service commitments. We regularly review our capital expenditures and may adjust our investments based on changes in commodity prices, service costs and drilling success. Actual amounts invested will depend on our calculated rates of return which are significantly influenced by commodity prices.

Though there are a variety of factors that could curtail, delay or even cancel some of our planned operations, we believe our projected program is likely to occur. The majority of projects are in hand, drilling rigs are being scheduled and the historical results of our drilling efforts warrant pursuit of the projects.

Production for 2013 is projected to be in the range of 675 - 705 MMcfe per day, an 8 - 13% increase over 2012. Liquids are projected to account for 51% of total equivalent production, up from 48% in the prior year. Combined Mid-Continent and Permian Basin production volumes are projected to grow 11 - 15% in 2013, averaging between 652 - 672 MMcfe per day. Gulf Coast volumes are projected to average 23 - 32 MMcfe per day.

Revenues from oil, gas and NGL sales are dependent not only on the level actually produced, but also on the price received. During 2012, realized prices averaged $89.25 per barrel of oil , $2.88 per Mcf of gas and $30.66 per barrel of NGL. Commodity prices can be volatile and the possibility of 2013 realized prices varying from those received in 2012 is high.

Certain expenses for 2013 on a per Mcfe basis are currently estimated as follows:

	2013
Production expense	$1.05 - $1.17
Transportation expense	0.27 - 0.32
DD&A and asset retirement obligation	2.40 - 2.55
General and administrative	0.22 - 0.28
Taxes other than income (% of oil and gas revenue)	6.0% - 6.5%

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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.

A complete list of our significant accounting policies are described in Note 1 to our Consolidated Financial Statements included in this report. We have identified certain of these 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 our management.

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. We believe the following to be our most critical accounting policies and estimates that involve significant judgments and discuss the selection and development of these policies and estimates with our Audit Committee.

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 2012, 20% of our total proved reserves are categorized as PUDs. All of the PUD reserves are related to the Cana-Woodford shale play. 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.

The following table presents information regarding reserve revisions largely resulting from items we do not control, such as revisions due to price, and revisions resulting from better information about production history, well performance and production costs.

Approximately 72 Bcfe of the 257.3 Bcfe net negative revisions during 2012 relate to production performance of certain wells recently drilled in our Cana-Woodford shale project. PUD reserve additions in extensions and discoveries for 2012 now reflect revised expectations of future production performance. The remainder of the net negative revision primarily resulted from decreases in prices (91 Bcfe), increases

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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).

	Years Ended December 31,					
	2012		2011		2010	
	Bcfe Change	Percent of total Reserves	Bcfe Change	Percent of total Reserves	Bcfe Change	Percent of total Reserves
Revisions resulting from price changes	(91.4)	(4.47)%	3.8	0.20%	44.8	2.92%
Other changes in estimates	(165.9)	(8.11)%	(11.0)	(0.58)%	103.6	6.75%
Total	(257.3)	(12.58)%	(7.2)	(0.38)%	148.4	9.67%

See Note 15, Unaudited Supplemental Oil and Gas Disclosures in this report for additional reserve data.

Full Cost Accounting

We use the full cost method of accounting for our oil and gas operations. All costs associated with property acquisition, exploration and development activities are capitalized. Exploration and development costs include dry hole costs, geological and geophysical costs, direct overhead related to exploration and development activities and other costs incurred for the purpose of finding oil and gas reserves. Salaries and benefits paid to employees directly involved in the exploration and development of properties, as well as other internal costs that can be directly identified with acquisition, exploration and development activities are also 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 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 and depletion expense. As of December 31, 2012, the calculated value of the ceiling limitation exceeded the carrying value of our oil and gas properties subject to the test, therefore, no impairment was necessary. However, the amount of the excess has declined approximately 87% since December 31, 2011. As of December 31, 2012, a decline of 3% in the value of the ceiling limitation would have caused an impairment. If negative trends continue, we may incur impairment charges in the future, which could have a material adverse effect on our results of operations in the period taken.

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

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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 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 assessment at December 31, 2012, goodwill was not impaired. However, it is possible that goodwill could become impaired in the future if commodity prices or other economic factors become less favorable. A goodwill impairment charge would have no effect on liquidity or our capital resources, but could adversely affect our results of operations in the period incurred.

During the fourth quarter of 2012, we determined that our goodwill was overstated due to certain errors in the calculation of net deferred tax liability in conjunction with our 2005 business combination. We have concluded this is an immaterial correction of error and we have restated the accompanying balance sheet as of December 31, 2005, to decrease both goodwill and deferred income tax liability by $71.2 million. The errors were noncash and had no effect on our statements of income and comprehensive income, cash flow or stockholders' equity.

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.

At December 31, 2012, 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* was filed as a statewide royalty putative class-action 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. The Court has entered an order preliminarily approving the parties' settlement. The deadline for putative class members to opt out of the settlement class was February 15, 2013, and less than $^{1}/_{2}$% of the class members opted out. The Court will hold the settlement fairness hearing on March 22, 2013. 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 transaction to shareholders of H&P, by which Cimarex became a publicly-traded entity, Cimarex assumed the assets and liabilities of H&P's exploration and production business, including this lawsuit. In 2008 we recorded a litigation expense of $119.6 million for this lawsuit. We have accrued additional post-judgment interest and costs during the appeal of the District Court's judgment.

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. We are awaiting a ruling from the Oklahoma Supreme Court, and the final outcome cannot be determined at this time. If the District Court's original judgment is ultimately affirmed in its entirety, the $119.6 million, plus the then-determined amount of post-judgment interest and costs would become payable.

In the normal course of business, we have other various litigation matters. We assess the probability of estimable amounts related to litigation matters in accordance with guidance established by the Financial Accounting Standards Board (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 of this Report for additional information regarding our contingencies.

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, 2012.

ITEM 7A. QUALITATIVE AND QUANTITATIVE DISCLOSURES ABOUT MARKET RISK

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

Price Fluctuations

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

To manage exposure to commodity prices, we periodically hedge a portion of the price risk associated with future oil and gas production. The goal of these arrangements is to decrease our exposure to price volatility thereby increasing the predictability of future cash flow. However, hedges can also limit potential gains if oil and gas prices rise above the price established by the hedges.

At December 31, 2012, we had no hedges in place. Subsequent to December 31, 2012, we entered into oil collars and swaps. 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 also part of our credit facility.

Interest Rate Risk

At December 31, 2012, our long-term debt consisted of $750 million in 5.875% senior notes that will mature May 1, 2022. Because all of our long-term debt is at a fixed rate, we consider our interest rate exposure to be minimal. The sensitivity analysis for interest rate risk excludes accounts receivable, accounts payable and accrued liabilities because of the short-term nature of such instruments. See Note 3 and Note 5 to the Consolidated Financial Statements of this report for additional information regarding debt.

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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, 2012 and 2011, 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, 2012. 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, 2012 and 2011, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2012, 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, 2012, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 26, 2013 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

KPMG LLP

Denver, Colorado
February 26, 2013

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CIMAREX ENERGY CO.

CONSOLIDATED BALANCE SHEETS

(in thousands, except share and per share information)

	December 31, 2012	December 31, 2011
Assets		
Current assets:		
Cash and cash equivalents	$ 69,538	$ 2,406
Accounts receivable:		
Trade, net of allowance	55,528	58,519
Oil and gas sales, net of allowance	239,106	245,681
Gas gathering, processing, and marketing, net of allowance	7,901	7,565
Other	439	47,644
Oil and gas well equipment and supplies	81,029	85,141
Deferred income taxes	8,477	2,723
Prepaid Expenses	7,420	7,393
Other current assets	699	823
Total current assets	470,137	457,895
Oil and gas properties at cost, using the full cost method of accounting:		
Proved properties	11,258,748	9,933,517
Unproved properties and properties under development, not being amortized	645,078	607,219
	11,903,826	10,540,736
Less accumulated depreciation, depletion and amortization	(6,899,057)	(6,414,528)
Net oil and gas properties	5,004,769	4,126,208
Fixed assets, less accumulated depreciation of $145,130 and $118,278	152,605	118,215
Goodwill Restated (Note 1)	620,232	620,232
Other assets, net	57,409	34,827
	$ 6,305,152	$ 5,357,377
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable:		
Trade	$ 88,168	$ 64,856
Gas gathering, processing, and marketing	15,485	14,932
Accrued liabilities:		
Exploration and development	155,002	173,549
Taxes other than income	29,179	33,946
Other	208,728	178,401
Revenue payable	149,300	150,655
Total current liabilities	645,862	616,339
Long-term debt	750,000	405,000
Deferred income taxes Restated (Note 6)	1,121,353	903,732
Asset retirement obligation	133,991	139,680

Other liabilities	179,210	162,013
Total liabilities	2,830,416	2,226,764
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, 86,595,976 and 85,774,084 shares issued, respectively	866	858
Paid-in capital	1,939,628	1,908,506
Retained earnings	1,533,768	1,221,263
Accumulated other comprehensive income (loss)	474	(14)
	3,474,736	3,130,613
	$ 6,305,152	$ 5,357,377

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,		
	2012	**2011**	**2010**
Revenues:			
Gas sales	$ $340,744	$ $530,334	$ 653,793
Oil sales	1,027,757	909,344	755,618
NGL Sales	213,149	263,842	149,151
Gas gathering, processing and other	43,042	53,640	54,662
Gas marketing, net of related costs of $86,813, $119,725 and $99,713 respectively	(754)	729	459
	$ 1,623,938	1,757,889	1,613,683
Costs and expenses:			
Depreciation, depletion and amortization	513,916	390,461	304,222
Asset retirement obligation	13,019	11,451	7,322
Production	258,584	247,048	194,015
Transportation	57,354	56,711	45,982
Gas gathering and processing	21,965	23,327	26,148
Taxes other than income	86,994	126,468	121,781
General and administrative	54,428	45,256	48,620
Stock compensation	21,919	18,949	12,353
Gain on derivative instruments, net	(245)	(10,322)	(62,696)
Other operating, net	24,961	10,263	4,575
	1,052,895	919,612	702,322
Operating income	571,043	838,277	911,361
Other (income) and expense:			
Interest expense	49,317	35,611	36,613
Capitalized interest	(35,174)	(29,057)	(29,215)
(Gain) loss on early extinquishment of debt	16,214		(3,776)
Other, net	(19,864)	(9,758)	(5,992)
Income before income tax	560,550	841,481	913,731
Income tax expense	206,727	311,549	338,949
Net income	$ 353,823	$ 529,932	$ 574,782
Earnings per share to common shareholders:			
Basic			
Distributed	$ 0.48	$ 0.40	$ 0.32
Undistributed	3.60	5.77	6.42
	$ 4.08	$ 6.17	$ 6.74
Diluted			
Distributed	$ 0.48	$ 0.40	$ 0.32
Undistributed	3.59	5.75	6.38

	$	4.07	$	6.15	$	6.70
Comprehensive income:						
Net income	$	353,823	$	529,932	$	574,782
Other comprehensive income:						
Change in fair value of investments, net of tax		488		(278)		283
Total comprehensive income	$	354,311	$	529,654	$	575,065

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, 2012	2011	2010
Cash flows from operating activities:			
Net income	$ 353,823	$ 529,932	$ 574,782
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	513,916	390,461	304,222
Asset retirement obligation	13,019	11,451	7,322
Deferred income taxes	208,216	357,622	292,612
Stock compensation	21,919	18,949	12,353
Derivative instruments, net	(245)	(3,611)	(10,598)
(Gain) loss on early extinguishment of debt	16,214		(3,776)
Changes in non-current assets and liabilities	3,125	4,418	12,772
Other, net	4,728	5,739	(1,558)
Changes in operating assets and liabilities:			
(Increase) decrease in receivables, net	56,435	(48,632)	(83,386)
Decrease in oil and gas well equipment and supplies and other current assets	4,209	32,593	34,250
Decrease in accounts payable and other current liabilities	(2,595)	(6,647)	(8,563)
Net cash provided by operating activities	1,192,764	1,292,275	1,130,432
Cash flows from investing activities:			
Oil and gas expenditures	(1,662,707)	(1,562,159)	(959,751)
Sales of oil and gas assets	311,562	117,344	28,235
Sales of other assets	1,060	112,011	5,840
Other capital expenditures	(64,987)	(96,642)	(51,882)
Net cash used by investing activities	(1,415,072)	(1,429,446)	(977,558)
Cash flows from financing activities:			
Net increase (decrease) in bank debt	(55,000)	55,000	(25,000)
Increase in other long-term debt	750,000		
Decrease in other long-term debt	(363,595)		(19,450)
Financing costs incurred	(13,821)	(7,379)	(101)
Dividends paid	(39,577)	(32,581)	(25,499)
Issuance of common stock and other	11,433	10,411	28,758
Net cash provided by (used in) financing activities	289,440	25,451	(41,292)
Net change in cash and cash equivalents	67,132	(111,720)	111,582
Cash and cash equivalents at beginning of period	2,406	114,126	2,544
Cash and cash equivalents at end of period	$ 69,538	$ 2,406	$ 114,126

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				Accumulated Other Comprehensive		Total
	Shares	Amount	Paid-in Capital	Retained Earnings	Income (loss)	Treasury Stock	Stockholders' Equity
Balance, December 31, 2009	83,542	$ 835	$ 1,859,255	$ 178,035	$ (19)	$	$ 2,038,106
Dividends				(27,166)			(27,166)
Net Income				574,782			574,782
Unrealized change in fair value of investments, net of tax					283		283
Stock issued due to conversion of convertible debt	408	4	30,126				30,130
Issuance of restricted stock awards	638	6	(6)				
Common stock reacquired and retired	(428)	(4)	(32,200)				(32,204)
Restricted stock forfeited and retired	(76)	(1)	1				
Exercise of stock options	596	6	17,985				17,991
Vesting of restricted stock units	555	6	(6)				
Stock-based compensation			21,688				21,688
Stock-based compensation tax benefit			22,767				22,767
Equity attributable to Floating rate convertible notes			(36,545)				(36,545)
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

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, New Mexico and Kansas.

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 2012 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, 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 within three months at the date of acquisition. Cash equivalents are stated at cost, which approximates market value. We have restricted cash of $811 thousand and $758 thousand at December 31, 2012 and 2011, respectively, included in our noncurrent other assets consisting of monies from third parties which are being held by Cimarex, as operator of a property in Oklahoma. The cash will be released when ownership disputes among the third parties are resolved.

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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, 2012, 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. As of December 31, 2012, a decline of 3% or more in the value of the ceiling limitation would have resulted in an impairment. If negative trends continue, we may incur impairment charges in the future, which could have a material adverse effect on our results of operations in the period taken.

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

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CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 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 assessment at December 31, 2012, goodwill was not impaired. However, it is possible that goodwill could become impaired in the future if commodity prices or other economic factors become less favorable. A goodwill 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.

During the fourth quarter of 2012, we determined that our goodwill was overstated due to certain errors in the calculation of our net deferred tax liability in conjunction with our 2005 business combination. We have concluded this is an immaterial correction of error and we have restated the accompanying balance sheet as of December 31, 2005 to decrease both goodwill and deferred income tax liability by $71.2 million. The errors were noncash and had no effect on our statements of income and comprehensive income, cash flow or stockholder's equity.

Revenue Recognition

Oil, Gas and NGL Sales

Revenues from oil, gas and NGL sales are based on the sales method, with revenue recognized on actual volumes sold to purchasers. There is a ready market for our production, with sales occurring 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.

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CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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. In situations where there are insufficient reserves available to make-up an overproduced imbalance, then a liability is established. The natural gas imbalance liability at December 31, 2012 and 2011 was $5.4 million and $4.5 million, respectively. At December 31, 2012 and 2011, we were also in an under-produced position relative to certain other third parties.

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

In the period incurred, asset retirement obligations associated with the retirement of tangible long-lived assets are recognized as liabilities, along with an increase to the carrying amounts of the related long-lived assets. The cost of the tangible asset, including the asset retirement cost, is depreciated over the useful life of the asset. Oil and gas producing companies incur this liability which includes costs related to the plugging of wells, the removal of facilities and equipment, and site restorations. Subsequent to initial

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CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

measurement, the asset retirement liability is required to be accreted each period. Capitalized costs associated with the abandoning of wells are depleted as a component of the full cost pool.

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 (includes service-based vesting and market condition-based vesting) 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, 2012.

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 oil and/or gas prices and the corresponding negative impact on cash flow available for

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2. DERIVATIVE INSTRUMENTS/HEDGING (Continued)

reinvestment. While the use of these instruments limits the downside risk of adverse price changes, their use may also limit future revenues from favorable price changes.

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

Our derivative contracts are carried at their fair value on our balance sheet using Level 2 inputs. We entered into oil contracts at the end of 2011 and in the beginning of 2012. All of these oil contracts were settled as of December 31, 2012. The estimated fair value of our oil contracts as of December 31, 2011 was a liability of $245 thousand and is located in Current liabilities other accrued liabilities on the balance sheet.

Because we elect not to account for our derivative contracts as cash flow hedges, we recognize all realized settlements and unrealized changes in fair value in earnings. Cash settlements of our derivative contracts are included in cash flows from operating activities in our statements of cash flows.

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

(in thousands)	2012	2011	2010
Settlements gains (losses):			
Natural gas contracts	$	$ 8,485	$ 53,985
Oil contracts		(1,774)	(1,887)
Total settlements gains (losses)		6,711	52,098
Unrealized gains (losses) from change in fair value:			
Natural gas contracts		(5,731)	8,802
Oil contracts	245	9,342	1,796
Total net unrealized gains (losses) from change in fair value	245	3,611	10,598
Total gain (loss) on derivative instruments, net	$ 245	$ 10,322	$ 62,696

At December 31, 2012, we did not have any hedges in place. Subsequent to December 31, 2012 we entered into the following oil hedges:

				Weighted Average Price		
Period	**Type**	**Volume/Day**	**Index(1)**	**Floor**	**Ceiling**	**Swap**
Feb 13 - Dec 13	Collars	6,000 Bbls	WTI	$ 85.00	$ 102.31	
Feb 13 - Dec 13	Swaps	6,000 Bbls	WTI			$ 96.13

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

We are exposed to financial risks associated with these contracts from non-performance by our counterparties. Counterparty risk is also a component of our estimated fair value calculations. 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.

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CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2012 and December 31, 2011 (in thousands).

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

	Carrying Amount	Fair Value
December 31, 2011:		
Financial Liabilities:		
Bank Debt	$ 55,000	$ 55,000
7.125% Notes due 2017	$ 350,000	$ 366,772
Derivative instruments current liabilities	$ 245	$ 245

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, 2011 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% and 7.125% fixed rate notes was based on their last traded value before year end.

Derivative Instruments (Level 2)

The fair value of our derivative instruments at December 31, 2011 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.

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

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

3. FAIR VALUE MEASUREMENTS (Continued)

nature of these assets and liabilities. Included in Accrued liabilities, other at December 31, 2012 and 2011, respectively, are liabilities of approximately $36.9 million and $46.9 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, 2012 and 2011, respectively, are accrued payroll related general and administrative expenses of $31.3 million and $24.0 million, and the current portion of the Asset retirement obligation of $51.1 million and $43.7 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, in that our customers and joint working interest owners may be similarly affected by changes in economic, industry or other conditions.

We conduct credit analyses of customers 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, based on the judgment of management, it is probable that a receivable will not be collected and the amount of the reserve may be reasonably estimated. At December 31, 2012, the allowance for doubtful accounts totaled $6.5 million. At December 31, 2011, the allowance for doubtful accounts was $6.4 million.

Major Customers

Our major customers during 2012 were Sunoco Logistics Partners L.P. (Sunoco) and Enterprise Products Partners L.P. (Enterprise) and accounted for 22% and 21%, respectively, of our consolidated revenues in 2012. During 2011, our major customers were Sunoco Logistics Partners L.P. and DCP Midstream LLC and accounted for 22% and 15%, respectively, of our 2011 consolidated revenues. Sunoco is a significant purchaser of our oil in New Mexico and Beaumont, Texas areas. Enterprise is our primary oil purchaser in Oklahoma and Ward/Culberson Counties in Texas. If either of these purchasers were to stop purchasing our production from these areas, 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.

4. ASSET RETIREMENT OBLIGATIONS

We recognize the fair value of liabilities for retirement obligations associated with tangible long-lived assets in the period in which there is a legal obligation associated with the retirement of such assets and the amount can be reasonably estimated. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. Oil and gas producing companies incur this liability which includes costs related to the abandoning 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 depleted as a component of the full cost pool.

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CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. ASSET RETIREMENT OBLIGATIONS (Continued)

The following table reflects the components of the change in the carrying amount of the asset retirement obligation for the years ended December 31, 2012 and 2011:

(in thousands)	2012	2011
Asset retirement obligation at January 1,	$ 183,361	$ 138,769
Liabilities incurred	22,355	5,710
Liability settlements and disposals	(42,958)	(29,634)
Accretion expense	10,318	7,204
Revisions of estimated liabilities	12,062	61,312
Asset retirement obligation at December 31,	185,138	183,361
Less current obligation	51,147	43,681
Long-term asset retirement obligation	$ 133,991	$ 139,680

The revisions recognized during 2011 were primarily from increases in the undiscounted abandonment cost estimates for our Gulf of Mexico properties ($35.8 million) and for our Permian basin properties ($25.1 million).

5. LONG TERM DEBT

A summary of our debt is as follows:

(in thousands)	December 31, 2012	December 31, 2011
Bank debt	$	$ 55,000
7.125% Senior Notes due 2017		350,000
5.875% Senior Notes due 2022	750,000	
Total long-term debt	$ 750,000	$ 405,000

Bank Debt

We have a five-year senior unsecured revolving credit facility (Credit Facility) which matures July 14, 2016. The Credit Facility provides for a borrowing base of $2 billion. Aggregate commitments from our lenders were increased from $800 million to $1 billion in July 2012.

The borrowing base under the Credit Facility is determined at the discretion of lenders based on the value of our proved reserves. The next regular annual redetermination date is on April 15, 2013.

As of December 31, 2012, we had no bank debt outstanding. We had letters of credit outstanding under the Credit Facility of $2.5 million leaving an unused borrowing availability of $997.5 million.

At Cimarex's 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 of greater than 1.0 to 1.0. We also must

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CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. LONG TERM DEBT (Continued)

maintain a leverage ratio of total debt to earnings before interest expense, income taxes and noncash 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 to 1.0. Other covenants could limit our ability to incur additional indebtedness, pay dividends, repurchase our common stock, or sell assets. As of December 31, 2012, we were in compliance with all of the financial and nonfinancial 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.

Net proceeds from the offering approximated $737 million, after deducting underwriting discounts and offering costs. We used a portion of the net proceeds to retire our 7.125% senior notes. The remaining net proceeds were used for general corporate purposes, including repayment of $232 million outstanding under our Credit Facility.

7.125% Notes due 2017 and other

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 (the Tender Offer) to purchase all of the outstanding 7.125% senior notes.

Under the terms of the Tender Offer, holders who tendered their notes on or prior to April 4, 2012 received (i) $1,035.63 per $1,000.00 in principal amount of notes tendered plus (ii) a consent payment of $3.75 per $1,000.00 in principal amount of notes tendered. Through April 18, 2012, a total of $300,163,000 of notes had been redeemed. In May 2012, the remaining notes were redeemed at 103.563% of the principal amount. We recognized a $16.2 million loss on early extinguishment of debt during the second quarter of 2012.

In connection with the Tender Offer, holders who tendered their notes were deemed to consent to proposed amendments to eliminate or modify certain covenants and events of default and other provisions contained in the indenture governing the 7.125% senior notes.

On July 1, 2010, certain holders of our floating rate convertible notes elected to convert their notes. The holders received $20.5 million and 408,450 shares of common stock. We recorded a gain of $3.8 million on the settlement of the notes.

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CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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)	**2012**	**2011**	**2010**
Current Taxes:			
Federal (benefit)	$ (1,629)	$ (45,404)	$ 42,952
State (benefit)	140	(669)	3,385
	(1,489)	(46,073)	46,337
Deferred taxes:			
Federal	199,459	345,397	280,190
State	8,757	12,225	12,422
	208,216	357,622	292,612
	$ 206,727	$ 311,549	$ 338,949

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)	**2012**	**2011**	**2010**
Provision at statutory rate	$ 196,192	$ 294,518	$ 319,806
Effect of state taxes	8,902	11,445	15,619
Domestic Production Activities allowance	567	2,343	(1,240)
Other permanent differences	1,066	3,243	4,764
Income tax (benefit) expense	$ 206,727	$ 311,549	$ 338,949

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CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

6. INCOME TAXES (Continued)

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

	December 31,	
(in thousands)	**2012**	**2011**
Long-term:		
Assets:		
Stock compensation and other accrued amounts	$ 97,972	$ 70,092
Net operating loss carryforward	161,308	41,147
Credit carryforward	4,449	2,909
	263,729	114,148
Liabilities:		
Property, plant and equipment	(1,385,082)	(1,017,880)
Net, long-term deferred tax liability restated	(1,121,353)	(903,732)
Current:		
Assets:		
Derivative instruments		89
Other	8,477	2,634
	8,477	2,723
Net deferred tax liabilities	$ (1,112,876)	$ (901,009)

During the fourth quarter of 2012, we determined that our net deferred tax liability was overstated due to certain errors in the calculation of our deferred taxes in conjunction with our 2005 business combination. We have concluded this is an immaterial correction of an error and we have restated the above table and the accompanying balance sheet as of December 31, 2005 to decrease our net deferred income tax liability by $71.2 million with a corresponding decrease in goodwill. The errors were noncash and had no effect on our statements of income and comprehensive income, cash flow or stockholder's equity.

At December 31, 2012, the company had a U.S. net tax operating carryforward of approximately $467.7 million which would expire in 2032. We believe that the carryforward will be utilized before it expires. We also had an alternative minimum tax credit carryforward of approximately $4.4 million.

At December 31, 2012 and 2011 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 - 2011 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 tax years 2005 - 2011 for examination.

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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, 2012 there were no shares of preferred stock outstanding. A summary of our issued and outstanding common stock activity follows:

(in thousands)	
December 31, 2009	83,542
Shares issued due to conversion of convertible debt	408
Restricted shares issued under compensation plans, net of reacquired stock and cancellations	755
Option exercises, net of cancellations	530
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

Dividends

A cash dividend has been paid to shareholders in every quarter since the first quarter of 2006. In February 2012, the quarterly dividend was increased to $0.12 per share from $0.10 per share. Future dividend payments will depend on our level of earnings, financial requirements and other factors considered relevant by the Board of Directors.

	2012	**2011**	**2010**
Dividend declared (in millions)	$ 41.3	$ 34.3	$ 27.2
Dividend per share	$ 0.48	$ 0.40	$ 0.32

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.

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. STOCK-BASED COMPENSATION (Continued)

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

	Year Ended December 31,		
(in thousands)	**2012**	**2011**	**2010**
Restricted stock and units	$ 31,297	$ 27,602	$ 17,865
Stock options	2,889	3,518	3,826
	34,186	31,120	21,691
Less amounts capitalized to oil and gas properties	(12,267)	(12,171)	(9,338)
Compensation expense	$ 21,919	$ 18,949	$ 12,353

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,					
	2012		**2011**		**2010**	
	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-based stock awards	262,770	$ 43.22	363,758	$ 73.01	396,000	$ 41.94
Service-based stock awards	299,499	$ 54.17	291,053	$ 89.47	242,224	$ 70.39
Total restricted stock awards	562,269	$ 49.05	654,811	$ 80.33	638,224	$ 52.74

Performance-based 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-based 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 and units is based upon the grant-date market value of the award. Such costs are recognized ratably over the applicable vesting period.

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. STOCK-BASED COMPENSATION (Continued)

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

	Year Ended December 31,		
(in thousands)	**2012**	**2011**	**2010**
Performance-based stock awards	$ 19,066	$ 16,268	$ 9,604
Service-based stock awards	12,231	11,300	8,228
Restricted unit awards		34	33
	31,297	27,602	17,865
Less amounts capitalized to oil and gas properties	(11,132)	(10,241)	(6,941)
Restricted stock and units compensation expense	$ 20,165	$ 17,361	$ 10,924

Compensation cost in 2012 for the performance-based awards includes $3.9 million of accelerated vesting related to the death of former Chairman, F.H. Merelli.

Unrecognized compensation cost related to unvested restricted shares and units at December 31, 2012 was $54 million. We expect to recognize that cost over a weighted average period of 2 years.

The following table provides information on restricted stock and unit activity during the last three years:

	Year Ended December 31,		
	2012	**2011**	**2010**
Restricted Stock:			
Outstanding beginning of period	2,019,552	1,899,511	1,727,250
Vested	(602,372)	(497,720)	(389,443)
Granted	562,269	654,811	638,224
Canceled	(140,713)	(37,050)	(76,520)
Outstanding end of period	1,838,736	2,019,552	1,899,511
Restricted Stock Units:			
Outstanding beginning of period	59,470	94,807	649,843
Converted to Stock	(25,632)	(35,337)	(555,036)
Outstanding end of period	33,838	59,470	94,807
Vested included in outstanding	33,838	59,470	93,543

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CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. STOCK-BASED COMPENSATION (Continued)

Stock Options

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

	Year Ended December 31,								
	2012			2011			2010		
	Options	Weighted Average Grant-Date Fair Value	Weighted Average Exercise Price	Options	Weighted Average Grant-Date Fair Value	Weighted Average Exercise Price	Options	Weighted Average Grant-Date Fair Value	Weighted Average Exercise Price
Granted to certain executive officers		$	$	90,000	$ 19.17	$ 55.96		$	$
Granted to other employees	152,800	$ 20.55	$ 51.92	91,300	$ 34.20	$ 86.01	93,000	$ 28.63	$ 70.30
	152,800			181,300			93,000		

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.

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,		
	2012	2011	2010
Options granted	152,800	181,300	93,000
Weighted average grant-date fair value	$ 20.55	$ 26.74	$ 28.63
Total Fair Value (in thousands)	$ 3,140	$ 4,848	$ 2,662
Expected years until exercise	5.3	4.3	5.5
Expected stock volatility	47.4%	48.7%	44.6%
Dividend yield	0.9%	0.6%	0.6%
Risk-free interest rate	0.6%	0.9%	1.9%

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. STOCK-BASED COMPENSATION (Continued)

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

(in thousands)	Year Ended December 31, 2012	2011	2010
Stock option awards	2,889	3,518	3,826
Less amounts capitalized to oil and gas properties	(1,135)	(1,930)	(2,397)
Stock option compensation expense	$ 1,754	$ 1,588	$ 1,429

As of December 31, 2012, there was $4.8 million of unrecognized compensation cost related to non-vested stock options. We expect to recognize that cost on a pro rata basis over a weighted average period of 2 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, 2012	1,113,334	$ 37.94		
Exercised	(558,419)	$ 20.47		
Granted	152,800	$ 51.92		
Canceled	(3,149)	$ 61.38		
Forfeited	(17,107)	$ 62.38		
Outstanding as of December 31, 2012	687,459	$ 54.51	5.9 Years	$ 5,132
Exercisable as of December 31, 2012	370,397	$ 49.32	5.7 Years	$ 4,308

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

(in thousands)	Year Ended December 31, 2012	2011	2010
Number of options exercised	558,419	78,661	596,344
Cash received from option exercises	$ 11,433	$ 3,193	$ 17,991
Tax benefit from option exercises included in paid-in-capital	$ 76	$ 1,407	$ 9,199
Intrinsic value of options exercised	$ 22,482	$ 3,856	$ 25,210
Grant-date fair value of options vested	$ 2,560	$ 4,128	$ 3,624

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CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. STOCK-BASED COMPENSATION (Continued)

The following summary reflects the status of non-vested stock options as of December 31, 2012 and changes during the year:

	Options	Weighted Average Grant-Date Fair Value	Weighted Average Exercise Price
Non-vested as of January 1, 2012	308,411	$ 23.37	$ 60.75
Vested	(127,042)	$ 20.15	$ 50.33
Granted	152,800	$ 20.55	$ 51.92
Forfeited	(17,107)	$ 24.94	$ 62.38
Non-vested as of December 31, 2012	317,062	$ 23.22	$ 60.58

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)	**2012**	**2011**	**2010**
Basic:			
Net income	$ 353,823	$ 529,932	$ 574,782
Participating securities' share in earnings	(6,753)	(12,005)	(12,798)
Net income applicable to common shareholders	$ 347,070	$ 517,927	$ 561,984
Diluted:			
Net income	$ 353,823	$ 529,932	$ 574,782
Participating securities' share in earnings	(6,732)	(11,950)	(12,731)
Net income applicable to common shareholders	$ 347,091	$ 517,982	$ 562,051
Shares:			
Basic shares outstanding	84,757	83,755	83,335
Incremental shares from assumed exercise of stock options	277	398	452
Fully diluted common stock	85,034	84,153	83,787
Excluded(1)	414	273	184
Earnings per share to common shareholders:(2)			
Basic	$ 4.08	$ 6.17	$ 6.74
Diluted	$ 4.07	$ 6.15	$ 6.70

(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.

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CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

10. EMPLOYEE BENEFIT PLANS

We maintain and sponsor a contributory 401(k) plan for our employees. Annual costs related to the plan were $8.2 million for 2012 and $8.9 million for each of 2011 and 2010.

11. RELATED PARTY TRANSACTIONS

Helmerich & Payne, Inc. (H&P) provides contract drilling services to Cimarex. Drilling costs of approximately $20.8 million were incurred by Cimarex related to such services for 2012. During 2011 and 2010, such costs were $37.4 million and $22.6 million, respectively. At December 31, 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 and $8.3 million at December 31, 2011 and 2010, respectively. Hans Helmerich, a director of Cimarex, is Chairman and Chief Executive Officer of H&P.

Certain subsidiaries of Newpark Resources, Inc. have provided various drilling services to Cimarex. Costs of such services were $4.1 million in 2012. During 2011 and 2010, such costs were $7.3 million and $10.2 million, respectively. Jerry Box, a director of Cimarex, is the non-executive Chairman of the Board of Newpark.

12. SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

	For the Years Ended December 31,		
(in thousands)	**2012**	**2011**	**2010**
Cash paid during the period for:			
Interest expense (including capitalized amounts)	$ 42,420	$ 29,650	$ 29,686
Interest capitalized	$ 30,255	$ 24,193	$ 23,688
Income taxes	$ 377	$ 1,753	$ 108,846
Cash received for income taxes	$ 49,754	$ 59,109	$ 4,166

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 $5.7 million in 2012. They were $5.3 million and $6.1 million for 2011 and 2010, respectively. Shown below are future minimum payments required under these leases as of December 31, 2012:

(in thousands)	**Operating Leases**
2013	$ 13,486
2014	8,205
2015	9,685
2016	9,893
2017	9,538
Later years	80,764
Total future minimum lease payments	$ 131,571

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CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

13. COMMITMENTS AND CONTINGENCIES (Continued)

Other Commitments

We have drilling commitments of approximately $206.1 million consisting of obligations to finish drilling and completing wells in progress at December 31, 2012. We also have various commitments for drilling rigs as well as certain service contracts. The total minimum expenditure commitments under these agreements are $6.6 million.

We have projects in Oklahoma, New Mexico, and Texas where we are constructing gathering facilities and pipelines. At December 31, 2012, we had commitments of $1.7 million relating to this construction.

At December 31, 2012, we had firm sales contracts to deliver approximately 26.8 Bcf of natural gas over the next 16 months. If this gas is not delivered, our financial commitment would be approximately $86.4 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 reserves and production levels.

We have other various transportation and delivery commitments in the normal course of business, which approximate $9.5 million.

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* was filed as a statewide royalty putative class action 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. The Court has entered an order preliminarily approving the parties' settlement. The deadline for putative class members to opt out of the settlement class was February 15, 2013, and less than $^1/_2$% of the class members opted out. The Court will hold the settlement fairness hearing on March 22, 2013. 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 transaction to shareholders of H&P, by which Cimarex became a publicly-traded entity, Cimarex assumed the assets and liabilities of H&P's exploration and production business, including this lawsuit. In 2008 we recorded a litigation expense of $119.6 million for

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CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

13. COMMITMENTS AND CONTINGENCIES (Continued)

this lawsuit. We have accrued additional post-judgment interest and costs during the appeal of the District Court's judgment.

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. We are awaiting a ruling from the Oklahoma Supreme Court, and the final outcome cannot be determined at this time. If the District Court's original judgment is ultimately affirmed in its entirety, the $119.6 million, plus the then-determined amount of post-judgment interest and costs would become payable.

The following table reflects the change in the noncurrent accrued liability for this lawsuit for the years ending December 31:

(in thousands)	2012	2011	2010
Beginning of period	$ 146,310	$ 137,611	$ 128,759
Accrued post-judgment interest and costs	9,064	8,699	8,852
End of period	$ 155,374	$ 146,310	$ 137,611

14. PROPERTY SALES AND ACQUISITIONS

In 2012, we sold interests in non-core oil and gas assets for $306 million. Of this total, $290 million, which occurred in the fourth quarter, 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 in the Permian basin.

During 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.

In 2010 we sold various interests in oil and gas properties for $28.2 million, most of which were located in Mississippi.

We intend to continue to actively evaluate acquisitions and dispositions relative to our property holdings, particularly in our Cana-Woodford shale play and in the Permian Basin.

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

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CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

15. UNAUDITED SUPPLEMENTAL OIL AND GAS DISCLOSURES (Continued)

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)	**2012**	**2011**	**2010**
Oil, gas and NGL revenues from production	$ 1,581,650	$ 1,703,520	$ 1,558,562
Less operating costs and income taxes:			
Depletion	484,529	367,509	282,374
Asset retirement obligation	13,019	11,451	7,322
Production	258,584	247,048	194,015
Transportation	57,354	56,711	45,982
Taxes other than income	86,994	126,468	121,781
Income tax expense	251,215	331,082	336,530
	1,151,695	1,140,269	988,004
Results of operations from oil and gas producing activities	$ 429,955	$ 563,251	$ 570,558
Amortization rate per Mcfe	$ 2.11	$ 1.70	$ 1.30

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)	**2012**	**2011**	**2010**
Costs incurred during the year:			
Acquisition of properties			
Proved	$ 2,645	$ 23,071	$ 15,220
Unproved	117,695	168,238	136,929
Exploration	109,169	82,531	119,577
Development	1,426,918	1,351,617	766,980
Oil and gas expenditures	1,656,427	1,625,457	1,038,706
Property sales	(305,862)	(117,344)	(28,235)
	1,350,565	1,508,113	1,010,471
Asset retirement obligation, net	12,525	63,246	9,321
	$ 1,363,090	$ 1,571,359	$ 1,019,792

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CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

15. UNAUDITED SUPPLEMENTAL OIL AND GAS DISCLOSURES (Continued)

Aggregate Capitalized Costs The table below reflects the aggregate capitalized costs relating to our oil and gas producing activities at December 31, 2012:

(in thousands)		
Proved properties	$	11,258,748
Unproved properties and properties under development, not being amortized		645,078
		11,903,826
Less-accumulated depreciation, depletion and amortization		(6,899,057)
Net oil and gas properties	$	5,004,769

Costs Not Being Amortized The following table summarizes oil and gas property costs not being amortized at December 31, 2012, by year that the costs were incurred:

(in thousands)		
2012	$	321,762
2011		170,861
2010		49,217
2009 and prior		103,238
	$	645,078

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 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 eighteen 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 eight 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, 2012. 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-eight years of experience in oil and gas reservoir studies and evaluations.

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CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

15. UNAUDITED SUPPLEMENTAL OIL AND GAS DISCLOSURES (Continued)

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.

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, 2009	1,186,585	56,764	1,253	1,534,689
Revisions of previous estimates	(24,756)	3,279	25,588	148,440
Extensions and discoveries	216,338	14,133	18,419	411,650
Purchases of reserves	12,834	104	322	15,391
Production	(132,813)	(9,844)	(4,272)	(217,510)
Sales of properties	(4,022)	(780)		(8,703)
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
Proved developed reserves:				
December 31, 2009	865,720	52,636	1,253	1,189,054
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
Proved undeveloped reserves:				
December 31, 2009	320,865	4,128		345,635
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

During 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 proved undeveloped (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 relate to production performance of certain wells recently drilled in our Cana-Woodford shale project. PUD reserve additions

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CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

15. UNAUDITED SUPPLEMENTAL OIL AND GAS DISCLOSURES (Continued)

in extensions and discoveries for 2012 now reflect revised expectations of future production performance. The remainder of the net negative revision primarily resulted from decreases in prices (91 Bcfe), increases in operating expenses (21 Bcfe) which shortened the economic lives, adjustments to previously PUD reserves (25 Bcfe) and the removal of PUD locations due to altered future drilling plans (42 Bcfe).

In 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.

During 2010, we added 411.7 Bcfe of proved reserves through extensions and discoveries, primarily as the result of wells drilled in our Cana-Woodford shale area, in the Permian Basin and in southeast Texas.

Net revisions during 2010 added 148.4 Bcfe, which included 44.8 Bcfe driven by higher oil and gas prices. The rest of these net revisions relate primarily to increases in our NGL volumes stemming from new gas processing contracts and certain contractual amendments.

At December 31, 2012 we had PUD reserves of 450 Bcfe, up 72 Bcfe from 378 Bcfe of PUDs at December 31, 2011. Changes in our PUD reserves are summarized in the table below (in Bcfe):

PUDs at December 31, 2011	377.7
Converted to developed	(176.4)
Additions	315.9
Net revisions	(67.4)
PUDs at December 31, 2012	449.8

The 316 Bcfe of PUD additions occurred in our western Oklahoma, Cana Woodford shale play. All of our PUDs are associated with this play. 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.

PUD reserves at December 31, 2011 and 2010 totaled 378 Bcfe and 424 Bcfe, respectively. The majority of the 2011 reserves were associated with our western Oklahoma, Cana-Woodford shale play. Roughly half of our 2010 PUD reserves were associated with a gas development project in Sublette County, Wyoming. These assets were sold in August, 2011. Please see Note 14 for further information on this sale.

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.

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

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CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

15. UNAUDITED SUPPLEMENTAL OIL AND GAS DISCLOSURES (Continued)

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)	**2012**	**2011**	**2010**
Cash inflows	$ 12,384,251	$ 13,824,129	$ 11,355,448
Production costs	(3,684,875)	(3,999,352)	(3,615,419)
Development costs	(562,994)	(555,963)	(426,914)
Income tax expense	(2,368,115)	(2,938,590)	(2,243,558)
Net cash flow	5,768,267	6,330,224	5,069,557
10% annual discount rate	(2,859,566)	(3,190,474)	(2,554,280)
Standardized measure of discounted future net cash flow	$ 2,908,701	$ 3,139,750	$ 2,515,277

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

	December 31,		
(in thousands)	**2012**	**2011**	**2010**
Standardized Measure, beginning of period	$ 3,139,750	$ 2,515,277	$ 1,667,955
Sales, net of production costs	(1,178,718)	(1,268,175)	(1,192,798)
Net change in sales prices, net of production costs	(957,606)	448,727	806,109
Extensions and discoveries, net of future production and development costs	1,707,024	1,662,706	1,186,787
Changes in future development costs	146,808	(57,847)	(40,748)
Previously estimated development costs incurred during the period	148,976	42,492	56,848
Revision of quantity estimates	(457,013)	(16,269)	300,676
Accretion of discount	459,490	361,662	228,593
Change in income taxes	197,916	(353,804)	(483,370)
Purchases of reserves in place	572	41,854	21,076
Sales of properties	(214,746)	(123,870)	(20,981)
Change in production rates and other	(83,752)	(113,003)	(14,870)
Standardized Measure, end of period	$ 2,908,701	$ 3,139,750	$ 2,515,277

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

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CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

15. UNAUDITED SUPPLEMENTAL OIL AND GAS DISCLOSURES (Continued)

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

	December 31,		
	2012	2011	2010
Gas price per Mcf	$ 2.27	$ 3.79	$ 4.12
Oil price per Bbl	$ 88.91	$ 89.64	$ 75.35
NGL price per Bbl	$ 29.12	$ 41.70	$ 33.89

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

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 (loss)	$ 106,107	$ 64,302	$ 84,262	$ 99,152
Earnings (loss) 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

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CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

16. UNAUDITED SUPPLEMENTAL QUARTERLY FINANCIAL DATA (Continued)

2011	**First**	**Second**	**Third**	**Fourth**
(in thousands, except for per share data)				
Revenues	$ 426,596	$ 467,213	$ 433,809	$ 430,271
Expenses, net	308,434	300,464	305,657	313,402
Net income (loss)	$ 118,162	$ 166,749	$ 128,152	$ 116,869
Earnings (loss) per share to common stockholders:				
Basic:				
Distributed	$ 0.10	$ 0.10	$ 0.10	$ 0.10
Undistributed	1.28	1.85	1.39	1.26
	$ 1.38	$ 1.95	$ 1.49	$ 1.36
Diluted:				
Distributed	$ 0.10	$ 0.10	$ 0.10	$ 0.10
Undistributed	1.27	1.84	1.39	1.26
	$ 1.37	$ 1.94	$ 1.49	$ 1.36

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, 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 Exchange Act Rules 13a-15(e)) as of December 31, 2012 and concluded that the disclosure controls and procedures are effective in providing reasonable assurance that the 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 also 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

The management of Cimarex is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act). The company's internal control over financial reporting is a process designed 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, 2012, 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. Based on that assessment, the company maintained effective internal control over financial reporting as of December 31, 2012.

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, 2012, based on criteria established in *Internal Control Integrated Framework* 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, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

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, 2012 and 2011, 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, 2012, and our report dated February 26, 2013 expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP

Denver, Colorado
February 26, 2013

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ITEM 9B. OTHER INFORMATION

None.

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PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF CIMAREX

Information concerning the directors of Cimarex is incorporated by reference from the Cimarex Energy Co. definitive Proxy Statement for the May 15, 2013 Annual Meeting of Stockholders. The Proxy Statement will be filed with the Securities and Exchange Commission no later than April 30, 2013. Information concerning the executive officers of Cimarex is set forth under Item 4A in Part I of this report.

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, 2013 Annual Meeting of Stockholders. The Proxy Statement will be filed with the Securities and Exchange Commission no later than April 30, 2013.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Information required under this item is incorporated by reference from the Cimarex Energy Co. definitive Proxy Statement for the May 15, 2013 Annual Meeting of Stockholders. The Proxy Statement will be filed with the Securities and Exchange Commission no later than April 30, 2013.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Information required under this item is incorporated by reference from the Cimarex Energy Co. definitive Proxy Statement for the May 15, 2013 Annual Meeting of Stockholders. The Proxy Statement will be filed with the Securities and Exchange Commission no later than April 30, 2013.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information required under this item is incorporated by reference from the Cimarex Energy Co. definitive Proxy Statement for the May 15, 2013 Annual Meeting of Stockholders. The Proxy Statement will be filed with the Securities and Exchange Commission no later than April 30, 2013.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(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 (file no. 001-31446) dated June 7, 2005 and incorporated herein by reference).
3.2	Amended and Restated By-laws of Cimarex Energy Co. (filed as Exhibit 3.2 to the Registrant's Current Report on Form 8-K dated August 30, 2011 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 1, 1992 between Key Production Company, Inc. and F.H. Merelli (filed as Exhibit 10.5 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 F. H. Merelli (filed as Exhibit 10.7 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 September 7, 1999, by and between Paul Korus and Key Production Company, Inc. (filed as Exhibit 10.6 to the Registration Statement on Form S-4 dated May 9, 2002 (Registration No. 333-87948) and incorporated herein by reference).
10.5	Amendment to Employment Agreement effective January 1, 2009 between Cimarex Energy Co. and Paul Korus (filed as Exhibit 10.9 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).
10.6	Employment Agreement, dated October 25, 1993, by and between Thomas E. Jorden and Key Production Company, Inc. (filed as Exhibit 10.7 to the Registration Statement on Form S-4 dated May 9, 2002 (Registration No. 333-87948) and incorporated herein by reference).
10.7	Amendment to Employment Agreement effective January 1, 2009 between Cimarex Energy Co. and Thomas E. Jorden (filed as Exhibit 10.11 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).
10.8	Employment Agreement, dated February 2, 1994, by and between Stephen P. Bell and Key Production Company, Inc. (filed as Exhibit 10.8 to the Registration Statement on Form S-4 dated May 9, 2002 (Registration No. 333-87948) and incorporated herein by reference).
10.9	Amendment to Employment Agreement effective January 1, 2009 between Cimarex Energy Co. and Stephen P. Bell (filed as Exhibit 10.13 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).
10.10	Employment Agreement, dated March 11, 1994, by and between Joseph R. Albi and Key Production Company, Inc. (filed as Exhibit 10.9 to the Registration Statement on Form S-4 dated May 9, 2002 (Registration No. 333-87948) and incorporated herein by reference).
10.11	Amendment to Employment Agreement effective January 1, 2009 between Cimarex Energy Co. and Joseph R. Albi (filed as Exhibit 10.15 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).
10.12	Amended and Restated 2002 Stock Incentive Plan of Cimarex Energy Co. effective January 1, 2009 (filed as Exhibit 10.16 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).
10.13	2011 Equity Incentive Plan adopted May 18, 2011 (filed as Appendix A to the Definitive Proxy Statement 14-A filed on March 23, 2011 (Commission File No. 001-31446) and incorporated herein by reference).
10.14	Form of Notice of Grant of Award of Performance Stock and Award Agreement (filed as Exhibit 10.2 to Registrant's Quarterly Report on Form 10-Q filed on August 4, 2011 (File no. 001-31446) and incorporated herein by reference).
10.15	Form of Notice of Grant of Restricted Stock and Award Agreement (filed as Exhibit 10.3 to Registrant's Quarterly Report on Form 10-Q filed on August 4, 2011 (File no. 001-31446) and incorporated herein by reference).
10.16	Form of Notice of Grant of Nonqualified Stock Option and Award Agreement (filed as Exhibit 10.4 to Registrant's Quarterly Report on Form 10-Q filed on August 4, 2011 (File no. 001-31446) and incorporated herein by reference).

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Exhibit	Title
10.17	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).
10.18	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).
10.19	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).
10.20	Form of Indemnification Agreement between Cimarex Energy Co. and each of its executive officers and directors.*
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, 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 25, 2013 from DeGolyer and MacNaughton, independent petroleum engineering consulting firm, reporting the results of its audit of Cimarex reserves as of December 31, 2012 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 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, 2013

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, 2013
* *Attorney-in-Fact* Joseph R. Albi	Director, Executive Vice President and Chief Operating Officer	February 26, 2013
/s/ PAUL KORUS Paul Korus	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 26, 2013
/s/ JAMES H. SHONSEY James H. Shonsey	Vice President, Chief Accounting Officer and Controller (Principal Accounting Officer)	February 26, 2013
* *Attorney-in-Fact* Jerry Box	Director	February 26, 2013
* *Attorney-in-Fact* Hans Helmerich	Director	February 26, 2013

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Signature	Title	Date
* *Attorney-in-Fact* David A. Hentschel	Director	February 26, 2013
* *Attorney-in-Fact* Harold R. Logan, Jr.	Director	February 26, 2013
* *Attorney-in-Fact* Floyd R. Price	Director	February 26, 2013
* *Attorney-in-Fact* Monroe W. Robertson	Director	February 26, 2013
* *Attorney-in-Fact* Michael J. Sullivan	Director	February 26, 2013
* *Attorney-in-Fact* L. Paul Teague	Director	February 26, 2013

* By:	/s/ PAUL KORUS Paul Korus *Attorney-in-Fact*	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 26, 2013