CIMAREX ENERGY CO
Form 10-K
February 22, 2012

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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, 2011

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, 2011 was approximately $7.5 billion.

Number of shares of Cimarex Energy Co. common stock outstanding as of February 15, 2012 was 85,701,346.

Documents Incorporated by Reference: Portions of the Registrant's Proxy Statement for its 2012 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 Cimarex's working interest percentage

Net Production Gross production multiplied by Cimarex's net revenue interest

NGL 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

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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.

ITEM 1. BUSINESS

General

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.

Proved oil and gas reserves as of year-end 2011 totaled 2.05 Tcfe, consisting of 1.2 Tcf of gas and 138 million barrels of oil and natural gas liquids. Of total proved reserves, 59% are gas and 82% are classified as proved developed.

Our 2011 production averaged 592.3 MMcfe per day, comprised of 329.1 MMcf of gas per day and 43,875 barrels of oil and natural gas liquids per day. The wells we operate account for 76% of our total proved reserves and approximately 81% of our 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.

Our Web site 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.

History

Cimarex was formed in February 2002 as a wholly owned subsidiary of Tulsa-based Helmerich & Payne, Inc. ("H&P"). On September 30, 2002, Cimarex was completely spun off to H&P shareholders and simultaneously merged with Denver-based Key Production Company, Inc. Our common stock began trading on the New York Stock Exchange on October 1, 2002 under the symbol XEC.

On June 7, 2005, we acquired Dallas-based Magnum Hunter Resources, Inc. in a $1.5 billion stock-for-stock merger including assumption of liabilities. Since 2005, we have principally focused on exploration and development drilling and have funded these investments with cash flow provided by operating activities.

2011 Summary Highlights

During 2011 we accomplished the following:

- Net income of $530 million, or $6.15 (diluted) per share;
- Cash flow from operating activities of $1.3 billion;
- Increased proved reserves 9% to 2.05 Tcfe; adjusted for property sales, proved reserves increased 23%;
- Added 587 Bcfe of proved reserves from extensions and discoveries replacing 272% of production;
- Sold $229 million of non-strategic assets and reinvested proceeds in core area exploration and development activities;

Evaluated, de-risked and expanded our acreage position in several key long-term future drilling projects;

Grew Permian and Mid-Continent production 16% to an all-time high of 487 MMcfe/d; overall production of 592 MMcfe/d was about flat with 2010 production; and

Exited the year with a debt to total capitalization ratio of 11%, down from 12% at year-end 2010.

Business Strategy

Our principal business objective is to profitably grow our proved reserves and production for the long-term benefit of our shareholders. Our strategy centers on maximizing cash flow from our producing properties and profitably reinvesting that cash flow in exploration and development drilling.

During 2011, our cash flow from operating activities totaled $1.3 billion. Our total 2011 capital investment was $1.625 billion, including $1.58 billion on exploration and development. We funded our capital program primarily with cash flow and property sales.

A cornerstone to our approach is a detailed evaluation of each drilling decision based on its risk-adjusted discounted cash flow rate of return on investment. Our analysis includes estimates and assessments of potential reserve size, geologic and mechanical risks, expected costs, future production profiles and future oil and gas prices.

Our integrated teams of geoscientists, landmen and petroleum engineers continually generate new prospects to maintain a rolling portfolio of drilling opportunities in different basins with varying geologic characteristics. We have a centralized exploration management system that measures actual results and provides feedback to the originating exploration team in order to help them improve and refine future investment decisions. We believe that our detailed technical analysis and disciplined capital investment process mitigates risk and positions us to continue to achieve consistent increases in proved reserves and production.

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. The 2005 Magnum Hunter acquisition significantly increased our presence in the Permian Basin and enhanced our Mid-Continent operations in the Texas Panhandle. In 2008, we acquired 38,000 net acres in our western Oklahoma Cana-Woodford shale play, and we have continued to increase our acreage positions in this play over the last three years.

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 2011 we had $405 million of long-term debt and our debt to total capitalization ratio was 11%.

2012 Outlook

Our 2012 exploration and development capital investment is presently expected to be in the range of $1.4-1.6 billion. We expect nearly all of our 2012 capital to be directed towards oil or liquids-rich gas drilling in the Permian and Cana-Woodford shale play.

Full-year 2012 Mid-Continent and Permian production volumes are projected to grow 19-25% above 2011, averaging between 580-610 MMcfe/d. Gulf Coast volumes, assuming no new production contribution from drilling, are projected to average 35-40 MMcfe/d for 2012. Total company 2012 volumes are projected to average 615-650 MMcfe/d, or 4-10% growth over 2011.

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.

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For 2012 we have approximately 50% of our oil production hedged. We do not have any of our gas or natural gas liquids production hedged. For a complete discussion of our hedging activities, a listing of open contracts as of December 31, 2011 and the estimated fair value of these contracts as of that date, see Note 4, Derivative Instruments/Hedging, to our consolidated financial statements.

Business Segments

Cimarex has one reportable segment (exploration and production).

Exploration and Development Overview

Our exploration and development (E&D) activities have been conducted primarily within two main areas: the Mid-Continent region and the Permian Basin. The Mid-Continent region consists of Oklahoma, the Texas Panhandle and southwest Kansas. The Permian Basin encompasses west Texas and southeast New Mexico. Our Gulf Coast operations were conducted in southeast Texas.

We drilled and completed 331 gross (174 net) wells during 2011, investing $1.6 billion on E&D. Of total expenditures, 47% were invested in projects located in the Mid-Continent area; 46% in the Permian Basin; and 7% in the Gulf Coast and other.

A summary of our 2011 exploration and development activity by region is as follows.

	Exploration and Development Capital (in millions)	Gross Wells Drilled	Net Wells Drilled	Completion Rate	12/31/11 Proved Reserves (Bcfe)
Mid-Continent	$ 741	180	64	100%	1,376
Permian Basin	731	140	100	96%	620
Gulf Coast/Other	108	11	10	27%	49
	$ 1,580	331	174	96%	2,045

Mid-Continent

Our Mid-Continent region encompasses operations in Oklahoma, southwest Kansas and the Texas Panhandle. We drilled 180 gross (64 net) Mid-Continent wells during 2011, completing 100% as producers. The bulk of this drilling activity was in the Anadarko Basin of western Oklahoma. Full-year 2011 investment in this area was $741 million, or 47% of total E&D capital.

In the Anadarko Basin of western Oklahoma, our largest investment is 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. During 2011, we drilled and completed 154 gross (49 net) horizontal Cana-Woodford wells. At year-end there were 13 gross (4.9 net) wells waiting on completion. We have approximately 120,000 net acres in the play.

Since the Cana play began in late 2007, Cimarex has participated in a total of 330 gross (119 net) wells. Of total wells, 297 gross (105 net) were on production and the remainder were either in the process of being drilled or awaiting completion at year-end 2011. On average gross estimated well-head recovery exceeds 6.3 Bcfe per well. Our acreage positions have multiple years of drilling opportunity.

In the Texas Panhandle, we drilled or participated in 14 gross (7.6 net) successful Granite Wash and Morrow wells. Our land position in the Texas Panhandle is primarily in Roberts and Hemphill counties.

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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, Abo and Paddock formations. In total, we drilled 140 gross (100 net) wells in this area during 2011 completing 134 gross (95 net) as producers. Full-year 2011 investment in this area totaled $731 million, or 46% of total E&D capital. Our 2011 drilling focused on horizontal oil plays and new emerging liquids rich gas.

Full-year 2011 New Mexico Bone Spring wells drilled and completed totaled 63 gross (40 net). The 30-day gross production from the 2011 Bone Spring wells averaged 530 barrels equivalent (Boe) per day (84% oil). Seventeen of these wells were brought on in the fourth-quarter with an average 30-day gross rate of 597 Boe per day (85% oil). Texas Third Bone Spring drilling totaled 17 gross (14 net) wells, which on average had 30-day gross production rates of 730 Boe/d (73% oil).

We are also evaluating multiple shale intervals in the Delaware Basin, including the Wolfcamp, Avalon and Cisco/Canyon. The majority of drilling to date has been in the Wolfcamp. In southern Eddy County New Mexico and Culberson County Texas, we drilled 11 gross (10 net) horizontal Wolfcamp shale wells in 2011. Since commencing the play in 2010, we have drilled a total of 18 gross (16.8 net) Wolfcamp wells. Thirty-day average initial production on these wells averaged 6.5 MMcfe/d, comprised of 44% gas, 24% oil and 32% NGL.

Gulf Coast

Our Gulf Coast exploration drilling was primarily in southeast Texas. This effort is generally characterized by reliance on three-dimensional (3-D) seismic information for prospect generation. Compared to our other core areas, we often experience larger potential reserves per well, greater drilling depths and lower success rates in the Gulf Coast. Full-year 2011 investment in the Gulf Coast area was $95 million, or 6% of total E&D capital. During 2011 we drilled 11 gross (9.6 net) Gulf Coast wells, realizing a 27% success rate. The majority of the activity occurred near Beaumont in Jefferson County, Texas.

We also own interests offshore Louisiana on the Gulf of Mexico shelf (water depth less than 300 feet). We obtained all of our offshore position through the Magnum Hunter acquisition. We had no capital investment activity during 2011.

Production, Pricing and Cost Information

The following table sets forth certain information regarding the company's production volumes, the average commodity prices received and production cost per Mcfe. In 2011, the total proved reserves of our

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Cana-Woodford shale play, located in the Watonga-Chickasha field, were 42.4% of our total proved reserves. No other field had reserves in excess of 15% of our total proved reserves.

	Total Company Years Ending December 31,			Total Watonga-Chickasha Field (Cana-Woodford) Year Ending December 31,
	2011	2010	2009	2011
Production Volumes:				
Gas (MMcf)	120,113	132,813	117,968	30,187
Oil (MBbls)	9,778	9,844	8,278	630
NGL (MBbls)	6,236	4,272	220	2,194
Equivalent (MMcfe)	216,918	217,509	168,956	47,130
Net Average Daily Volumes:				
Gas (MMcf)	329.1	363.9	323.2	82.7
Oil (MBbls)	26.8	27.0	22.7	1.7
NGL (MBbls)	17.1	11.7	0.6	6.0
Equivalent (MMcfe)	592.3	595.9	462.9	129.1
Average Sales Price:				
Gas ($/Mcf)	$ 4.42	$ 4.92	$ 4.12	$ 3.92
Oil ($/Bbl)	$ 93.00	$ 76.76	$ 56.63	$ 91.71
NGL ($/Bbl)	$ 42.31	$ 34.91	$ 37.11	$ 38.38
Production Cost ($/Mcfe)	$ 1.14	$ 0.89	$ 1.05	$ 0.18

Total equivalent 2011 production averaged 592.3 MMcfe per day as compared to 595.9 MMcfe per day in 2010. Gas production in 2011 decreased 10% to 329.1 MMcf per day and oil and NGL production grew 13% to 43,875 barrels per day.

The following table summarizes Cimarex's daily production by region for 2011 and 2010.

	2011 Average Daily Production				2010 Average Daily Production			
	Gas (MMcf/d)	Oil (MBbl/d)	NGL (MBbl/d)	Total (MMcfe/d)	Gas (MMcf/d)	Oil (MBbl/d)	NGL (MBbl/d)	Total (MMcfe/d)
Mid-Continent	203.0	5.7	9.3	292.6	194.1	4.7	5.5	255.4
Permian Basin	73.6	16.8	3.4	194.4	71.5	14.0	1.7	165.4
Gulf Coast/Other	52.5	4.3	4.4	105.3	98.3	8.3	4.5	175.1
	329.1	26.8	17.1	592.3	363.9	27.0	11.7	595.9

Our largest producing area is the Mid-Continent region. During 2011 our Mid-Continent production averaged 292.6 MMcfe per day, or 49% of our total 2011 production. Drilling activity in our western Oklahoma Cana-Woodford shale play resulted in Mid-Continent production increasing 15% in 2011.

The Permian Basin contributed 194.4 MMcfe per day in 2011, which was 33% of our total production. Permian drilling increased throughout 2011 as a result of continuing improvement in oil prices and return on investment. Most of the activity was focused in the Bone Spring, Abo and Paddock formations. Oil production grew 20% in 2011 over 2010.

Gulf Coast production averaged 105.3 MMcfe per day during 2011, or 18% of total production. Full-year 2011 Gulf Coast volumes decreased by 40% as compared to 2010 as a result of declines in wells drilled in Jefferson County Texas, near Beaumont. Gulf Coast volumes can fluctuate significantly depending on timing of exploration success relative to natural production declines.

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Acquisitions and Divestitures

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 related assets and 210 Bcf of proved undeveloped gas reserves. The sales contract also provides for up to a $15 million contingent payment to be paid by the buyer at the time the gas processing facility is operational and certain other performance standards are met, which is expected to occur in the second quarter of 2012.

We also sold interests in certain other non-strategic oil and gas properties with proved reserves of 16.3 Bcfe, most of which were located in south Texas and southeast New Mexico. These transactions totaled $33.3 million. Certain of these properties were included as part of like-kind exchanges for selected purchases in our core plays. We acquired additional oil and gas properties in 2011 for a total of $45.4 million of which $42.2 million was in our Cana-Woodford shale play.

During 2010, we sold oil and gas properties, mostly in Mississippi, for a total of $28.2 million. Associated proved reserves were 8.7 Bcfe. Through several transactions in 2010 totaling $38 million we acquired additional interests in our Cana-Woodford shale play.

In 2009, we sold various oil and gas properties for a total of $109.4 million, to which we attributed 25 Bcfe of proved reserves. The largest transaction was $79 million for an interest in a West Texas secondary oil field. There were no significant acquisitions during 2009.

Marketing

Our oil and gas production is sold under several short-term arrangements at market-responsive prices. We sell our oil at various prices directly or indirectly tied to field postings and monthly futures contract prices on the New York Mercantile Exchange (NYMEX). 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 two largest customers accounted for approximately 22% and 15%, respectively, of 2011 revenues. Because over 95% of our gas production is from wells in Texas, Oklahoma, New Mexico, and Kansas, most of our customers are either from those states or nearby end-user market centers. We regularly monitor the credit worthiness of all our customers and may require parental guarantees, letters of credit or prepayments when we deem such security is necessary.

Employees

We employed 824 people on December 31, 2011. None of our employees are subject to collective bargaining agreements.

Competition

The oil and gas industry is highly competitive. Competition is particularly intense for prospective undeveloped leases and purchases of proved oil and gas reserves. There is also competition for rigs and related equipment we use 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 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 that the titles to our properties are good and defensible, and are 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 upon our operations or financial condition. In recent years, we have been most directly affected by federal and state environmental regulations and energy conservation rules. We are also affected 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. The effect of these regulations is to limit the amounts of oil and natural gas that we can produce from our wells and to limit the number of wells or locations at which we can drill.

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, and 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.

We are committed to environmental protection and believe we are in substantial compliance with applicable environmental laws and regulations. We routinely 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. We have made, and will continue to make, expenditures in our efforts to comply with environmental regulations and requirements. These costs are considered a normal, recurring cost of our ongoing 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 do 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.

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

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

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

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

Federal and State Income and Other Local Taxation

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

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 for our production 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 the price and technological advancement of alternative fuels.

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Our proved oil and gas reserves and production volumes 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. If prices decrease significantly, we may incur impairment charges in the future, which could have a material adverse effect on our results of operations in the period taken. For example, low prices contributed to the impairment charge of $791 million that we recorded in the carrying value of our oil and gas properties in 2009.

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 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. Exploration and development 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

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assumptions. See Forward-Looking Statements 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;
- work-over and remediation costs; and
- Federal and state income taxes.

At December 31, 2011, 18% of our total proved reserves are categorized as proved undeveloped. Of these proved undeveloped reserves, 98% are in our western Oklahoma, 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, 2011.

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 average of the previous twelve months' prices and costs as of the date of the estimate, whereas actual future prices and costs may be materially different.

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

To manage our exposure to price risk, we from time to time enter into hedging arrangements. We use commodity derivatives with respect to a significant portion of our future production. For 2012, we have hedged approximately 50% 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 addition, hedging transactions may expose us to the risk of financial loss in certain circumstances, 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.

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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.

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, most 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 owned by third parties. 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 shut-in of producing wells or the delay or discontinuance of drilling plans for properties. 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 we do. These companies may be able 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.

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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 our 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 that have tended to become more onerous over time. Our operations create the risk of environmental liability to the government and private parties, including for the discharge of oil, gas or other substances into the air, soil or water. Liabilities under environmental law can be joint and several and can in some cases be imposed regardless of fault on our part. Further, we may be 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, these liabilities could have a material adverse effect on both our financial condition and operations.

Federal and state legislation and regulatory initiatives related to hydraulic fracturing could result in operating restrictions or delays in the completion of oil and gas wells.

In order to achieve economic production rates and recoverable reserves, we use hydraulic fracturing for almost all of our wells. Hydraulic fracturing is a process that involves pumping fluid at high pressure into a hydrocarbon bearing formation to create 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 typically made up primarily of water and sand, but it also 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. The efforts to regulate hydraulic fracturing at both the state and Federal level are increasing. Many new regulations are being considered, including limiting water withdrawals and water used, restricting which additives may be used, implementing state-wide hydraulic fracturing moratoriums and temporary or permanent bans in certain environmentally sensitive areas. Public debate over hydraulic fracturing and shale gas production also has been increasing, which has resulted in delays of well permits in some areas. The potential result of these efforts could render permitting and compliance requirements to become more stringent for hydraulic fracturing, which could have a material adverse effect on our operations and financial results.

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 properties not operated by us could result in economic losses that are partially beyond our control.

Other companies operate approximately 19% 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. They would also include 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 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
- repair and remediation costs.

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, 2011, our long-term debt consisted of $350 million of 7.125% Senior Notes and $55 million of bank debt. In addition to interest expense and principal on our long-term debt, we have demands on our cash resources including, among others, operating expenses and capital expenditures.

Our ability to pay the principal and interest on our long-term debt and to satisfy our other liabilities will depend upon future performance and our ability to repay or refinance our debt as it becomes due. Our future operating performance and ability to refinance will be affected by economic and capital market conditions, results of operations and other factors, many of which are beyond our control. Our ability to meet our debt service obligations may also be affected 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 our credit agreement contain various restrictive covenants that may limit our management's discretion in certain respects. In particular, these agreements limit our and our 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 7, 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:

- recoverable reserves;
- future oil and gas prices and their appropriate differentials;
- operating costs; and
- potential environmental 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. H&P" case. See Note 16, Commitments and Contingencies in this report for more detailed information.

Because this case is subject to further appeal, 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, 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 the President recommends elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies, and 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; (iii) the elimination of the deduction for certain U.S. production activities, including the production of oil and gas; and (iv) 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

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.

Corporate engineers are responsible for the Company's reserve estimates on all properties within specified geographic areas. For both newly drilled and existing properties, 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 a reserve estimate. After preparing the reserve updates, the corporate engineers review their recommendations with the Vice President Corporate Engineering. After the Vice President Corporate Engineering approves the proposed changes, the revisions are entered into the Company's reserve database by the engineering technician.

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

Together, these internal controls are designed to promote a comprehensive, objective and accurate reserve estimation process. As an additional confirmation of the reasonableness of the Company's internal reserve 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, 2011. 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-seven years of experience in oil and gas reservoir studies and evaluations.

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

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 76% 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 18, 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,		
	2011	**2010**	**2009**
Total Proved Reserves			
Gas (MMcf)	1,216,441	1,254,166	1,186,585
Oil (MBbls)	72,322	63,656	56,764
NGL (MBbls)	65,815	41,310	1,253
Equivalent (MMcfe)	2,045,265	1,883,957	1,534,689
Standardized measure of discounted future net cash flow after-tax, discounted at 10% (in thousands)	$ 3,139,750	$ 2,515,277	$ 1,667,955
Average price used in calculation of future net cash flow			
Gas ($/Mcf)	$ 3.79	$ 4.12	$ 3.56
Oil ($/Bbl)	$ 89.64	$ 75.35	$ 57.58
NGL ($/Bbl)	$ 41.70	$ 33.89	$ 28.53

Significant Properties

As of December 31, 2011, 98% of our total proved reserves were located in the Mid-Continent and Permian Basin regions. In total we owned an interest in 12,701 gross (4,805 net) productive oil and gas wells.

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The following table summarizes our estimated proved oil and gas reserves by region as of December 31, 2011.

	Gas (Bcf)	Oil (MBbl)	NGL (MBbl)	Equivalent (Bcfe)	Percent of Proved Reserves
Mid-Continent	939.5	17,438	55,268	1,375.7	67%
Permian Basin	245.2	53,162	9,378	620.4	31%
Gulf Coast/Other	31.7	1,722	1,169	49.1	2%
	1,216.4	72,322	65,815	2,045.2	100%

Our ten largest producing fields hold 59% of our total equivalent proved reserves. We are the principal operator of our production in each of these fields (except Jo-Mill). 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	42.4	44.0	11,000' - 16,000'	Woodford
Mendota	Mid-Continent	2.6	68.4	11,000'	Granite Wash
Phantom	Permian	2.3	95.7	11,500'	Bone Spring
Eola-Robberson	Mid-Continent	2.3	89.6	5,500' - 11,000'	Bromide/McLish/Oil Creek
Quail Ridge	Permian	1.7	65.3	8,000' - 13,000'	Bone Spring/Morrow
Lusk	Permian	1.6	50.4	9,500'	Bone Spring
Caprock	Permian	1.6	73.1	9,000'	Abo
Cottonwood Draw	Permian	1.6	84.4	3,000' - 10,000'	Delaware/Wolfcamp
Two Georges	Permian	1.5	71.4	11,500'	Bone Spring
Jo-Mill	Permian	1.2	12.8	7,500'	Spraberry
		58.8			

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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, 2011. 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	20,842	18,236	144,440	102,937	165,282	121,173
Oklahoma	138,757	122,736	512,179	253,014	650,936	375,750
Texas	120,874	106,386	201,674	126,039	322,548	232,425
	280,473	247,358	858,293	481,990	1,138,766	729,348
Permian Basin						
New Mexico	109,645	83,651	185,205	131,565	294,850	215,216
Texas	123,846	101,333	180,391	121,065	304,237	222,398
	233,491	184,984	365,596	252,630	599,087	437,614
Gulf Coast						
Louisiana	6,138	1,722	15,436	3,535	21,574	5,257
Texas	66,778	38,174	100,318	37,266	167,096	75,440
Offshore	35,900	16,007	108,869	28,049	144,769	44,056
	108,816	55,903	224,623	68,850	333,439	124,753
Western/Other						
Arkansas	948	783	4,184	1,596	5,132	2,379
Arizona	2,111,139	2,111,139	17,207		2,128,346	2,111,139
California	382,205	382,205	364	364	382,569	382,569
Colorado	147,668	59,410	26,476	5,818	174,144	65,228
Illinois	1,902	556	391	20	2,293	576
Michigan	19,486	19,408	1,183	1,183	20,669	20,591
Montana	38,271	10,934	8,539	2,067	46,810	13,001
Nebraska	9,268	1,044	1,043	168	10,311	1,212
Nevada	1,196,299	1,196,299	440	1	1,196,739	1,196,300
New Mexico	1,651,741	1,637,216	19,717	2,512	1,671,458	1,639,728
North Dakota	36,673	4,538	7,740	1,027	44,413	5,565
South Dakota	9,597	8,841	1,529	49	11,126	8,890
Texas	63,458	63,325	31	31	63,489	63,356
Utah	88,452	59,343	29,970	1,692	118,422	61,035
Wyoming	153,287	13,132	60,308	5,077	213,595	18,209
	5,910,394	5,568,173	179,122	21,605	6,089,516	5,589,778
Total	6,533,174	6,056,418	1,627,634	825,075	8,160,808	6,881,493

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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									
	2012		2013		2014		2015		2016	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Mid-Continent	3,908	2,614	41,595	37,329	21,523	21,404	3,258	3,253	10,831	10,831
Permian Basin	14,150	13,521	48,945	48,923	4,759	4,759	25,858	23,904	4,392	4,341
Gulf Coast	19,049	19,016	4,692	3,919	4,366	4,366	18	18		
Western/Other	3,877	2,882	109,715	109,689	7,602	7,562	18,525	18,525	189,132	189,132
	40,984	38,033	204,947	199,860	38,250	38,091	47,659	45,700	204,355	204,304
Percent of undeveloped	0.6	0.6	3.1	3.3	0.6	0.6	0.7	0.8	3.1	3.4

Gross Wells Drilled

We participated in drilling the following number of gross wells during calendar years 2011, 2010, and 2009:

	Exploratory			Developmental		
	Productive	Dry	Total	Productive	Dry	Total
Year ended December 31, 2011	3	7	10	314	7	321
Year ended December 31, 2010	10	3	13	199	7	206
Year ended December 31, 2009	7	4	11	95	4	99

We were in the process of drilling 27 gross (11.9 net) wells at December 31, 2011 and there were 23 gross (11.2 net) wells waiting on completion.

Net Wells Drilled

The number of net wells we drilled during calendar years 2011, 2010, and 2009 are shown below:

	Exploratory			Developmental		
	Productive	Dry	Total	Productive	Dry	Total
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
Year ended December 31, 2009	5.6	3.8	9.4	54.1	3.5	57.6

Productive Wells

We have working interests in the following productive wells as of December 31, 2011:

	Gas		Oil	
	Gross	Net	Gross	Net
Mid-Continent	4,238	2,171	1,150	572
Permian	1,066	590	5,249	1,299
Gulf Coast / Other	422	123	576	50
	5,726	2,884	6,975	1,921

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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 H&P case. This lawsuit was originally filed in 1998 and addressed H&P's conduct pertaining to a 1989 take-or-pay settlement, along with potential drainage issues and other related matters. 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. In 2008 we recorded litigation expense of $119.6 million for this lawsuit. We have accrued additional expense for associated post-judgment interest and fees that have accrued during the appeal of the District Court's judgments.

Additional information regarding this and other litigation is included in Note 16, 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 22, 2012 were:

Name	Age	Office
F.H. Merelli	75	Chairman of the Board
Thomas E. Jorden	54	President and Chief Executive Officer
Joseph R. Albi	53	Executive Vice President and Chief Operating Officer
Stephen P. Bell	57	Senior Vice President, Business Development and Land
Paul Korus	55	Senior Vice President and Chief Financial Officer
Gary R. Abbott	39	Vice President, Corporate Engineering
Richard S. Dinkins	67	Vice President, Human Resources
James H. Shonsey	60	Vice President, Chief Accounting Officer, and Controller
Thomas A. Richardson	66	Vice President, General Counsel

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.

F.H. MERELLI continues to serve as executive chairman of the board. From September 30, 2002 to September 30, 2011, Mr. Merelli served as chairman of the board, chief executive officer, and president. Prior to its merger with Cimarex, Mr. Merelli served as chairman and chief executive officer of Key Production Company, Inc. from September 1992 to September 2002. From June 1988 to July 1991 he was president and chief operating officer of Apache Corporation.

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

JOSEPH R. ALBI was named executive vice president and chief operating officer effective September 30, 2011. Since March 1, 2005, Mr. Albi served as executive vice president of operations. Since December 8, 2003, Mr. Albi served as senior vice president of corporate engineering. From September 30, 2002 to December 8, 2003, Mr. Albi served as vice president of engineering. Prior to September 30, 2002,

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Mr. Albi was with Key Production Company, Inc. where he served as vice president of engineering (October 1999 to September 2002) and manager of engineering (June 1994 to October 1999).

STEPHEN P. BELL was elected senior vice president of business development and land on September 30, 2002. Prior to its merger with Cimarex, Mr. Bell had been 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 after having served in a similar role as vice president and 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 on 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 and since February 1999, Mr. Dinkins was with Sprint.

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.

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.

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PART II

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

Our $.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 2011. 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 Quarters. 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.

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

2010	**High**	**Low**	**Dividends Paid Per Share**
First Quarter	$ 63.09	$ 48.68	$ 0.06
Second Quarter	$ 81.50	$ 58.64	$ 0.08
Third Quarter	$ 77.11	$ 62.88	$ 0.08
Fourth Quarter	$ 90.86	$ 65.48	$ 0.08

The closing price of Cimarex stock as reported on the New York Stock Exchange on February 15, 2012, was $81.59. At December 31, 2011, Cimarex's 85,774,084 shares of outstanding common stock were held by approximately 2,433 stockholders of record.

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, 2006 to December 31, 2011.

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COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*

Among Cimarex Energy Co., the S&P 500 Index
and the Dow Jones US Exploration & Production Index

*$100 invested on 12/31/06 in stock or index, including reinvestment of dividends.
Fiscal year ending December 31.

	12/06	**12/07**	**12/08**	**12/09**	**12/10**	**12/11**
Cimarex Energy Co.	100.00	117.01	74.08	147.62	247.81	174.11
S&P 500	100.00	105.49	66.46	84.05	96.71	98.75
Dow Jones US Exploration & Production	100.00	143.67	86.02	120.92	141.16	135.25

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,				
	2011	2010	2009	2008	2007
	(In thousands, except per share amounts)				
Operating results:					
Revenues	$ 1,757,889	$ 1,613,683	$ 1,009,794	$ 1,970,347	$ 1,430,513
Net income (loss)	529,932	574,782	(311,943)	(915,245)	345,262
Earnings (loss) per share to common Stockholders:					
Basic					
Distributed	$ 0.40	$ 0.32	$ 0.24	$ 0.24	$ 0.18
Undistributed	5.77	6.42	(4.06)	(11.46)	3.97
	$ 6.17	$ 6.74	$ (3.82)	$ (11.22)	$ 4.15
Diluted					
Distributed	$ 0.40	$ 0.32	$ 0.24	$ 0.24	$ 0.18
Undistributed	5.75	6.38	(4.06)	(11.46)	3.87
	$ 6.15	$ 6.70	$ (3.82)	$ (11.22)	$ 4.05
Cash dividends declared per share	0.40	0.32	0.24	0.24	0.18
Balance sheet data:					
Total assets	$ 5,428,577	$ 4,358,247	$ 3,444,537	$ 4,164,933	$ 5,362,794
Total debt	$ 405,000	$ 350,000	$ 392,793	$ 587,630	$ 462,216
Stockholders' equity	$ 3,130,613	$ 2,609,832	$ 2,038,106	$ 2,351,647	$ 3,275,128
Other financial data:					
Commodity sales	$ 1,703,520	$ 1,558,562	$ 962,443	$ 1,880,891	$ 1,364,622
Oil and gas capital expenditures	$ 1,625,457	$ 1,038,706	$ 528,041	1,620,778	1,023,434
Proved Reserves:					
Gas (MMcf)	1,216,441	1,254,166	1,186,585	1,067,333	1,122,694
Oil (MBbls)	72,322	63,656	56,764	44,286	57,150
NGL (MBbls)	65,815	41,310	1,253	916	1,100
Total equivalent (MMcfe)	2,045,265	1,883,957	1,534,689	1,338,545	1,472,195

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 2011 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

We are an independent oil and gas exploration and production company. Our operations are entirely located in the United States, mainly in Oklahoma, New Mexico, Texas and Kansas.

Our principle business objective is to achieve profitable growth in proved reserves and production for the long-term benefit of our shareholders, primarily through exploration and development. Our strategy

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centers on maximizing cash flow from our producing properties and profitably reinvesting that cash flow in exploration and development drilling.

To supplement our growth and to provide for new drilling opportunities, we also consider property acquisitions and mergers that allow us to enhance our competitive position in existing core areas or to add new areas. 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. To further mitigate risk, we have chosen to seek geologic and geographic diversification by operating in multiple basins. We also strive to maintain a balance between oil-focused activities and gas-related projects.

Our operations are currently focused in two main areas: the Mid-Continent region and the Permian Basin. The Mid-Continent region consists of Oklahoma, northern Texas 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.

Our growth is generally funded with cash flow provided by our operating activities together with occasional sales of non-strategic assets. Conservative use of leverage has long been a part of our financial strategy.

Our revenue, profitability and future growth are highly dependent on the commodity prices we receive. Oil and gas prices affect the amount of cash flow available for capital expenditures, our ability to raise additional capital and the fair market value of our assets. Prices also affect the accounting for our oil and gas activities, 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 affect our reported results of operations and the amount of our reported assets, liabilities, equity and proved reserves. We use the full cost method of accounting for oil and gas activities. Any extended decline in oil and gas prices could have an adverse effect on our financial position and results of operations.

2011 Summary:

- Net income totaled $529.9 million, or $6.15 per diluted share. This compares to 2010 net income of $574.8 million, or $6.70 per diluted share.

- Cash flow provided by operating activities totaled $1.3 billion, up from $1.1 billion in 2010.

- In 2011, our production of 592 MMcfe/d was about flat with 2010.

- Proved reserves increased 9% to 2.05 Tcfe; adjusted for property sales, proved reserves increased 23%.

- We added 587 Bcfe of proved reserves from extensions and discoveries, replacing 272% of production.

- Oil, gas and NGL sales increased 9% to $1.7 billion compared to $1.6 billion a year earlier.

- Total assets increased by $1 billion, or 25%, to $5.4 billion compared to $4.4 billion in 2010.

- Total debt increased by $55 million to $405 million compared to $350 million at year-end 2010.

During 2011 we evaluated and expanded our acreage position in several key long-term future drilling projects. Our exploration and development capital expenditures were $1.58 billion and we had property acquisitions of $45.4 million. Total exploration and development expenditures for 2010 were $998.9 million and property acquisitions were $39.8 million.

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Drilling activities were focused primarily in our Mid-Continent and Permian Basin regions. During 2011 we drilled and completed 331 gross (174 net) wells. Of total wells drilled, 180 gross (64 net) were in our Mid-Continent Region and 140 gross (100 net) were in the Permian Basin.

We sold $229.4 million of non-strategic assets during 2011. Proceeds from the sales were reinvested in core area exploration and development activities. Non-strategic asset sales in 2010 were $34.1 million.

In July 2011, we entered into a new five-year senior unsecured revolving credit facility. The credit facility provides for a borrowing base of $2 billion with aggregate commitments of $800 million. The credit facility will mature on July 14, 2016. At December 31, 2011, our outstanding bank debt was $55 million. At the end of 2010 we did not have any bank borrowings outstanding.

Capital Expenditures

Our E&D capital expenditures for 2011 totaled $1.58 billion. We drilled and completed 331 gross (174 net) wells, primarily focused within our Mid-Continent and Permian Basin regions.

Approximately 47% of our capital expenditures were for Mid-Continent projects where we drilled and completed 180 gross (64 net) wells as producers. In the Permian Basin we drilled 140 gross (100 net) wells, completing 96% of the wells as producers. Approximately 46% of our total capital expenditures were for Permian Basin projects.

We also had operations in the Gulf Coast region of southeast Texas. During 2011 we invested approximately 6% of our total capital expenditures to drill 11 gross (9.6 net) wells, with 27% of the wells completed as producers.

In 2011 our E&D expenditures were largely funded by cash flow provided by operating activities and sales of non-strategic assets. Based on current market prices and service costs, our 2012 E&D capital expenditures are presently projected to be in the range of $1.4 - 1.6 billion. We expect nearly all of our 2012 capital to be directed towards oil or liquids-rich gas drilling in the Permian Basin and Cana-Woodford shale play. We expect our 2012 E&D capital expenditures to be funded from cash flow, property sales and borrowings.

Proved Reserves

Our year end 2011 proved reserves grew 9% to 2.05 Tcfe, up from 1.88 Tcfe at year-end 2010. The increase in 2011 proved reserves is net of production of 216.2 Bcfe and sales of 226.3 Bcfe. Adjusted for the impact of property sales, proved reserves increased 23% over 2010.

Reserve additions were comprised of 45% oil and NGLs and 55% gas. With our continued focus on liquids rich production, the amount of proved reserves comprised of liquids at year-end 2011 increased to 41% as compared to 33% at year-end 2010. Proved reserves are 82% developed at year-end 2011 compared to 77% at year-end 2010.

Reserves added from E&D totaled 587.0 Bcfe and 23.9 Bcfe were acquired via property purchases. Net negative revisions during 2011 were 7.2 Bcfe, which included positive 3.8 Bcfe driven by commodity prices. The negative revisions relate primarily to increases in operating expenses, which shortened the economic lives of the properties.

Overall, approximately 67% of our proved reserves are in our Mid-Continent region and 31% are in the Permian Basin. Our onshore Gulf Coast and other onshore operations collectively make up another 2% of total proved reserves. Less than 1% of our total proved reserves are in the Gulf of Mexico.

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

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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 18, Unaudited Supplemental Oil and Gas Disclosures for more reserve information.

Revenues

All of our revenues are derived from the sale of our oil, gas, and NGL production and do not include the effects of the settlements of our hedges. While our 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 2010, our 2011 average realized gas price decreased by 10% and our average realized oil price increased by 21%. The NGL price we received also increased by 21%. Since year-end 2011, gas prices have declined further and oil prices have remained stable. Like gas, NGL prices have also declined.

The following table presents our average realized commodity prices for the years ended 2011, 2010 and 2009. The realized prices do not include settlements of our commodity hedging contracts.

	Years Ended December 31,		
	2011	**2010**	**2009**
Gas Prices:			
Average Henry Hub price ($/Mcf)	$ 4.04	$ 4.39	$ 3.99
Average realized sales price ($/Mcf)	$ 4.42	$ 4.92	$ 4.12
Oil Prices:			
Average WTI Cushing price ($/Bbl)	$ 95.14	$ 79.54	$ 61.81
Average realized sales price ($/Bbl)	$ 93.00	$ 76.76	$ 56.63
NGL Prices:			
Average realized sales price ($/Bbl)	$ 42.31	$ 34.91	$ 37.11

On an energy equivalent basis, 56% of our 2011 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, 44% of our production was crude oil and NGL's. A $1.00 per barrel change in our average realized sales prices would have resulted in a $16 million change in our oil and NGL 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 2011, we owned interests in 12,701 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 separately pay for transportation. If costs are netted in the proceeds received, both the gross revenues and gross costs are shown in sales and expenses, respectively.

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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. 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.

General and administrative 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. While we expect these costs to increase with our growth, we also expect such increases to be proportionately smaller than our production growth.

Production taxes are assessed by state and local taxing authorities pertaining to production, revenues or the value of properties. These typically include production severance, ad valorem, and excise taxes.

Stock compensation expense consists of non-cash charges resulting from the issuance of restricted stock, restricted stock units and stock options. In accordance with our stock incentive plan, such grants are periodically made to non-employee directors, officers and other eligible employees.

The net gain or loss on derivative instruments is the net realized and unrealized gain or loss on derivative contracts, to which we did not apply hedge accounting treatment. That amount will fluctuate based on changes in the fair value of the underlying commodities.

Hedging

From time to time we attempt to mitigate a portion of our price risk through the use of hedging transactions. Management has been authorized to hedge up to 50% of our anticipated 2012 and 2013 equivalent production.

In 2009 we entered into derivative contracts covering approximately 40% of our anticipated 2010 oil and gas production volumes. These contracts were settled in 2010 for a net gain of $52.1 million.

During 2010 we entered into oil and gas contracts relative to our 2011 production which approximated 40 to 45% of our anticipated 2011 oil production and 5 to 6% of projected gas production. Those contracts were settled in 2011 for a net gain of $6.7 million.

For 2012 we have hedged approximately 50% of our anticipated oil production. We do not have any of our gas or NGL production hedged.

As of December 31, 2011 we had entered into the following contracts relative to our 2012 production:

Oil Contracts

				Weighted Average Price	
Period	**Type**	**Volume/Day**	**Index(1)**	**Floor**	**Ceiling**
Jan 12 - Dec 12	Collar	2,000 Bbls	WTI	$ 80.00	$ 114.70

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

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Subsequent to December 31, 2011 we entered into additional oil contracts as follows:

Period	Type	Volume/Day	Index(1)	Weighted Average Price Floor	Weighted Average Price Ceiling
Jan 12	Collar	2,000 Bbls	WTI	$ 80.00	$ 119.45
Feb 12	Collar	7,000 Bbls	WTI	$ 80.00	$ 119.56
Mar 12 - Dec 12	Collar	12,000 Bbls	WTI	$ 80.00	$ 120.13

(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 current hedging positions. While the use of such instruments limits the downside risk of adverse price changes, their use may also limit future revenues from favorable price changes.

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 4, Derivative Instruments/Hedging, to the Consolidated Financial Statements of this report for additional information regarding our derivative instruments.

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 Analysis Price	Volume	Variance
(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%			

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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 NGL's.

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	(18,209)	(22,162)
Gas gathering and processing margin	$ 35,431	$ 32,500
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 $35.4 million of pre-tax cash operating margin (revenues less direct expenses) versus $32.5 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
	2011	2010	2011/2010
Operating costs and expenses (in thousands):			
Depreciation, depletion and amortization (DD&A)	$ 390,461	$ 304,222	$ 86,239
Asset retirement obligation	11,451	7,322	4,129
Production	247,048	194,015	53,033
Transportation	61,829	49,968	11,861
Taxes other than income	126,468	121,781	4,687
General and administrative	45,256	48,620	(3,364)
Stock compensation, net	18,949	12,353	6,596
(Gain) loss on derivative instruments, net	(10,322)	(62,696)	52,374
Other operating, net	10,263	4,575	5,688
	$ 901,403	$ 680,160	$ 221,243

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. We expect the average DD&A rate to continue to increase during 2012.

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.

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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.

Our production costs consist of lease operating expense and workover expense as follows (in thousands):

	For the Years Ended December 31,		Variance Between
	2011	2010	2011/2010
Lease operating expense	$ 208,097	$ 164,968	$ 43,129
Workover expense	38,951	29,047	9,904
	$ 247,048	$ 194,015	$ 53,033

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 $61.8 million ($0.29 per Mcfe) for 2011 from $50.0 million ($0.23 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.

Our general and administrative expense was $45.3 million in 2011 compared to $48.6 million for 2010. The $3.4 million decrease is mostly due to lower bonus expense in 2011.

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,		Variance Between
	2011	2010	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, net	$ 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, net 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 10 to the Consolidated Financial Statements of this report for a detailed discussion regarding our stock-based compensation.

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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:

	For the Years Ended December 31,		Variance Between
	2011	2010	2011/2010
	(In thousands)		
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 4 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 16, Commitments and Contingencies, in this report for further information regarding litigation matters.

Other income and expense

Interest expense for 2011 was $35.6 million compared to $36.6 million for 2010. 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 at approximately $29 million for both 2011 and 2010.

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. Other, net increased from $6.0 million of income in 2010 to $9.8 million of income in 2011. The $3.8 million increase in 2011 was mainly due to sales of oil and gas well equipment and supplies.

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Income tax

For the year ended December 31, 2011, we recognized income tax expense of $311.5 million, of which $46.1 million is a current tax benefit. This compares with 2010 income tax expense of $338.9 million, which included $46.3 million of current tax expense. The combined Federal and state effective income tax rates were 37% for both 2011 and 2010. 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 8, Income Taxes, in this report for further information.

RESULTS OF OPERATIONS

2010 compared to 2009

For the year-ended December 31, 2010, net income totaled $574.8 million, or $6.70 per diluted share. This compares to a net loss of $311.9 million, or $3.82 per share for 2009. The increase in net income results from increased production and the improvement of realized oil and gas prices. In addition, in 2009 we recorded a $791.1 million non-cash full cost ceiling write-down, which was the main reason for the net loss in 2009. These changes are discussed further in the analysis that follows.

Commodity Sales	For the Years Ended December 31, 2010	2009	Percent Change Between 2010/2009	Price / Volume Analysis Price	Volume	Variance
(In thousands or as indicated)						
Gas sales	$ 653,793	$ 485,448	35%	$ 106,250	$ 62,095	$ 168,345
Oil sales	755,618	468,833	61%	198,160	88,625	286,785
NGL sales	149,151	8,162	1727%	(9,398)	150,387	140,989
Total commodity sales	$ 1,558,562	$ 962,443	62%	$ 295,012	$ 301,107	$ 596,119
Total gas volume MMcf	132,813	117,968	13%			
Gas volume MMcf per day	363.9	323.2				
Average gas price per Mcf	$ 4.92	$ 4.12	19%			
Total oil volume thousand barrels	9,844	8,278	19%			
Oil volume barrels per day	26,969	22,681				
Average oil price per barrel	$ 76.76	$ 56.63	36%			
Total NGL volume thousand barrels	4,272	220	1842%			
NGL volume barrels per day	11,705	603				
Average NGL price per barrel	$ 34.91	$ 37.11	-6%			

Commodity sales during 2010 totaled $1.6 billion, compared to $962.4 million in 2009. Approximately 51% of the $596.1 million increase between the two periods resulted from higher production volumes. The remainder of the increase was due to higher realized oil and gas prices, which had a positive impact of $304.4 million.

Our full year 2010 gas production averaged 363.9 MMcf per day, compared to 323.2 MMcf per day for 2009. This 13% increase resulted in $62.1 million of incremental revenue for 2010. During the fourth quarter of 2010 our daily gas production averaged 341.5 MMcf per day, up slightly from 330.0 MMcf per day for the fourth quarter of 2009. This 3% increase contributed $5.6 million of additional revenues for the fourth quarter of 2010.

Oil production for 2010 averaged 26,969 barrels per day. For 2009 our average daily oil production was 22,681 barrels per day. The year over year increase of 19% in 2010 daily production contributed an additional $88.6 million of revenue for the year. Our fourth quarter 2010 oil production averaged 27,137 barrels per day, or an increase of 22% compared to average daily production of 22,309 barrels for the

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fourth quarter of 2009. The higher production in the fourth quarter of 2010 increased oil sales by $32.4 million.

During 2010 we began separately reporting NGL volumes. The determination of whether to record and separately disclose NGL volumes is based on where title transfer occurs during processing of the well stream. New gas processing contracts and certain contractual amendments resulted in title of NGL volumes transferring to the Company.

Our average daily NGL production volumes were 11,705 barrels per day. This compares to average daily NGL volumes for all of 2009 of 603 barrels per day. The higher production volumes in 2010 contributed an additional $150.4 million of revenue. For the fourth quarter of 2010 our average daily NGL production was 16,702 barrels per day, up from 626 barrels per day during the fourth quarter of 2009. This increase provided an additional $71.8 million of revenue in the fourth quarter of 2010.

Overall, increases in our 2010 production volumes primarily reflect positive drilling results in our western Oklahoma Cana-Woodford shale play, our Permian Basin oil programs and our Yegua/Cook Mountain play in southeast Texas.

Our average realized gas price for 2010 increased by 19% to $4.92 per Mcf, compared to $4.12 per Mcf in 2009. This price increase contributed $106.3 million to gas sales in 2010.

During the fourth quarter of 2010 our average realized gas price fell to $4.18 per Mcf. For the same period of 2009, we realized an average price per Mcf of $5.30. The decrease in prices received in the fourth quarter of 2010 resulted in $35.2 million less in gas sales compared to the same period of 2009.

Realized oil prices during all of 2010 averaged $76.76 per barrel, an increase of 36% over the average price received for oil in 2009 of $56.63 per barrel. This increase resulted in an additional $198.2 million of oil sales in 2010. For the fourth quarter of 2010 our average realized oil price was $82.33 per barrel versus $72.93 per barrel received in the fourth quarter of 2009. The increase in fourth quarter 2010 oil sales due to the 13% increase in oil prices totaled $23.5 million.

During 2010 our NGL average realized price was $34.91 per barrel. In 2009 we realized $37.11 per barrel. The drop in realized price resulted in a decrease of $9.4 million for NGL sales in 2010. For the fourth quarter of 2010 our average realized price for NGL was $37.59 per barrel, or 23% less than the average realized price of $48.57 per barrel received for the same period of 2009. The decrease in fourth quarter 2010 NGL sales attributed to the decline in price was $16.9 million.

Increases and decreases in realized commodity prices were the result of supply and demand factors and overall market conditions. There continues to be significant upward volatility in oil prices stemming from concerns about sustained economic growth and geopolitical instability. Abundant domestic supplies of natural gas have continued to dampen prices in the first quarter of 2011.

	For the Years Ended December 31,	
	2010	**2009**
Gas Gathering, Processing and Marketing (in thousands):		
Gas gathering, processing and other revenues	$ 54,662	$ 46,763
Gas gathering and processing costs	(22,162)	(20,560)
Gas gathering and processing margin	$ 32,500	$ 26,203
Gas marketing revenues, net of related costs	$ 459	$ 588

We sometimes transport, process and market third-party gas that is associated with our gas. In 2010, third-party gas gathering, processing and other contributed $32.5 million of pre-tax cash operating margin (revenues less direct cash expenses) versus $26.2 million in 2009. Our gas marketing margin (revenues less purchases) decreased 22% to $459 thousand in 2010 from $588 thousand in 2009. Changes in net margins

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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, 2010	2009	Variance Between 2010/2009
Operating costs and expenses (in thousands):			
Impairment of oil and gas properties	$	$ 791,137	$ (791,137)
Depreciation, depletion and amortization (DD&A)	304,222	265,699	38,523
Asset retirement obligation	7,322	12,313	(4,991)
Production	194,015	178,215	15,800
Transportation	49,968	33,758	16,210
Taxes other than income	121,781	75,634	46,147
General and administrative	48,620	41,724	6,896
Stock compensation, net	12,353	9,254	3,099
(Gain) loss on derivative instruments, net	(62,696)	13,059	(75,755)
Other operating, net	4,575	24,263	(19,688)
	$ 680,160	$ 1,445,056	$ (764,896)

Total operating costs and expenses (not including gas gathering, marketing and processing costs, or income tax expense) decreased to $680.2 million in 2010 compared to $1.4 billion in 2009. The largest component of the change between periods is the non-cash impairment of oil and gas properties of $791.1 million recorded in the first quarter of 2009. The impairment resulted from a ceiling test write-down as a result of declines in natural gas prices during the first quarter of 2009. The full cost method of accounting is discussed in detail under "Critical Accounting Policies and Estimates" in this report.

Operating costs and expenses for 2010 compared to 2009 costs of $653.9 million (excluding the $791.1 million impairment) increased by $26.2 million, or 4%. Analyses of the year over year differences are discussed below.

DD&A increased $38.5 million from $265.7 million in 2009 to $304.2 million in 2010. On a unit of production basis, DD&A was $1.40 per Mcfe in 2010 compared to $1.57 per Mcfe for 2009. The lower DD&A rate was 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. The decrease in expense resulting from the 11% decrease in the DD&A rate per Mcfe was more than offset by increased expense related to higher production volumes for 2010.

Asset retirement obligation expense declined 41% from $12.3 million in 2009 to $7.3 million in 2010. The decrease was primarily due to certain plugging and abandonment costs in 2009 that exceeded our original asset retirement obligation estimates. This occurred because of hurricane damage to our offshore properties which caused additional expenses to be incurred during site restoration.

Our production costs consist of lease operating expense and workover expense. Our aggregate costs for 2010 of $194 million were 9% higher than 2009 aggregate costs of $178.2 million. Approximately 61% of the aggregate increase relates to higher operating expense associated primarily with new wells we've drilled in 2009 and 2010. Our workover expenditures in 2010 accounted for the remainder of the increase. Our average cost per Mcfe decreased $0.16, from $1.05 per Mcfe in 2009 to $0.89 per Mcfe in 2010. The decrease in rate resulted from our continued focus on efficiencies in production operations. However, we expect to see our production cost per Mcfe begin to trend upward, due to expected increases in certain service costs.

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Transportation costs rose to $50 million ($0.23 per Mcfe) for 2010 from $33.8 million ($0.20 per Mcfe) in 2009. Transportation costs will fluctuate based on increases or decreases in sales volumes and fluctuation in the price of the fuel cost component. Also, during 2010 we recorded $1.7 million of well connection reimbursement costs. These costs resulted from a failure to meet minimum volume delivery commitments entered into in prior years.

Taxes other than income increased $46.1 million from $75.6 million in 2009 to $121.8 million in 2010. The increased taxes resulted from increases in production volumes and from higher realized commodity prices in 2010.

Our general and administrative expense was $48.6 million in 2010 compared to $41.7 million for 2009. The $6.9 million increase is mostly due to higher costs associated with employee-benefits, including bonus and profit sharing expenses, in 2010.

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,		Variance Between
	2010	**2009**	**2010/2009**
Performance-based restricted stock awards	$ 9,604	$ 5,942	$ 3,662
Service-based restricted stock awards	8,228	6,964	1,264
Restricted unit awards	33	498	(465)
Restricted stock and units	17,865	13,404	4,461
Stock option awards	3,826	3,374	452
Total stock compensation	21,691	16,778	4,913
Less amounts capitalized to oil and gas properties	(9,338)	(7,524)	(1,814)
Stock compensation, net	$ 12,353	$ 9,254	$ 3,099

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 value 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 that we entered into in 2010 and 2009. (See Note 4 to the Consolidated Financial Statements in this report for a complete discussion of our derivative instruments).

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The following table reflects the net realized and unrealized (gains) and losses on our derivative instruments:

	For the Years Ended December 31,	
	2010	2009
	(In thousands)	
Realized (gain) loss on settlement of derivative instruments	$ (52,098)	$ (1,394)
Unrealized (gain) loss from changes to the fair value of the derivative instruments	(10,598)	14,453
(Gain) loss on derivative instruments, net	$ (62,696)	$ 13,059

Other operating, net consists of costs related to various legal matters, most of which pertain to litigation and contract settlements and title and royalty issues. Our Other operating net costs decreased from $24.3 million in 2009 to $4.6 million for 2010. The decrease was mainly a result of less litigation accruals and fewer contract settlements in 2010 and the favorable resolution of items in 2010 that had been accrued for in prior years. For further information on litigation matters please see Contingencies under "Critical Accounting Policies and Estimates" in this report.

Other income and expense

Our 2010 interest expense was $36.6 million compared to $39.8 million for 2009. The $3.2 million decrease resulted from lower average bank debt outstanding during 2010 compared to 2009. During 2010 we only had bank borrowings outstanding in the first quarter of the year. This resulted in average daily bank debt outstanding of $4.5 million for 2010. During 2009 our average daily bank debt outstanding was $269.6 million.

Capitalized interest for 2010 increased by $5.8 million to $29.2 million, compared to $23.4 million in 2009. The increase results from more costs associated with our unproved properties and construction project in 2010 and a higher average interest rate for 2010 versus 2009.

In July of 2010, holders of our floating rate convertible senior notes elected to convert their notes for cash and shares of our common stock. We recorded a gain of $3.8 million on the early extinguishment of the notes. (See Note 7 to the Consolidated Financial Statements of this report for a complete discussion of our convertible 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, interest income, and income or loss from equity investees. Other, net increased from $16.3 million of expense in 2009 to $6 million of income in 2010. Approximately 68% of the $22.3 million change from 2009 to 2010 is attributable to losses in 2009 related to oil and gas well equipment. In 2009 the value of drill pipe decreased due to the significant slowing of drilling activity across the industry. Another 24% of the change resulted from gains on fixed asset sales during 2010.

Income tax

For the year ended December 31, 2010, we recognized net income tax expense of $338.9 million (of which $46.3 million is current). This compares with a 2009 net income tax benefit of $176.5 million (including a current tax benefit of $11.8 million). The combined Federal and state effective income tax rates were 37.1% for 2010 and 36.1% for 2009. The effective tax rate of 37.1% for 2010 differs from the statutory rate of 35% due to the effects of state income taxes, the Domestic Production Activities allowance and other permanent differences.

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LIQUIDITY AND CAPITAL RESOURCES

Overview

Our liquidity is highly dependent on the commodity prices we receive. Oil and gas prices are market driven and historically have been very volatile. We cannot predict future commodity prices. The prices we receive for our production heavily influence our revenue, cash flow, profitability, access to capital and future rate of growth.

The prices we receive for natural gas have significantly declined since year-end 2011, primarily as a result of an oversupply of natural gas and an exceptionally mild winter. The prices we receive for oil and NGLs may fluctuate during 2012, depending on global supply and demand, seasonality and other economic factors.

We intend to deal with volatility in the current commodity price environment by maintaining flexibility in our planned capital investment program for 2012. Based on current market prices and service costs, our 2012 E&D capital expenditures are presently projected to be in the range of $1.4 - 1.6 billion. We expect nearly all of our 2012 capital to be directed towards oil or liquids-rich gas drilling in the Permian Basin and Cana-Woodford shale play.

Historically our exploration and development expenditures have generally been funded by cash flow provided by operating activities ("operating cash flow"). During 2011, our E&D expenditures of $1.6 billion were largely funded by operating cash flow and sales of non-strategic assets. We expect our 2012 E&D capital expenditures to be funded by operating cash flow, property sales and long-term debt. We have hedged a portion of our 2012 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 are unpredictable. To stay prepared for potential acquisitions and possible declines in commodity prices, we have a revolving credit facility which provides for bank commitments of $800 million. Our credit facility is described in more detail under "***Long-term Debt***" below.

At December 31, 2011, our total debt outstanding was $405 million, which is comprised of $55 million of bank debt and $350 million of our 7.125% Notes due 2017. Our debt to total capitalization ratio at year-end was 11%. The reconciliation of debt to total capitalization, which is a non-GAAP measure, is: long-term debt of $405 million divided by long-term debt of $405 million plus stockholders' equity of $3.13 billion. Management believes that this non-GAAP measure is useful information and it is a common statistic referred to by the investment community.

We believe that our operating cash flow and other capital resources will be adequate to continue to meet our needs for our planned capital expenditures, working capital, debt servicing, and dividend payments for 2012 and beyond.

Sources and Uses of Cash

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

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The following table presents the sources and uses of our cash and cash equivalents from 2009 to 2011. The table presents capital expenditures on a cash basis. These amounts differ from the amounts of capital expenditures (including accruals) that are referred to elsewhere in this report.

	For the Years Ended December 31, 2011	2010	2009
		(in thousands)	
Sources of cash and cash equivalents:			
Operating cash flow	$ 1,292,275	$ 1,130,432	$ 675,177
Sales of oil and gas and other assets	229,355	34,075	119,735
Net increase in bank debt	55,000		
Sales of short-term investments			3,328
Issuance of common stock and other	10,411	28,758	3,421
Total sources of cash and cash equivalents	1,587,041	1,193,265	801,661
Uses of cash and cash equivalents:			
Oil and gas expenditures	(1,562,159)	(959,751)	(535,308)
Other expenditures	(96,642)	(51,882)	(31,849)
Net decrease in bank debt		(25,000)	(195,000)
Decrease in other long-term debt		(19,450)	
Financing costs incurred	(7,379)	(101)	(18,001)
Dividends paid	(32,581)	(25,499)	(20,172)
Total uses of cash and cash equivalents	(1,698,761)	(1,081,683)	(800,330)
Net increase (decrease) in cash and cash equivalents	$ (111,720)	$ 111,582	$ 1,331
Cash and cash equivalents at end of year	$ 2,406	$ 114,126	$ 2,544

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

Cash flow provided by operating activities for 2011 was $1.3 billion compared to $1.1 billion for 2010 and $675.2 million for 2009. The increase in 2011 was due to higher realized prices for oil and NGLs. The increase from 2009 to 2010 resulted primarily from higher realized oil and gas prices together with higher production.

Cash flow used in investing activities for 2011 was $1.4 billion compared to $977.6 million for 2010 and $444.1 million for 2009. In 2011 we had oil and gas and other capital expenditures of $1.7 billion, which were partially offset by proceeds from asset sales of $229.4 million. For 2010, expenditures for oil and gas and other capital expenditures were $1.0 billion with proceeds from asset sales of $34.1 million. In 2009, oil and gas and other capital expenditures were $567.1 million which were partially offset by asset sales of $123.1 million.

During 2011 we had net cash flow of $25.5 million provided by financing activities. Net cash flow used in financing activities in 2010 and 2009 was $41.3 million and $229.8 million, respectively. In 2011 our net cash inflow was primarily due to net bank borrowing of $55 million plus $10.4 million from issuance of our common stock, less $7.3 million of financing costs and $32.6 million of dividend payments. In 2010 we had cash inflow of $28.8 million from issuance of our common stock, less payments of bank and other long-term debt of $44.5 million and dividend payments of $28.8 million. In 2009 we had net bank debt payments of $195 million, $18 million of financing costs and dividend payments of $20.2 million. Proceeds from issuance of common stock were $3.4 million.

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Reconciliation of Cash Flow from Operations

	For the Year Ended December 31,		
	2011	2010	2009
	(in thousands)		
Net cash provided by operating activities	$ 1,292,275	$ 1,130,432	$ 675,177
Change in operating assets and liabilities	22,686	57,699	(16,696)
Cash flow from operations	$ 1,314,961	$ 1,188,131	$ 658,481

Management believes that the non-GAAP measure of cash flow from operations is useful information for investors because it is used internally and is accepted by the investment community as a means of measuring the company's ability to fund its capital program. 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 our oil and gas acquisition, exploration and development activities and property sales (in thousands):

	For Years Ended December 31,		
	2011	2010	2009
Acquisitions:			
Proved	$ 23,071	$ 15,220	$ 13,530
Unproved	22,327	24,552	(9,915)*
	45,398	39,772	3,615
Exploration and development:			
Land & seismic	164,285	128,283	48,466
Exploration	64,157	103,671	45,603
Development	1,351,617	766,980	430,357
	1,580,059	998,934	524,426
Property sales	(117,344)	(28,235)	(109,408)
	$ 1,508,113	$ 1,010,471	$ 418,633

* The negative balance reflects purchase price adjustments related to an acreage acquisition in the fourth quarter of 2008.

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 2011 our exploration and development expenditures were $1.6 billion, compared to $1.0 billion in 2010 and $0.5 billion in 2009.

During 2011 we drilled and completed 331 gross (174 net) wells. In 2010 we drilled and completed 219 gross (129 net) wells, versus 110 gross (67 net) wells drilled and completed in 2009. At year-end 2011 we had 25 operated rigs running, compared to 23 at the end of 2010 and 14 at the end of 2009.

Based on current market prices and service costs, our 2012 E&D capital expenditures are presently projected to be in the range of $1.4 - 1.6 billion. We expect nearly all of our 2012 capital to be directed towards oil or liquids-rich gas drilling in the Permian Basin and Cana-Woodford shale play. We expect our

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2012 E&D capital expenditures to be funded from cash flow, property sales and long-term debt. The timing of capital expenditures and the receipt of cash flows do not necessarily match. For example, our planned capital expenditures are front-end loaded and we may outspend cash flows for a period of time. Therefore, we may 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.

During 2011, we had property acquisitions of approximately $45.4 million of which $42.2 million was in our western Oklahoma Cana-Woodford shale play and $3 million was in the Permian Basin. In 2010 we had property acquisitions of $39.8 million, primarily for additional interests in our Cana-Woodford shale play. Of this total amount, $15.2 million was for proved properties. The remainder was for undeveloped acreage. In 2010 we also had land and seismic purchases of $128.3 million, of which 62% was in the Permian Basin. We made no significant property acquisitions in 2009.

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 related assets ($111.4 million) and 210 Bcf of proved undeveloped gas reserves ($84.1 million). 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.

At June 30, 2011 the gas processing plant and related assets and liabilities were classified as assets held for sale. We determined that the carrying amounts of the assets and liabilities were equal to their fair value, therefore no gain or loss was recognized on the sale. Because the gas plant was still under construction we had not recognized any income or expense related to plant operations in our statements of operations. The sales contract also provides for a maximum $15 million contingent payment to be made to Cimarex if certain operational and performance goals related to the start-up of the gas processing plant are met. The contingent payment is expected to be received in the second quarter of 2012.

Also during 2011, we sold various non-core interests in oil and gas properties for approximately $33.3 million, including our 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 our non-core Mississippi assets. During 2009 we sold various interests in non-core oil and gas properties for $109.4 million. Approximately 72% of the 2009 sales were our Westbrook field interests in our Permian Basin region.

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 and not an extraordinary cost of compliance. 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 2011 exploration and development drilling program is discussed in more detail in *Exploration and Development Activity Overview* under Item 1 of this report.

Financial Condition

Future cash flows and the availability of financing will be subject to a number of variables, such as our success in locating and producing new reserves, the level of production from existing wells and realized commodity prices. To meet our capital and liquidity requirements, we rely on certain resources, including

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cash flows from operating activities, bank borrowings and access to capital markets. We anticipate periodically accessing our credit facility to finance our working capital needs and growth.

During 2011 our total assets increased by $1.0 billion to $5.4 billion, up from $4.4 billion at December 31, 2010. The increase was primarily due to a $1.2 billion increase in our net oil and gas properties which was partially offset by a decrease of $112 million in our cash and cash equivalents.

Our total liabilities at the end of 2011 had increased by $550 million to $2.3 billion, up from $1.7 billion at year-end 2010. Year over year current liabilities increased by $104.0 million, primarily as a result of increases in operations related accounts payable. Long-term deferred income taxes increased during 2011 by $355.9 million and long-term debt outstanding increased by $55.0 million. At December 31, 2011, stockholders' equity totaled $3.1 billion, up from $2.6 billion at December 31, 2010. The $500 million increase is primarily the result of our 2011 net income.

Dividends

In 2009 a quarterly cash dividend of $0.06 per share was paid. The dividend was increased to $0.08 per share in February 2010 and to $0.10 per share in February 2011. Future dividend payments will depend on our level of earnings, financial requirements and other factors considered relevant by the Board of Directors.

Common Stock Repurchase Program

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 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.

Working Capital Analysis

Our working capital balance fluctuates primarily as a result of our exploration and development activities, our realized commodity prices and our production operating activities. Working capital is also impacted by our current tax provisions, accrued G&A and changes in the fair value of our outstanding derivative instruments.

Our working capital balance decreased $207.2 million from $48.8 million at year-end 2010 to a deficit of $158.4 million at December 31, 2011.

Working capital decreased primarily because of the following:

- Cash and cash equivalents decreased by $111.7 million as cash was used primarily to fund our E&D activity.

- Our operations related accounts payable and accrued liabilities increased by $62.2 million.

- Accrued liabilities related to our E&D expenditures increased by $51.1 million.

- Prepaid expenses decreased by $26.5 million.

These working capital decreases were partially offset by:

- Our operations related accounts receivable increased by $25.8 million.

- Income tax receivable increased by $22.6 million.

Our receivables are a major component of our working capital and are made up of a diverse group of companies including major energy companies, pipeline companies, local distribution companies and end-users in various industries. The collection of receivables during the period presented has been timely. Historically, losses associated with uncollectible receivables have not been significant.

Long-Term Debt

Debt at December 31, 2011 and 2010 consisted of the following (in thousands):

	2011	2010
Bank debt	$ 55,000	$
7.125% Notes due 2017	350,000	350,000
Total long-term debt	$ 405,000	$ 350,000

Bank Debt

In July 2011, we entered into a new five-year senior unsecured revolving credit facility ("Credit Facility"). The Credit Facility provides for a borrowing base of $2 billion with aggregate commitments of $800 million from 14 lenders. The facility matures July 14, 2016.

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 1, 2012.

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 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, 2011, we were in compliance with all of the financial and nonfinancial covenants.

At December 31, 2011, there were $55 million of borrowings outstanding under the credit facility at a prime interest rate of 4%. We also had letters of credit outstanding of $2.5 million leaving an unused borrowing availability of $742.5 million.

During 2011 we had an average daily bank debt outstanding of $17.8 million, compared to $4.5 million for the same period of 2010. Our largest amount of bank borrowings outstanding during 2011 was $149 million occurring in mid July. During 2010 our largest amount of outstanding bank borrowings was $69.0 million in mid January.

7.125% Notes due 2017

In May, 2007, we issued $350 million of 7.125% senior unsecured notes that mature May 1, 2017 at par. Interest on the notes is payable May 1 and November 1 of each year. The notes are governed by an indenture containing covenants that could limit our ability to incur additional indebtedness; pay dividends or repurchase our common stock; make investments and other restricted payments; incur liens; enter into sale/leaseback transactions; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets.

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The notes are redeemable at our option, in whole or in part, at any time on and after May 1, 2012 at the following redemption prices (expressed as percentages of the principal amount) plus accrued interest, if any, thereon to the date of redemption.

	Percentage
2012	103.6%
2013	102.4%
2014	101.2%
2015 and thereafter	100.0%

If a specified change of control occurs, subject to certain conditions, we must make an offer to purchase the notes at a purchase price of 101% of the principal amount of the notes, plus accrued and unpaid interest to the date of the purchase.

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, 2011, the material off-balance sheet arrangements that we have entered into included operating lease agreements, all of which are customary in the oil and gas industry.

Contractual Obligations and Material Commitments

At December 31, 2011, 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)		
Debt(1)	$ 405,000	$	$ 55,000	$	$ 350,000
Fixed-Rate interest payments(1)	137,156	24,938	49,875	49,875	12,468
Operating leases(2)	75,606	5,109	15,595	11,807	43,095
Drilling commitments(3)	249,099	246,999	2,100		
Gas facilities and pipelines(4)	22,228	22,228			
Asset retirement obligation	183,361	43,681	(5)	(5)	(5)
Other liabilities(6)	50,509	12,887	24,658	17	12,947
Firm transportation	2,691	1,893	655	143	

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

(2) In 2011 we entered into a 12-year lease agreement for new office space in Tulsa, Oklahoma, which increased our aggregate minimum lease commitments beginning December 2012 by approximately $62 million over the term of this lease.

(3) We have drilling commitments of approximately $203 million consisting of obligations to finish drilling and completing wells in progress at December 31, 2011. We also have various commitments for drilling rigs as well as certain service contracts. The total minimum expenditure commitments under these agreements are $18.8 million to secure the use of drilling rigs and $27.3 million to secure certain dedicated services associated with completion activities.

(4) We have projects in Oklahoma, New Mexico, and Texas where we are constructing gathering facilities and pipelines. At December 31, 2011, we had commitments of $22.2 million relating to this construction.

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(5)

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

(6)

Other liabilities include the fair value of our liabilities associated with our benefit obligations, derivative contracts and other miscellaneous commitments.

At December 31, 2011, we had firm sales contracts to deliver approximately 10.7 Bcf of natural gas over the next eight months. If this gas is not delivered, our financial commitment would be approximately $35.5 million. This commitment will fluctuate due to price volatility and actual volumes delivered. However, we believe no financial commitment will be due based on our current proved reserves and production levels.

In connection with gas gathering and processing agreements, we have commitments to deliver a minimum of 14.4 Bcf of gas over the next four years. The production from certain wells is counted toward those commitments; these wells also have individual commitments for gas deliveries. If no gas is delivered, the maximum amount that would be payable under these commitments would be approximately $9.9 million, some of which would be reimbursed by working interest owners who are selling with us under our marketing agreements. We do not expect to make significant payments relative to these commitments.

We have various other delivery commitments in the normal course of business, which are individually and in the aggregate not material.

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

Based on current commodity prices and anticipated levels of production, we believe that the estimated net cash generated from operations, amounts available under our existing bank credit facility and occasional sales of non-strategic assets will be adequate to meet future liquidity needs, including satisfying our financial obligations and funding our operations and planned exploration, development and other capital expenditures.

2012 Outlook

Our 2012 exploration and development capital investment is presently expected to be in the range of $1.4-1.6 billion. We expect nearly all of our 2012 capital to be directed towards oil or liquids-rich gas drilling in the Permian and Cana-Woodford shale play. We have a large inventory of drilling opportunities, limited lease expirations and few service commitments. Actual amounts invested will depend on our calculated rate of return which is significantly influenced by commodity prices.

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 cost and drilling success. Operationally we have the flexibility to adjust our capital expenditures based upon market conditions.

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 2012 is projected to be in the range of 615 to 650 MMcfe per day, or a 4 - 10% growth over 2011. Revenues from production will be dependent not only on the level of oil and gas actually produced, but also the prices that will be realized. During 2011, our realized prices averaged $4.42 per Mcf of gas, $93.00 per barrel of oil, and $42.31 per barrel of NGL. Commodity prices can be very volatile and the possibility of realized 2012 prices varying from prices in 2011 is high.

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Certain expenses for 2012 on a per Mcfe basis are currently estimated as follows:

	2012
Production expense	$1.05 - $1.25
Transportation expense	0.28 - 0.33
DD&A and asset retirement obligation	2.00 - 2.15
General and administrative	0.20 - 0.25
Production taxes (% of oil and gas revenue)	7.0% - 8.0%

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Our discussion and analysis of our financial condition and results of operation are based upon 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 3 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 our estimates 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. 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 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.

At year-end, 18% of our total proved reserves are categorized as proved undeveloped. Of these proved undeveloped reserves, 98% is related to our western Oklahoma, Cana-Woodford shale play. Our reserve engineers review and revise our reserve estimates regularly, as new information becomes available.

We use the units-of-production method to amortize the cost of our oil and gas properties. Changes in our estimate of reserve quantities and commodity prices will cause corresponding changes in depletion expense in periods subsequent to these changes, 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 other revisions resulting from better information about production history, well performance and production costs.

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Net negative revisions during 2011 of 7.2 Bcfe, which included a positive 3.8 Bcfe driven by commodity prices, relate primarily to increases in operating expenses which shortened the economic lives of the properties.

	Years Ended December 31,					
	2011		2010		2009	
	Bcfe Change	Percent of total Reserves	Bcfe Change	Percent of total Reserves	Bcfe Change	Percent of total Reserves
Revisions resulting from price changes	3.8	0.20%	44.8	2.92%	(30.8)	(2.30)%
Other changes in estimates	(11.0)	(0.58)%	103.6	6.75%	104.7	7.82%
Total	(7.2)	(0.38)%	148.4	9.67%	73.9	5.52%

See Note 18, 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 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. Holding all factors constant other than commodity prices, a 10% decline in prices as of December 31, 2011 would not have resulted in a ceiling test impairment. However, oil and gas prices are market driven and historically have been very volatile. Since year-end 2011, oil prices have been relatively stable while gas and NGL prices have declined. Further declines in prices could cause impairment of our oil and gas properties. In the first quarter of 2009, we recorded a non-cash impairment of oil and gas properties of $791.1 million ($501.8 million after tax) as a result of declines in gas prices.

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. The capitalized costs of unproved properties, including those in wells in progress, are excluded from the costs being amortized. We do not have major development projects that are excluded from costs being amortized. On a quarterly basis, we evaluate excluded costs for inclusion in the costs to be amortized resulting from the determination of proved reserves or impairments. To the extent that the evaluation indicates these properties are impaired, the amount of the impairment is added to the capitalized costs to be amortized. Expenditures for maintenance and repairs are charged to production expense in the period incurred.

Goodwill

Accounting for the acquisition of a business requires the allocation of the purchase price to the tangible and intangible net assets acquired with any excess recorded as goodwill. Goodwill is assessed for impairment at least annually. The impairment test requires allocating goodwill and all other assets and liabilities to assigned reporting units. Cimarex is one reporting unit. The fair value is estimated and compared to the net book value. If the estimated fair value is less than the net book value, including goodwill, then the goodwill is written down to the implied fair value of the goodwill through a charge to expense.

The annual impairment test, which we conduct during the fourth quarter, requires us to estimate the fair value of the Company. The most significant judgments involved in estimating our fair value relates to the valuation of our oil and gas assets. We develop estimated fair value of our oil and gas assets by performing various discounted cash flow analyses. Due to volatility in the stock markets, management does not consider the market value of our shares to be an accurate reflection of the fair value of our net assets for goodwill impairment purposes.

Based upon our assessment at December 31, 2011, no impairment of goodwill is required.

Unfavorable changes in reserves or in our price forecast would increase the likelihood of a goodwill impairment charge. A goodwill impairment charge would have no effect on liquidity or capital resources. However, it would adversely affect our results of operations in that period.

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.

In January 2009, the Tulsa County District Court issued a judgment totaling $119.6 million in the H.B. Krug, et al versus H&P case. This lawsuit was originally filed in 1998 and addressed H&P's conduct pertaining to a 1989 take-or-pay settlement, along with potential drainage issues and other related matters. 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. In 2008 we recorded litigation expense of $119.6 million for this lawsuit. We have accrued additional expense for associated post-judgment interest and costs that have accrued during the appeal of the District Court's judgments.

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, finding 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 October 27, 2011, Cimarex filed a petition with the Oklahoma Supreme Court requesting review of the affirmed portion of the judgment. This case is subject to further appeal 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 related matters. We assess the probability of estimable amounts related to litigation matters in accordance with guidance established by the FASB and adjust our accruals accordingly. Though some of the related claims may be significant, the resolution of them we believe, individually or in the aggregate, would not have a material adverse effect on our financial condition or results of operations. See Note 16 of this Report for additional information regarding our contingencies.

Asset Retirement Obligation

Our asset retirement obligation primarily represents the estimated present value of the amount we will incur to plug, abandon and remediate our producing properties at the end of their productive lives, in accordance with applicable state laws. We determine our asset retirement obligation 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 the asset's inception, with an offsetting increase to producing properties. Periodic accretion of discount of the estimated liability is recorded as an expense in the income statement.

Our liability is determined using significant assumptions, including current estimates of plugging and abandonment costs, annual inflation of these costs, the productive lives of wells and our risk-adjusted interest rate. Changes in any of these assumptions can result in significant revisions to the estimated asset retirement obligation. For example, as we analyze actual plugging and abandonment information, we may revise our estimates of current costs, the assumed annual inflation of these costs and/or the assumed productive lives of our wells depreciation, depletion and amortization expense and accretion of discount. Because of the subjectivity of assumptions and the relatively long lives of most of our wells, the costs to ultimately retire our wells may vary significantly from prior estimates. See Note 6 of this Report for additional information regarding our asset retirement obligations.

Recently Issued Accounting Standards

The FASB has issued final guidance on goodwill impairment that permits an entity to make a qualitative assessment of whether it is more likely than not that a reporting unit's fair value is less than its carrying amount before applying the two-step goodwill impairment test. If an entity concludes that it is not more likely than not that the fair value of a reporting unit is less than its carrying amount, it would not be required to perform the two-step impairment test for that reporting unit. The guidance is effective for fiscal years beginning after December 15, 2011.

ITEM 7A. QUALITATIVE AND QUANTITATIVE DISCLOSURES ABOUT MARKET RISK

The term "market risk" refers to the risk of loss arising from adverse changes in oil and gas prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses.

Price Fluctuations

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

We periodically hedge a portion of our price risk associated with our future oil and gas production.

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The following table details the contracts we have in place as of December 31, 2011:

Oil Contracts

Period	Type	Volume/Day	Index(1)	Weighted Average Price Floor	Weighted Average Price Ceiling	Fair Value (000's)
Jan 12 - Dec 12	Collar	2,000 Bbls	WTI	$ 80.00	$ 114.70	$ (245)

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

While these contracts limit the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. For the contracts listed above, a hypothetical $1.00 change in the price below or above the contracted price applied to the notional amounts would cause a change in our gain (loss) on mark-to-market derivatives in 2011 of $732,000.

Subsequent to December 31, 2011 we entered into additional oil collars. See Note 4 to the Consolidated Financial Statements of this report for additional information regarding our derivative instruments.

In spite of the recent turmoil in the financial markets, counterparty credit risk did not have a significant effect on our cash flow calculations and commodity derivative valuations. This is primarily the result of two factors. First, we have mitigated our exposure to any single counterparty by contracting with numerous counterparties. Second, our derivative contracts are held with "investment grade" counterparties that are a part of our credit facility.

Interest Rate Risk

At December 31, 2011, our debt was comprised of the following (in thousands):

	Fixed Rate Debt	Variable Rate Debt
Bank debt	$	$ 55,000
7.125% Notes due 2017	350,000	
Total long-term debt	$ 350,000	$ 55,000

As of December 31, 2011, the amounts outstanding under our five-year senior unsecured revolving credit facility bears interest at either (a) LIBOR plus 1.75-2.5%, based on our leverage ratio, or (b) the higher of (i) a prime rate, (ii) the federal funds effective rate plus 0.50%, or (iii) adjusted one-month LIBOR plus 1.0% plus, in each case, an additional 0.75-1.5%, based on our leverage ratio. Our senior unsecured notes bear interest at a fixed rate of 7.125% and will mature on May 1, 2017.

We consider our interest rate exposure to be minimal because approximately 86% of our long-term debt obligations were at fixed rates. An increase of 100 basis points in the interest rate of our variable rate debt would increase our annual interest expense by $550,000. This sensitivity analysis for interest rate risk excludes accounts receivable, accounts payable and accrued liabilities because of the short-term maturity of such instruments. See Note 5 and Note 7 to the Consolidated Financial Statements in this report for additional information regarding debt.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

CIMAREX ENERGY CO.

INDEX TO FINANCIAL STATEMENTS AND SUPPLEMENTAL SCHEDULES

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

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Cimarex Energy Co.:

We have audited the accompanying consolidated balance sheets of Cimarex Energy Co. and subsidiaries (the Company) as of December 31, 2011 and 2010, and the related consolidated statements of operations, stockholders' equity and comprehensive income (loss), and cash flows for each of the years in the three-year period ended December 31, 2011. 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, 2011 and 2010, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2011, 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, 2011, 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 22, 2012 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

KPMG LLP

Denver, Colorado

February 22, 2012

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CIMAREX ENERGY CO.

CONSOLIDATED BALANCE SHEETS

(In thousands, except share and per share information)

	December 31, 2011	December 31, 2010
Assets		
Current assets:		
Cash and cash equivalents	$ 2,406	$ 114,126
Accounts receivable:		
Trade, net of allowance	58,519	60,298
Oil and gas sales, net of allowance	245,681	218,543
Gas gathering, processing, and marketing, net of allowance	7,565	7,127
Other	47,644	25,000
Oil and gas well equipment and supplies	85,141	81,871
Deferred income taxes	2,723	4,293
Derivative instruments		5,731
Prepaid Expenses	7,393	33,886
Other current assets	823	10,193
Total current assets	457,895	561,068
Oil and gas properties at cost, using the full cost method of accounting:		
Proved properties	9,933,517	8,421,768
Unproved properties and properties under development, not being amortized	607,219	547,609
	10,540,736	8,969,377
Less accumulated depreciation, depletion and amortization	(6,414,528)	(6,047,019)
Net oil and gas properties	4,126,208	2,922,358
Fixed assets, less accumulated depreciation of $118,278 and $97,066	118,215	156,579
Goodwill	691,432	691,432
Other assets, net	34,827	26,810
	$ 5,428,577	$ 4,358,247
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable:		
Trade	$ 64,856	$ 34,120
Gas gathering, processing, and marketing	14,932	13,122
Accrued liabilities:		
Exploration and development	173,549	122,422
Taxes other than income	33,946	35,489
Other	178,156	163,078
Derivative instruments	245	9,587
Revenue payable	150,655	134,495
Total current liabilities	616,339	512,313
Long-term debt	405,000	350,000
Deferred income taxes	974,932	619,040
Asset retirement obligation	139,680	109,493

Other liabilities	162,013	157,569
Total liabilities	2,297,964	1,748,415
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, 85,774,084 and 85,234,721 shares issued, respectively	858	852
Paid-in capital	1,908,506	1,883,065
Retained earnings	1,221,263	725,651
Accumulated other comprehensive (loss) income	(14)	264
	3,130,613	2,609,832
	$ 5,428,577	$ 4,358,247

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

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CIMAREX ENERGY CO.

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per share data)

	For the Years Ended December 31,		
	2011	**2010**	**2009**
Revenues:			
Gas sales	$ $530,334	$ $653,793	$ 485,448
Oil sales	909,344	755,618	468,833
NGL Sales	263,842	149,151	8,162
Gas gathering, processing and other	53,640	54,662	46,763
Gas marketing, net of related costs of $119,725, $99,713 and $68,719 respectively	729	459	588
	$ 1,757,889	1,613,683	1,009,794
Costs and expenses:			
Impairment of oil and gas properties			791,137
Depreciation, depletion and amortization	390,461	304,222	265,699
Asset retirement obligation	11,451	7,322	12,313
Production	247,048	194,015	178,215
Transportation	61,829	49,968	33,758
Gas gathering and processing	18,209	22,162	20,560
Taxes other than income	126,468	121,781	75,634
General and administrative	45,256	48,620	41,724
Stock compensation, net	18,949	12,353	9,254
(Gain) loss on derivative instruments, net	(10,322)	(62,696)	13,059
Other operating, net	10,263	4,575	24,263
	919,612	702,322	1,465,616
Operating income (loss)	838,277	911,361	(455,822)
Other (income) and expense:			
Interest expense	35,611	36,613	39,777
Capitalized interest	(29,057)	(29,215)	(23,408)
Gain on early extinquishment of debt		(3,776)	
Other, net	(9,758)	(5,992)	16,290
Income (loss) before income tax	841,481	913,731	(488,481)
Income tax expense (benefit)	311,549	338,949	(176,538)
Net income (loss)	$ 529,932	$ 574,782	$ (311,943)
Earnings (loss) per share to common shareholders:			
Basic			
Distributed	$ 0.40	$ 0.32	$ 0.24
Undistributed	5.77	6.42	(4.06)
	$ 6.17	$ 6.74	$ (3.82)
Diluted			
Distributed	$ 0.40	$ 0.32	$ 0.24

Undistributed		5.75		6.38		(4.06)
	$	6.15	$	6.70	$	(3.82)

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,		
	2011	**2010**	**2009**
Cash flows from operating activities:			
Net income (loss)	$ 529,932	$ 574,782	$ (311,943)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Impairments and other valuation losses			806,039
Depreciation, depletion and amortization	390,461	304,222	265,699
Asset retirement obligation	11,451	7,322	12,313
Deferred income taxes	357,622	292,612	(164,760)
Stock compensation, net	18,949	12,353	9,254
Derivative instruments, net	(3,611)	(10,598)	14,453
Changes in non-current assets and liabilities	4,418	12,772	8,948
Other, net	5,739	(5,334)	18,478
Changes in operating assets and liabilities:			
(Increase) decrease in receivables, net	(48,632)	(83,386)	29,881
Decrease in oil and gas well equipment and supplies and other current assets	32,593	34,250	49,894
Decrease in accounts payable and other current liabilities	(6,647)	(8,563)	(63,079)
Net cash provided by operating activities	1,292,275	1,130,432	675,177
Cash flows from investing activities:			
Oil and gas expenditures	(1,562,159)	(959,751)	(535,308)
Sales of oil and gas assets	117,344	28,235	109,408
Sales of other assets	112,011	5,840	10,327
Sales of short-term investments			3,328
Other capital expenditures	(96,642)	(51,882)	(31,849)
Net cash used by investing activities	(1,429,446)	(977,558)	(444,094)
Cash flows from financing activities:			
Net increase (decrease) in bank debt	55,000	(25,000)	(195,000)
Decrease in other long-term debt		(19,450)	
Financing costs incurred	(7,379)	(101)	(18,001)
Dividends paid	(32,581)	(25,499)	(20,172)
Issuance of common stock and other	10,411	28,758	3,421
Net cash provided by (used in) financing activities	25,451	(41,292)	(229,752)
Net change in cash and cash equivalents	(111,720)	111,582	1,331
Cash and cash equivalents at beginning of period	114,126	2,544	1,213
Cash and cash equivalents at end of period	$ 2,406	$ 114,126	$ 2,544

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

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CIMAREX ENERGY CO.

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME (LOSS)

(In thousands)

	Common Stock				Accumulated Other Comprehensive		Total
	Shares	Amount	Paid-in Capital	Retained Earnings	Income (loss)	Treasury Stock	Stockholders' Equity
Balance, December 31, 2008	84,144	$ 841	$ 1,874,834	$ 510,271	$ (955)	$ (33,344)	$ 2,351,647
Dividends				(20,293)			(20,293)
Issuance of restricted stock awards	381	4	(4)				
Retirement of treasury stock	(885)	(9)	(33,335)			33,344	
Common stock reacquired and retired	(78)		(2,440)				(2,440)
Restricted stock forfeited and retired	(159)	(2)	2				
Exercise of stock options	134	1	2,212				2,213
Vesting of restricted stock units	5						
Stock-based compensation			16,778				16,778
Stock-based compensation tax benefit			1,208				1,208
Comprehensive (loss):							
Net (loss)				(311,943)			(311,943)
Unrealized change in fair value of investments, net of tax					936		936
Total comprehensive (loss)							(311,007)
Balance, December 31, 2009	83,542	$ 835	$ 1,859,255	$ 178,035	$ (19)	$	$ 2,038,106
Dividends				(27,166)			(27,166)
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)
Comprehensive income:							
Net income				574,782			574,782
Unrealized change in fair value of investments, net of tax					283		283
Total comprehensive income							575,065
Balance, December 31, 2010	85,235	$ 852	$ 1,883,065	$ 725,651	$ 264	$	$ 2,609,832
Dividends				(34,320)			(34,320)
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
Comprehensive income:							

Net income				529,932			529,932
Unrealized change in fair value of investments, net of tax					(278)		(278)
Total comprehensive income							529,654
Balance, December 31, 2011	85,774	$ 858	$ 1,908,506	$ 1,221,263	$ (14)	$	$ 3,130,613

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. DESCRIPTION OF BUSINESS

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.

2. BASIS OF PRESENTATION

The accounts of Cimarex and its subsidiaries are presented in the accompanying Consolidated Financial Statements. All intercompany accounts and transactions were eliminated in consolidation.

Our Consolidated Financial Statements 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. Our significant accounting policies are described in Note 3 to our Consolidated Financial Statements. We analyze our estimates, including those related to oil, gas and NGL revenues, reserves and properties, as well as goodwill and contingencies, 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.

Certain amounts in prior years' financial statements have been reclassified to conform to the 2011 financial statement presentation.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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 $758 thousand and $699 thousand at December 31, 2011 and 2010, respectively, included in our noncurrent Other assets consisting of monies from third parties which is 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.

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.

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Cimarex Energy Co.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

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. Holding all factors constant other than commodity prices, a 10% decline in prices as of December 31, 2011 would not have resulted in a ceiling test impairment. In the first quarter of 2009, we recorded a non-cash impairment of oil and gas properties of $791.1 million ($501.8 million after tax) as a result of declines in gas prices.

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. The capitalized costs of unproved properties, including those in wells in progress, are excluded from the costs being amortized. We do not have major development projects that are excluded from costs being amortized. On a quarterly basis, we evaluate excluded costs for inclusion in the costs to be amortized resulting from the determination of proved reserves or impairments. To the extent that the evaluation indicates these properties are impaired, the amount of the impairment is added to the capitalized costs to be amortized. Expenditures for maintenance and repairs are charged to production expense in the period incurred.

Goodwill

Accounting for the acquisition of a business requires the allocation of the purchase price to the tangible and intangible net assets acquired with any excess recorded as goodwill. Goodwill is assessed for impairment at least annually. The impairment test requires allocating goodwill and all other assets and liabilities to assigned reporting units. Cimarex is one reporting unit. The fair value is estimated and compared to the net book value. If the estimated fair value is less than the net book value, including goodwill, then the goodwill is written down to the implied fair value of the goodwill through a charge to expense.

The annual impairment test, which we conduct during the fourth quarter, requires us to estimate the fair value of the Company. The most significant judgments involved in estimating our fair value relates to the valuation of our oil and gas assets. We develop estimated fair value of our proved oil and gas assets by performing various discounted cash flow analyses. Due to volatility in the stock markets, management does not consider the market value of our shares to be an accurate reflection of the fair value of our net assets for goodwill impairment purposes.

Based upon our assessment at December 31, 2011, no impairment of goodwill is required.

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Cimarex Energy Co.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Unfavorable changes in reserves or in our price forecast would increase the likelihood of a goodwill impairment charge. A goodwill impairment charge would have no effect on liquidity or capital resources. However, it would adversely affect our results of operations in that period.

Revenue Recognition

Oil, Gas and NGL Sales

Revenues from oil, gas and natural gas liquids (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 statement of operations.

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, 2011 and 2010 was $4.5 million and $4.0 million, respectively. At December 31, 2011 and 2010, we were also in an under-produced position relative to certain other third parties.

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 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.

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Cimarex Energy Co.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

At year-end 2011, 18% of our total proved reserves are categorized as proved undeveloped. Of these proved undeveloped reserves, 98% are in our western Oklahoma, Cana-Woodford shale play. Our reserve engineers review and revise our reserve estimates regularly, as new information becomes available.

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

Transportation Costs

Amounts paid for transportation are classified as an operating expense and are not netted against gas sales.

Derivatives

Our derivative contracts are recorded on the balance sheet at fair value. The accounting treatment for settlements and the changes in fair value is dependent upon whether or not a derivative instrument is designated as a hedge for accounting treatment purposes. We did not choose to apply hedge accounting treatment to any of the contracts we entered into during the periods covered in this filing. Realized and unrealized gains and losses on derivatives that are not designated as hedges are recognized currently in costs and expenses associated with operating income in our consolidated statements of operations. Cash settlements of our derivative contracts are included in cash flows from operating activities in our statements of cash flows. See Note 4 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.

At December 31, 2011 we have no unrecognized tax benefits that would impact our effective rate and we have made no provisions for interest or penalties related to uncertain tax provisions.

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 16 for additional information regarding our contingencies.

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Cimarex Energy Co.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Asset Retirement Obligations

We recognize the fair value of a liability for an asset retirement obligation in the period in which it is incurred if a reasonable estimate of fair value can be made; 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 plugging of wells, the removal of facilities and equipment, and site restorations, upon acquiring or drilling a successful well. Subsequent to initial measurement, the asset retirement liability is required to be accreted each period. Capitalized costs 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 anaysis. Compensation cost is recognized ratably over the applicable vesting period. See Note 10 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 restricted stock units, qualify as participating securities.

Comprehensive Income (Loss)

Comprehensive income is a term used to refer to net income plus other comprehensive income (loss). Other comprehensive income (loss) is comprised of revenues, expenses, gains, and losses that under GAAP

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Cimarex Energy Co.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

are reported as separate components of shareholders' equity instead of net income. Our other comprehensive income (loss) for the three years ended December 31, 2011 is as follows (in 000's):

	Net Unrealized Gain (or Loss) On Short-Term Investments and Other(1)
Balance at January 1, 2009	$ (955)
2009 activity	936
Balance at December 31, 2009	$ (19)
2010 activity	283
Balance at December 31, 2010	$ 264
2011 activity	(278)
Balance at December 31, 2011	$ (14)

(1) Net of tax

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.

Assets Held For Sale

At June 30, 2011 we reflected certain assets as held for sale. An asset is classified as held for sale when among other requirements, management commits to a plan to sell the asset, the asset is being actively marketed at a price that is reasonable in relation to its current fair value, and completion of the sale is probable and expected to occur within one year. We sold these assets in August 2011. See Note 17 for further information on the sale of these assets.

Recently Issued Accounting Standards

The Financial Accounting Standards Board ("FASB") has issued final guidance on goodwill impairment that permits an entity to make a qualitative assessment of whether it is more likely than not that a reporting unit's fair value is less than its carrying amount before applying the two-step goodwill impairment test. If an entity concludes that it is not more likely than not that the fair value of a reporting unit is less than its carrying amount, it would not be required to perform the two-step impairment test for that reporting unit. The guidance is effective for fiscal years beginning after December 15, 2011.

Subsequent Events

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

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Cimarex Energy Co.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. DERIVATIVE INSTRUMENTS/HEDGING

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

For 2012 and 2013, management has been authorized to hedge up to 50% of our anticipated equivalent oil and gas production. 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.

At December 31, 2011, we had the following outstanding contracts relative to our future production. We have elected not to account for these derivatives as cash flow hedges.

Oil Contracts

				Weighted Average Price		Fair Value
Period	**Type**	**Volume/Day**	**Index(1)**	**Floor**	**Ceiling**	**(000's)**
Jan 12 - Dec 12	Collar	2,000 Bbls	WTI	$ 80.00	$ 114.70	$ (245)

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

Subsequent to December 31, 2011 we entered into additional oil collars as follows:

				Weighted Average Price	
Period	**Type**	**Volume/Day**	**Index(1)**	**Floor**	**Ceiling**
Jan 12	Collar	2,000 Bbls	WTI	$ 80.00	$ 119.45
Feb 12	Collar	7,000 Bbls	WTI	$ 80.00	$ 119.56
Mar 12 - Dec 12	Collar	12,000 Bbls	WTI	$ 80.00	$ 120.13

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

Including contracts entered into subsequent to December 31, 2011, we have hedged approximately 50% of our anticipated oil production for 2012.

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

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

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

Cimarex Energy Co.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. DERIVATIVE INSTRUMENTS/HEDGING (Continued)

Due to the volatility of commodity prices, the estimated fair value of our derivative instruments is subject to fluctuation from period to period, which could result in significant differences between the current estimated fair value and the ultimate settlement price. The following tables present the estimated fair value of our derivative assets and liabilities as of December 31, 2011 and 2010:

December 31, 2011:	**Balance Sheet Location**		**Asset**	**Liability**
			(In thousands)	
Oil contracts	Current liabilities	Derivative instruments	$	$ 245
December 31, 2010:				
Natural gas contracts	Current assets	Derivative instruments	$ 5,731	$
Oil contracts	Current liabilities	Derivative instruments		9,587
			$ 5,731	$ 9,587

Because we have elected not to account for our current 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:

	2011	**2010**	**2009**
Settlements gains (losses):			
Natural gas contracts	$ 8,485	$ 53,985	$ 1,394
Oil contracts	(1,774)	(1,887)	
Total settlements gains (losses)	6,711	52,098	1,394
Unrealized gains (losses) from change in fair value:			
Natural gas contracts	(5,731)	8,802	(3,070)
Oil contracts	9,342	1,796	(11,383)
Total net unrealized gains (losses) from change in fair value	3,611	10,598	(14,453)
Gain (loss) on derivative instruments, net	$ 10,322	$ 62,696	$ (13,059)

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.

5. FAIR VALUE MEASUREMENTS

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

Cimarex Energy Co.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. FAIR VALUE MEASUREMENTS (Continued)

inputs are inputs other than quoted prices that are observable for the asset or liability, either directly or indirectly. Level 3 inputs are unobservable inputs for an asset or liability.

The following tables provide fair value measurement information for certain assets and liabilities as of December 31, 2011 and 2010:

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

December 31, 2010:	Carrying Amount	Fair Value
	(In thousands)	
Financial Assets (Liabilities):		
7.125% Notes due 2017	$ (350,000)	$ (358,750)
Derivative instruments assets	$ 5,731	$ 5,731
Derivative instruments liabilities	$ (9,587)	$ (9,587)

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

Debt

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. We had no bank debt at December 31, 2010.

The fair value for our 7.125% fixed rate notes was based on their last traded value before year end.

Derivative Instruments

The fair value of our derivative instruments at December 31, 2011 and 2010 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 4 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 of these assets and liabilities. Included in Accrued liabilities, other at December 31, 2011 and 2010, respectively, are liabilities of approximately $46.9 million and $31.3 million representing the amount by which checks issued, but not yet presented to our banks for collection, exceeded balances in applicable bank accounts. Also

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Cimarex Energy Co.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. FAIR VALUE MEASUREMENTS (Continued)

included in Accrued liabilities, other at December 31, 2011 and 2010, respectively, are accrued payroll related general and administrative expenses of $24.0 million and $44.8 million, and the current portion of the Asset retirement obligation of $43.7 million and $29.3 million.

At December 31, 2011, the allowance for doubtful accounts for trade, oil and gas sales, and gas gathering, processing, and marketing receivables was $6.0 million, $0.4 million, and zero, respectively. At December 31, 2010, the allowance for doubtful accounts for trade, oil and gas sales, and gas gathering, processing, and marketing receivables was $6.3 million, $0.5 million, and zero, respectively. Most of our accounts receivable balances are uncollateralized and result from transactions with other companies in the oil and gas industry. Concentration of customers may impact our overall credit risk because our customers may be similarly affected by changes in economic or other conditions within the industry.

6. ASSET RETIREMENT OBLIGATIONS

We recognize the fair value of a liability for an asset retirement obligation in the period in which it is incurred if a reasonable estimate of fair value can be made, and 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 plugging of wells, the removal of facilities and equipment, and site restorations, upon acquiring or drilling a successful well. 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.

The following table reflects the components of the change in the carrying amount of the asset retirement obligation for the years ended December 31, 2011 and 2010 (in thousands):

	2011	2010
Asset retirement obligation at January 1,	$ 138,769	$ 149,310
Liabilities incurred	5,710	4,555
Liability settlements and disposals	(29,634)	(31,514)
Accretion expense	7,204	7,535
Revisions of estimated liabilities	61,312	8,883
Asset retirement obligation at December 31,	183,361	138,769
Less current obligation	43,681	29,276
Long-term asset retirement obligation	$ 139,680	$ 109,493

During 2011 we recognized revisions of $61.3 million to our asset retirement obligation primarily from increases in abandonment cost estimates for our Gulf of Mexico properties ($35.8 million) and for our Permian basin properties ($25.1 million). The revisions recognized during 2010 were primarily from increases in abandonment cost estimates for our Gulf of Mexico properties.

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Cimarex Energy Co.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

7. LONG TERM DEBT

Debt at December 31, 2011 and December 31, 2010 consisted of the following (in thousands):

	December 31, 2011	December 31, 2010
Bank debt	$ 55,000	$
7.125% Senior Notes due 2017	350,000	350,000
Total long-term debt	$ 405,000	$ 350,000

Bank Debt

In July 2011, we entered into a new five-year senior unsecured revolving credit facility ("Credit Facility"). The Credit Facility provides for a borrowing base of $2 billion with aggregate commitments of $800 million from 14 lenders. The facility matures July 14, 2016.

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 1, 2012.

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 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, 2011, we were in compliance with all of the financial and nonfinancial covenants.

At December 31, 2011, there were $55 million of borrowings outstanding under the credit facility at a prime interest rate of 4%. We also had letters of credit outstanding of $2.5 million leaving an unused borrowing availability of $742.5 million.

7.125% Notes due 2017

In May, 2007, we issued $350 million of 7.125% senior unsecured notes that mature May 1, 2017 at par. Interest on the notes is payable May 1 and November 1 of each year. The notes are governed by an indenture containing covenants that could limit our ability to incur additional indebtedness, pay dividends, repurchase our common stock or make investments and other restricted payments. Our ability to incur liens, enter into sale/leaseback transactions, engage in transactions with affiliates, sell assets, and consolidate, merge or transfer assets could also be restricted.

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Cimarex Energy Co.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

7. LONG TERM DEBT (Continued)

The notes are redeemable at our option, in whole or in part, at any time on and after May 1, 2012 at the following redemption prices (expressed as percentages of the principal amount) plus accrued interest, if any, to the date of redemption.

Year	Percentage
2012	103.6%
2013	102.4%
2014	101.2%
2015 and thereafter	100.0%

If a specified change of control occurs, subject to certain conditions, we must make an offer to purchase the notes at a purchase price of 101% of the principal amount of the notes, plus accrued and unpaid interest to the date of the purchase.

Other

On July 1, 2010, the remaining holders of our floating rate convertible notes elected to convert their notes for cash and shares. The holders received $20.5 million (principal of $19.5 million and $1.0 million for fractional shares) and 408,450 shares of common stock. We recorded a gain of $3.8 million on the settlement of the notes.

8. INCOME TAXES

Federal income tax expense (benefit) for the years presented differ 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 (in thousands):

	Years Ended December 31,		
	2011	2010	2009
Current Taxes:			
Federal (benefit)	$ (45,404)	$ 42,952	$ (11,335)
State (benefit)	(669)	3,385	(443)
	(46,073)	46,337	(11,778)
Deferred taxes:			
Federal	345,397	280,190	(158,264)
State	12,225	12,422	(6,496)
	357,622	292,612	(164,760)
	$ 311,549	$ 338,949	$ (176,538)

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Cimarex Energy Co.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. INCOME TAXES (Continued)

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

	Years Ended December 31,		
	2011	**2010**	**2009**
Provision at statutory rate	$ 294,518	$ 319,806	$ (170,969)
Effect of state taxes	11,445	15,619	(6,863)
Domestic Production Activities allowance	2,343	(1,240)	663
Other permanent differences	3,243	4,764	631
Income tax (benefit) expense	$ 311,549	$ 338,949	$ (176,538)

The components of Cimarex's net deferred tax liabilities are as follows (in thousands):

	December 31,	
	2011	**2010**
Long-term:		
Assets:		
Stock compensation and other accrued amounts	$ 70,092	$ 72,405
Net operating loss carryforward	41,147	
Credit carryforward	2,909	
	114,148	72,405
Liabilities:		
Property, plant and equipment	(1,089,080)	(691,445)
Net, long-term deferred tax liability	(974,932)	(619,040)
Current:		
Assets:		
Derivative instruments	89	1,407
Other	2,634	2,886
	2,723	4,293
Net deferred tax liabilities	$ (972,209)	$ (614,747)

The company has a U.S. net tax operating loss (NOL) carryforward of approximately $107 million at December 31, 2011. The NOL carryforward expires in 2031. We believe that the carryforward will be utilized before it expires. The Company has an alternative minimum tax credit carryfoward of approximately $2.9 million at December 31, 2011.

At December 31, 2011 and 2010 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 2005 - 2010 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 - 2010 for examination.

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Cimarex Energy Co.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

9. CAPITAL STOCK

A summary of our common stock activity follows:

	Number of Shares (in thousands)		
	Issued	Treasury	Outstanding
December 31, 2008	84,144	(885)	83,259
Restricted shares issued under compensation plans, net of reacquired stock and cancellations	166		166
Option exercises, net of cancellations	117		117
Treasury shares cancelled	(885)	885	
December 31, 2009	83,542		83,542
Shares issued due to conversion of convertible debt	408		408
Restricted shares issued under compensation plans, net of reacquired stock and cancellations	755		755
Option exercises, net of cancellations	530		530
December 31, 2010	85,235		85,235
Restricted shares issued under compensation plans, net of reacquired stock and cancellations	461		461
Option exercises, net of cancellations	78		78
December 31, 2011	85,774		85,774

Dividends and Stock Repurchases

In 2009 a quarterly cash dividend of $0.06 per share was paid. The dividend was increased to $0.08 per share in February 2010 and to $0.10 per share in February 2011. Future dividend payments will depend on our level of earnings, financial requirements and other factors considered relevant by the Board of Directors.

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 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.

Stockholder Rights Plan

At December 31, we had a stockholder rights plan designed to inhibit a non-negotiated takeover. The plan was allowed to expire in February 2012.

10. STOCK-BASED COMPENSATION

Our 2011 Equity Incentive Plan (the "2011 Plan") was approved by stockholders in May 2011. The 2011 Plan replaces the 2002 Stock Incentive Plan (the "2002 Plan"). No new grants will be made under the 2002 Plan. The 2011 Plan provides for the grant of stock options, restricted stock, restricted stock units, performance stock and performance stock units to officers, other eligible employees and nonemployee directors. 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)

10. STOCK-BASED COMPENSATION (Continued)

The 2011 Plan is modeled after the 2002 Plan, with two major changes: we have reduced the maximum term of any option granted under the 2011 Plan from ten years to seven years, and dividends will be accrued on all shares subject to performance awards, but will only be paid at the time of vesting of the award, and then only with respect to shares that are issued upon attainment of the performance goals. Service-based restricted awards will continue to receive dividends on unvested shares.

We have recognized non-cash stock-based compensation cost as follows (in thousands):

	Year Ended December 31,		
	2011	2010	2009
Restricted stock and units	$ 27,602	$ 17,865	$ 13,404
Stock options	3,518	3,826	3,374
	31,120	21,691	16,778
Less amounts capitalized to oil and gas properties	(12,171)	(9,338)	(7,524)
Compensation expense	$ 18,949	$ 12,353	$ 9,254

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. No restricted unit awards were granted during the noted periods.

	Year Ended December 31,					
	2011		2010		2009	
	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	363,758	$ 73.01	396,000	$ 41.94	228,000	$ 23.93
Service-based stock awards	291,053	$ 89.47	242,224	$ 70.39	153,090	$ 31.17
Total restricted stock awards	654,811	$ 80.33	638,224	$ 52.74	381,090	$ 26.84

The performance-based awards were issued to certain executive officers 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. The material terms of performance goals applicable to these awards were approved by stockholders in May 2006 and May 2010. The other restricted shares granted in 2011 have service-based vesting schedules of three to five years.

A restricted unit represents a right to an unrestricted share of common stock upon satisfaction of defined vesting and holding conditions. Restricted units have a five-year vesting schedule and an additional three-year holding period following vesting, prior to payment in common stock.

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

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Cimarex Energy Co.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

10. STOCK-BASED COMPENSATION (Continued)

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.

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

	Year Ended December 31,		
	2011	2010	2009
Performance-based stock awards	$ 16,268	$ 9,604	$ 5,942
Service-based stock awards	11,300	8,228	6,964
Restricted unit awards	34	33	498
	27,602	17,865	13,404
Less amounts capitalized to oil and gas properties	(10,241)	(6,941)	(5,356)
Restricted stock and units compensation expense	$ 17,361	$ 10,924	$ 8,048

Unamortized compensation cost related to unvested restricted shares and units at December 31, 2011 was $62 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,		
	2011	2010	2009
Restricted Stock:			
Outstanding beginning of period	1,899,511	1,727,250	1,672,245
Vested	(497,720)	(389,443)	(166,725)
Granted	654,811	638,224	381,090
Canceled	(37,050)	(76,520)	(159,360)
Outstanding end of period	2,019,552	1,899,511	1,727,250
Restricted Stock Units:			
Outstanding beginning of period	94,807	649,843	655,205
Converted to Stock	(35,337)	(555,036)	(5,362)
Outstanding end of period	59,470	94,807	649,843
Vested included in outstanding	59,470	93,543	620,559

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Cimarex Energy Co.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

10. STOCK-BASED COMPENSATION (Continued)

Stock Options

The following tables provide information about stock options granted during the last three years:

	Year Ended December 31,								
	2011			2010			2009		
	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	91,300	$ 34.20	$ 86.01	93,000	$ 28.63	$ 70.30	228,175	$ 11.11	$ 27.74
	181,300			93,000			228,175		

Options granted under our 2011 and 2002 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,		
	2011	2010	2009
Options granted	181,300	93,000	228,175
Weighted average grant-date fair value	$ 26.74	$ 28.63	$ 11.11
Total Fair Value (in thousands)	$ 4,848	$ 2,662	$ 2,535
Expected years until exercise	4.3	5.5	5.5
Expected stock volatility	48.7%	44.6%	43.4%
Dividend yield	0.6%	0.6%	0.9%
Risk-free interest rate	0.9%	1.9%	2.7%

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

	Year Ended December 31,		
	2011	2010	2009
Stock option awards	3,518	3,826	3,374
Less amounts capitalized to oil and gas properties	(1,930)	(2,397)	(2,168)
Stock option compensation expense	$ 1,588	$ 1,429	$ 1,206

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Cimarex Energy Co.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

10. STOCK-BASED COMPENSATION (Continued)

As of December 31, 2011, there was $5.4 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 (000's)
Outstanding as of January 1, 2011	1,026,527	$ 32.60		
Exercised	(78,661)	$ 40.59		
Granted	181,300	$ 71.09		
Canceled		$		
Forfeited	(15,832)	$ 58.04		
Outstanding as of December 31, 2011	1,113,334	$ 37.94	4.3 Years	$ 30,082
Exercisable as of December 31, 2011	804,923	$ 29.19	3.2 Years	$ 26,988

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

	Year Ended December 31, 2011	2010	2009
Number of options exercised	78,661	596,344	134,082
Cash received from option exercises	$ 3,193	$ 17,991	$ 2,213
Tax benefit from option exercises included in paid-in-capital	$ 1,407	$ 9,199	$ 1,208
Intrinsic value of options exercised	$ 3,856	$ 25,210	$ 3,302
Grant-date fair value of options vested	$ 4,128	$ 3,624	$ 3,084

The following summary reflects the status of non-vested stock options as of December 31, 2011 and changes during the year:

	Options	Weighted Average Grant-Date Fair Value	Weighted Average Exercise Price
Non-vested as of January 1, 2011	375,322	$ 18.25	$ 47.80
Vested	(232,379)	$ 17.77	$ 48.08
Granted	181,300	$ 26.74	$ 71.09
Forfeited	(15,832)	$ 22.82	$ 58.04
Non-vested as of December 31, 2011	308,411	$ 23.37	$ 60.75

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Cimarex Energy Co.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

11. EARNINGS (LOSS) PER SHARE

The calculations of basic and diluted net earnings (loss) per common share under the two-class method are presented below (in thousands, except per share data):

	Year Ended December 31,		
	2011	**2010**	**2009**
Net income (loss)	$ 529,932	$ 574,782	$ (311,943)
Less distributed earnings (dividends declared during the period)	(34,292)	(27,188)	(20,282)
Undistributed earnings (loss) for the period	$ 495,640	$ 547,594	$ (332,225)
Allocation of undistributed earnings (loss)			
Basic allocation to unrestricted common stockholders	$ 483,635	$ 534,796	$ (332,225)
Basic allocation to participating securities	$ 12,005	$ 12,798	$ (1)
Diluted allocation to unrestricted common stockholders	$ 483,690	$ 534,863	$ (332,225)
Diluted allocation to participating securities	$ 11,950	$ 12,731	$ (1)
Basic Shares Outstanding			
Unrestricted outstanding common shares	83,755	83,335	81,815
Add Participating securities:			
Restricted stock outstanding	2,020	1,900	1,727
Restricted stock units outstanding	59	95	650
Total participating securities	2,079	1,995	2,377
Total Basic Shares Outstanding	85,834	85,330	84,192
Fully Diluted Shares			
Unrestricted outstanding common shares	83,755	83,335	81,815
Incremental shares from assumed exercise of stock options	398	452	(2)
Incremental shares from assumed conversion of the convertible senior notes			(2)
Fully diluted common stock	84,153	83,787	81,815
Participating securities	2,079	1,995	2,377(1)
Total Fully Diluted Shares	86,232	85,782	84,192
Basic earnings (loss) per share			
Unrestricted common stockholders:			
Distributed earnings	$ 0.40	$ 0.32	$ 0.24
Undistributed earnings (loss)	5.77	6.42	(4.06)
	$ 6.17	$ 6.74	$ (3.82)
Participating securities:			
Distributed earnings	$ 0.40	$ 0.32	$ 0.24
Undistributed earnings (loss)	5.77	6.42	
	$ 6.17	$ 6.74	$ 0.24
Fully diluted earnings (loss) per share			
Unrestricted common stockholders:			
Distributed earnings	$ 0.40	$ 0.32	$ 0.24

Undistributed earnings (loss)		5.75		6.38		(4.06)
	$	6.15	$	6.70	$	(3.82)
Participating securities:						
Distributed earnings	$	0.40	$	0.32	$	0.24
Undistributed earnings (loss)		5.75		6.38		
	$	6.15	$	6.70	$	0.24

(1) Participating securities are included in distributed earnings but not in undistributed earnings when a loss from continuing operations exists.

(2) No potential common shares or securities are included in the diluted share computation when a loss from continuing operations exists.

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Cimarex Energy Co.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

11. EARNINGS (LOSS) PER SHARE (Continued)

Certain stock options and restricted units and shares and the convertible notes were considered to be anti-dilutive as follows:

	2011	2010	2009
Stock options	272,842	184,129	1,573,974
Restricted stock			1,727,250
Restricted stock units			649,843
Convertible notes			311,200
	272,842	184,129	4,262,267

12. EMPLOYEE BENEFIT PLANS

We maintain and sponsor a contributory 401(k) plan for our employees. Annual costs related to the plan were $8.9 million for 2011 and 2010, and $5.1 million for 2009.

13. RELATED PARTY TRANSACTIONS

Helmerich & Payne, Inc. (H&P) provides contract drilling services to Cimarex. Drilling costs of approximately $37.4 million were incurred by Cimarex related to such services for 2011. During 2010 and 2009, such costs were $22.6 million and $17.5 million, respectively. At December 31, 2011, we have minimum expenditure commitments of $3.5 million to secure the use of H&P's drilling rigs. We had minimum expenditure commitments of $8.3 million and $16.2 million at December 31, 2010 and 2009, respectively. Hans Helmerich, a Director of Cimarex, is President 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 $7.3 million in 2011. During 2010 and 2009, such costs were $10.2 million and $10.8 million, respectively. In 2009, we sold tubulars to a subsidiary of Newpark Resources, Inc. for $108 thousand. Jerry Box, a Director of Cimarex, is a non-executive Director and Chairman of the Board of Newpark Resources, Inc.

14. MAJOR CUSTOMERS

Our two major purchasers accounted for approximately 22% and 15%, respectively, of our 2011 and 2010 revenues. During 2009, sales to one purchaser represented approximately 14% of our revenues.

15. SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION (IN THOUSANDS)

	For the Years Ended December 31,		
	2011	2010	2009
Cash paid during the period for:			
Interest expense (including capitalized amounts)	$ 29,650	$ 29,686	$ 34,077
Interest capitalized	$ 24,193	$ 23,688	$ 20,054
Income taxes	$ 1,753	$ 108,846	$ 2,270
Cash received for income taxes	$ 59,109	$ 4,166	$ 94,617

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Cimarex Energy Co.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

16. COMMITMENTS AND CONTINGENCIES

Shown below are the five year debt maturities and five year lease commitments as of December 31, 2011:

	Payments Due by Period				
	Total	Less than 1 year	1-3 Years	4-5 Years	More than 5 Years
			(In Thousands)		
Long term debt (face value)	$ 405,000	$	$ 55,000	$	$ 350,000
Operating leases	$ 75,606	$ 5,109	$ 15,595	$ 11,807	$ 43,095

Litigation

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 H&P case. This lawsuit was originally filed in 1998 and addressed H&P's conduct pertaining to a 1989 take-or-pay settlement, along with potential drainage issues and other related matters. 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. In 2008 we recorded litigation expense of $119.6 million for this lawsuit. We have accrued additional expense for associated post-judgment interest and costs that have accrued during the appeal of the District Court's judgments.

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, finding 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 October 27, 2011, Cimarex filed a petition with the Oklahoma Supreme Court requesting review of the affirmed portion of the judgment. This case is subject to further appeal 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 accrued liability for this lawsuit for the years ending December 31 (in thousands):

	2011	2010	2009
Beginning of period	$ 137,611	$ 128,759	$ 119,594
Accrued post-judgment interest and costs	8,699	8,852	9,165
End of period	$ 146,310	$ 137,611	$ 128,759

Other litigation

In the normal course of business, we have other various litigation related 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

Cimarex Energy Co.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

16. COMMITMENTS AND CONTINGENCIES (Continued)

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.

Other

We have drilling commitments of approximately $203 million consisting of obligations to finish drilling and completing wells in progress at December 31, 2011. We also have various commitments for drilling rigs as well as certain service contracts. The total minimum expenditure commitments under these agreements are $18.8 million to secure the use of drilling rigs and $27.3 million to secure certain dedicated services associated with completion activities.

We have projects in Oklahoma, New Mexico, and Texas where we are constructing gathering facilities and pipelines. At December 31, 2011, we had commitments of $22.2 million relating to this construction.

At December 31, 2011, we had firm sales contracts to deliver approximately 10.7 Bcf of natural gas over the next eight months. If this gas is not delivered, our financial commitment would be approximately $35.5 million. This commitment will fluctuate due to price volatility and actual volumes delivered. However, we believe no financial commitment will be due based on our current proved reserves and production levels.

In connection with gas gathering and processing agreements, we have commitments to deliver a minimum of 14.4 Bcf of gas over the next four years. The production from certain wells is counted toward those commitments; these wells also have individual commitments for gas deliveries. If no gas is delivered, the maximum amount that would be payable under these commitments would be approximately $9.9 million, some of which would be reimbursed by working interest owners who are selling with us under our marketing agreements. We do not expect to make significant payments relative to these commitments.

We have various other transportation and delivery commitments in the normal course of business, which approximate $2.9 million.

We have non-cancelable operating leases for office and parking space in Denver, Colorado; Tulsa, Oklahoma; Dallas, Texas; Midland, Texas and for various district and field offices. During 2011, we entered into a 12-year lease agreement for new office space in Tulsa, Oklahoma. The expected commencement date of the lease is December 2012. Our aggregate minimum lease commitments have increased to $75.6 million versus $15.5 million at December 31, 2010. Rental expense for the operating leases totaled $5.3 million in 2011. They were $6.1 million and $6 million for 2010 and 2009, respectively.

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

17. PROPERTY ACQUISITIONS AND SALES

In order to acquire and sell oil and gas properties in a tax efficient manner, we periodically enter into like-kind exchange tax-deferred transactions. For these transactions, we utilize an exchange accommodation titleholder, a type of variable interest entity, of which we are the primary beneficiary. For an acquisition, we consolidate the oil and gas assets and reserves, as well as production, revenues and expenses attributable to properties in these like-kind exchange transactions.

During 2011, we had property acquisitions of approximately $45.4 million of which $42.2 million was in our western Oklahoma Cana-Woodford shale play and $3 million was in the Permian Basin. A portion of these transactions were included as part of our like-kind exchanges. During 2010 we had property

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Cimarex Energy Co.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

17. PROPERTY ACQUISITIONS AND SALES (Continued)

acquisitions of $39.8 million, primarily for additional interests in our western Oklahoma, Cana-Woodford shale play.

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 related assets ($111.4 million) and 210 Bcf of proved undeveloped gas reserves ($84.1 million). 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.

At June 30, 2011 the gas processing plant and related assets and liabilities were classified as assets held for sale. We determined that the carrying amounts of the assets and liabilities were equal to their fair value, therefore no gain or loss was recognized on the sale. Because the gas plant was still under construction we had not recognized any income or expense related to plant operations in our statements of operations. The sales contract also provides for a maximum $15 million contingent payment to be made to Cimarex if certain operational and performance goals related to the start-up of the gas processing plant are met.

Also during 2011, we sold various interests in oil and gas properties for approximately $33.3 million, including our assets in Lea County, New Mexico and Willacy County, Texas. Certain of these transactions were included as part of our like-kind exchanges.

In 2010 we sold various interests in oil and gas properties for $28.2 million. Most of which were our Mississippi assets. During 2009 we sold interests in oil and gas properties for $109.4 million. Approximately 72% of the 2009 sales were our Westbrook field interests in our Permian Basin Region.

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.

18. UNAUDITED SUPPLEMENTAL OIL AND GAS DISCLOSURES

Oil and Gas Operations The following tables contain direct revenue and cost information relating to our oil and gas exploration and production activities for the periods indicated. We have no long-term supply or purchase agreements with governments or authorities in which we act as producer. Income tax

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Cimarex Energy Co.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

18. UNAUDITED SUPPLEMENTAL OIL AND GAS DISCLOSURES (Continued)

expense (benefit) related to our oil and gas operations are computed using the effective tax rate for the period (in thousands):

	Years Ended December 31,		
	2011	2010	2009
Oil, gas and NGL revenues from production	$ 1,703,520	$ 1,558,562	$ 962,443
Less operating costs and income taxes:			
Impairment of oil and gas properties			791,137
Depletion	367,509	282,374	243,471
Asset retirement obligation	11,451	7,322	12,313
Production	247,048	194,015	178,215
Transportation	61,829	49,968	33,758
Taxes other than income	126,468	121,781	75,634
Income tax expense (benefit)	329,187	335,412	(134,472)
	1,143,492	990,872	1,200,056
Results of operations from oil and gas producing activities	$ 560,028	$ 567,690	$ (237,613)
Amortization rate per Mcfe	$ 1.70	$ 1.30	$ 1.44

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

	Years Ended December 31,		
	2011	2010	2009
Costs incurred during the year:			
Acquisition of properties			
Proved	$ 23,071	$ 15,220	$ 13,530
Unproved	168,238	136,929	24,804
Exploration	82,531	119,577	59,350
Development	1,351,617	766,980	430,357
Oil and gas expenditures	1,625,457	1,038,706	528,041
Property sales	(117,344)	(28,235)	(109,408)
	1,508,113	1,010,471	418,633
Asset retirement obligation, net	63,246	9,321	12,850
	$ 1,571,359	$ 1,019,792	$ 431,483

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Cimarex Energy Co.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

18. 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, 2011 (in thousands):

Proved properties	$	9,933,517
Unproved properties and properties under development, not being amortized		607,219
		10,540,736
Less-accumulated depreciation, depletion and amortization		(6,414,528)
Net oil and gas properties	$	4,126,208

Costs Not Being Amortized The following table summarizes oil and gas property costs not being amortized at December 31, 2011, by year that the costs were incurred (in thousands):

2011	$	353,374
2010		83,353
2009		21,570
2008 and prior		148,922
	$	607,219

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 Corporate Engineering. This individual graduated from the Colorado School of Mines with a Bachelor of Science degree in Engineering and has more than seventeen years of practical experience in reserve evaluation. This individual has been directly involved in the annual reserve reporting process of Cimarex since 2002 and has served in the current role for the past seven 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, 2011. 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-seven years of experience in oil and gas reservoir studies and evaluations.

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Cimarex Energy Co.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

18. 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 following reserve data represents estimates only and should not be construed as being exact. For year-end periods below, the commodity prices were determined using an average price based upon the prior 12 months.

	December 31, 2011			December 31, 2010			December 31, 2009		
	Gas (MMcf)	Oil (MBbl)	NGL (MBbl)	Gas (MMcf)	Oil (MBbl)	NGL (MBbl)	Gas (MMcf)	Oil (MBbl)	NGL (MBbl)
Total proved reserves:									
Beginning of year	1,254,166	63,656	41,310	1,186,585	56,764	1,253	1,067,333	44,286	916
Revisions of previous estimates	(35,981)	(2,062)	6,865	(24,756)	3,279	25,588	6,718	10,852	349
Extensions and discoveries	321,419	21,253	23,019	216,338	14,133	18,419	229,625	13,562	208
Purchases of reserves	13,480	308	1,430	12,834	104	322	2,106	300	
Production	(120,113)	(9,778)	(6,236)	(132,813)	(9,844)	(4,272)	(117,968)	(8,278)	(220)
Sales of properties	(216,530)	(1,055)	(573)	(4,022)	(780)		(1,229)	(3,958)	
End of year	1,216,441	72,322	65,815	1,254,166	63,656	41,310	1,186,585	56,764	1,253
Proved developed reserves	989,511	68,250	44,755	911,898	60,231	31,051	865,720	52,636	1,253
Proved undeveloped reserves	226,930	4,072	21,060	342,268	3,425	10,259	320,865	4,128	

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.

During 2011, we added 587.0 Bcfe of proved reserves through extensions and discoveries, primarily as the result of wells drilled in our Cana-Woodford shale area in western Oklahoma and in the Permian Basin.

Net negative revisions during 2011 of 7.2 Bcfe, which included a positive 3.8 Bcfe driven by commodity prices, relate primarily to increases in operating expenses which shortened the economic lives of the properties.

In 2010, we added 411.7 Bcfe of proved reserves through extensions and discoveries. These additions were primarily due to wells drilled in our Cana-Woodford shale area in western Oklahoma, in the Permian Basin and in southeast Texas.

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Cimarex Energy Co.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

18. UNAUDITED SUPPLEMENTAL OIL AND GAS DISCLOSURES (Continued)

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

During 2009, we added 312.3 Bcfe of proved reserves through extensions and discoveries, primarily as the result of wells drilled in our Cana-Woodford shale area in western Oklahoma, in the Permian Basin and in southeast Texas. Net revisions during 2009 added 73.9 Bcfe which included 104.7 Bcfe of positive revisions resulting from better than expected production performance from wells drilled in prior years and lower estimated operating costs. Partially offsetting these positive revisions was a decrease of 30.8 Bcfe driven by lower gas prices.

At December 31, 2011 we had proved undeveloped ("PUD") reserves of 378 Bcfe, down 46 Bcfe from 424 Bcfe of PUDs at December 31, 2010. Changes in our PUD reserves are summarized in the table below:

PUDs at December 31, 2010 (Bcfe)	424
Sales	(215)
Converted to developed	(5)
Acquisitions	10
Additions	162
Net revisions	2
PUDs at December 31, 2011	378

Of the 215 Bcfe of PUDs sold during 2011, 210 Bcfe were related to the Sublette County, Wyoming Riley Ridge development project. The 162 Bcfe of additions occurred in our western Oklahoma, Cana Woodford shale play. Approximately 98% 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, 2010 and 2009 totaled 424 Bcfe and 346 Bcfe, respectively. The majority of these reserves were associated with our development project in Sublette County, Wyoming and our western Oklahoma, Cana-Woodford shale play. Our development project in Sublette County, Wyoming was sold in August, 2011. Please see Note 17 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 calculation. Future net cash flow after income taxes is discounted using a 10% annual discount rate to arrive at the Standardized Measure.

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Cimarex Energy Co.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

18. UNAUDITED SUPPLEMENTAL OIL AND GAS DISCLOSURES (Continued)

The following summary sets forth our Standardized Measure (in thousands):

	December 31,		
	2011	**2010**	**2009**
Cash inflows	$ 13,824,129	$ 11,355,448	$ 7,521,219
Production costs	(3,999,352)	(3,615,419)	(2,773,338)
Development costs	(555,963)	(426,914)	(354,340)
Income tax expense	(2,938,590)	(2,243,558)	(1,205,984)
Net cash flow	6,330,224	5,069,557	3,187,557
10% annual discount rate	(3,190,474)	(2,554,280)	(1,519,602)
Standardized measure of discounted future net cash flow	$ 3,139,750	$ 2,515,277	$ 1,667,955

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

	December 31,		
	2011	**2010**	**2009**
Standardized Measure, beginning of period	$ 2,515,277	$ 1,667,955	$ 1,724,253
Sales, net of production costs	(1,268,175)	(1,192,798)	(674,836)
Net change in sales prices, net of production costs	448,727	806,109	(427,313)
Extensions and discoveries, net of future production and development costs	1,662,706	1,186,787	730,969
Changes in future development costs	(57,847)	(40,748)	20,055
Previously estimated development costs incurred during the period	42,492	56,848	40,364
Revision of quantity estimates	(16,269)	300,676	106,521
Accretion of discount	361,662	228,593	232,790
Change in income taxes	(353,804)	(483,370)	(14,327)
Purchases of reserves in place	41,854	21,076	10,624
Sales of properties	(123,870)	(20,981)	(34,038)
Change in production rates and other	(113,003)	(14,870)	(47,107)
Standardized Measure, end of period	$ 3,139,750	$ 2,515,277	$ 1,667,955

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. In all years where future gas sales are covered by contracts at specified prices, the contract prices are 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)

18. UNAUDITED SUPPLEMENTAL OIL AND GAS DISCLOSURES (Continued)

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

	December 31,		
	2011	2010	2009
Gas price per Mcf	$ 3.79	$ 4.12	$ 3.56
Oil price per Bbl	$ 89.64	$ 75.35	$ 57.58
NGL price per Bbl	$ 41.70	$ 33.89	$ 28.53

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.

19. UNAUDITED SUPPLEMENTAL QUARTERLY FINANCIAL DATA

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

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Cimarex Energy Co.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

19. UNAUDITED SUPPLEMENTAL QUARTERLY FINANCIAL DATA (Continued)

2010	**First**	**Second**	**Third**	**Fourth**
	(In thousands, except for per share data)			
Revenues	$ 448,570	$ 378,501	$ 378,583	$ 408,029
Expenses, net	244,209	253,881	250,367	290,444
Net income (loss)	$ 204,361	$ 124,620	$ 128,216	$ 117,585
Earnings (loss) per share to common stockholders:				
Basic:				
Distributed	$ 0.08	$ 0.08	$ 0.08	$ 0.08
Undistributed	2.34	1.39	1.42	1.30
	$ 2.42	$ 1.47	$ 1.50	$ 1.38
Diluted:				
Distributed	$ 0.08	$ 0.08	$ 0.08	$ 0.08
Undistributed	2.31	1.38	1.42	1.29
	$ 2.39	$ 1.46	$ 1.50	$ 1.37

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, 2011 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, 2011, 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, 2011.

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Cimarex Energy Co.:

We have audited Cimarex Energy Co. and subsidiaries (the Company) internal control over financial reporting as of December 31, 2011, 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, 2011, 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, 2011 and 2010, and the related consolidated statements of operations, stockholders' equity and comprehensive income (loss), and cash flows for each of the years in the three-year period ended December 31, 2011, and our report dated February 22, 2012 expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP

Denver, Colorado
February 22, 2012

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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 16, 2012 Annual Meeting of Stockholders. The Proxy Statement will be filed with the Securities and Exchange Commission no later than April 29, 2012. 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 16, 2012 Annual Meeting of Stockholders. The Proxy Statement will be filed with the Securities and Exchange Commission no later than April 29, 2012.

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 16, 2012 Annual Meeting of Stockholders. The Proxy Statement will be filed with the Securities and Exchange Commission no later than April 29, 2012.

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 16, 2012 Annual Meeting of Stockholders. The Proxy Statement will be filed with the Securities and Exchange Commission no later than April 29, 2012.

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 16, 2012 Annual Meeting of Stockholders. The Proxy Statement will be filed with the Securities and Exchange Commission no later than April 29, 2012.

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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.

2.1 Agreement and Plan of Merger, dated as of February 23, 2002, among Helmerich & Payne, Inc., Cimarex Energy Co., Mountain Acquisition Co. and Key Production Company, Inc. (filed as Exhibit 2.1 to the Registrant's Registration Statement on Form S-4 dated May 9, 2002 (Registration No. 333-87948) and incorporated herein by reference).

2.2 Agreement and Plan of Merger, dated as of January 25, 2005, among Cimarex Energy Co., Cimarex Nevada Acquisition Co. and Magnum Hunter Resources, Inc. (attached as Annex A to the joint proxy statement/prospectus which forms a part of the Registration Statement on Form S-4 dated February 25, 2005 (Registration No. 333-123019) and incorporated herein by reference).

2.3 Amendment No. 1 to Agreement and Plan of Merger, dated as of February 18, 2005, among Cimarex Energy Co., Cimarex Nevada Acquisition Sub and Magnum Hunter Resources, Inc. (attached as Annex A to the joint proxy statement/prospectus which forms a part of the Registration Statement on Form S-4 dated February 25, 2005 (Registration No. 333-123019) and incorporated herein by reference).

2.4 Amendment No. 2 to Agreement and Plan of Merger, dated as of April 20, 2005, among Cimarex Energy Co., Cimarex Nevada Acquisition Sub and Magnum Hunter Resources, Inc. (attached as Annex A to the joint proxy statement/prospectus which forms a part of this registration statement and incorporated herein by reference).

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 4.1 to Amendment No. 1 to Registration Statement on Form S-4 dated July 2, 2002 (Registration No. 333-87948) and incorporated herein by reference).

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4.2 Senior Indenture dated as of May 1, 2007, by and among Cimarex Energy Co., the Subsidiary Guarantors party thereto and U.S. Bank National Association, as trustee, filed on May 2, 2007 as Exhibit 4.1 to the Registrant's Current Report on Form 8-K and incorporated herein by reference.

4.3 Form of Senior Notes due 2017 included in Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on May 2, 2007 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 Distribution Agreement, dated as of February 23, 2002, by and between Helmerich & Payne, Inc. and Cimarex Energy Co. (filed as Exhibit 10.1 to the Registration Statement on Form S-4 dated May 9, 2002 (Registration No. 333-87948) and incorporated herein by reference).

10.3 Employee Benefits Agreement, dated as of February 23, 2002, by and between Helmerich & Payne, Inc. and Cimarex Energy Co. (filed as Exhibit 10.3 to the Registration Statement on Form S-4 dated May 9, 2002 (Registration No. 333-87948) and incorporated herein by reference).

10.4 First Amendment to Employee Benefits Agreement, dated August 2, 2002, by and among Helmerich & Payne, Inc., Cimarex Energy Co. and Key Production Company, Inc. (filed as Exhibit 10.3.1 to Amendment No. 2 to the Registration Statement on Form S-4 dated August 2, 2002 (Registration No. 333-87948) and incorporated herein by reference).

10.5 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).

10.6 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).

10.7 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).

10.8 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).

10.9 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).

10.10 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).

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10.11 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).

10.12 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).

10.13 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).

10.14 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).

10.15 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).

10.16 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.

10.17 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).

10.18 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).

10.19 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).

10.20 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).

10.21 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).

10.22 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).

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10.23 Indemnification Agreement effective December 5, 2008 with Jerry Box (filed as Exhibit 10.21 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

10.24 Indemnification Agreement effective December 5, 2008 with Hans Helmerich (filed as Exhibit 10.22 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

10.25 Indemnification Agreement effective December 5, 2008 with David A. Hentschel (filed as Exhibit 10.23 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

10.26 Indemnification Agreement effective December 5, 2008 with Paul D. Holleman (filed as Exhibit 10.24 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

10.27 Indemnification Agreement effective December 5, 2008 with F. H. Merelli (filed as Exhibit 10.25 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

10.28 Indemnification Agreement effective December 5, 2008 with Monroe W. Robertson (filed as Exhibit 10.26 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

10.29 Indemnification Agreement effective December 5, 2008 with Michael J. Sullivan (filed as Exhibit 10.27 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

10.30 Indemnification Agreement effective December 5, 2008 with L. Paul Teague (filed as Exhibit 10.28 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

10.31 Indemnification Agreement effective February 26, 2009 with Gary R. Abbott (filed as Exhibit 10.29 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

10.32 Indemnification Agreement effective February 26, 2009 with Joseph R. Albi (filed as Exhibit 10.30 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

10.33 Indemnification Agreement effective December 5, 2008 with Stephen P. Bell (filed as Exhibit 10.31 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

10.34 Indemnification Agreement effective December 5, 2008 with Richard S. Dinkins (filed as Exhibit 10.32 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

10.35 Indemnification Agreement effective December 5, 2008 with Thomas A. Jorden (filed as Exhibit 10.33 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

10.36 Indemnification Agreement effective December 5, 2008 with Paul Korus (filed as Exhibit 10.34 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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10.37	Indemnification Agreement effective December 5, 2008 with James H. Shonsey (filed as Exhibit 10.35 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).
10.38	Indemnification Agreement effective March 20, 2009 with Harold R. Logan, Jr.*
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	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 20, 2012 from DeGolyer and MacNaughton, independent petroleum engineering consulting firm, reporting the results of its audit of Cimarex reserves as of December 31, 2011 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 22, 2012

CIMAREX ENERGY CO.

By: /s/ THOMAS E. JORDEN

Thomas E. Jorden
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
F.H. Merelli	Chairman of the Board and Director	February 22, 2012
/s/ THOMAS E. JORDEN Thomas E. Jorden	Director, President and Chief Executive Officer (Principal Executive Officer)	February 22, 2012
* *Attorney-in-Fact* Joseph R. Albi	Director, Executive Vice President and Chief Operating Officer	February 22, 2012
/s/ PAUL KORUS Paul Korus	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 22, 2012
/s/ JAMES H. SHONSEY James H. Shonsey	Vice President, Chief Accounting Officer and Controller (Principal Accounting Officer)	February 22, 2012
* *Attorney-in-Fact* Jerry Box	Director	February 22, 2012

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Signature	Title	Date
* *Attorney-in-Fact* Hans Helmerich	Director	February 22, 2012
* *Attorney-in-Fact* David A. Hentschel	Director	February 22, 2012
* *Attorney-in-Fact* Harold R. Logan, Jr.	Director	February 22, 2012
* *Attorney-in-Fact* Monroe W. Robertson	Director	February 22, 2012
* *Attorney-in-Fact* Michael J. Sullivan	Director	February 22, 2012
* *Attorney-in-Fact* L. Paul Teague	Director	February 22, 2012

* By:	/s/ PAUL KORUS Paul Korus *Attorney-in-Fact*	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 22, 2012