CIMAREX ENERGY CO
Form 10-K
February 27, 2009

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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, 2008

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 ($.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 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, 2008 was approximately $5,701,925,730.

Number of shares of Cimarex Energy Co. common stock outstanding as of February 18, 2009 was 83,350,488.

Documents Incorporated by Reference: Portions of the Registrant's Proxy Statement for its 2009 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) per day

Bbls Barrels (of oil)

Bcf Billion cubic feet

Bcfe Billion cubic feet equivalent

MBbls Thousand barrels

Mcf Thousand cubic feet (of natural gas)

Mcfe Thousand cubic feet equivalent

MMBbls Million barrels

MMBtu Million British Thermal Units

MMcf Million cubic feet

MMcf/d Million cubic feet per day

MMcfe Million cubic feet equivalent

MMcfe/d Million cubic feet equivalent per day

Net Acres Gross acreage multiplied by working interest percentage

Net Production Gross production multiplied by net revenue interest

NGL Natural gas liquids

Tcf Trillion cubic feet

Tcfe Trillion cubic feet equivalent

One barrel of oil 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; and*
- *marketing of oil and natural gas.*

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

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

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ITEM 1. BUSINESS

General

Cimarex Energy Co. is an independent oil and gas exploration and production company. Our operations are mainly located in Texas, Oklahoma, New Mexico, Kansas, Louisiana and Wyoming. Proved oil and gas reserves as of year-end 2008 totaled 1.3 Tcfe, consisting of 1.1 Tcf of gas and 45.2 million barrels of oil and natural gas liquids. Of total proved reserves, 80 percent are gas and 82 percent are classified as proved developed. Our 2008 production averaged 485.8 MMcfe per day, comprised of 348.2 MMcf of gas per day and 22,937 barrels of oil per day. We operate the wells that account for 83 percent of our total proved reserves and approximately 81 percent of production.

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

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 SEC filings. We have also posted our Code of Ethics, Code of Business Conduct, Corporate Governance Guidelines, Audit Committee Charter and Governance Committee Charter. Copies of these documents are also available in print upon a written or telephone 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. On September 30, 2002, Cimarex was completely spun off to Helmerich and Payne 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. That transaction effectively tripled our proved reserves and doubled our production. Since 2005, we have principally focused on exploration and development drilling and have funded these investments with cash flow provided by operating activities.

Market Conditions

During the fourth quarter of 2008, severe disruptions in the credit markets and reductions in global economic activity caused significant decreases in oil and gas prices. Oil prices fell from a mid-year 2008 peak of $130 per barrel to $37 per barrel at year-end. Gas prices fell from $12.00 per Mcf in mid 2008 to $4.50 per Mcf in the fourth quarter 2008. The large decrease in prices had a significant adverse impact on the amount of cash flow available to invest in exploration and development drilling, the present value of our proved reserves, our stock price and total market capitalization.

The continued credit crisis and related turmoil in the global financial system may have further impact on our business and our financial position. A further decrease in oil and gas prices would have a negative impact on our earnings, cash flow available for reinvestment, and future growth in proved reserves and production. Our ability to access the capital markets to fund our growth may also be restricted. Further, the economic situation could have an impact on our lenders and customers, causing them to fail to meet their obligations to us.

As a result of lower commodity prices we have sharply reduced our drilling activity. Our exploration and development capital investment is expected to decrease from $1.4 billion in 2008 to $400-$600 million in 2009, depending on prices and corresponding cash flow.

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2008 Summary

During 2008 we accomplished the following positive highlights:

- Oil and gas sales increased 38 percent to a record $1.9 billion.
- Cash flow from operating activities increased 37 percent to an all-time high of $1,367.5 million.
- Production averaged 485.8 MMcfe per day in 2008, increasing throughout the year to a fourth quarter peak of 493.7 MMcfe per day.
- Added 215 Bcfe of proved reserves from extensions, discoveries and improved recovery, replacing 121 percent of production.
- Increased our western Oklahoma, Anadarko-Woodford position to 98,000 net acres, including a $180.9 million purchase of 38,000 net acres.
- Ended the year with a debt to total capitalization ratio of 20 percent.

However, largely as a result of the collapse in oil and gas prices we also experienced the following negative consequences:

- $1.4 billion after-tax, non-cash full-cost ceiling test write-down of oil and gas properties.
- Negative price-related revisions to proved reserves of 157 Bcfe, resulting in an overall 9% decrease in our proved reserves to 1.3 Tcfe.

Business Strategy

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

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.

During 2008, our cash flow from operating activities totaled approximately $1.4 billion. Our 2008 investment in ongoing exploration and development activity also approximated $1.4 billion.

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 risk assessment is a competitive advantage and best positions us to continue to achieve attractive rates of return and 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 Woodford Shale core area. The cost of that acquisition was $180.9 million.

Conservative use of leverage has long been a part of our financial strategy. We believe that maintaining a strong balance sheet enables us to withstand low prices and challenging capital markets. At year-end 2008 we had $591 million of long-term debt and our debt to total capitalization ratio was 20 percent.

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Business Segments

Cimarex has one reportable segment (exploration and production).

Exploration and Development Activity Overview

Our operations are currently focused in the Mid-Continent region which consists of Oklahoma, the Texas Panhandle and southwest Kansas; the Permian Basin region of west Texas and southeast New Mexico; and the Gulf Coast areas of Texas, south Louisiana, and offshore Louisiana. We also have operations in Michigan and Wyoming.

A summary of our 2008 exploration and development (E&D) activity by region is as follows.

	Exploration and Development Capital (in millions)	Gross Wells Drilled	Net Wells Drilled	Completion Rate	12/31/08 Proved Reserves (Bcfe)
Mid-Continent	$ 648	256	138	96%	609
Permian Basin	549	164	117	98%	442
Gulf Coast	210	28	21	54%	74
Other	31	2	1	50%	214
	$ 1,438	450	277	94%	1,339

Company-wide, we participated in drilling 450 gross wells during 2008, with an overall completion rate of 94 percent. On a net basis, 253 of 277 total wells drilled during 2008 were completed as producers.

Our 2008 E&D investment totaled $1,438 million and resulted in 215 Bcfe of proved reserve additions. Of total expenditures, 45 percent were invested in projects located in the Mid-Continent area; 38 percent in the Permian Basin; and 15 percent in the Gulf Coast.

Mid-Continent

Our Mid-Continent region encompasses operations in Oklahoma, southwest Kansas and the Texas Panhandle. We drilled 256 gross (138 net) Mid-Continent wells during 2008, completing 96 percent as producers. The bulk of this drilling activity is directed at gas-bearing geological formations in the Anadarko Basin of western Oklahoma and Texas Panhandle. Full-year 2008 investment in this area was $648 million, or 45 percent of total E&D capital.

We drilled 82 gross (22 net) Anadarko Basin wells, of which 95 percent were completed as producers. Our drilling activity mainly targets the Woodford Shale, Red Fork and Clinton Lake/Atoka formations at depths ranging from 11,000-15,000 feet. Our largest investment in this area is the Anadarko-Woodford Shale play. Our activities began in this area in 2007, and our early success in drilling led to leasing a significant land position. We have approximately 98,000 net acres in the play, which includes the purchase of 38,000 net acres in the fourth quarter of 2008 for $180.9 million.

The Woodford formation is a shale interval that varies in thickness from 120-280 feet at depths of 12,000-16,000 feet throughout our acreage. During 2008, we drilled 22 (10 net) horizontal Anadarko-Woodford wells. At year-end 2008 our production was over 50 MMcfe per day gross. Our acreage position developed on 160-acre well spacing has multiple years of drilling opportunity.

In the Texas Panhandle, we drilled 118 gross (84 net) wells with 96 percent being completed as producers. Most of these wells targeted the Granite Wash formation in Roberts and Hemphill counties at depths ranging from 11,000-14,000 feet.

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Permian Basin

Our Permian Basin operations cover both west Texas and southeast New Mexico. In total, we drilled 164 gross (117 net) wells in this area during 2008 completing 160 gross (114 net) as producers. Full-year 2008 investment in this area totaled $549 million, or 38 percent of total E&D capital. Our 2008 drilling focused on horizontal oil plays.

In West Texas, a total of 82 gross (59 net) wells were drilled, of which 100 percent were successful. Geologic targets include the Bone Spring, Devonian and Ellenburger formations. In Ward and Reeves Counties drilling totaled 30 gross (25 net) horizontal Third Bone Spring oil wells.

Southeast New Mexico drilling totaled 82 gross (58 net) wells with 95 percent being completed as producers. The primary formations we target in this area are the Abo/Wolfcamp, Morrow, Atoka and Strawn at depths ranging from 9,000-14,000 feet. Our largest investment was in drilling 33 gross (24 net) horizontal Abo/Wolfcamp oil wells during 2008.

Gulf Coast

Our onshore Gulf Coast focus area generally encompasses coastal Texas, south Louisiana and Mississippi. This effort is generally characterized by a greater reliance on three-dimensional (3-D) seismic information for prospect generation, larger potential reserves per well, greater drilling depths and lower success rates.

We also own interests in 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. Our 2008 activity in this area consisted primarily of workovers and recompletions.

Full-year 2008 investment in the Gulf Coast area was $210 million, or 15 percent of total E&D capital. During 2008 we drilled 28 gross (21 net) Gulf Coast wells, realizing a 54 percent success rate. A significant portion of the drilling occurred in Liberty and Hardin Counties, Texas. Targeting the Yegua and Cook Mountain formations at approximately 10,500 feet, we drilled 18 gross (15 net) wells with a success rate of 50 percent.

Other

We have a large development project in Sublette County, Wyoming where we are developing the deep Madison gas formation and constructing a gas processing plant. During 2008 we invested a total of $23.9 million in this project and our cumulative investment in this project is $32.4 million. We presently expect that we will initiate gas sales from this project in 2010. Our total investment, including planned expansion, will approximate $208 million.

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Production and Pricing Information

The following table sets forth certain information regarding the company's production volumes and the average oil and gas prices received:

	Years Ending December 31,		
	2008	**2007**	**2006**
Production Volumes			
Gas (MMcf)	127,444	119,937	124,733
Oil (MBbls)	8,395	7,445	6,529
Equivalent (MMcfe)	177,814	164,607	163,907
Net Average Daily Volumes:			
Gas (MMcf)	348.2	328.6	341.7
Oil (MBbls)	22.9	20.4	17.9
Equivalent (MMcfe)	485.8	451.0	449.1
Average Sales Price			
Gas ($/Mcf)	$8.43	$7.05	$6.50
Oil ($/Bbl)	$96.03	$69.71	$61.96

Total 2008 oil and gas production grew eight percent averaging 485.8 MMcfe per day as compared to 451.0 MMcfe per day in 2007. Gas production in 2008 increased six percent to 348.2 MMcf per day and oil production grew 12 percent to 22,937 barrels per day. The gas volume growth resulted primarily from Texas Panhandle and Anadarko-Woodford shale drilling. The growing oil volume was principally a result of successful horizontal Third Bone Spring and Abo/Wolfcamp drilling in the Permian Basin.

We sold our 2008 gas at an average price of $8.43 per Mcf, which was 20 percent higher than the $7.05 per Mcf we received in 2007. We had natural gas collars for calendar year 2008 covering 40,000 MMBtu per day. The collars increased our 2008 average realized gas price by $0.09 per Mcf. For a discussion of derivatives, see Note 3 of Notes to Consolidated Financial Statements contained herein. Our annual average realized oil price during 2008 increased 38 percent to $96.03 per barrel from $69.71 per barrel in 2007.

Strong global demand and overall tight commodity market conditions for oil, natural gas and natural gas liquids for the first nine months of 2008 resulted in overall higher average realized price in 2008 compared to 2007. During the fourth quarter of 2008, reductions in global economic activity and energy demands caused significant decreases in oil and gas prices. Year-end 2008 oil and gas prices fell 50-70% from their mid-year peak. Our overall average fourth quarter equivalent price realization was approximately 50% below our average third quarter equivalent price.

The following table summarizes Cimarex's daily production by region for 2008 and 2007.

	2008 Average Daily Production			2007 Average Daily Production		
	Oil (MBbl/d)	**Gas (MMcf/d)**	**Total (MMcfe/d)**	**Oil (MBbl/d)**	**Gas (MMcf/d)**	**Total (MMcfe/d)**
Mid-Continent	5.6	190.3	223.9	5.4	160.2	192.3
Permian Basin	12.9	88.6	166.2	9.5	87.2	144.3
Gulf Coast	4.3	65.8	91.3	5.3	75.0	106.9
Other	0.1	3.5	4.4	0.2	6.2	7.5
	22.9	348.2	485.8	20.4	328.6	451.0

Our largest producing area is the Mid-Continent region. During 2008 our Mid-Continent production averaged 223.9 MMcfe per day, or 46 percent of our total 2008 production. Successful drilling programs in the Texas Panhandle and the Anadarko Basin helped boost our Mid-Continent production by 16 percent in

2008. The Permian Basin contributed 166.2 MMcfe per day in 2008, which was 34 percent of our total production for this period. Production increased 15 percent as a result of successful horizontal oil drilling in the Abo/Wolfcamp formations in southeast New Mexico and in the West Texas Third Bone Spring formation. Gulf Coast production averaged 91.3 MMcfe per day during 2008, or 19 percent of total production. Gulf Coast volumes decreased in 2008 as a result of natural production declines and no new drilling in the Gulf of Mexico.

Acquisitions and Divestitures

Cimarex acquired Magnum Hunter Resources, Inc, on June 7, 2005. Magnum Hunter was an independent oil and gas exploration and production company with operations concentrated in the Permian Basin and the Gulf of Mexico. Magnum's oil and gas properties were valued at $1.8 billion and resulted in the addition of 886.7 Bcfe of proved reserves (60 percent gas and 73 percent proved developed).

During 2007 we sold various interests in oil and gas properties located in West Texas, California and Gulf of Mexico. In total we sold 123 Bcfe of proved reserves for $177 million. During 2008 we sold various interests in oil and gas properties located in South Texas. In total we sold 17 Bcfe of proved reserves for $38.1 million.

During 2007 we purchased $40.9 million of assets, with the largest acquisition being in the Texas Panhandle Area. During 2008 we purchased 38,000 acres in western Oklahoma, Anadarko Basin Woodford Shale play for $180.9 million. In total we have approximately 98,000 net acres in the play.

Marketing

Our oil and gas production is sold under various 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 largest customer accounted for ten percent of 2008 revenues. Because over 95 percent of our gas production is from wells in Kansas, Oklahoma, Texas and Louisiana, 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 831 people on December 31, 2008. 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

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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 significantly 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 indirectly 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 may 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.

Certain Risks

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. If any of the following risks and uncertainties develop into actual events, this could have a material adverse affect on our business, financial condition or results of operations and could negatively impact the value of our common stock.

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

The oil and gas markets are very volatile, and we cannot predict future oil and natural gas prices. The price we receive for our oil and natural gas production heavily influences 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, 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, domestic and foreign governmental regulations, proximity and capacity of oil and gas pipelines and other transportation facilities and the price and technological advancement of alternative fuels.

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During the fourth quarter of 2008, severe disruptions in the credit markets and reductions in global economic activity caused significant decreases in oil and gas prices. Oil and gas prices fell 50-70% from the mid-year 2008 peak to the end of the year and 30-60% from the third to the fourth-quarter 2008. The dramatic decrease in prices significantly decreased the amount available to invest in exploration and development drilling, the present value of our proved reserves and our stock price and corresponding market capitalization. As a result of the drop in commodity prices in 2008, we recorded $1.4 billion after-tax, full-cost ceiling test write-down of proved properties book-value.

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. For the foreseeable future, we expect to make substantial capital investments for the exploration and development of new oil and gas reserves to replace the reserves we produce and to increase our total proved reserves. Historically, we have paid for these types of capital expenditures with cash flow provided by our production operations. Low prices also 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 would also be impacted.

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

Accounting rules require that we review the carrying value of our oil and gas properties and goodwill for possible impairment at the end of each reporting period. If prices fall further, we may incur additional impairment charges in the future, which could have a material adverse effect on our results of operations in the period taken.

The global financial crisis may have impacts on our business and financial condition that we currently cannot predict.

The continued credit crisis and related turmoil in the global financial system may have an impact on our business and our financial condition, and we may face challenges if conditions in the financial markets do not improve. Our ability to access the capital markets may be restricted at a time when we would like, or need, to raise financing, which could have an impact on our flexibility to react to changing economic and business conditions. The economic situation could have an impact on our lenders or customers, causing them to fail to meet their obligations to us.

Failure of our exploration and development program to find commercial quantities of new oil and gas reserves could negatively affect our financial results and future rate of growth.

Most of our wells produce from reservoirs characterized by high initial production rates which decline rapidly and stabilize within three to five years. 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. 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 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 from productive wells that do not produce sufficient reserves to return a profit.

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, 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 rigs and related equipment.

The high-rate production characteristics of our properties subject us to high reserve replacement needs and require significant capital expenditures to replace our reserves.

Unless we conduct successful development activities or acquire properties containing proved reserves, our proved reserves will decline as they are produced. Producing natural gas and oil reservoirs are generally characterized by declining production rates that vary depending on reservoir characteristics and other factors. Because of the high-rate production profiles of our properties, replacing produced reserves is more difficult for us than for companies whose reserves have longer-life production profiles. This imposes greater reinvestment risk for our company as we may not be able to continue to economically replace our reserves.

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

Estimates of total proved oil and gas reserves (consisting of proved developed and proved undeveloped reserves) and associated future net cash flow depend on a number of variables and assumptions. Among others, changes in any of the following factors may cause estimates to vary considerably from actual results:

- production rates, reservoir pressure, and other subsurface information;
- future oil and gas prices;
- assumed effects of governmental regulation;
- future operating costs;
- future property, severance, excise and other taxes incidental to oil and gas operations;
- capital expenditures;
- workover and remedial costs; and
- Federal and state income taxes.

The estimation of the category of proved undeveloped reserves can be subject to an even greater possibility of revision. At December 31, 2008, 18 percent of our total proved reserves are categorized as proved undeveloped. Of these proved undeveloped reserves, 89 percent are related to a project in Wyoming.

Our proved oil and gas reserve estimates are prepared by Cimarex engineers in accordance with guidelines established by the Securities and Exchange Commission (SEC). DeGolyer and MacNaughton, independent petroleum engineers, reviewed our reserve estimates for properties that comprised at least 80 percent of the discounted future net cash flows before income taxes, using a 10 percent discount rate, as of December 31, 2008.

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The values 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 prices and costs as of the date of the estimate, whereas actual future prices and costs may be materially different.

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

New or emerging plays have limited or no production history. Consequently, we are unable to use past drilling results in those areas 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, and the value of our undeveloped acreage will 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.

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

The marketability of our oil and natural gas production depends in large part on the availability, proximity and capacity of pipeline systems owned by third parties. The lack of available capacity on these systems and facilities 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, 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.

The differential between the NYMEX or other benchmark price of oil and natural gas and the wellhead price we receive could have a material adverse effect on our results of operations, financial condition and cash flows.

The prices that we receive for our oil and natural gas production generally trade at a discount to the relevant benchmark prices, such as NYMEX, that are used for calculating hedge positions. The difference between the benchmark price and the price we receive is called a differential. We cannot accurately predict oil and natural gas differentials. Increases in the differential between the benchmark price for oil and natural gas and the wellhead price we receive could have a material adverse effect on our results of operations, financial condition and cash flows.

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 and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit.

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

Exploration, development, production and sale of oil and gas are subject to extensive Federal, state and local laws and regulations, including complex environmental laws. We may be required to make large expenditures to comply with environmental and other governmental regulations. Failure to comply with these laws and regulations may result in the suspension or termination of our operations and subject us to

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administrative, civil and criminal penalties. Matters subject to regulation include discharge permits for drilling operations, drilling bonds, spacing of wells, unitization and pooling of properties, environmental protection, and taxation. Our operations create the risk of environmental liabilities to the government or third parties for any unlawful discharge of oil, gas or other pollutants into the air, soil or water. In the event of environmental violations, we may be charged with remedial costs. Pollution and similar environmental risks generally are not fully insurable. Such liabilities and costs could have a material adverse effect on our financial condition and results of operations.

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 percent of our net production. Our success in properties operated by others depends upon a number of factors outside of our control, including 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, and 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, 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, 2008, we had total long-term debt of $591.2 million, consisting of $220 million of bank debt, $350 million of unsecured 7.125% Senior Notes and $21.2 million of Convertible Notes ($19.45 million face value). Subject to the limits contained in the agreements governing our senior revolving credit facility, we would have been able to incur up to $1 billion of debt as of December 31, 2008, only $500 million of which is currently committed. We have demands on our cash resources in addition to interest expense and principal on our long-term debt, 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 our 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, our financial condition, results of operations and prospects 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 and our Convertible Notes bear interest at floating rates.

Our business may not generate sufficient cash flow from operations, nor could there be adequate future sources of capital to enable us to service our indebtedness, or to fund our other liquidity needs. If we are unable to service our indebtedness and fund our operating costs, we will be forced to adopt alternative strategies that may include:

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

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

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

The indentures governing our senior subordinated notes and credit agreement contain various restrictive covenants that may potentially limit our management's discretion in certain respects. In particular, these agreements will 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 3.0 to 1 and a working capital ratio of greater than 1 to 1. Also, the indentures under which we issued our senior unsecured notes restrict us from incurring additional indebtedness, subject to certain exceptions, unless our fixed charge coverage ratio (as defined in the indentures) is at least 2.25 to 1. If we were in violation of this covenant, then we may not incur additional indebtedness above our $1.0 billion revolving credit facility. See Note 6, Long-term Debt, in Notes to Consolidated Financial Statements for further information.

If we fail to comply with the restrictions in the indentures governing our senior notes or 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.

We evaluate opportunities and engage in bidding and negotiating for acquisitions, some of which are substantial. Under certain circumstances, we may pursue acquisitions of businesses that complement or expand our current business and acquisition and development of new exploration prospects that complement or expand our prospect inventory. We may not be successful in identifying or acquiring any material property interests, which could hinder us in replacing our reserves and adversely affect our financial results and rate of growth. Even if we do identify attractive opportunities, there is no assurance that we will be able to complete the acquisition of the business or prospect on commercially acceptable terms. If we do complete an acquisition, we must anticipate difficulties in integrating its operations, systems, technology, management and other personnel with our own. These difficulties may disrupt our ongoing operations, distract our management and employees and increase our expenses.

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. In particular, our Chairman and Chief Executive Officer, F.H. Merelli, has over 48 years of oil and gas experience and is well known in the industry. The loss of his services for any reason could adversely affect our business, revenues and results of 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.

There are inherent limitations in all control systems, and misstatements due to error or fraud may occur and not be detected.

While we have taken actions designed to address compliance with the internal control, disclosure control and other requirements of the Sarbanes-Oxley Act of 2002 and the rules and regulations promulgated by the SEC implementing these requirements, there are inherent limitations in its ability to control all circumstances. See Item 9A of this report for a complete discussion of controls and procedures. Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our internal controls and disclosure controls will prevent all error and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. In addition, the design of a control system must reflect the fact that there are resource constraints and the benefit of controls must be relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, in our company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple errors or mistakes. Further, controls can be circumvented by individual acts of some persons, by collusion of two or more persons, or by management override of the controls. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Over time, a control may be inadequate because of changes in conditions, such as growth of the company or increased transaction volume, or the degree of compliance with the policies or procedures may deteriorate. Because of inherent limitations in a control system, misstatements due to error or fraud may occur and not be detected.

The Cimarex certificate of incorporation, by-laws and stockholders' rights plan include provisions that could discourage an unsolicited corporate takeover and could prevent stockholders from realizing a premium on their investment.

The certificate of incorporation and by-laws of Cimarex provide for a classified board of directors with staggered terms, restrict the ability of stockholders to take action by written consent and prevent stockholders from calling a meeting of the stockholders. In addition, Delaware General Corporation Law imposes restrictions on business combinations with interested parties. Cimarex also has adopted a stockholders' rights plan. The stockholders' rights plan, the certificate of incorporation and the by-laws may have the effect of delaying, deferring or preventing a change in control of Cimarex, even if the change in control might be beneficial to Cimarex stockholders.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Oil and Gas Properties and Reserves

All of our proved reserves and undeveloped acreage are located in the United States. We have varying levels of ownership interests in our properties consisting of working, royalty and overriding royalty interests. We operate the wells that comprise 83 percent of our proved reserves.

Our engineers estimate our proved oil and gas reserve quantities in accordance with guidelines established by the SEC. DeGolyer and MacNaughton, independent petroleum engineers, reviewed our reserve estimates for those properties that comprised at least 80 percent of the discounted value of the projected future net cash flow before income taxes as of December 31, 2008. All information in this Form 10-K relating to oil and gas reserves is net to our interest unless stated otherwise. See Note 16, 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,		
	2008	**2007**	**2006**
Total Proved Reserves			
Gas (MMcf)	1,067,333	1,122,694	1,090,362
Oil, condensate and NGLs (MBbls)	45,202	58,250	59,797
Equivalent (MMcfe)	1,338,545	1,472,195	1,449,146
Standardized measure of discounted future net cash flow after-tax, discounted at 10 percent (in thousands)	$1,724,253	$2,897,631	$2,200,889
Average price used in calculation of future net cash flow			
Gas ($/Mcf)	$5.33	$6.51	$5.54
Oil ($/Bbl)	$36.34	$93.66	$56.91

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Significant Properties

As of December 31, 2008, 79 percent of proved reserves were located in the Mid-Continent and Permian Basin regions. In total we owned an interest in 12,980 gross (4,960 net) productive oil and gas wells.

The following table summarizes our estimated proved oil and gas reserves by region as of December 31, 2008.

	Oil (MBbl)	Gas (Bcf)	Equivalent (Bcfe)	Percent of Proved Reserves
Mid-Continent	7,773	562.5	609.2	46%
Permian Basin	33,542	240.8	442.0	33%
Gulf Coast	3,649	51.8	73.8	5%
Wyoming/Other	238	212.2	213.5	16%
	45,202	1,067.3	1,338.5	100%

Our ten largest producing fields hold 41 percent of our total equivalent proved reserves. We are the principal operator of our production in each of these fields. The table below summarizes certain key statistics about these properties.

Field	Region	% of Total Proved Reserves	Avg. Working Interest	Avg. Depth (feet)	Primary Formation
Riley Ridge	Wyoming	15.7%	56.9%	16,000'	Madison
Watonga-Chichasha	Mid-Continent	4.6%	42.6%	13,000'	Woodford
Eola-Robberson	Mid-Continent	4.4%	92.7%	5,500'-11,000'	Bromide/McLish/Oil Creek
Hemphill	Mid-Continent	3.8%	97.0%	11,000'	Granite Wash
Hugoton	Mid-Continent	3.1%	58.7%	2,600'	Chase
Mendota	Mid-Continent	2.9%	78.5%	11,000'	Granite Wash
Red Deer Creek	Mid-Continent	2.3%	63.1%	11,000'	Granite Wash
Phantom	Permian Basin	1.8%	87.4%	11,500'	Bone Spring
Quail Ridge	Permian Basin	1.7%	66.6%	13,000'	Morrow
East Sour Lake	Gulf Coast	0.7%	72.1%	12,000'	Yegua/Cook Mountain
		41%			

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Acreage

The following table sets forth as of December 31, 2008, the gross and net acres of both developed and undeveloped leases held by Cimarex. 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.

	Undeveloped Acreage		**Developed Acreage**		**Total Acreage**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Mid-Continent						
Kansas	2,727	2,480	156,080	103,914	158,807	106,394
Oklahoma	148,459	125,661	429,061	193,117	577,520	318,778
Texas	126,706	110,940	179,629	110,913	306,335	221,853
	277,892	239,081	764,770	407,944	1,042,662	647,025
Permian Basin						
New Mexico	91,688	70,427	154,478	102,651	246,166	173,078
Texas	60,689	31,380	189,595	117,531	250,284	148,911
	152,377	101,807	344,073	220,182	496,450	321,989
Gulf Coast						
Louisiana	7,623	2,476	19,442	5,558	27,065	8,034
Mississippi	6,851	4,274	25,785	6,919	32,636	11,193
Texas	97,678	53,621	134,137	53,647	231,815	107,268
Offshore	290,862	155,951	218,828	72,116	509,690	228,067
	403,014	216,322	398,192	138,240	801,206	354,562
Other						
Arkansas	870	55	5,190	1,616	6,060	1,671
Arizona	914,695	914,695			914,695	914,695
California	1,061	407	364	364	1,425	771
Colorado	107,277	18,800	27,971	6,498	135,248	25,298
Illinois	1,782	1,191	554	183	2,336	1,374
Michigan	57,729	57,729	598	598	58,327	58,327
Montana	42,946	13,077	10,646	2,871	53,592	15,948
Nebraska	4,560	116	1,043	168	5,603	284
Nevada	160	1	440	1	600	2
New Mexico	1,640,553	1,622,486	16,011	2,708	1,656,564	1,625,194
North Dakota	66,492	29,091	14,953	1,820	81,445	30,911
South Dakota	10,482	9,329	2,414	373	12,896	9,702
Utah	104,764	59,351	33,950	2,543	138,714	61,894
Wyoming	237,304	28,028	113,589	22,968	350,893	50,996
	3,190,675	2,754,356	227,723	42,711	3,418,398	2,797,067
	4,023,958	3,311,566	1,734,758	809,077	5,758,716	4,120,643

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Gross Wells Drilled

We participated in drilling the following number of gross wells during calendar years 2008, 2007, and 2006:

	Exploratory			Developmental		
	Productive	**Dry**	**Total**	**Productive**	**Dry**	**Total**
Year ended December 31, 2008	36	16	52	384	14	398
Year ended December 31, 2007	55	18	73	361	18	379
Year ended December 31, 2006	20	32	52	490	16	506

We were in the process of drilling 31 gross (22 net) wells at December 31, 2008.

Net Wells Drilled

The number of net wells we drilled during calendar years 2008, 2007, and 2006 are shown below:

	Exploratory			Developmental		
	Productive	**Dry**	**Total**	**Productive**	**Dry**	**Total**
Year ended December 31, 2008	25.9	13.6	39.5	226.5	10.9	237.4
Year ended December 31, 2007	36.7	13.1	49.8	221.9	9.6	231.5
Year ended December 31, 2006	12.4	23.9	36.3	303.7	6.2	309.9

Productive Wells

We have working interests in the following productive wells as of December 31, 2008:

	Gas		Oil	
	Gross	**Net**	**Gross**	**Net**
Mid-Continent	3,931	2,044	1,021	540
Permian	1,060	591	5,779	1,506
Gulf Coast	493	161	207	94
Other	108	8	381	16
	5,592	2,804	7,388	2,156

ITEM 3. LEGAL PROCEEDINGS

In January 2009, the Tulsa County District Court issued a judgment in the H.B. Krug, et al versus Helmerich & Payne, Inc. ("H&P") case. This lawsuit was originally filed in 1998 and addresses H&P's conduct pertaining to a 1989 take-or-pay settlement, along with potential drainage issues and other related matters. Damages of $6.9 million plus $119.5 million for disgorgement of H&P's estimated potential compounded profit since 1989, resulting from the noted damages, were awarded to plaintiff royalty owners, for a total of $126.4 million. This amount was subsequently adjusted by the court to a total of $119.6 million. 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. We periodically assess the probability of estimable amounts related to litigation matters, as required by Financial Accounting Standard No. 5 (*Accounting for Contingencies)* and adjust our accruals accordingly. In September 2008, based on the available information at the time, we accrued an estimated litigation expense of $12 million for both damages and probable disgorgement. The higher disgorgement award could not be reasonably estimated until the final judgment in January 2009. We therefore accrued an additional $107.6 million, bringing the total accrued litigation expense for the year ended December 31, 2008 to $119.6 million for this lawsuit. We have appealed the District Court's judgments.

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As of December 31, 2008, in the normal course of business, we have other various litigation related matters and associated accruals. 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.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

No matters were submitted for a vote of security holders during the fourth quarter of 2008.

ITEM 4A. EXECUTIVE OFFICERS

The executive officers of Cimarex as of February 27, 2009 were:

Name	Age	Office
F.H. Merelli	72	Chairman of the Board, Chief Executive Officer, and President
Joseph R. Albi	50	Executive Vice President, Operations
Thomas E. Jorden	51	Executive Vice President, Exploration
Stephen P. Bell	54	Senior Vice President, Business Development and Land
Paul Korus	52	Vice President, Chief Financial Officer, and Treasurer
Gary R. Abbott	36	Vice President, Corporate Engineering
Richard S. Dinkins	64	Vice President, Human Resources
James H. Shonsey	57	Vice President, Chief Accounting Officer, and Controller
Thomas A. Richardson	63	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 was elected chairman of the board, chief executive officer, and president on September 30, 2002. 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.

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

THOMAS E. JORDEN was named executive vice president of exploration on December 8, 2003 and has 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.

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 elected vice president, chief financial officer and treasurer on September 30, 2002. Mr. Korus was vice president and chief financial officer of Key Production Company, Inc. from September 1999 to September 2002. Prior to September 1999 and since June 1995, Mr. Korus was an equity research analyst with Petrie Parkman & Co., an investment banking firm.

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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 of $.06 per share was paid to shareholders in each quarter of 2008. 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.

2008	High	Low	Dividends Paid Per Share
First Quarter	$56.53	$37.03	$ .06
Second Quarter	$74.50	$54.35	$ .06
Third Quarter	$72.00	$42.85	$ .06
Fourth Quarter	$48.94	$22.38	$ .06

2007	High	Low	Dividends Paid Per Share
First Quarter	$38.07	$34.06	$ .04
Second Quarter	$42.87	$36.99	$ .04
Third Quarter	$42.01	$33.83	$ .04
Fourth Quarter	$42.86	$36.88	$ .04

The closing price of Cimarex stock as reported on the New York Stock Exchange on February 18, 2009, was $21.82. At December 31, 2008, Cimarex's 83,258,632 shares of outstanding common stock were held by approximately 4,356 stockholders of record.

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 is currently set to expire on December 31, 2009. Through December 31, 2007, we had repurchased and cancelled a total of 1,364,300 shares at an overall average price of $39.05. Purchases may be made in both the open market and through negotiated transactions, and purchases may be increased, decreased or discontinued at any time without prior notice. There were no shares repurchased in the fourth quarter of 2008, or since the quarter ended September 30, 2007.

Issuer Purchases of Equity Securities for the Quarter Ended December 31, 2008

	Total Number of Shares purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of shares that may yet be Purchased Under the Plans or Programs
October, 2008	None	NA	None	2,635,700
November, 2008	None	NA	None	2,635,700
December, 2008	None	NA	None	2,635,700

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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 Form 10-K.

	For the Years Ended December 31,				
	2008	2007	2006	2005	2004
Operating results:					
Revenues	$1,970,347	$1,430,513	$1,265,400	$1,117,241	$ 475,164
Net income (loss)	(901,685)	346,469	345,719	328,325	153,592
Basic earnings (loss) per share	(11.07)	4.23	4.21	5.07	3.70
Diluted earnings (loss) per share	(11.07)	4.09	4.11	4.90	3.59
Cash dividends declared per share	.24	.18	.16		
Balance sheet data:					
Total assets	4,164,933	5,362,794	4,829,750	4,180,335	1,105,446
Total debt	591,223	487,159	443,667	352,451	
Stockholders' equity	2,349,365	3,259,287	2,976,143	2,595,453	700,712
Other financial data:					
Oil and gas sales	1,880,891	1,364,622	1,215,411	1,072,422	472,389
Oil and gas capital expenditures	1,620,778	1,023,434	1,074,673	2,462,826	296,429
Proved Reserves:					
Gas (MMcf)	1,067,333	1,122,694	1,090,362	1,004,482	364,641
Oil (MBbls)	45,202	58,250	59,797	64,710	14,063
Total equivalent (MMcfe)	1,338,545	1,472,195	1,449,146	1,392,742	449,020

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. Certain amounts in prior years' financial statements have been reclassified to conform to the 2008 financial statement presentation. This discussion also includes forward- looking statements. Please refer to "Cautionary Information about Forward- Looking Statements" in Part I of this Form 10-K for important information about these types of statements.

OVERVIEW

We are an independent oil and gas exploration and production company with operations entirely located in the United States. 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.

We seek to achieve profitable growth in proved reserves and production primarily through exploration and development. We generally fund our growth with cash flow provided by our operating activities. 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. Our oil and gas reserves and operations are mainly located in Texas, Oklahoma, New Mexico, Kansas, Louisiana and Wyoming.

To supplement our growth and to provide for new drilling opportunities, we also consider mergers and acquisitions. In 2005 we acquired Magnum Hunter Resources, Inc, in a stock-for-stock merger with a total transaction value of approximately $2.1 billion. Magnum Hunter was a Dallas-based independent oil and gas exploration and production company with operations concentrated in the Permian Basin of West Texas

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and New Mexico and in the Gulf of Mexico. During 2007 we purchased $40.9 million of assets, with the largest acquisition being in the Texas Panhandle area. In October 2008 we acquired 38,000 net acres in our western Oklahoma, Anadarko Basin Woodford shale play, at a total cost of $180.9 million. We have increased our position in the play to approximately 98,000 net acres.

From time to time we also consider selling certain assets. In 2007, we sold $177.0 million of non-core properties. The two largest sales were $87.5 million for our West Texas Spraberry oil properties and $53.5 million for our Gulf of Mexico Main Pass area operated properties. During 2008, we sold 17 Bcfe of proved reserves for $38.1 million.

Market Conditions

During the fourth quarter of 2008, severe disruptions in the credit markets and reductions in global economic activity caused significant decreases in oil and gas prices. The dramatic decrease in prices had a significant adverse impact on the amount of cash flow available to invest in exploration and development drilling, the present value of our proved reserves, our stock price and market capitalization.

The continued credit crisis and related turmoil in the global financial system may have further impact on our business and our financial position if conditions in the financial markets do not improve. Our ability to access the capital markets may be restricted, which could have an impact on our flexibility to react to changing economic and business conditions. Further, the economic situation could have an impact on our lenders or customers, causing them to fail to meet their obligations to us.

As a result of lower commodity prices we have sharply reduced our drilling activity. Our exploration and development capital investment is expected to decrease from $1.4 billion in 2008 to $400-$600 million in 2009, depending on prices and corresponding cash flow.

2008 Summary

During 2008 we accomplished the following positive operating and financial highlights:

- Oil and gas sales increased 38 percent to a record $1.9 billion.
- Cash flow from operating activities increased 37 percent to an all-time high of $1,367.5 million.
- Production averaged 485.8 MMcfe per day in 2008, increasing throughout the year to a fourth quarter peak of 493.7 MMcfe per day.
- Added 215 Bcfe of proved reserves from extensions, discoveries and improved recovery, replacing 121 percent of production.
- Increased our western Oklahoma, Anadarko-Woodford position to 98,000 net acres, including a $180.9 million purchase of 38,000 net acres.
- Ended the year with a debt to total capitalization ratio of 20 percent.

However, largely as a result of the collapse in oil and gas prices we also experienced the following negative consequences:

- $1.4 billion after-tax, non-cash full-cost ceiling test write-down of oil and gas properties.

Negative price-related revisions to proved reserves of 157 Bcfe, resulting in an overall 9% decrease in our proved reserves to 1.3 Tcfe.

Oil and Gas Prices

While our revenues are a function of both production and prices, wide swings in prices have had the greatest impact on our results of operations. Our annual average realized gas price increased from $7.05

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per Mcf in 2007 to $8.43 per Mcf in 2008; and oil prices increased from $69.71 per barrel in 2007 to $96.03 per barrel in 2008.

Strong global demand and overall tight commodity market conditions for oil, natural gas and natural gas liquids for the first nine months of 2008 resulted in overall higher average realized prices in 2008 compared to 2007. During the fourth quarter of 2008, reductions in global economic activity and energy demands caused significant decreases in oil and gas prices. Year-end 2008 oil and gas prices fell 50-70% from their mid-year peak. Our overall average fourth quarter equivalent price realization was approximately 50% below our average third quarter equivalent price.

In addition to supply and demand, oil and gas prices are affected by seasonal, economic and geo-political factors that we can neither control nor predict. However, we made limited use of hedging transactions during 2007 and 2008 to somewhat reduce price risk as discussed further below.

	Years Ended December 31,		
	2008	**2007**	**2006**
Gas Prices:			
Average Henry Hub price ($/Mcf)	$ 9.04	$ 6.86	$ 7.23
Average realized sales price ($/Mcf)	$ 8.43	$ 7.05	$ 6.50
Effect of hedges ($/Mcf)	$ 0.09	$ 0.23	$
Oil Prices:			
Average WTI Cushing price ($/Bbl)	$99.65	$72.28	$66.22
Average realized sales price ($/Bbl)	$96.03	$69.71	$61.96

On an energy equivalent basis, 72% of our 2008 aggregate production was natural gas. A $0.10 per Mcf change in our average realized gas sales price would have resulted in approximately a $12.7 million change in our gas revenues. Similarly, 28% of our production was crude oil. A $1.00 per barrel change in our average realized crude oil sales price would have resulted in approximately an $8.4 million change in our oil revenues.

In July 2006 we entered into certain derivative contracts covering approximately 24% of our overall 2007 gas production and 11% of our 2008 gas volumes. We executed cash flow effective hedges by purchasing $7.00/MMbtu put options on a portion of our 2007 and 2008 Mid-Continent gas production. We used the proceeds from selling call options on the same volume of gas to pay for the puts, thus establishing what is commonly known as a "zero-cost collar." We hedged 29.2 million MMbtu and 14.6 million MMbtu for 2007 and 2008, respectively. See Note 3 to the Consolidated Financial Statements for additional information regarding our derivative instruments.

Reserve replacement and Growth

Because oil and gas are non-renewable forms of energy resources, exploration and production companies face the challenge of resource depletion and natural production decline. Our operations also entail significant complexities that require the use of advanced technologies and highly trained personnel. Even when modern exploration technology is properly used, the interpreter still may not know conclusively if hydrocarbons will be present, the rate at which they will be produced, or economic viability. Future growth will continue to depend upon our ability to economically add reserves in excess of production.

Year end 2008 total proved oil and gas reserves decreased by 9% from 1.47 Tcfe to 1.34 Tcfe. This decrease includes production of 177.8 Bcfe, property sales of 16.8 Bcfe and negative price related revisions of 156.8 Bcfe. Proved natural gas reserves at year-end 2008 were 1.07 Tcf compared to 1.12 Tcf at year-end 2007. Natural gas comprised 80% and 76% of our total proved reserves at year-end 2008 and 2007, respectively. Our proved oil reserves at year-end 2008 were 45.2 MMBbls compared to 58.3 MMBbls at the end of 2007. Overall, about 46% of our proved reserves are in our Mid-Continent region and 33% are in

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the Permian Basin. Our onshore Gulf Coast and other onshore operations collectively make another 20% of total proved reserves. Only 1% of our total proved reserves are in the Gulf of Mexico.

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 reserve estimates reported 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. For 2008, negative revisions resulting from lower oil and gas prices and higher lease operating expenses decreased proved reserves by 12% on December 31, 2008. See Note 16, Supplemental Oil and Gas Disclosures for more reserve information.

In most years our primary source for reserve replacement and growth is exploration and development (E&D). We invested $1,438.4 million on E&D during 2008 and $982.5 million in 2007. Approximately 45% of 2008 expenditures were in the Mid-Continent area, 38% in the Permian Basin, 15% in the Gulf Coast area, and 2% in Western/other. Cash flow from operating activities for 2008 totaled $1,367.5 million, which largely funded our drilling program.

As a result of expected lower commodity prices and corresponding cash flow we project that 2009 exploration and development expenditures will range from $400 million to $600 million.

Production and other operating expenses

The costs associated with finding and producing oil and gas are substantial. Some of these costs vary with oil and gas prices, some trend with production volume and some are a function of the number of wells we own. At the end of 2008, we owned interests in 12,980 wells.

Production expense generally consists of the cost of power and fuel, direct labor, third-party field services, compression, water disposal, and certain maintenance activity 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.

Depreciation, depletion and amortization (DD&A) of our producing properties is computed using the units-of-production method. Because the economic life of each producing well depends upon the assumed price for future sales of production, fluctuations in oil and gas prices may impact the level of proved reserves used in the calculation. Higher prices generally have the effect of increasing reserves, which reduces depletion expense, while lower prices generally have the effect of decreasing reserves, which increases depletion expense. In addition, changes in estimates of reserve quantities and estimates of future development costs or 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.

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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.

Significant expenses that generally do not trend with production

Stock compensation expense consists of non-cash charges resulting from the issuance of restricted stock and restricted stock units to certain employees and the expensing of stock options resulting from the adoption of SFAS No. 123R, *Share Based Payment*. Net stock compensation expense in 2008 was $10.1 million compared to $10.8 million in 2007.

The derivative fair value (gain) loss is the net realized and unrealized gain or loss on derivative financial instruments that do not qualify for hedge accounting treatment and fluctuates based on changes in the fair value of underlying commodities. As of December 31, 2006 all contracts associated with derivative instruments that did not qualify for hedge accounting treatment had settled. The net derivative fair value gain was $23.0 million in 2006.

RESULTS OF OPERATIONS

2008 compared to 2007

We recognized a net loss for 2008 of $901.7 million or $11.07 per share. This compares to net income of $346.5 million, or $4.09 per diluted share for the same period in 2007. The decrease in net income is primarily the result of a non-cash full cost ceiling write-down recorded in the third and fourth quarters of 2008. The full cost ceiling impairment is discussed further in the operating costs and expenses section below.

Oil and Gas Sales	**For the Years Ended December 31,**		**Percent Change Between**	**Price/Volume Analysis**		
(In thousands or as indicated)	**2008**	**2007**	**2008/2007**	**Price**	**Volume**	**Variance**
Gas sales	$1,074,705	$ 845,631	27%	$175,873	$ 53,201	$229,074
Oil sales	806,186	518,991	55%	220,956	66,239	287,195
Total oil and gas sales	$1,880,891	$1,364,622	38%	$396,829	$119,440	$516,269
Total gas volume Mcf	127,444	119,937	6%			
Gas volume MMcf per day	348.2	328.6				
Average gas price per Mcf	$ 8.43	$ 7.05	20%			
Effect of hedges per Mcf	$ 0.09	$ 0.23				
Total oil volume thousand barrels	8,395	7,445	13%			
Oil volume barrels per day	22,937	20,399				
Average oil price per barrel	$ 96.03	$ 69.71	38%			

Oil and gas sales during 2008 totaled $1.9 billion, compared to $1.4 billion in 2007. Of the $516.3 million increase in sales between the two periods, $396.8 million related to higher prices and $119.4 million resulted from higher production volumes.

Compared to 2007, our 2008 oil production increased by 13% to an average of 22,937 barrels per day in 2008. This increase resulted in $66.2 million of incremental revenues. Gas volumes averaged 348.2 MMcf per day in 2008 compared to 328.6 MMcf per day in 2007, resulting in an increase in revenues of $53.2 million. Total 2008 oil and gas production volumes were 485.8 MMcfe per day, up 34.8 MMcfe per day from 2007. Both our gas and oil volumes increased as 2008 unfolded. During the fourth quarter of 2008, our gas production averaged 350.3 MMcf per day up from 341.1 MMcf per day (a three percent increase) in the fourth quarter of 2007. Fourth quarter oil production increased by 10% to 23,907 barrels per day, up from 21,680 barrels per day in 2007.

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Average realized gas prices increased by 20% to $8.43 per Mcf in 2008, compared to $7.05 per Mcf for 2007. This price increase boosted gas sales by $175.9 million between the two periods. Included in our 2008 realized gas price is $11.3 million of cash receipts (a positive $0.09 per Mcf effect) from settlement of cash flow hedges on 40,000 MMBtu per day of Mid-Continent gas production.

Realized oil prices averaged $96.03 per barrel during 2008, compared to $69.71 per barrel in 2007. The increase in oil sales resulting from this 38% improvement in oil prices totaled $221.0 million.

Changes in realized gas and oil prices were mostly the result of overall market conditions and our modest gas hedging program.

	For the Years Ended December 31,	
	2008	**2007**
Gas Gathering, Processing and Marketing (in thousands):		
Gas gathering, processing and other revenues	$ 87,757	$ 60,818
Gas gathering and processing costs	(43,838)	(29,860)
Gas gathering and processing margin	$ 43,919	$ 30,958
Gas marketing revenues, net of related costs	$ 1,699	$ 5,073

We sometimes transport, process and market third-party gas that is associated with our gas. In 2008, third-party gas gathering and processing contributed $43.9 million of pre-tax cash operating margin (revenues less direct cash expenses) versus $31 million in 2007. Our gas marketing margin (revenues less purchases) decreased to $1.7 million in 2008 from $5.1 million in 2007. Changes in net margins from gas gathering, processing and marketing activities are the direct result of changes in volumes and overall market conditions.

	For the Years Ended December 31,		Variance Between
	2008	**2007**	**2008/2007**
Operating costs and expenses (in thousands):			
Impairment of oil and gas properties	$2,242,921	$	$2,242,921
Depreciation, depletion and amortization	547,404	461,791	85,613
Asset retirement obligation	8,796	8,937	(141)
Production	218,736	201,512	17,224
Transportation	38,107	26,361	11,746
Taxes other than income	130,490	93,630	36,860
General and administrative	44,500	49,260	(4,760)
Stock compensation	10,090	10,772	(682)
Other operating, net	126,433	6,637	119,796
	$3,367,477	$858,900	$2,508,577

Total operating costs and expenses (not including gas gathering, marketing and processing costs, or income tax expense) increased to $3,367.5 million in 2008 compared to $858.9 million in 2007.

The largest component of the increase between periods is the non-cash impairment of oil and gas properties in the amount of $2.2 billion ($1.4 billion, net of tax) that was recorded as a result of declines in natural gas and oil prices during the last half of 2008. At September 30, 2008, our ceiling limitation calculation resulted in excess capitalized costs of $657.1 million ($417.4 million, net of tax), for which we recorded a non-cash impairment of oil and gas properties. As a result of further declines in natural gas and oil prices during the fourth quarter of 2008, we recorded an additional non-cash impairment of oil and gas properties. Electing to use period end prices, at December 31, 2008, our ceiling limitation calculation

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resulted in excess capitalized costs of $1.6 billion ($1.0 billion after tax). Due to the volatility of oil and gas prices and because the ceiling calculation requires that prices in effect as of the last day of the period be held constant in valuing proved reserves, we may be required to record a ceiling test write-down in future periods. The full cost method of accounting is discussed in detail under "Critical Accounting Policies and Estimates".

DD&A increased $85.6 million between periods from $461.8 million in 2007 to $547.4 million in 2008. On a unit of production basis, DD&A was $3.08 per Mcfe in 2008 compared to $2.81 per Mcfe for 2007. The increase stems from replacement costs for reserves added being higher than costs of reserves produced. Service costs to drill and complete wells have been increasing and we are drilling deeper and more complex wells. Additionally, the significant decrease in oil and gas prices over the last half of 2008 reduced the amount of our estimated reserve quantities (future production), causing an increase in our depletion rate. Due to the reduction to the carrying value of oil and gas properties recorded at year end we expect the DD&A rate to be lower in the first quarter of 2009 in comparison to the full year 2008.

Production costs rose $17.2 million, or nine percent, from $201.5 million ($1.22 per Mcfe) in 2007 to $218.7 million ($1.23 per Mcfe) in 2008. This increase resulted from an eight percent increase in production volumes and a $7.4 million increase in workover expense between periods.

Transportation costs increased from $26.4 million in 2007 to $38.1 million in 2008. The increase is the result of higher sales volumes, increased market rates and a higher fuel cost component due to higher natural gas prices during the year.

Taxes other than income were $36.9 million greater, rising from $93.6 million in 2007 to $130.5 million in 2008. The increase between periods resulted from increases in oil and gas sales stemming from higher production volumes and commodity prices.

General and administrative (G&A) expenses decreased $4.8 million from $49.3 million in 2007 to $44.5 million in 2008. The decrease between periods is due to lower employee-benefit costs due to a decrease in bonus and profit sharing expenses resulting from significant decreases in commodity prices during the last quarter of 2008.

In 2008, the increase in Other operating, net to $126.4 million from $6.6 million was primarily related to the Tulsa County District Court issuing a judgment in the H.B. Krug case. The total accrued litigation expense for the year ended December 31, 2008 for this lawsuit is $119.6 million. We have appealed the District Court's judgments. For further information on this lawsuit and other litigation please see Contingencies under "Critical Accounting Policies and Estimates".

Other income and expense

Interest expense decreased by $5.9 million, or 16%, primarily because of a decrease in our average bank debt outstanding during the year. In addition, in comparison to prior year, we experienced a decrease in our average interest rate on both our bank borrowings and convertible notes. Capitalized interest increased by $2.4 million mainly because we had more costs incurred to develop our unproved properties than we had in 2007. We also had a gain on the repurchase of convertible notes of $9.6 million compared to a $5.1 million gain in 2007 on the early extinguishment of debt arising from redemption of our $195 million face value of 9.6% senior unsecured notes.

Other, net decreased from $14.2 million of income in 2007 to $10.3 million of income in 2008. Components consist of miscellaneous income and expense items that will vary from period to period, including income and loss in equity investees, gain or loss on sale of inventory, impairments and interest income. Included in our 2008 Other, net is $16.0 million of impairment expense on our equity investments and $0.8 million of impairment on our short-term investments. These additional expenses were offset by a $17.2 million increase in gain on sale of inventory in comparison to 2007. Another element of the decrease between periods is lower income of $4.2 million from equity investees.

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Income tax

During 2008, a net deferred income tax benefit of $528.6 million was recognized (the year end deferred tax benefit included $66.2 million of income tax expense). This compares with 2007 current taxes of $30.6 million and deferred income tax expense of $167.5 million. The combined Federal and state effective income tax rates were 37.0% and 36.4% in the years of 2008 and 2007, respectively. The effective tax rate of 37.0% for 2008 differs from the statutory rate due to effects of the domestic production activities deduction and percentage depletion.

RESULTS OF OPERATIONS

2007 compared to 2006

Net income for 2007 was $346.5 million, or $4.09 per diluted share. This compares to net income of $345.7 million, or $4.11 per diluted share in 2006. The small change in year-over-year net income is generally the result of higher oil and gas sales being offset by higher costs and expenses.

Oil and Gas Sales	**For the Years Ended December 31,**		**Percent Change Between**	**Price/Volume Analysis**		
(In thousands or as indicated)	**2007**	**2006**	**2007/2006**	**Price**	**Volume**	**Variance**
Gas sales	$ 845,631	$ 810,894	4%	$ 65,965	$ (31,228)	$ 34,737
Oil sales	518,991	404,517	28%	57,699	56,775	114,474
Total oil and gas sales	$ 1,364,622	$ 1,215,411	12%	$ 123,664	$ 25,547	$ 149,211
Total gas volume Mcf	119,937	124,733	(4)%			
Gas volume MMcf per day	328.6	341.7				
Average gas price per Mcf	$ 7.05	$ 6.50	8%			
Effect of hedges per Mcf	$ 0.23	$				
Total oil volume thousand barrels	7,445	6,529	14%			
Oil volume barrels per day	20,399	17,887				
Average oil price per barrel	$ 69.71	$ 61.96	13%			

Oil and gas sales during 2007 totaled $1.4 billion, compared to $1.2 billion in 2006. Of the $149.2 million increase in sales between the two periods, $25.6 million related to higher production volumes and $123.7 million resulted from higher prices.

Compared to 2006, our 2007 oil production increased by 14% to an average of 20,399 barrels per day in 2007. This increase resulted in $56.8 million of incremental revenues. Gas volumes averaged 328.6 MMcf per day in 2007 compared to 341.7 MMcf per day in 2006, resulting in a decrease in revenues of $31.2 million. Total 2007 oil and gas production volumes were 451 MMcfe per day, up 2 MMcfe per day from 2006. Both our gas and oil volumes increased as 2007 unfolded. During the fourth quarter of 2007, our gas production averaged 341.1 MMcf per day up from 329.4 MMcf per day (a 4% increase) in the fourth quarter of 2006. Fourth quarter oil production increased by 17% to 21,680 barrels per day, up from 18,587 barrels per day in 2006.

Average realized gas prices increased by 8% to $7.05 per Mcf in 2007, compared to $6.50 per Mcf for 2006. This price increase boosted gas sales by $65.9 million between the two periods. Included in our 2007 realized gas price is $27.8 million of cash receipts (a positive $0.23 per Mcf effect) from settlement of cash flow hedges on 80,000 MMBtu per day of Mid-Continent gas production. We currently have 40,000 MMBtu per day of our Mid-Continent gas production hedged for 2008 at a floor price of $7.00/MMBtu.

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Realized oil prices averaged $69.71 per barrel during 2007, compared to $61.96 per barrel in 2006. The increase in oil sales resulting from this 13% improvement in oil prices totaled $57.7 million.

Changes in realized gas and oil prices were mostly the result of overall market conditions and our modest gas hedging program. We did not have any cash flow effective hedges in place for 2006 volumes.

	For the Years Ended December 31,	
	2007	**2006**
Gas Gathering, Processing and Marketing (in thousands):		
Gas gathering and processing revenues	$ 60,818	$ 46,135
Gas gathering and processing costs	(29,860)	(25,666)
Gas gathering and processing margin	$ 30,958	$ 20,469
Gas marketing revenues, net of related costs	$ 5,073	$ 3,854

We sometimes transport, process and market third-party gas that is associated with our gas. In 2007, third-party gas gathering and processing contributed $31 million of pre-tax cash operating margin (revenues less direct cash expenses) versus $20.5 million in 2006. Our gas marketing margin (revenues less purchases) increased to $5.1 million in 2007 from $3.9 million in 2006. Increases in net margins from gas gathering, processing and marketing activities are the direct result of increased volumes and overall market conditions.

	For the Years Ended December 31,		Variance Between
	2007	**2006**	**2007/2006**
Operating costs and expenses (in thousands):			
Depreciation, depletion and amortization	$461,791	$396,394	$ 65,397
Asset retirement obligation	8,937	7,018	1,919
Production	201,512	176,833	24,679
Transportation	26,361	21,157	5,204
Taxes other than income	93,630	91,066	2,564
General and administrative	49,260	42,288	6,972
Stock compensation	10,772	8,243	2,529
Other operating, net	6,637	2,064	4,573
Gain on derivative instruments		(22,970)	22,970
	$858,900	$722,093	$136,807

Total operating costs and expenses (not including gas gathering, marketing and processing costs, or income tax expense) increased to $858.9 million in 2007 compared to $722.1 million in 2006.

DD&A was the largest component of the increase between periods. DD&A totaled $461.8 million in 2007 compared to $396.4 million in 2006. On a unit of production basis, DD&A was $2.81 per Mcfe in 2007 compared to $2.42 per Mcfe for 2006. The increase stems from replacement costs for reserves added being higher than costs of reserves produced. Service costs to drill and complete wells have been increasing and we are drilling deeper and more complex wells.

Production costs rose $24.7 million from $176.8 million ($1.08 per Mcfe) in 2006 to $201.5 million ($1.22 per Mcfe) in 2007. We have experienced higher direct labor cost, higher third-party field service costs, increased electricity rates and greater water disposal costs.

Transportation costs increased from $21.2 million in 2006 to $26.4 million in 2007. The increase is the result of higher sales volumes and that expiring contracts are being renewed with increased current market rates.

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General and administrative (G&A) expenses increased $7.0 million from $42.3 million in 2006 to $49.3 million in 2007. The increase between periods is due to an expansion of staff, higher average salaries, higher employee-benefit costs, and increased legal representation costs.

In 2007, the increase in Other operating, net to $6.6 million from $2.1 million was primarily related to resolution of and accruals related to title and royalty issues.

Another component of change in total operating costs and expenses between 2007 and 2006 stems from the $23 million derivative fair value gain we recognized in 2006. This gain was associated with price risk management contracts that were not designated for hedge accounting. These contracts all expired on December 31, 2006.

Other income and expense

Interest expense increased by $8 million, or 27%, primarily because of a 10% increase in our total debt outstanding at an average interest rate of 7.1%. Capitalized interest decreased by $4.6 million mainly because we are carrying less value associated with unproved properties than we were in 2006. We also had a gain in 2007 on the early extinguishment of debt arising from redemption of our $195 million face value of old 9.6% senior unsecured notes. We replaced the old notes with new ten-year, 7.125% senior unsecured notes.

Other, net decreased from $28.6 million of income in 2006 to $14.2 million of income in 2007. Components consist of miscellaneous income and expense items that will vary from period to period, including income and loss in equity investees, gain or loss on sale of inventory and interest income. The decrease from 2006 to 2007 is due primarily to the 2006 liquidation of the Company's investment in the Company's limited partnership affiliates, Teal Hunter L.P. and Mallard Hunter L.P. Excess distributions of $19.8 million from this liquidation were recorded during 2006. In 2007, we received an additional distribution from this liquidation in the amount of $3.0 million.

Income tax expense

Income tax expense totaled $198.2 million for 2007 versus $198.6 million for 2006. The combined federal and state effective income tax rate was 36.4% and 36.5% in 2007 and 2006, respectively. Included in the 2007 income tax expense of $198.2 million was a current tax expense of $30.6 million.

LIQUIDITY AND CAPITAL RESOURCES

Overview

The world's economy is being driven by the economic downturn and continuing credit crisis. These constraints, in turn, have pulled down energy prices because of slowing demand. If the capital and credit markets continue to experience volatility or prices continue to decline, and the availability of funds remains limited, we, and third parties with whom we do business, will continue to be negatively impacted. This could lead to losses associated with uncollectible receivables as well as affect our ability to advance our strategic plans as currently anticipated.

To adapt to current conditions and to prepare for an eventual economic upswing, we have focused on maintaining liquidity, promoting operational efficiency, and expanding long-term reserves through focused drilling projects and potential acquisitions. Historically our exploration and development expenditures and dividend payments have generally been funded by cash flow provided by operating activities ("operating cash flow"). With the intent to continue to operate within our operating cash flows, we have significantly scaled back our planned 2009 drilling program, focusing on our highest rate of return projects which are primarily in our Woodford Shale position in the Anadarko Basin of Western Oklahoma and our south Texas Yegua and Cook Mountain play. With this reduced capital program, we believe that our operating cash flow and other capital resources will be adequate to fund our planned 2009 capital expenditures.

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Because our 2009 exploration program has been reduced, we may not be able to replace the reserves in 2009.

Sources and Uses of Cash

Our primary sources of liquidity and capital resources are cash flow from operating activities, occasional property sales, borrowings under our bank credit facility and public offerings of debt securities. Our primary uses of funds are exploration and development, property acquisitions, common stock dividends and occasional share repurchases.

The following table presents the sources and uses of our cash and cash equivalents from 2006 to 2008. 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 document.

	For the Years Ended December 31.		
	2008	**2007**	**2006**
		(in thousands)	
Sources of cash and cash equivalents:			
Operating cash flow	$ 1,367,488	$ 994,680	$ 878,419
Proceeds from sale of assets	39,096	177,195	10,705
Net increase in bank debt	220,000		95,000
Distributions from equity investees	39	3,015	59,823
Sales of short term investments	10,679	1,424	
Increase in other long-term debt		350,000	
Proceeds from issuance of common stock and other	13,141	9,886	4,311
Total sources of cash and cash equivalents	1,650,443	1,536,200	1,048,258
Uses of cash and cash equivalents:			
Oil and gas expenditures	(1,594,775)	(1,021,456)	(1,054,581)
Merger related costs			(439)
Purchase of short-term investments		(16,000)	
Other expenditures	(51,757)	(19,574)	(25,310)
Net decrease in bank debt		(95,000)	
Decrease in other long-term debt	(105,550)	(204,360)	
Financing costs incurred	(158)	(6,113)	(153)
Treasury stock acquired and retired		(42,266)	(11,016)
Dividends paid	(20,040)	(13,429)	(13,358)
Total uses of cash and cash equivalents	(1,772,280)	(1,418,198)	(1,104,857)
Net increase (decrease) in cash and cash equivalents	$ (121,837)	$ 118,002	$ (56,599)
Cash and cash equivalents at end of year	$ 1,213	$ 123,050	$ 5,048

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

Cash flow provided by operating activities for 2008 was $1,367.5 million, compared to $994.7 million for 2007 and $878.4 million for 2006. The increase from 2007 to 2008 resulted primarily from higher gas prices, higher oil prices and increased production. The increase from 2006 to 2007 resulted primarily from higher gas prices, high oil prices and increased oil production.

Cash flow used in investing activities for 2008 was $1.6 billion, compared to $875.4 million for 2007 and $1.0 billion for 2006. Changes in the cash flow used in investing activities are generally the result of changes in our exploration and development programs, acquisitions and property sales. The increase from 2007 to 2008 was mostly caused by increased oil and gas expenditures resulting from a more active drilling

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program. In addition, we had $138.1 million less proceeds from sales of assets in 2008 when compared to 2007. The decrease from 2006 to 2007 was mostly caused by increased proceeds from property sales. We sold $177 million of oil and gas properties in 2007 versus $4.5 million in 2006.

Net cash flow provided from financing activities in 2008 was $107.4 million versus $1.3 million used in 2007. In 2008 we had borrowings under our credit facility of $220.0 million and $13.1 million in proceeds from issuance of common stock and other. We used $105.6 million of the borrowings under our credit facility to repurchase a portion of our convertible notes in December and we made $20.0 million in dividend payments during the year.

Net cash flow used in financing activities in 2007 was $1.3 million versus $74.8 million provided in 2006. Two significant uses were for share repurchases of $42.3 million and $13.4 million for dividends. Proceeds from our May 2007 issuance of $350 million of ten-year, 7.125% senior unsecured notes were used to redeem our old 9.6% notes and reduce outstanding borrowings under our credit facility.

Capital Expenditures

The following table sets forth certain historical information regarding capitalized expenditures by us in our oil and gas acquisition, exploration, and development activities (in thousands):

	For Years Ended December 31,		
	2008	**2007**	**2006**
Acquisitions:			
Proved	$ 6,618	$ 17,334	$ 25,970
Unproved	175,777	23,580	513
	182,395	40,914	26,483
Exploration and development:			
Land & Seismic	157,403	98,162	104,527
Exploration	245,538	217,696	251,717
Development	1,035,442	666,662	691,946
	1,438,383	982,520	1,048,190
Property sales	(38,093)	(176,659)	(4,459)
	$ 1,582,685	$ 846,775	$ 1,070,214

2008 property acquisitions primarily relate to various producing properties and exploratory nonproducing leases that we purchased in October. This $180.9 million acquisition expanded our Woodford Shale position in the Anadarko Basin of western Oklahoma by 38,000 net acres.

We make significant expenditures to find, acquire, and develop oil and natural gas reserves. Our exploration and development expenditures increased 46% in 2008 compared to 2007. The increase in 2008 resulted primarily from increases in exploration activity in our Mid-continent and Permian regions.

We have reduced our planned capital program for 2009 to approximately $500 million due to the expectation of continued low oil and gas prices. If these prices drop even further, or if operating difficulties are encountered that result in cash flow from operations being less than expected, we may have to reduce our capital expenditures even more.

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.

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Our 2008 exploration and development drilling program is discussed in *Exploration and Development Activity Overview* under Item 1 of this Form 10-K.

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 prices of oil and natural gas. To meet our capital and liquidity requirements, we rely on certain resources, including cash flows from operating activities, access to capital markets, and bank borrowings. While we attempt to operate within forecasted cash flows from operations, we do periodically access our credit facility to finance our working capital needs and growth. Recent adverse developments in financial and credit markets have made it more difficult and more expensive to access the short-term capital market to meet our liquidity needs. Due to the tightened credit markets and significantly lower commodity prices we have planned to scale back our 2009 capital program by approximately 60% in comparison to 2008. With these planned reductions and amounts available to us under our existing credit facility we believe we will be able to continue to meet our needs for working capital, construction expenditures, debt servicing and dividend payments.

During the year our total assets, net oil and gas assets, net income and stockholders' equity were reduced by a non-cash impairment of oil and gas properties in the amount of $2.2 billion ($1.4 billion after tax). Total assets decreased by $1.2 billion in 2008 from $5.4 billion at the beginning of the year to $4.2 billion by year end. Our net oil and gas assets decreased by $1.2 billion. Our cash position decreased by $121.8 million primarily as a result of our Woodford Shale acquisition in October and a decrease in commodity prices during the fourth quarter. As of December 31, 2008, stockholders' equity totaled $2.3 billion, down from $3.3 billion at December 31, 2007. The decrease resulted primarily from a 2008 net loss of $901.7 million.

Dividends

In December 2005, the Board of Directors declared the Company's first quarterly cash dividend of $.04 per share payable to shareholders. A dividend has been authorized in every quarter since then. On December 12, 2007 the Board of Directors increased the regular cash dividend on our common stock from $0.04 to $0.06 per common share.

Common Stock Repurchase Program

In December 2005, the Board of Directors authorized the repurchase of up to four million shares of common stock. During 2007 we repurchased a total of 1,114,200 shares at an average purchase price of $37.93. Cumulative purchases through December 31, 2007 total 1,364,300 shares at an average price of $39.05. No purchases were made in 2008.

Working Capital

Working capital decreased $94.7 million from year-end 2007 to $45.4 million at year-end 2008. Working capital decreased primarily because of the following:

- Our cash position decreased by $121.8 million compared to year end 2007 primarily as a result of our Woodford Shale acquisition in October and a decrease in commodity prices during the fourth quarter.

- Oil and gas receivables decreased by $107.7 million due to a significant decrease in commodity prices from the prior year.

- Trade payables increased by $48.0 million due to timing of payments.

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These working capital decreases were mostly offset by:

- Revenue payable decreased by $27.1 million due to a significant decrease in commodity prices from the prior year.

- Inventories increased by $156.4 million due to increased steel prices and a planned increase in the amount of pipe inventory in our yards.

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.

Financing

Debt at December 31, 2008 and 2007 consisted of the following (in thousands):

	2008	2007
Bank debt	$220,000	$
7.125% Notes due 2017	350,000	350,000
Floating rate convertible notes due 2023 (face value $19,450 and $125,000, respectively)	21,223	137,159(1)
Total long-term debt	$591,223	$487,159

(1) Fair market value at June 7, 2005 was $144.75 million. The subsequent noted balances represent the fair market value at date of acquisition less amortization of the premium of fair market value over face value.

Bank Debt

We have a $1.0 billion senior secured revolving credit facility ("credit facility") with a syndicate of banks that had a borrowing base of $1.0 billion as of December 31, 2008. At our option we set the banks' lending commitment under the credit facility at $500 million. The borrowing base is determined at the discretion of the lenders, based on the collateral value of our proved reserves and is subject to potential special and regular semi-annual redeterminations.

The credit facility matures on July 1, 2010 and is secured by mortgages on certain oil and gas properties and the stock of certain wholly-owned operating subsidiaries. Amounts outstanding bear interest at our election at either a floating London Interbank Offered Rate (LIBOR) plus 1%-1.75% or at the JP Morgan Chase Bank prime rate plus 0%-0.5%. At December 31, 2008, there was $220 million of borrowings outstanding under the credit facility at a weighted average interest rate of approximately 1.66%. We also had letters of credit outstanding of $2.8 million leaving an unused borrowing availability of $277.2 million at December 31, 2008.

The credit facility contains various covenants and restrictive provisions which may limit our ability to incur additional indebtedness, make investments or loans and create liens. The credit agreement requires us to maintain a current ratio (current assets to current liabilities, as defined) greater than 1 to 1 and a leverage ratio (indebtedness to EBITDA, as defined) not to exceed 3.0 to 1. The current ratio, as defined by the credit agreement, at December 31, 2008, was 1.69 to 1 and our leverage ratio was 0.42 to 1. As of December 31, 2008, we were in compliance with all of the financial and non-financial covenants.

We have initiated discussions with our syndicate of banks regarding a new three-year senior secured revolving credit facility with the intent to increase the banks' lending commitment from $500 million to $800 million. In addition, we may consider a high-yield bond offering in the future, if appropriate.

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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.

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.

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

At any time prior to May 1, 2010, we may redeem up to 35% of the original principal amount of the notes with the proceeds of certain equity offerings of our shares of common stock at a redemption price of 107.125% of the principal amount of the notes, together with accrued and unpaid interest, if any, to the date of redemption.

At any time prior to May 1, 2012, we may also redeem all, but not part, of the notes at a price of 100% of the principal amount of the notes plus accrued and unpaid interest plus a "make-whole" premium.

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.

Floating rate convertible notes due 2023

The floating rate convertible senior notes were assumed in the Magnum Hunter merger and mature on December 15, 2023. The notes are senior unsecured obligations and bear interest at an annual rate of three month LIBOR, reset quarterly. On December 31, 2008, the interest rate was 2.0%.

The holders as of December 15, 2008, had the right to require us to repurchase all or a portion of the notes at a price of 100% of the principal amount (plus accrued interest). As of December 15, 2008, holders with principal of $105.550 million submitted their notes for repurchase leaving $19.450 million still outstanding. We repurchased the $105.550 million in notes with borrowings under our credit facility. The remaining notes have future repurchase dates as of December 15, 2013, and 2018. We have the right at any time to redeem some or all of the notes still outstanding at a redemption price of 100% of the principal amount (plus accrued interest).

In addition to the repurchase rights, holders of the convertible notes may surrender their notes for conversion into a combination of cash and shares of our common stock upon the occurrence of certain circumstances, including if the price of our common stock has been trading above the conversion price of $28.59 per share. On December 31, 2008, the closing price of our common stock traded on the New York Stock Exchange was $26.78.

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.

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Contractual Obligations and Material Commitments

At December 31, 2008, we had contractual obligations and material commitments as follows:

	Payments Due by Period				
Contractual obligations	**Total**	**Less than 1 Year**	**1-3 Years**	**4-5 Years**	**More than 5 Years**
			(In thousands)		
Long-term debt(1)	$589,450	$220,000	$	$	$369,450
Fixed-Rate interest payments(1)	211,969	24,938	49,875	49,875	87,281
Operating leases	28,233	5,681	10,814	9,632	2,106
Drilling commitments(2)	187,412	187,412			
Inventory commitments(3)	81,929	81,929			
Gas processing facility(4)	108,611	38,887	42,348	27,376	
Asset retirement obligation	139,948	14,610	(5)	(5)	(5)
Other liabilities(6)	51,216	8,823	17,636	17,636	7,121

(1) These amounts do not include interest on the $220 million of bank debt outstanding at December 31, 2008. The weighted average interest rate at December 31, 2008 was approximately 1.66%. See item 7A: Interest Rate Risk for more information regarding fixed and variable rate debt.

(2) We have drilling commitments of approximately $101.7 million consisting of obligations to complete drilling wells in progress at December 31, 2008. We also have minimum expenditure commitments of $85.7 million to secure the use of drilling rigs. Hurricanes Gustav and Ike occurred during the third quarter of 2008. We are continuing to evaluate damages to our wells and platforms. It is not presently determinable what our share of the total damages will be after insurance proceeds.

(3) At December 31, 2008, we had outstanding purchase order commitments of $81.9 million for tubular inventory. Subsequent to year-end we have been able to cancel approximately $17.1 million of those commitments, and efforts continue to further reduce our inventory commitments.

(4) We have a large development project in Sublette County, Wyoming where we are developing the deep Madison gas formation and constructing a gas processing plant. At December 31, 2008, we had commitments of $176.8 million relating to construction of the gas processing plant of which $108.6 million is subject to a construction contract. The total cost of the project will approximate $362 million. Pursuant to the terms of our operating agreement with our partners in this project, we will be reimbursed by them for $42\frac{1}{2}$% of the costs.

(5) We have excluded 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 and other miscellaneous commitments.

At December 31, 2008, we had firm sales contracts to deliver approximately 8.5 Bcf of natural gas over the next twelve months. If this gas is not delivered, our financial commitment would be approximately $40 million. This commitment may fluctuate due to either price volatility or volumes delivered. However, we do not anticipate that a financial commitment will be due.

In connection with a gas gathering and processing agreement, we have commitments to deliver 59.4 Bcf of gas over the next five years. If no gas was delivered, the maximum amount that would be payable under these commitments would be approximately $45.1 million.

We have other various delivery commitments in the normal course of business, none of which are individually material. In aggregate, these commitments have a maximum amount that would be payable, if no gas is delivered, of approximately $5.9 million.

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

Based on current commodity prices and anticipated levels of production, we believe that the estimated net cash generated from operations, coupled with the cash on hand and amounts available under our existing bank credit facility will be adequate to meet future liquidity needs, including satisfying our financial obligations and funding our operations and planned exploration and development activities.

2009 Outlook

Our exploration and development expenditures program for 2009 are projected to range from $400 million to $600 million. 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 estimates for 2009 range from 440 to 460 MMcfe per day. 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 2008, our realized prices averaged $8.43 per Mcf of gas and $96.03 per barrel of oil. Prices can be very volatile and the possibility of 2009 realized prices being different than they were in 2008 is high.

Certain expenses for 2009 on a per Mcfe basis are currently estimated as follows:

		2009
Production expense	$	1.20 - $1.30
Transportation expense		0.17 - 0.22
DD&A and Asset retirement obligation		1.85 - 2.10
General and Administrative		0.27 - 0.30
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 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 reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various fields make these estimates generally less precise than other estimates included in the financial statement disclosures. Estimations of proved undeveloped reserves can be subject to an even greater possibility of revision. At year-end, 18 percent of our total proved reserves are categorized as proved undeveloped. Of these proved undeveloped reserves, 89 percent are related to a project in Wyoming. Our reserve engineers review and revise our reserve estimates annually. Additionally, we annually engage an independent petroleum engineering firm to review our proved reserve estimates associated with at least 80% of the discounted future net cash flows before income taxes.

We use the units-of-production method to amortize our oil and gas properties. For depletion purposes, reserve quantities are adjusted at interim quarterly periods for the estimated impact of additions, dispositions and price changes. Changes in reserve quantities cause corresponding changes in depletion expense in periods subsequent to the quantity revision. It is also possible that a full cost ceiling limitation charge could occur 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 due to production history, well performance and changes in production costs.

	Years Ended December 31,					
	2008		2007		2006	
	Bcfe Change	**Percent of total Reserves**	**Bcfe Change**	**Percent of total Reserves**	**Bcfe Change**	**Percent of total Reserves**
Revisions resulting from price changes	(145.2)	(9.86)%	35.5	2.45%	(40.1)	(2.88)%
Other changes in estimates	(11.6)	(0.79)%	22.0	1.52%	3.5	0.25%
Total	(156.8)	(10.65)%	57.5	3.97%	(36.6)	(2.63)%

Non-price related revisions added 13.9 Bcfe over the three-year period 2006-2008. Over the same period we have seen a 149.8 Bcfe decrease resulting from lower prices. See Note 16, Supplemental Oil and Gas Disclosures 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. In addition, gains or losses on the sale or other disposition of oil and gas properties are not recognized in earnings unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves of oil and natural gas attributable to our full cost pool.

At the end of each quarter, we make a full cost ceiling limitation calculation, whereby net capitalized costs related to proved properties less associated deferred income taxes may not exceed the amount of the present value discounted at ten percent of estimated future net revenues from proved reserves less estimated future production and development costs and related income tax expense. Future net revenues used in the calculation of the full cost ceiling limitation are determined based on current oil and gas prices and are adjusted for designated cash flow hedges. Changes in proved reserve estimates (whether based upon quantity revisions or oil and gas 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. However, if commodity prices increase after period end and before issuance of the financial

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statements, these higher commodity prices may be used to determine if the capital costs are in fact impaired as of the end of the period. Any recorded impairment of oil and gas properties is not reversible at a later date.

Due to a significant decrease in period end commodity prices, at September 30, 2008, our ceiling limitation calculation resulted in excess capitalized costs of $657.1 million ($417.4 million, net of tax), for which we recorded a non-cash impairment of oil and gas properties. As a result of further declines in natural gas and oil prices during the fourth quarter of 2008, we recorded an additional non-cash impairment of oil and gas properties. Based on prices at December 31, 2008, our ceiling limitation calculation resulted in excess capitalized costs of $1.6 billion ($1.0 billion after tax). The Company's quarterly and annual ceiling test is primarily impacted by period end 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, 2008 would have resulted in an additional ceiling test impairment of approximately 12% of our full cost pool. Also, goodwill could be potentially impaired. Changes in actual reserve quantities added and produced along with our actual overall exploration and development costs will impact the Company's actual ceiling test calculation and impairment analyses.

Goodwill

At December 31, 2008, we had $691.4 million of goodwill recorded in conjunction with past business combinations. Goodwill is subject to annual reviews for impairment based on a two step accounting test. The first step is to compare the estimated fair value of the Company with the recorded net book value (including the goodwill), after giving effect to all other period impairments, including the impairment of oil and gas properties from the full cost pool ceiling limitation calculation. If the estimated fair value is higher than the recorded net book value, no impairment is deemed to exist and no further testing is required. If, however, the estimated fair value is below the recorded net book value, then a second step must be performed to determine the goodwill impairment required, if any. In this second step, a hypothetical acquisition value of the Company is computed utilizing purchase business combination accounting rules.

We perform our annual goodwill impairment review in the fourth quarter of each year. During the fourth quarter of 2008, there were severe disruptions in the credit markets and reductions in global economic activity which had significant adverse impacts on stock markets and oil-and-gas-related commodity prices. Management must apply judgment in determining the estimated fair value of the Company for purposes of performing the annual goodwill impairment test. As of December 31, 2008, the book value per share of our common stock exceeded the market price by less than $2 per share. Management does not consider the market value of our shares to be an accurate reflection of our net assets, for impairment purposes. To estimate the fair value of the Company, we used all available information, including the present values of expected future cash flows using discount rates commensurate with the risks involved in the assets. This estimated fair value differs significantly from the valuation used in the ceiling limitation calculation, which requires the use of prices and costs in effect at year end, discounted at 10 percent. The ceiling calculation is not intended to be indicative of fair value.

In estimating the fair value of our oil and gas properties, we used projected future prices based on the NYMEX strip index at December 31, 2008 (adjusted for estimated delivery point price differentials). Based on our current exploration plans, we included estimated future cash flows from development of our unproved properties and applied a discount rate of 15% to 20%, depending on the reserve category. This resulted in a slight excess of fair value over the carrying value of our net assets at year end. Should lower prices or quantities result in the future, or higher discount rates be necessary, the carrying value of our net assets may exceed the estimated fair value, resulting in an impairment of goodwill.

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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 in the H.B. Krug, et al versus Helmerich & Payne, Inc. ("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. Damages of $6.9 million plus $119.5 million for disgorgement of H&P's estimated potential compounded profit since 1989, resulting from the noted damages, were awarded to plaintiff royalty owners, for a total of $126.4 million. This amount was subsequently adjusted by the court to a total of $119.6 million. 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. We periodically assess the probability of estimable amounts related to litigation matters, as required by Financial Accounting Standard No. 5 (*Accounting for Contingencies)* and adjust our accruals accordingly. In September 2008, based on the available information at the time, we accrued an estimated litigation expense of $12 million for both damages and probable disgorgement. The higher disgorgement award could not be reasonably estimated until the final judgment in January 2009. We therefore accrued an additional $107.6 million, bringing the total accrued litigation expense for the year ended December 31, 2008 to $119.6 million for this lawsuit. We have appealed the District Court's judgments.

In the normal course of business, we have other various litigation related matters and associated accruals. 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.

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. During 2008, we revised our existing estimated asset retirement obligation by $23.0 million, or approximately 16.4 percent of the asset retirement obligation at December 31, 2008, due to changes in the various related attributes. Over the past three years, revisions to the estimated asset retirement obligation averaged approximately 9.3 percent. Revisions to the asset retirement obligation are recorded with an offsetting change to producing properties, resulting in prospective changes to 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.

Recently Issued Accounting Standards

In May, 2008, the Financial Accounting Standards Board ("FASB") issued a new Staff Position (No. APB 14-1), *Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion (Including Partial Cash Settlement),* that will impact the accounting for the components of convertible debt that can be settled wholly or partly in cash upon conversion. The new requirements apply not only to new instruments, but also would be applied retrospectively to previously issued convertible instruments. The debt and equity components of the instruments are to be accounted for separately. The value assigned to the debt component is the estimated value of similar debt without a conversion feature as of the issuance date, with the remaining proceeds allocated to the equity component and recorded as additional paid-in capital. The debt component is recorded at a discount and is subsequently accreted to its par value, thereby reflecting an overall market rate of interest in the income statement. This Staff Position is effective for both new and previously issued instruments for current and comparative periods in fiscal years beginning after December 15, 2008, and interim periods within those years. We will adopt this in the first quarter of 2009. Upon adoption, without considering tax effects, we will retrospectively record a decrease in the book value of our Floating Rate Convertible Notes of approximately $30 million as of June 7, 2005, and a corresponding increase in additional paid-in-capital. In addition, we will record additional non-cash interest expense of approximately $1.9 million per year for 2008, 2007 and 2006.

In June, 2008, the FASB issued a new Staff Position (EITF 03-6-1), *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities,* which holds that unvested share-based payment awards that contain non forfeitable rights to dividends or dividend equivalents are "participating securities" (as defined by EITF 03-6 as securities that may participate in undistributed earnings with common stock, whether that participation is conditioned upon the occurrence of a specified event or not, regardless of the form of participation),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. This Staff Position is effective for financial statements issued in fiscal years beginning after December 15, 2008, and interim periods within those years. Once effective, the requirements will be applied by restating previously reported earnings per share data. We will adopt this in the first quarter of 2009.

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, interest rates and value of our short-term investments. 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 (See risk factors in Item 1).

Currently, we are largely accepting the volatility risk that the change in prices presents. None of our future oil and gas production is subject to hedging. At December 31, 2008, our derivative contracts were completed. See Note 3 to the Consolidated Financial Statements in Item 8 of this report for additional information regarding our derivative instruments.

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Interest Rate Risk

At December 31, 2008, we had total debt outstanding of $591.2 million. Of this amount, $220 million is outstanding under our senior secured revolving credit facility and $350 million is senior unsecured notes that bear interest at a fixed rate of 7.125% and will mature on May 1, 2017. The credit facility matures on July 1, 2010 and amounts outstanding bear interest at our election at either a floating LIBOR rate plus 1%-1.75% or the prime rate plus 0%-0.5%. The remaining debt of our unsecured convertible senior notes is $19.45 million (face value) which matures on December 15, 2023. These convertible notes bear interest at an annual rate of three-month LIBOR, reset quarterly. The book value of our revolving credit facility and the convertible notes approximates the current fair value. The fair value of our 7.125% notes was approximately $267.8 million at December 31, 2008.

We consider our interest rate exposure to be minimal because as of December 31, 2008 about 59% of our long-term debt obligations were at fixed rates. A 1% increase in the three-month LIBOR rate would increase annual interest expense by $2.4 million. This sensitivity analysis for interest rate risk excludes accounts receivable, accounts payable and accrued liabilities because of the short-term maturity of such instruments. See Note 4 and Note 6 to the Consolidated Financial Statements in Item 8 of this report for additional information regarding debt.

Market Value of Investments

We currently have $2.5 million invested in an asset-backed securities fund. We expect to liquidate our investment in this fund within the next 12 months. A five percent change in these investments' market value would have a $125 thousand impact on our investments.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

CIMAREX ENERGY CO.

INDEX TO FINANCIAL STATEMENTS AND SUPPLEMENTAL SCHEDULES

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

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Report of Independent Registered Public Accounting Firm

The Board of Directors
Cimarex Energy Co.:

We have audited the accompanying consolidated balance sheets of Cimarex Energy Co. and subsidiaries (the Company) as of December 31, 2008 and 2007, 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, 2008. 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, 2008 and 2007, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2008, 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, 2008, 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 27, 2009 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

KPMG LLP

Denver
February 27, 2009

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CIMAREX ENERGY CO.

CONSOLIDATED BALANCE SHEETS

(In thousands, except share and per share information)

	December 31,	
	2008	**2007**
Assets		
Current assets:		
Cash and cash equivalents	$ 1,213	$ 123,050
Restricted cash	502	
Short-term investments	2,502	14,391
Accounts receivable:		
Trade, net of allowance	73,676	64,600
Oil and gas sales, net of allowance	136,606	244,299
Gas gathering, processing, and marketing, net of allowance	6,974	6,428
Other	41,826	
Inventories	186,062	29,642
Deferred income taxes	2,435	5,697
Derivative instruments		12,124
Other current assets	63,148	64,346
Total current assets	514,944	564,577
Oil and gas properties at cost, using the full cost method of accounting:		
Proved properties	7,052,464	5,545,977
Unproved properties and properties under development, not being amortized	465,638	364,618
	7,518,102	5,910,595
Less accumulated depreciation, depletion and amortization	(4,709,597)	(1,938,863)
Net oil and gas properties	2,808,505	3,971,732
Fixed assets, less accumulated depreciation of $67,020 and $49,629	119,616	90,584
Goodwill	691,432	691,432
Other assets, net	30,436	44,469
	$ 4,164,933	$ 5,362,794
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable:		
Trade	$ 89,221	$ 41,213
Gas gathering, processing, and marketing	11,936	11,458
Accrued liabilities:		
Exploration and development	111,511	92,640
Taxes other than income	26,473	26,109
Other	126,010	121,638
Revenue payable	104,438	131,513
Total current liabilities	469,589	424,571
Long-term debt	591,223	487,159
Deferred income taxes	499,634	1,076,223
Asset retirement obligation	125,338	105,784
Other liabilities	129,784	9,770
Total liabilities	1,815,568	