

CIMAREX ENERGY CO
Form 10-K/A
March 13, 2008

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**UNITED STATES
SECURITIES AND EXCHANGE COMMISSION**

Washington, D C 20549

Form 10-K/A-1

(Mark One)

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

For the fiscal year ended December 31, 2007

OR

**TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES
EXCHANGE ACT OF 1934**

Commission file number 001-31446

CIMAREX ENERGY CO.

(Exact name of registrant as specified in its charter)

Delaware
(State or other jurisdiction of
incorporation or organization)

45-0466694
(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 NO

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. YES NO

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Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. YES NO

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer (as defined in Rule 12b-2 of the Securities Exchange Act of 1934). (Check One):

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

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

Aggregate market value of the voting stock held by non-affiliates of Cimarex Energy Co. as of June 30, 2007 was approximately \$3,227,233,825.

Number of shares of Cimarex Energy Co. common stock outstanding as of February 15, 2008 was 82,779,666.

Documents Incorporated by Reference: Portions of the Registrant's Proxy Statement for its 2008 Annual Meeting of Stockholders are incorporated by reference into Part III of this Form 10-K.

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EXPLANATORY NOTE

This Amendment on Form 10-K/A-1 is being filed to amend the tabular presentation of the proved reserve data shown in Footnote 17 of the Notes to the Consolidated Financial Statements. The changes to the proved reserve information are summarized below:

	December 31, 2007
	OIL
	(MBbl)
<i>Reserve data as originally presented:</i>	
Production	(8,812)
Sales of Properties	(7,446)
<i>Reserve data as revised:</i>	
Production	(7,446)
Sales of Properties	(8,812)

All other information contained in the Original Form 10-K remains unchanged, and the entire report with all Items is included in this Form 10-K/A-1 for the convenience of the reader. We have not updated the disclosures contained herein to reflect events that occurred after the date of the Original Form 10-K.

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CIMAREX ENERGY CO.

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.

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.

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 2007 totaled nearly 1.5 Tcfe, consisting of 1.1 Tcf of gas and 58.3 million barrels of oil and natural gas liquids. Of total proved reserves, 76 percent are gas and 79 percent are classified as proved developed. We operate the wells that account for 82 percent of our total proved reserves and approximately 79 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.

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.

During 2007 we accomplished the following highlights:

Oil and gas sales increased 12 percent to a record \$1.4 billion.

Realized record net income of \$346.5 million.

Cash flow from operating activities increased 13 percent to an all-time high of \$995 million.

Production averaged 451 MMcfe per day in 2007, increasing throughout the year to a fourth-quarter peak of 471 MMcfe per day.

Added 300 Bcfe of proved reserves from extensions, discoveries and improved recovery, replacing 182 percent of production.

Sold non-core properties with 123 Bcfe of proved reserves for \$177 million.

Increased proved reserves 11 percent over year-end 2006 (adjusting for 2007 property sales) to 1.47 Tcfe.

Sold \$350 million of ten-year 7.125% senior unsecured notes, using the net proceeds to redeem our old 9.6% senior notes and reduce bank debt.

Ended the year with a debt to total capitalization ratio of 13 percent.

Repurchased 1,114,200 shares of our common stock.

Increased our regular quarterly common stock cash dividend from \$0.04 to \$0.06 per share.

History

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Cimarex, a Delaware corporation, 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 plus assumption of liabilities. That transaction effectively tripled our proved reserves and doubled our production.

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 continually expanding our drilling program and maximizing cash flow from our production.

A cornerstone to our approach is 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 and future production profiles.

During 2007, we drilled 452 gross wells and invested \$983 million on exploration and development. 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.

We also periodically divest selected assets that we no longer deem important to our ongoing operations. During 2007, we sold properties with estimated proved reserves of 123 Bcfe, or about eight percent of our beginning of the year reserves.

Conservative use of leverage has long been a part of our financial strategy. We believe that maintaining a strong balance sheet enables us to carry on a consistent drilling program and pursue acquisition and other opportunities, when conditions warrant. Our year-end 2007 debt to total capitalization ratio was 13 percent.

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.

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A summary of our 2007 exploration and development activity by region is as follows.

	Exploration and Development Capital	Gross Wells Drilled	Net Wells Drilled	Completion Rate	12/31/07 Proved Reserves (Bcfe)
	(in millions)				
Mid-Continent	\$ 385	237	134	95%	617
Permian Basin	368	172	118	91%	528
Gulf Coast	225	42	29	71%	125
Other	5	1		100%	202
	\$ 983	452	281	91%	1,472

Company-wide, we participated in drilling 452 gross wells during 2007, with an overall completion rate of 91 percent. On a net basis, 256 of 281 total wells drilled during 2007 were completed as producers.

Our 2007 exploration and development expenditures (E&D) totaled \$983 million and resulted in 242 Bcfe of proved reserve additions. Of total expenditures, 39 percent were invested in projects located in the Mid-Continent area; 37 percent in the Permian Basin; and 23 percent in the Gulf Coast.

Mid-Continent

Our Mid-Continent operations encompass broad areas in Oklahoma, southwest Kansas and the Texas Panhandle. We drilled 237 gross (134 net) Mid-Continent wells during 2007, completing 95 percent as producers. The bulk of this activity occurred in the Texas Panhandle and the Anadarko Basin of western Oklahoma. Full-year 2007 investment in this area was \$385 million, or 39 percent of total E&D capital.

We drilled 106 gross (75 net) Texas Panhandle wells with 99 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. Drilling activity in the Granite Wash remains active with 125-150 wells planned for 2008.

We drilled 70 gross (14 net) Anadarko Basin wells, of which 89 percent were completed as producers. Our drilling activity mainly targets the Red Fork and Clinton Lake/Atoka formations at depths ranging from 12,000-15,000 feet. We began in the fourth quarter of 2007 evaluating a potential horizontal drilling program targeting the Woodford Shale formation at 13,000 feet.

We also have a large inventory of recompletion, workover and in-fill drilling locations in southern Oklahoma and in the Texas Panhandle Panoma field. The Panoma field produces from the Brown Dolomite formation at depths of approximately 2,200 feet. In 2007 we drilled 27 gross (26 net) wells at Panoma with a 100 percent success rate, increasing field production by 2.7 MMcfe/d.

Permian Basin

Our Permian Basin operations cover both west Texas and southeast New Mexico. In total, we drilled 172 gross (118 net) wells in this area during 2007 completing 157 gross (106 net) as producers. Full-year 2007 investment in this area totaled \$368 million, or 37 percent of total E&D capital.

Southeast New Mexico drilling totaled 67 gross (48 net) wells with 84 percent being completed as producers. The primary formations we target in this area are the Wolfcamp, Morrow, Atoka and Strawn at depths ranging from 9,000-14,000 feet.

In West Texas, a total of 71 gross (58 net) wells were drilled, of which 94 percent were successful. Geologic targets include the Devonian, Ellenburger and Bone Spring formations. In Ward and Reeves Counties drilling totaled 16 gross (9.5 net) horizontal wells in the Third Bone Spring formation.

Gulf Coast

Our onshore Gulf Coast focus area generally encompasses coastal Texas, south Louisiana and Mississippi. We also own interest 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 Gulf Coast 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. Full-year 2007 investment in this area was \$225 million, or 23 percent of total E&D capital.

During 2007 we drilled 42 gross (29 net) Gulf Coast wells, realizing a 71 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 19 gross (16 net) wells with a success rate of 79 percent.

Other

We are currently conducting exploration activity in Michigan and have a large gas development project in Sublette County, Wyoming.

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,		
	2007	2006	2005
Production Volumes			
Gas (MMcf)	119,937	124,733	100,272
Oil (MBbls)	7,445	6,529	4,804
Equivalent (MMcfe)	164,607	163,907	129,096
Net Average Daily Volumes:			
Gas (MMcf)	328.6	341.7	274.7
Oil (MBbl)	20.4	17.9	13.2
Equivalent (MMcfe)	451.0	449.1	353.7
Average Sales Price			
Gas (\$/Mcf)	\$ 7.05	\$ 6.50	\$ 8.05
Oil (\$/Bbl)	\$ 69.71	\$ 61.96	\$ 55.25

Total 2007 oil and gas production averaged 451 MMcfe per day versus 449 MMcfe per day in 2006. Gas production in 2007 decreased four percent to 328.6 MMcf per day and oil production increased 14 percent to 20,399 barrels per day. The decline in gas volumes resulted primarily from decreased investment in the Gulf of Mexico and property divestitures. The increase in oil volumes was principally a result of successful exploration and development drilling in the Permian Basin.

We sold our 2007 gas at an average price of \$7.05 per Mcf, which was eight percent higher than the \$6.50 per Mcf we received in 2006. Our annual average realized oil price during 2007 increased by 13 percent to \$69.71 per barrel from \$61.96 per barrel in 2006. Improved overall market conditions for oil, natural gas and natural gas liquids were the primary reason for the higher realized price in 2007 compared to 2006.

We had natural gas collars for calendar year 2007 covering 80,000 MMBtu per day. The collars increased our 2007 average realized gas price by \$0.23 per Mcf. For 2008, we have collars that cover 40,000 MMBtu per day of Mid-Continent production with a floor price of \$7.00 per MMBtu and a ceiling of \$9.90

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per MMBtu. For a discussion of derivatives, see Note 5 of Notes to Consolidated Financial Statements contained herein.

The following table summarizes Cimarex's daily production by region for 2007 and 2006.

	2007 Average Daily Production			2006 Average Daily Production		
	Oil (MBbl/d)	Gas (MMcf/d)	Total (MMcfe/d)	Oil (MBbl/d)	Gas (MMcf/d)	Total (MMcfe/d)
Mid-Continent	5.4	160.2	192.3	4.7	152.5	180.7
Permian Basin	9.5	87.2	144.3	8.1	83.8	132.4
Gulf Coast	5.3	75.0	106.9	4.8	98.0	126.6
Other	0.2	6.2	7.5	0.3	7.4	9.4
	20.4	328.6	451.0	17.9	341.7	449.1

Our largest producing area is the Mid-Continent region which averaged 192.3 MMcfe per day, or 43 percent of our total 2007 production. Successful drilling programs in the Texas Panhandle and the Anadarko Basin helped boost our Mid-Continent production by six percent in 2007. The Permian Basin contributed 144.3 MMcfe per day in 2007, which was 32 percent of our total production for this period. Production increased nine percent as a result of successful Morrow and Wolfcamp drilling programs in southeast New Mexico and new horizontal oil wells in the West Texas Bone Spring formation. Gulf Coast production averaged 106.9 MMcfe per day during 2007, or 24 percent of total production. Gulf Coast volumes decreased in 2007 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.

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 eight percent of 2007 revenues. Because over two-thirds 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 760 people on December 31, 2007. None of our employees are subject to collective bargaining agreements.

Competition

The oil and gas industry is highly competitive. Competition is particularly intense for prospective undeveloped leases and purchases of proved oil and gas reserves. There is also competition for rigs and related equipment we use to drill for and produce oil and gas. Our competitive position is also highly dependent on our ability to recruit and retain geological, geophysical and engineering expertise. We compete for prospects, proved reserves, oil-field services and qualified oil and gas professionals with major and diversified energy companies and other independent operators that have larger financial, human and technological resources than we do.

We compete with integrated, independent and other energy companies for the sale and transportation of oil and gas to marketing companies and end users. The oil and gas industry competes with other energy industries that supply fuel and power to industrial, commercial and residential consumers. Many of these competitors have greater financial and human resources. The effect of these competitive factors cannot be predicted.

Title to Oil and Gas Properties

We undertake title examination and perform curative work at the time we lease undeveloped acreage, prepare for the drilling of a prospect or acquire proved properties. We believe that the titles to our properties are good and defensible, and are in accordance with industry standards. Nevertheless, we are involved in title disputes from time to time which result in litigation. Our oil and gas properties are subject to customary royalty interests, liens incidental to operating agreements, tax liens and other burdens and minor encumbrances, easements and restrictions.

Government Regulation

Oil and gas production and transportation is subject to extensive Federal, state and local laws and regulations. Compliance with existing laws often is difficult and costly, but has not had a 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 often 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.

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.

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

Our revenues and results of operations are highly dependent on oil and gas prices. The prices we receive for our production are based on prevailing market conditions and are influenced by many factors that are beyond our control. Historically, oil and gas prices have fluctuated widely. For example, in 2007 we sold our gas at an average price of \$7.05 per Mcf, which was eight percent higher than our 2006 average sales price of \$6.50 per Mcf. The 2006 average gas sales price was 19 percent lower than our 2005 average sales price of \$8.05 per Mcf. Our average 2007 oil price of \$69.71 per barrel was 13 percent higher than the price we received in 2006 of \$61.96 per barrel, while the 2006 price was 12 percent higher than the price we received in 2005 of \$55.25 per barrel.

The volatility in oil and gas prices limits the predictability of the prices, which directly impacts future development plans and operations. If prices decline, future earnings would be reduced and growth could be adversely affected.

In recent years, oil prices have responded to changes in supply and demand stemming from actions taken by the Organization of Petroleum Exporting Countries, worldwide economic conditions, growing transportation and power generation needs, and other events. Factors affecting gas prices have included domestic supplies; the level and price of natural gas imports into the U.S.; weather conditions; the economy and the price and level of alternative sources of energy such as renewable energy assets, nuclear power, hydroelectric power, coal, and other petroleum products.

Our proved oil and gas reserves and production volumes will decrease in quantity unless we successfully replace the reserves we produce with new discoveries or acquisitions. 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. To the extent we have not hedged our production, any decline in oil and gas prices would negatively affect the amount of cash flow available to fund these capital investments. Low prices may 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. We may be required under accounting rules to write down the carrying value of our properties or impair goodwill when gas and oil prices are low. 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.

Our use of hedging arrangements could result in financial losses or reduce our income.

To reduce our exposure to fluctuations in natural gas prices, from time to time we enter into hedging arrangements for a portion of our natural gas production. These hedging arrangements could expose us to risk of financial loss in some circumstances, including when:

production is less than expected;

the counterparty to the hedging contract defaults on its contract obligations; or

there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received.

In July 2006, using zero-cost collars with Mid-Continent weighted average floor and ceiling prices of \$7.00 to \$10.17 for 2007 and \$7.00 to \$9.90 for 2008, we hedged 80,000 MMBtu per day for 2007 and 40,000 MMBtu per day for 2008. Though associated volumes for the existing contracts are significantly less than our overall production, hedging arrangements could limit the benefit we would otherwise receive from increases in natural gas prices.

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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.

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The estimation of the category of proved undeveloped reserves can be subject to an even greater possibility of revision. At December 31, 2007, 21.4 percent of our total proved reserves are categorized as

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proved undeveloped. Of these proved undeveloped reserves, 62 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, 2007.

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.

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.

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 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 21 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, 2007, we had total long-term debt of \$487.2 million, consisting of \$350 million of unsecured 7.125% Senior Notes and \$137.2 million of Convertible Notes (\$125 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, 2007, 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.

We have outstanding \$125 million of Convertible Notes (face value) that mature on December 15, 2023, and that are currently convertible into a combination of cash and our common stock. If the holders of our convertible notes choose to convert them, we might be required to borrow additional funds under our senior revolving credit facility in order to repay the required cash amount. Also, upon conversion of a Convertible Note, the holder would receive not only cash equal to the principal amount of the Convertible Note, but also Cimarex common stock for the Convertible Note's conversion value in excess of such principal amount. The number of Cimarex common shares into which the Convertible Notes are convertible is dependent upon the conversion value in excess of the principal amount of the Convertible Notes and our future common stock price. Any such conversion will be dilutive to our existing shareholders.

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

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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.

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 45 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 82 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, 2007. All information in this Form 10-K relating to oil and gas reserves is net to our interest unless stated otherwise. See Note 17, Supplemental Oil and Gas Disclosures, in Notes to Consolidated Financial Statements for further

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information. The following table sets forth the present value and estimated volume of our oil and gas proved reserves:

	Years Ending December 31,		
	2007	2006	2005
Total Proved Reserves			
Gas (MMcf)	1,122,694	1,090,362	1,004,482
Oil, condensate and NGLs (MBbls)	58,250	59,797	64,710
Equivalent (MMcfe)	1,472,195	1,449,146	1,392,742
Standardized measure of discounted future net cash flow after-tax, discounted at 10 percent (in thousands)	\$ 2,897,631	\$ 2,200,889	\$ 3,028,100
Average price used in calculation of future net cash flow			
Gas (\$/Mcf)	\$ 6.51	\$ 5.54	\$ 7.89
Oil (\$/Bbl)	\$ 93.66	\$ 56.91	\$ 57.65

Significant Properties

As of December 31, 2007, 78 percent of proved reserves were located in the Mid-Continent and Permian Basin regions. In total we owned an interest in 12,841 gross (4,845 net) productive oil and gas wells.

The following table summarizes our estimated proved oil and gas reserves by region as of December 31, 2007.

	Oil (MBbl)	Gas (MMcf)	Equivalent (MMcfe)	Percent of Proved Reserves
Mid-Continent	9,166	561,998	616,992	42%
Permian Basin	43,122	269,040	527,777	36%
Gulf Coast	5,435	93,058	125,668	8%
Other	527	198,598	201,758	14%
	58,250	1,122,694	1,472,195	100%

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Our ten largest producing fields hold 28 percent of our total equivalent proved reserves. We are the principal operator of our production in each of these fields (except Jo-Mill). The table below summarizes certain key statistics about these properties.

Field	Region	% of Total Proved Reserves	Avg. Working Interest	Avg. Depth (feet)	Primary Formation
Hemphill	Mid-Continent	4.4%	96%	11,000'	Granite Wash
Hugoton	Mid-Continent	3.9%	60%	2,600'	Chase
Eola-Robberson	Mid-Continent	3.8%	94%	5,500' - 11,000'	Bromide/McLish/Oil Creek
Red Deer Creek	Mid-Continent	3.3%	63%	11,000'	Granite Wash
Jo-Mill	Permian	2.7%	13%	7,500'	Spraberry
Mendota	Mid-Continent	2.4%	64%	11,000'	Granite Wash
Quail Ridge	Permian	2.3%	68%	13,000'	Morrow
Westbrook	Permian	1.9%	90%	3,500'	Clearfork
Howard Glasscock	Permian	1.7%	59%	2,000' - 2,600'	San Andres/Clearfork
War-Wink West	Mid-Continent	1.2%	58%	11,500'	Wolfcamp/Bone Spring
		27.6%			

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Acreage

The following table sets forth as of December 31, 2007, 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	3,454	2,388	158,391	105,601	161,845	107,989
Oklahoma	98,806	79,284	401,370	175,246	500,176	254,530
Texas	138,539	106,389	175,063	106,394	313,602	212,783
	<u>240,799</u>	<u>188,061</u>	<u>734,824</u>	<u>387,241</u>	<u>975,623</u>	<u>575,302</u>
Permian Basin						
New Mexico	86,652	65,262	150,942	99,596	237,594	164,858
Texas	49,551	35,890	183,679	113,150	233,230	149,040
	<u>136,203</u>	<u>101,152</u>	<u>334,621</u>	<u>212,746</u>	<u>470,824</u>	<u>313,898</u>
Gulf Coast						
Louisiana	16,361	11,792	21,535	6,371	37,896	18,163
Mississippi	6,209	3,265	26,090	7,046	32,299	10,311
Texas	80,322	37,501	141,880	57,930	222,202	95,431
Offshore	476,601	294,041	264,146	84,988	740,747	379,029
	<u>579,493</u>	<u>346,599</u>	<u>453,651</u>	<u>156,335</u>	<u>1,033,144</u>	<u>502,934</u>
Other						
Arkansas			6,719	2,115	6,719	2,115
Arizona	914,695	914,695			914,695	914,695
California	6,536	5,046	1,523	1,342	8,059	6,388
Colorado	95,255	6,759	27,971	6,498	123,226	13,257
Illinois	1,782	1,191	554	183	2,336	1,374
Michigan	35,200	35,083	598	598	35,798	35,681
Montana	47,893	15,283	10,785	2,882	58,678	18,165
Nebraska	4,560	116	2,118	168	6,678	284
Nevada	160	1	440	1	600	2
New Mexico	1,626,253	1,614,523	13,604	2,289	1,639,857	1,616,812
North Dakota	77,441	39,483	15,361	1,899	92,802	41,382
South Dakota	10,482	9,329	2,414	373	12,896	9,702
Utah	105,724	59,591	32,990	2,303	138,714	61,894
Wyoming	247,652	30,702	72,874	13,525	320,526	44,227
	<u>3,173,633</u>	<u>2,731,802</u>	<u>187,951</u>	<u>34,176</u>	<u>3,361,584</u>	<u>2,765,978</u>
	<u>4,130,128</u>	<u>3,367,614</u>	<u>1,711,047</u>	<u>790,498</u>	<u>5,841,175</u>	<u>4,158,112</u>

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Gross Wells Drilled

We participated in drilling the following number of gross wells during calendar years 2007, 2006, and 2005:

	Exploratory			Developmental		
	Productive	Dry	Total	Productive	Dry	Total
Year ended December 31, 2007	55	18	73	361	18	379
Year ended December 31, 2006	20	32	52	490	16	506
Year ended December 31, 2005	55	20	75	283	24	307

We were in the process of drilling 30 gross (23 net) wells at December 31, 2007.

Net Wells Drilled

The number of net wells we drilled during calendar years 2007, 2006, and 2005 are shown below:

	Exploratory			Developmental		
	Productive	Dry	Total	Productive	Dry	Total
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
Year ended December 31, 2005	33.2	15.6	48.8	144.8	16.8	161.6

Productive Wells

We have working interests in the following productive wells as of December 31, 2007:

	Gas		Oil	
	Gross	Net	Gross	Net
Mid-Continent	3,660	1,892	1,061	580
Permian	1,057	593	5,811	1,471
Gulf Coast	514	180	221	104
Other	110	8	407	17
	5,341	2,673	7,500	2,172

ITEM 3. LEGAL PROCEEDINGS

As of December 31, 2007, in the normal course of business, we have 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 aggregate, would not have a material adverse effect on our company.

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 2007.

ITEM 4A. EXECUTIVE OFFICERS

The executive officers of Cimarex as of February 28, 2008 were:

Name	Age	Office
F.H. Merelli	71	Chairman of the Board, Chief Executive Officer, and President
Joseph R. Albi	49	Executive Vice President, Operations
Thomas E. Jorden	50	Executive Vice President, Exploration
Stephen P. Bell	53	Senior Vice President, Business Development and Land
Paul Korus	51	Vice President, Chief Financial Officer, and Treasurer
Gary R. Abbott	35	Vice President, Corporate Engineering
Richard S. Dinkins	63	Vice President, Human Resources
James H. Shonsey	56	Vice President, Chief Accounting Officer, and Controller

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

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.

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 \$.04 per share cash dividend was paid to shareholders in every quarter through fourth quarter of 2007. In December 2007, the Board of Directors declared a \$.06 per share dividend payable in the first 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.

2007	High	Low	Dividends 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
2006	High	Low	Dividends Per Share
First Quarter	\$ 47.80	\$ 39.21	\$.04
Second Quarter	\$ 47.40	\$ 35.84	\$.04
Third Quarter	\$ 43.03	\$ 33.57	\$.04
Fourth Quarter	\$ 38.46	\$ 32.56	\$.04

The closing price of Cimarex stock as reported on the New York Stock Exchange on February 15, 2008, was \$44.73. At December 31, 2007, Cimarex's 82,541,658 shares of outstanding common stock were held by approximately 4,595 stockholders of record.

ITEM 5C. STOCK REPURCHASES.

In December 2005, the Board of Directors authorized the repurchase of up to four million shares of common stock. Through December 31, 2007, we have repurchased and cancelled a total of 1,364,300 shares at an overall average price of \$39.05. The shares were acquired as follows:

Period	Total Number of Shares Purchased	Average Price Paid per Share
Year ended December 31, 2005	68,000	\$ 43.03
Year ended December 31, 2006	182,100	\$ 44.43
Year ended December 31, 2007	1,114,200	\$ 37.93
	1,364,300	\$ 39.05

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,

	2007	2006	2005	2004	2003
Operating results:					
Revenues	\$ 1,431,166	\$ 1,267,144	\$ 1,118,622	\$ 475,164	\$ 325,621
Net income	346,469	345,719	328,325	153,592	94,633
Basic earnings per share	4.23	4.21	5.07	3.70	2.28
Diluted earnings per share	4.09	4.11	4.90	3.59	2.22
Cash dividends declared per share	.18	.16			
Balance sheet data:					
Total assets	5,362,794	4,829,750	4,180,335	1,105,446	805,508
Total debt	487,159	443,667	352,451		
Stockholders' equity	3,259,287	2,976,143	2,595,453	700,712	534,740
Other financial data:					
Oil and gas sales	1,364,622	1,215,411	1,072,422	472,389	324,119
Oil and gas capital expenditures	1,023,434	1,074,673	2,462,826	296,429	162,627
Proved Reserves:					
Gas (MMcf)	1,122,694	1,090,362	1,004,482	364,641	337,344
Oil (MBbls)	58,250	59,797	64,710	14,063	14,137
Total equivalent (MMcfe)	1,472,195	1,449,146	1,392,742	449,020	422,167

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 2007 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.

In 2007, we achieved the following financial and operating results:

Oil and gas production volumes averaged 451 million cubic feet equivalent per day (MMcfe/d), up from 449 MMcfe/d in 2006.

Year end proved reserves totaled 1.47 Tcfe versus 1.45 Tcfe on December 31, 2006.

We sold 123 Bcfe of proved reserves for \$177 million.

Oil and gas sales totaled \$1.4 billion, a 12% increase from 2006.

Cash flow from operating activities increased 13% to \$995 million.

Net income was \$346.5 million versus \$345.7 million in 2006.

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Stockholders' equity reached \$3.3 billion, a 10% increase from year end 2006.

Our debt-to-total capitalization on December 31, 2007 was 13%.

We had no bank debt and \$123 million of cash.

In May we sold \$350 million of ten-year 7.125% senior unsecured notes at par. Net proceeds were used to redeem our old 9.6% notes and to reduce bank debt.

We repurchased 1,114,200 shares of our common stock.

We increased our regular quarterly common stock cash dividend from \$0.04 to \$0.06 per share.

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 maintain 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 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 for \$35.8 million. This transaction added over 50 locations to our already active Texas Panhandle drilling program and eight Bcfe of proved reserves.

From time to time we also consider selling certain assets. During 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. We continue to evaluate alternatives for the rest of our Gulf of Mexico assets.

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 \$6.50 per Mcf in 2006 to \$7.05 per Mcf in 2007; and oil prices increased from \$61.96 per barrel in 2006 to \$69.71 per barrel in 2007. 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 have made limited use of hedging transactions to somewhat reduce price risk as discussed further below.

	Years Ended December 31,		
	2007	2006	2005
Gas Prices:			
Average Henry Hub price (\$/Mcf)	\$ 6.86	\$ 7.23	\$ 8.60
Average realized sales price (\$/Mcf)	\$ 7.05	\$ 6.50	\$ 8.05
Effect of hedges (\$/Mcf)	\$ 0.23	\$	\$
Oil Prices:			
Average WTI Cushing price (\$/Bbl)	\$ 72.31	\$ 66.22	\$ 56.44
Average realized sales price (\$/Bbl)	\$ 69.71	\$ 61.96	\$ 55.25

On an energy equivalent basis, 73% of our 2007 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 million change in our gas revenues. Similarly 27% 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 a \$7.4 million change in our oil revenues.

To mitigate a portion of our exposure to potentially adverse gas market changes, in July 2006 we entered into certain derivative contracts covering approximately 24% of our overall 2007 gas production and about 12% of our estimated 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 5 to the Consolidated Financial Statements and Item 7A of this report 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 required 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. Historically, we have been able to grow our proved reserves and production each year through drilling and acquisitions. Future growth will continue to depend upon our ability to economically add reserves in excess of production.

In 2007 our total proved oil and gas reserves increased by 1.5% from 1.449 Tcfe to 1.472 Tcfe. This was despite production of 165 Bcfe and property sales of 123.4 Bcfe. Proved natural gas reserves at year-end 2007 were 1.12 Tcf compared to 1.09 Tcf at year-end 2006. Natural gas comprised 76% and 75% of our total proved reserves at year-end 2007 and 2006, respectively. Our proved oil reserves at year-end 2007 were 58.3 MMBbls compared to 59.8 MMBbls at the end of 2006. Overall, about 42% of our proved reserves are in our Mid-Continent region and 36% are in the Permian Basin. Our onshore Gulf Coast and other onshore operations collectively make another 20% of total proved reserves. Only 2% 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 2007, revisions of previous estimates boosted proved reserves by 57.5 Bcfe or 4% of total proved reserves on December 31, 2007. Most of our positive revisions resulted from higher oil and gas prices and new data for one of our large fields in Wyoming. See Note 17, 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 \$982.5 million on E&D during 2007 and \$1,048.2 million in 2006. Approximately 39% of 2007 expenditures were in the Mid-Continent area, 37% in the Permian Basin, 17% in the Gulf Coast area, and 5% in the Gulf of Mexico. We project that 2008 exploration and development expenditures will range from \$1.1 billion to \$1.3 billion.

Cash flow from operating activities for 2007 totaled \$994.7 million, which more than funded our drilling program. Based on expected cash flow provided by operating activities, cash on hand and monies

available under our bank credit facility, we are well positioned to fund the capital program we have planned for 2008.

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 2007, we owned interests in over 12,841 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.

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 2007 was \$10.8 million compared to \$8.2 million in 2006.

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 compared to a loss of \$67.8 million in 2005.

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,			Price/Volume Analysis		
	2007	2006	Percent Change Between 2007/2006	Price	Volume	Variance
(In thousands or as indicated)						
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 MMcf per day, up 2 MMcf 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.

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.

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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	\$ 61,471	\$ 47,879
Gas gathering and processing costs	(30,513)	(27,410)
	\$ 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 equaled \$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. Tax expense equaled a combined federal and state effective income tax rate of 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.

RESULTS OF OPERATIONS

2006 compared to 2005: Our financial and operating results for 2005 include the operating results of properties acquired in the Magnum Hunter merger beginning June 7, 2005.

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Net income for the year 2006 was \$345.7 million, or \$4.11 per diluted share, compared to net income of \$328.3 million, or \$4.90 per diluted share in 2005. The change in net income results from the effect of changes in revenues and costs, as discussed further.

Oil and Gas Sales (In thousands or as indicated)	For the Years Ended December 31,			Price/Volume Analysis		
	2006	2005	Percent Change Between 2006/2005	Price	Volume	Variance
Gas sales	\$ 810,894	\$ 807,007	1%	\$ (192,982)	\$ 196,869	\$ 3,887
Oil sales	404,517	265,415	52%	43,821	95,281	139,102
Total oil and gas sales	\$ 1,215,411	\$ 1,072,422	13%	\$ (149,161)	\$ 292,150	\$ 142,989
Total gas volume Mcf	124,733	100,272	24%			
Gas volume MMcf per day	341.7	274.7				
Average gas price per Mcf	\$ 6.50	\$ 8.05	(19)%			
Total oil volume thousand barrels	6,529	4,804	36%			
Oil volume barrels per day	17,887	13,162				
Average oil price per barrel	\$ 61.96	\$ 55.25	12%			

Oil and gas sales for the year 2006 totaled \$1.2 billion, compared to \$1.1 billion for 2005. The \$143.0 million increase in sales between the two periods results from \$292.0 million related to higher production volumes, offset by a decrease of \$149.0 million resulting from lower commodity prices.

Sales benefited from higher production volumes. Average daily gas production rose 67.0 MMcf in 2006 to 341.7 MMcf from 274.7 MMcf in 2005, resulting in \$197.0 million of incremental revenues. Oil volumes averaged 17,887 barrels per day for 2006, compared to 13,162 barrels per day in 2005, resulting in increased revenues of \$95.0 million. The increase in sales volumes between the periods of 2006 and 2005 is due to the inclusion of Magnum Hunter operations beginning June 7, 2005 (date of acquisition) and positive drilling results during 2005 and 2006. Production volumes in the Gulf of Mexico and along the Texas and Louisiana Gulf Coast area were negatively impacted during the fourth quarter of 2005 as a result of hurricanes. It is estimated to have negatively impacted fourth-quarter 2005 production by 41 to 45 MMcf equivalent per day. These volumes were brought back online throughout 2006, and by the fourth quarter of 2006 less than one MMcf equivalent per day was shut-in from the 2005 hurricane activity. No oil and gas reserves have been lost as a result of the storms and the majority of associated repair costs will be covered by insurance.

Realized gas prices averaged \$6.50 per Mcf for 2006, compared to \$8.05 per Mcf for 2005. This 19% change decreased sales by \$193.0 million between the two periods. Realized oil prices, however, averaged \$61.96 per barrel for 2006, compared to \$55.25 per barrel for 2005. The increase in sales between periods resulting from this 12% improvement in oil prices totaled \$44.0 million. Changes in realized prices were the direct result of overall market conditions.

	For the Years Ended December 31,	
	2006	2005
Gas Gathering, Processing and Marketing (in thousands):		
Gas gathering and processing revenues	\$ 47,879	\$ 44,238
Gas gathering and processing costs	(27,410)	(31,890)
Gas gathering and processing margin	\$ 20,469	\$ 12,348
Gas marketing revenues, net of related costs	\$ 3,854	\$ 1,962

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We sometimes transport, process and market third-party gas that is associated with our gas. In 2006, third-party gas gathering and processing contributed \$20.5 million of pre-tax cash operating margin (revenues less direct cash expenses) versus \$12.4 million in 2005. Our gas marketing margin (revenues less purchases) increased to \$3.9 million in 2006 from \$2.0 million in 2005. 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 2006/2005
	2006	2005	
Operating costs and expenses (in thousands):			
Depreciation, depletion and amortization	\$ 396,394	\$ 258,287	\$ 138,107
Asset retirement obligation	7,018	3,819	3,199
Production	176,833	104,067	72,766
Transportation	21,157	15,338	5,819
Taxes other than income	91,066	73,360	17,706
General and administrative	42,288	33,497	8,791
Stock compensation	8,243	4,959	3,284
Other operating, net	2,064	15,897	(13,833)
(Gain) Loss on derivative instruments	(22,970)	67,800	(90,770)
	\$ 722,093	\$ 577,024	\$ 145,069

Total operating costs and expenses (not including gas gathering, marketing and processing costs, or income tax expense) were \$722.1 million in 2006 compared to \$577.0 million in 2005.

Depreciation, depletion and amortization (DD&A) was the largest component of the increase between periods. DD&A equaled \$396.4 million in 2006 compared to \$258.3 million in 2005. On a unit of production basis, DD&A was \$2.42 per Mcfe in 2006 compared to \$2.00 per Mcfe for 2005. The increase stems from higher costs for reserves added during 2005 and 2006. Service costs to drill and complete wells have been increasing. That along with certain high cost dry holes in our Gulf Coast and Gulf of Mexico regions have influenced our per unit rates, even though overall drilling success rates have remained high.

Asset retirement obligation increased \$3.2 million from \$3.8 million in 2005 to \$7.0 million in 2006. The Company recognizes the fair value of a liability for an asset retirement obligation in the period in which it is incurred if a reasonable estimate of fair value can be made, and the associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. Oil and gas producing companies incur this liability which includes costs related to the plugging of wells, the removal of facilities and equipment, and site restorations, upon acquiring or drilling a successful well. Since 2005 the liability has increased \$28.0 million from \$101.1 million in 2005 to \$129.1 million in 2006.

Production costs rose \$72.7 million from \$104.1 million (\$.81 per Mcfe) in 2005 to \$176.8 million (\$1.08 per Mcfe) in 2006. The higher costs in 2006 resulted from higher field operating expenses from an expanded number and type of properties, higher maintenance costs and increased insurance costs due to past hurricanes. Additional workover/maintenance projects were implemented in 2006, totaling \$28.9 million (\$0.18 per Mcfe) compared to \$11.6 million (\$0.09 per Mcfe) in 2005.

Transportation costs increased from \$15.3 million in 2005 to \$21.2 million in 2006. The increase is the result of higher sales volumes and that expiring contracts are being renewed with increased current market rates.

Taxes other than income were \$17.7 million greater, rising from \$73.4 million in 2005 to \$91.1 million in 2006. The increase between periods resulted from increases in oil and gas sales stemming from higher production volumes and oil prices.

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General and administrative (G&A) expenses increased \$8.8 million from \$33.5 million in 2005 to \$42.3 million in 2006. The increase between periods is due to an expansion of staff and higher employee-benefit costs.

Stock compensation expense consists of non-cash charges resulting from the issuance of restricted stock, restricted stock units and stock option awards. Stock compensation increased from \$5.0 million in 2005 to \$8.2 million in 2006.

Other operating, net decreased from \$15.9 million in 2005 to \$2.1 million in 2006. These expenses in 2005 consisted primarily of \$9.4 million of costs associated with the Magnum Hunter merger. Of this \$9.4 million, \$3.6 million is due to the acceleration of vesting of stock options and restricted stock units resulting from change of control provisions under our stock incentive plan becoming effective due to the Magnum Hunter merger. The remaining \$5.8 million consists of \$4.3 million of general integration costs, \$1.0 million for retention bonuses, and \$0.5 million of related financing costs. In addition to merger costs, 2005 expenses also included a mediated \$6.5 million litigation settlement pertaining to post-production deductions on properties operated by Cimarex. Other expense for 2006 included \$2.1 million of litigation settlements pertaining primarily to resolution of oil and gas property title issues.

Another component of change in total operating costs and expenses for 2006 and 2005 was the gain and loss on derivative instruments. In connection with the Magnum Hunter merger, Cimarex recognized a \$39.3 million liability associated with Magnum Hunter's existing commodity derivatives at the merger date (June 7, 2005). These derivative instruments were not designated for hedge accounting treatment. As a result, Cimarex recognized net gains for the year 2006 of \$23.0 million and net losses for 2005 of \$67.8 million, respectively. Activity includes both non-cash mark-to-market derivative gains and losses as well as cash settlements. Cash payments related to these contracts that settled in 2006 and 2005 totaled \$19.0 million and \$64.3 million, respectively. These contracts expired December 31, 2006.

Other income and expense

Net interest expense in 2006 totaled \$1.9 million, comprised of \$29.9 million of interest expense, offset by \$24.2 million of capitalized interest and \$3.8 million of amortization of fair value of debt. We capitalize interest related to borrowings associated with costs incurred to bring properties under development, not being amortized, to their intended use. This has decreased from \$5.8 million of net interest expense in 2005, which was comprised of \$19.6 million of interest expense, offset by \$11.7 million of capitalized interest and \$2.1 million of amortization of fair value of debt. The increases in the components of the 2006 net interest amount results from amounts associated with the debt assumed in the Magnum Hunter merger and an increase in costs incurred to bring properties under development, not being amortized, to their intended use. Prior to the Magnum Hunter merger, Cimarex had no outstanding debt.

Other, net increased from \$12.5 million of income in 2005 to \$28.6 million of income in 2006. The components of this other income net of other expenses consist of miscellaneous items that will vary from period to period, including income and loss in equity investees. The large increase from 2005 to 2006 is due primarily to distribution received in excess of our investment in the Company's limited partnership affiliates, Teal Hunter L.P. and Mallard Hunter L.P. These partnerships sold all of their interest in oil and gas properties during 2006. Cimarex's investments in these partnerships had been reflected in other assets, net. Net sales consideration received via distributions from the partnerships equaled \$59.3 million, which are in excess of the Company's investment balance in the partnerships. The excess distributions of \$19.8 million have been recorded in other income for 2006.

Income tax expense

Income tax expense totaled \$198.6 million for 2006 versus \$188.1 million for 2005. Tax expense equaled a combined federal and state effective income tax rate of 36.5% and 36.4% in 2006 and 2005, respectively. Included in the 2006 income tax expense of \$198.6 million is a current benefit of \$21.9 million.

LIQUIDITY AND CAPITAL RESOURCES

Overview

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.

Exploration and development expenditures and dividend payments have generally been funded by cash flow provided by operating activities. We believe that our cash flow from operating activities and other capital resources will be adequate to fund our planned 2008 capital expenditures.

Analysis of Cash Flow Changes

Cash flow provided by operating activities for 2007 was \$994.7 million, compared to \$878.4 million for 2006 and \$704.7 million for 2005. The increase from 2006 to 2007 resulted primarily from higher gas prices, higher oil prices and increased oil production. The increase from 2005 to 2006 resulted primarily from higher production and from higher oil prices. Our production volumes were higher in 2006 versus 2005 because we owned the Magnum Hunter properties for a full year versus seven months in 2005.

Cash flow used in investing activities for 2007 was \$875.4 million, compared to \$1.0 billion for 2006 and \$497.5 million for 2005. 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 decrease from 2006 to 2007 was mostly caused by increased proceeds from property sales. We sold \$177 million of properties in 2007 versus \$4.5 million in 2006. The increase from 2005 to 2006 resulted primarily from an increase in exploration and development expenditures.

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.

Cash flow provided by financing activities in 2006 was \$74.8 million versus \$261.4 million used in 2005. The cash provided by financing activities in 2006 resulted primarily from the borrowing of \$95.0 million on our credit facility. The cash used in financing activities in 2005 resulted primarily from the payment of debt (including \$3.5 million of capital lease debt) assumed in the Magnum Hunter acquisition, offset by proceeds from issuance of common stock from stock option exercises.

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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,		
	2007	2006	2005
Acquisitions:			
Proved	\$ 17,334	\$ 25,970	\$ 1,523,356
Unproved	23,580	513	297,692
	40,914	26,483	1,821,048
Exploration and development:			
Land & Seismic	98,162	104,527	68,703
Exploration	217,696	251,717	197,459
Development	666,662	691,946	375,616
	982,520	1,048,190	641,778
Property sales	(176,659)	(4,459)	(149,262)
	\$ 846,775	\$ 1,070,214	\$ 2,313,564

Property acquisitions in 2007 and 2006 primarily relate to various producing properties and exploratory nonproducing leases. The acquisitions in 2005 relate primarily to the purchase of Magnum Hunter.

We have experienced significant service and material cost inflation over the past three years. We are starting to see a flattening of drilling and services costs and expect to see this remain dependent upon commodity prices. Our exploration and development expenditures decreased six percent in 2007 compared to 2006. The decrease in 2007 resulted primarily from a decrease in exploration activity in the Gulf of Mexico.

Exploration and development expenditures increased 63% in 2006 compared to 2005. The increase in 2006 resulted from a larger exploration and development program. We drilled 558 gross wells in 2006 compared to 382 gross wells in 2005.

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

Our 2007 exploration and development drilling program is discussed in *Exploration and Development Activity Overview* under Item 1 of this Form 10-K.

Financial Condition

Total assets increased by \$0.5 billion in 2007 from \$4.8 billion at the beginning of the year to reach \$5.3 billion by year end. Our net oil and gas assets increased by \$0.4 billion, primarily because of our drilling program, and our cash position increased by \$118 million as a result of property sales that closed during December. As of December 31, 2007, stockholders' equity totaled \$3.3 billion, up from \$3.0 billion at December 31, 2006. The increase resulted primarily from 2007 net income of \$346.5 million.

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Dividends

In December 2005, the Board of Directors declared the Company's first quarterly cash dividend of \$.04 per share payable to shareholders. A \$.04 per share 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.

Working Capital

Working capital increased \$77.8 million from year-end 2006 to \$140.0 million at year-end 2007. Working capital increased primarily because of the following.

We closed on \$144.1 million of property sales in December which allowed us to pay off our remaining bank debt and increase our cash position by \$118 million compared to year-end 2006.

Other current assets increased by \$41.9 million, primarily due to cash advances paid for construction of a gas processing facility adjacent to our Riley Ridge field development project in Wyoming.

These working capital increases were partially offset by an increase in revenue payable of \$35.3 million due to increased production and prices and an increase in other accrued expenses of \$39.3 million due to having taxable income in the current year and an increase in cash advances from partners.

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, 2007 and 2006 consisted of the following (in thousands):

	December 31,	
	2007	2006
Bank debt	\$	\$ 95,000
9.6% Notes due 2012 (face value \$195,000)		210,746(1)
7.125% Notes due 2017	350,000	
Floating rate convertible notes due 2023 (face value \$125,000)	137,159(2)	137,921(2)
	\$	\$
Total long-term debt	487,159	443,667

(1)

Fair market value at June 7, 2005 (date of acquisition of Magnum Hunter) equaled \$215.5 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.

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(2)

Fair market value at June 7, 2005 equaled \$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.

Our revolving credit facility provides for \$500 million of long-term committed credit. The facility is scheduled to mature on July 1, 2010 and is secured by mortgages on certain oil and gas properties and the stock of certain wholly-owned operating subsidiaries. At December 31, 2007, there were no outstanding borrowings under the revolving credit facility. We had outstanding letters of credit for approximately \$2.7 million posted against the borrowing base, leaving an unused borrowing amount of approximately \$497.3 million.

The credit facility agreement contains both financial and non-financial covenants, including restricting our cash investments to "Cash Equivalent Investments" as defined under the agreement. We noted in early December 2007 that an investment of \$16 million in a money market fund was not in compliance with our covenants. We then obtained waivers from our lenders for the related investments and amended the definition of "Cash Equivalent Investments". We are in compliance with the amended covenants and do not view them as materially restrictive.

The 9.6% notes assumed in the Magnum Hunter merger were redeemed on May 18, 2007 at a redemption price of 104.8% of the principal amount plus \$3.3 million of accrued interest for a total redemption value of \$207.6 million. We recognized a gain on the early extinguishment of this debt of \$5.1 million which is reflected on the income statement under Other income and expense.

Also in May 2007 we sold \$350 million of new 7.125% senior unsecured notes that will mature May 1, 2017. The notes were sold to the public at par. Net proceeds from the sale were used to redeem the 9.6% notes and reduce borrowings under our credit facility. Interest on the new notes is payable May 1 and November 1 of each year. The first interest payment was made on November 1, 2007. 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 equal to 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.

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 equal to three-month LIBOR, reset quarterly. On December 31, 2007, the interest rate was 4.99%.

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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 fixed conversion price of \$28.99 per share. On December 31, 2007, the closing price of our common stock traded on the New York Stock Exchange was \$42.53. There is not an observable market for the notes. Based on an average common stock price of \$42.53, management estimates the fair value of the notes at December 31, 2007 was approximately \$183.4 million (or \$1,467 per bond).

In addition to the holders' right to redeem the notes if our common stock price is above the conversion price, the holders also have the right to require us to repurchase all or a portion of the notes at a repurchase price equal to 100% of the principal amount (plus accrued interest) on December 15, 2008, 2013, and 2018. The indenture agreement also provides us with an option to redeem some or all of the notes at a redemption price equal to 100% of the principal amount and shares for the value of the convertible feature (plus accrued interest) anytime after December 22, 2008.

Contractual Obligations and Material Commitments

At December 31, 2007, we had contractual obligations and material commitments as follows:

Contractual obligations	Payments Due by Period				
	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
	(In thousands)				
Long-term debt(1)	\$ 475,000	\$	\$	\$	\$ 475,000
Fixed-Rate interest payments(1)	236,906	24,938	49,875	49,875	112,218
Operating leases	32,491	5,855	10,778	9,585	6,273
Drilling commitments	98,153	98,153			
Gas processing facility(2)	57,871		57,871		
Asset retirement obligation	113,054	7,270	(3)	(3)	(3)
Other liabilities	6,828	37	65	56	6,670

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

(2) *At December 31, 2007, we had committed to construction of a gas processing facility adjacent to our Riley Ridge gas field in Sublette County, Wyoming. The total estimated remaining cost of the facility is \$102.8 million, of which \$57.9 million is subject to a construction contract for the facility. Pursuant to the terms of our operating agreement with our partners in this project, we will be reimbursed by them for approximately 43% of all costs related to the facility.*

(3) *We have excluded the long term asset retirement obligations because we are not able to precisely predict the timing of these amounts.*

At December 31, 2007, we had a firm sales contract to deliver approximately one Bcf of natural gas over the next three months. If this gas is not delivered, our financial commitment would be approximately \$2.9 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.

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 \$3.1 million.

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 exploration and development activities.

2008 Outlook

Our exploration and development expenditures program for 2008 are projected to range from \$1.1 billion to \$1.3 billion. 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. Approximately 43% of the expenditures will be in the Mid-Continent area, 38% in the Permian Basin, 16% in the Gulf Coast area, and 3% in our other areas.

Production estimates for 2008 range from 465 to 485 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 2007, our realized prices averaged \$7.05 per Mcf of gas and \$69.71 per barrel of oil. Prices can be very volatile and the possibility of 2008 realized prices being different than they were in 2007 is high.

Costs of operations on a per Mcfe basis for 2008 are currently estimated as follows:

	2008	2007
Production expense	\$1.20 - \$1.30	\$ 1.22
Transportation expense	0.16 - 0.18	0.16
DD&A and Asset retirement obligation	2.85 - 3.00	2.86
General and Administrative	0.28 - 0.32	0.30
Production taxes (% of oil and gas revenue)	6.5% - 7.5%	6.9%

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 4 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, 21 percent of our total proved reserves are categorized as proved undeveloped. Of these proved undeveloped reserves, 62 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,					
	2007		2006		2005	
	Bcfe Change	Percent of total Reserves	Bcfe Change	Percent of total Reserves	Bcfe Change	Percent of total Reserves
Revisions resulting from price changes	35.5	2.45%	(40.1)	(2.88)%	13.1	2.92%
Other changes in estimates	22.0	1.52%	3.5	0.25%	(1.9)	(0.42)%
Total	57.5	3.97%	(36.6)	(2.63)%	11.2	2.50%

Non-price related revisions added 23.6 Bcfe over the three-year period 2005-2007, comprising 1.4 percent of total reserves added over the period of 1,669 Bcfe. An 8.5 Bcfe increase resulted from higher prices. See Note 17, 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 an amount equal to 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 amount of 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 statements, these higher commodity prices will be used to determine if the capital costs are in fact impaired as of the end of the period.

Goodwill

We assess goodwill for impairment at least annually, and more often if volatility in oil and gas prices or other circumstances warrant. The impairment assessment requires us to make estimates regarding the fair value of goodwill. The estimated fair value is based on numerous factors, including future net cash flows of our estimates of proved reserves as well as the fair value of our nonproducing leases and other assets and liabilities. If our carrying amount for goodwill exceeds its estimated fair value, then a measurement of the loss must be performed and any deficiency is recorded as an impairment. To date, no related impairment has been recorded but we cannot predict when or if goodwill may be impaired in the future. Impairment charges may occur if we are unable to replace the value of our depleting asset base or if other adverse events (for example, materially lower oil and gas prices) reduce the fair value of our company.

Derivatives

We determine the fair value of derivative contracts based on the stated contract prices and current and projected market prices at the determination date discounted to reflect the time value of money until settlement. The accounting treatment for the changes in fair value is dependent upon whether or not a derivative instrument is designated as a hedge for accounting treatment purposes. Realized and unrealized gains and losses on derivatives that are not designated as hedges are recognized currently in costs and expenses associated with operating income in our consolidated statements of operations. For derivatives designated as cash flow hedges, changes in the fair value, to the extent the hedge is effective, are recognized in other comprehensive income until the hedged item is settled. Changes in the fair value of the hedge resulting from ineffectiveness are recognized currently as unrealized gains or losses in other income and expense in the consolidated statements of operations. Gains and losses upon settlement of the cash flow hedges will be recognized in gas revenues in the period the contracts are settled.

Depending on changes in oil and gas futures markets and management's view of underlying oil and natural gas supply and demand trends, we may increase or decrease our current hedging positions. See Note 5 to the Consolidated Financial Statements and Item 7A of this report for additional information regarding our derivative instruments.

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 the normal course of business we have 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 aggregate, would not have a material adverse effect on our company.

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 2007, we revised our existing estimated asset retirement obligation by \$1.0 million, or approximately one percent of the asset retirement obligation at December 31, 2006, due to changes in the various related attributes. Over the past three years, revisions to the estimated asset retirement obligation averaged approximately 15% of the asset retirement obligation at the beginning of the year. 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.

Recent Accounting Developments

In December 2007, the Financial Accounting Standards Board ("FASB") issued two new Statements. FASB Statement 141R, *Business Combinations*, requires most identifiable assets, liabilities, noncontrolling interests, and goodwill acquired in a business combination to be recorded at "full fair value". The Statement redefines various aspects related to the accounting for a business combination by now applying the acquisition method of accounting (previously referred to as the purchase method). FASB Statement 160, *Noncontrolling Interests in Consolidated Financial Statements*, requires noncontrolling interests (previously referred to as minority interests) to be reported as a component of equity, which changes the accounting for transactions with noncontrolling interest holders. Both Statements are effective for periods beginning on or after December 15, 2008, and earlier adoption is prohibited. We do not expect the adoption of either Statement to have a material impact on our financial statements.

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 production is subject to hedging. With regard to our future natural gas production, based on contracts currently in place, we have 40 MMBtu per day of gas production in 2008 that is subject to zero-cost collars (with weighted average floor and ceiling prices of \$7.00 to \$9.90). This amount represents approximately 12% of our estimated 2008 gas production (eight percent of our total Mcfe production).

While hedging limits the downside risk of adverse price movements, it may also limit future revenues from favorable price movements. Mid-Continent gas would have to be above the \$9.90 ceiling for us to have any downside risk. At December 31, 2007, the weighted average Mid-Continent prices for the 2008 contracts approximated \$6.74. These contracts are not expected to have a material effect on our realized gas prices for 2008. See Note 5 to the Consolidated Financial Statements in Item 8 of this report for additional information regarding our derivative instruments.

Interest Rate Risk

At December 31, 2007, we had total debt outstanding of \$487.2 million. Of this amount, \$350 million is senior unsecured notes that bear interest at a fixed rate of 7.125% and will mature on May 1, 2017. The remaining debt is \$125 million of unsecured convertible senior notes (face value) that mature on December 15, 2023. These convertible notes bear interest at an annual rate equal to three-month LIBOR, reset quarterly. The book value of our debt approximates the current fair value.

We consider our interest rate exposure to be minimal because as of December 31, 2007 about 74% 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 \$1.25 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 5 and Note 7 to the Consolidated Financial Statements in Item 8 of this report for additional information regarding debt.

Market Value of Investments

We currently have \$14.4 million invested in an asset back 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 \$0.7 million impact on our investments.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

CIMAREX ENERGY CO.

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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.

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, 2007 and 2006, and the related consolidated statements of operations, stockholders' equity and comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2007. 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, 2007 and 2006, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2007, 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, 2007, 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 28, 2008 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

KPMG LLP

Denver
February 28, 2008

CIMAREX ENERGY CO.

CONSOLIDATED BALANCE SHEETS

(In thousands, except share and per share information)

	December 31,	
	2007	2006
Assets		
Current assets:		
Cash and cash equivalents	\$ 123,050	\$ 5,048
Short-term investments	14,391	
Accounts receivable:		
Trade, net of allowance	64,600	62,866
Oil and gas sales, net of allowance	244,299	189,906
Gas gathering, processing, and marketing, net of allowance	6,428	8,083
Other		45,603
Inventories	29,642	39,397
Deferred income taxes	5,697	1,498
Derivative instruments	12,124	41,945
Other current assets	64,346	22,411
	<u>564,577</u>	<u>416,757</u>
Oil and gas properties at cost, using the full cost method of accounting:		
Proved properties	5,545,977	4,656,854
Unproved properties and properties under development, not being amortized	364,618	425,173
	<u>5,910,595</u>	<u>5,082,027</u>
Less accumulated depreciation, depletion and amortization	(1,938,863)	(1,494,317)
	<u>3,971,732</u>	<u>3,587,710</u>
Fixed assets, less accumulated depreciation of \$49,629 and \$33,273	90,584	88,924
Goodwill	691,432	691,432
Derivative instruments		7,051
Other assets, net	44,469	37,876
	<u>\$ 5,362,794</u>	<u>\$ 4,829,750</u>
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable:		
Trade	\$ 41,213	\$ 40,735
Gas gathering, processing, and marketing	11,458	15,506
Accrued liabilities:		
Exploration and development	92,640	94,403
Taxes other than income	26,109	25,376
Other	121,638	82,384
Revenue payable	131,513	96,184
	<u>424,571</u>	<u>354,588</u>
Long-term debt	487,159	443,667
Deferred income taxes	1,076,223	921,665
Asset retirement obligation	105,784	124,821
Other liabilities	9,770	8,866
	<u>2,103,507</u>	<u>1,853,607</u>

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	December 31,	
	_____	_____
	_____	_____
Commitments and contingencies		
Stockholders' equity:		
Preferred stock, \$0.01 par value, 15,000,000 shares authorized, no shares issued		
Common stock, \$0.01 par value, 200,000,000 shares authorized, 83,620,480 and 83,962,132 shares issued, respectively	836	840
Treasury stock, at cost, 1,078,822 shares held	(40,628)	(40,628)
Paid-in capital	1,842,690	1,867,448
Retained earnings	1,448,763	1,117,402
Accumulated other comprehensive income	7,626	31,081
	_____	_____
	3,259,287	2,976,143
	_____	_____
	\$ 5,362,794	\$ 4,829,750
	_____	_____

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

CIMAREX ENERGY CO.

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per share data)

	For the Years Ended December 31,		
	2007	2006	2005
Revenues:			
Gas sales	\$ 845,631	\$ 810,894	\$ 807,007
Oil sales	518,991	404,517	265,415
Gas gathering and processing	61,471	47,879	44,238
Gas marketing, net of related costs of \$107,678, \$144,702 and \$213,749 respectively	5,073	3,854	1,962
	<u>1,431,166</u>	<u>1,267,144</u>	<u>1,118,622</u>
Costs and expenses:			
Depreciation, depletion and amortization	461,791	396,394	258,287
Asset retirement obligation	8,937	7,018	3,819
Production	201,512	176,833	104,067
Transportation	26,361	21,157	15,338
Gas gathering and processing	30,513	27,410	31,890
Taxes other than income	93,630	91,066	73,360
General and administrative	49,260	42,288	33,497
Stock compensation, net	10,772	8,243	4,959
(Gain) loss on derivative instruments		(22,970)	67,800
Other operating, net	6,637	2,064	15,897
	<u>889,413</u>	<u>749,503</u>	<u>608,914</u>
Operating income	541,753	517,641	509,708
Other (income) and expense:			
Interest expense	37,966	29,940	19,607
Capitalized interest	(19,680)	(24,248)	(11,686)
Amortization of fair value of debt	(1,908)	(3,784)	(2,132)
Gain on early extinguishment of debt	(5,099)		
Other, net	(14,151)	(28,591)	(12,536)
	<u></u>	<u></u>	<u></u>
Income before income tax expense	544,625	544,324	516,455
Income tax expense	198,156	198,605	188,130
	<u></u>	<u></u>	<u></u>
Net income	\$ 346,469	\$ 345,719	\$ 328,325
Earnings per share:			
Basic	\$ 4.23	\$ 4.21	\$ 5.07
	<u></u>	<u></u>	<u></u>
Diluted	\$ 4.09	\$ 4.11	\$ 4.90
	<u></u>	<u></u>	<u></u>
Weighted average shares outstanding:			
Basic	81,819	82,066	64,761

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For the Years Ended
December 31,

Diluted

	84,632	84,090	67,000

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

CIMAREX ENERGY CO.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands, except per share data)

	Years Ended December 31,		
	2007	2006	2005
Cash flows from operating activities:			
Net income	\$ 346,469	\$ 345,719	\$ 328,325
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	461,791	396,394	258,287
Asset retirement obligation	8,937	7,018	3,819
Deferred income taxes	167,507	220,539	112,890
Stock compensation, net	10,772	8,243	4,959
Derivative instruments		(41,926)	3,483
Gain on liquidation of equity investees	(3,015)	(19,785)	
Other	(6,791)	1,540	12,844
Changes in operating assets and liabilities			
(Increase) in receivables, net	(7,777)	(9,811)	(45,787)
(Increase) in inventory and other current assets	(32,180)	(11,812)	(27,293)
Increase (decrease) in accounts payable and accrued liabilities	55,436	(18,293)	52,488
Increase (decrease) in other non-current liabilities	(6,469)	593	719
	<u>994,680</u>	<u>878,419</u>	<u>704,734</u>
Net cash provided by operating activities			
Cash flows from investing activities:			
Oil and gas expenditures	(1,021,456)	(1,054,581)	(633,522)
Merger related costs		(439)	(13,740)
Cash received in connection with acquisition			33,407
Proceeds from sale of assets	177,195	10,705	141,842
Distributions received from equity investees	3,015	59,823	302
Purchases of short-term investments	(16,000)		
Sales of short-term investments	1,424		
Other expenditures	(19,574)	(25,310)	(25,742)
	<u>(875,396)</u>	<u>(1,009,802)</u>	<u>(497,453)</u>
Net cash used by investing activities			
Cash flows from financing activities:			
Net Increase (decrease) in bank debt	(95,000)	95,000	
Increase in other long-term debt	350,000		
Decrease in other long-term debt	(204,360)		(273,501)
Financing costs incurred	(6,113)	(153)	(1,516)
Treasury stock acquired and retired	(42,266)	(11,016)	
Dividends paid	(13,429)	(13,358)	
Proceeds from issuance of common stock and other	9,886	4,311	13,637
	<u>(1,282)</u>	<u>74,784</u>	<u>(261,380)</u>
Net cash provided by (used in) financing activities			
	<u>118,002</u>	<u>(56,599)</u>	<u>(54,099)</u>
Net change in cash and cash equivalents			
Cash and cash equivalents at beginning of period	5,048	61,647	115,746

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	Years Ended December 31,		
Cash and cash equivalents at end of period	\$ 123,050	\$ 5,048	\$ 61,647

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

CIMAREX ENERGY CO.

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME

(In thousands)

	Common Stock		Paid-in Capital	Unearned Compensation	Retained Earnings	Accumulated Other Comprehensive Income	Treasury Stock	Total Stockholders' Equity
	Shares	Amount						
Balance, December 31, 2004	41,729	\$ 417	\$ 250,248	\$ (10,072)	\$ 460,031	\$ 88	\$	\$ 700,712
Issuance of common stock, net of offering costs	42,185	422	1,587,775					1,588,197
Issuance of restricted stock awards	249	2	9,913	(9,915)				
Issuance of restricted stock unit awards				(2,856)				(2,856)
Treasury Stock							(96,161)	(96,161)
Common stock reacquired and retired	(1,450)	(14)	(54,723)				52,607	(2,130)
Restricted stock forfeited and retired	(2)		(80)	78				(2)
Amortization of unearned compensation				4,259				4,259
Exercise of stock options, net of tax benefit of \$6,442 recorded in paid-in capital	659	7	15,761					15,768
Stock Option Compensation Expense			2,348					2,348
Accelerated vesting of stock options, restricted stock and restricted stock units	154	1	4,713	2,644				7,358
Equity attributable to Floating rate convertible notes			49,642					49,642
Comprehensive income:								
Net income					328,325			328,325
Unrealized loss on marketable securities of investments, net of tax						(7)		(7)
Total comprehensive income								328,318
Balance, December 31, 2005	83,524	\$ 835	\$ 1,865,597	\$ (15,862)	\$ 788,356	\$ 81	\$ (43,554)	\$ 2,595,453
Dividends					(16,673)			(16,673)
Issuance of restricted stock awards	601	6	13,682	(13,688)				
Treasury Stock							(8,090)	(8,090)
Common stock reacquired and retired	(278)	(3)	(12,039)				11,016	(1,026)
Restricted stock forfeited and retired	(55)		(361)	314				(47)
Amortization of unearned compensation			7,019	2,262				9,281
Reclass restricted unit liability to unearned compensation				13,881				13,881
Reclass remaining unearned compensation to paid-in capital			(13,093)	13,093				
	170	2	4,313					4,315

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	<u>Common Stock</u>			<u>Accumulated Other Comprehensive Income</u>			
Exercise of stock options, net of tax benefit of \$1,618 recorded in paid-in capital							
Stock Option Compensation Expense		2,330					2,330
Comprehensive income:							
Net income				345,719			345,719
Unrealized gain on derivatives, net of tax					30,954		30,954
Unrealized gain on marketable securities of investments, net of tax					46		46
Total comprehensive income							376,719
Balance, December 31, 2006	83,962	\$ 840	\$ 1,867,448	\$ 1,117,402	\$ 31,081	\$ (40,628)	\$ 2,976,143
Dividends				(15,108)			(15,108)
Issuance of restricted stock awards	572	5	(5)				
Treasury Stock					(42,266)		(42,266)
Common stock reacquired and retired	(1,306)	(13)	(49,270)		42,266		(7,017)
Restricted stock forfeited and retired	(61)	(1)	1				
Amortization of unearned compensation			12,738				12,738
Exercise of stock options, net of tax benefit of \$4,026 recorded in paid-in capital	454	5	9,881				9,886
Stock Option Compensation Expense			1,897				1,897
Comprehensive income:							
Net income				346,469			346,469
Net change from hedging activity					(23,302)		(23,302)
Unrealized loss on short-term investments and other, net of tax					(153)		(153)
Total comprehensive income							323,014
Balance, December 31, 2007	83,621	\$ 836	\$ 1,842,690	\$ 1,448,763	\$ 7,626	\$ (40,628)	\$ 3,259,287

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

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. BASIS OF PRESENTATION

Cimarex was formed in February 2002 as a wholly-owned subsidiary of Helmerich & Payne, Inc. (H&P). On September 30, 2002, Cimarex was spun-off and became a stand-alone company. Also on September 30, 2002, Cimarex acquired 100% of the outstanding common stock of Key Production Company, Inc. (Key) in a tax-free exchange.

In June of 2005, we acquired Magnum Hunter Resources, Inc. in a stock-for-stock merger. Magnum Hunter's results of operations are included in our consolidated statements of operations beginning June 7, 2005.

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

Our Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in the United States of America, or GAAP. The preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues, and expenses. Our significant accounting policies are described in Note 4 to our Consolidated Financial Statements. We analyze our estimates, including those related to oil and gas revenues, reserves and properties, as well as goodwill and contingencies, and base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions.

Certain amounts in prior years' financial statements have been reclassified to conform to the 2007 financial statement presentation.

2. DESCRIPTION OF BUSINESS

Cimarex Energy Co. is an independent oil and gas exploration and production company with operations entirely located in the United States. Our oil and gas reserves and operations are mainly located in Texas, Oklahoma, New Mexico, Kansas, Louisiana, and Wyoming.

3. BUSINESS COMBINATION

On June 7, 2005, Cimarex completed the acquisition of Magnum Hunter Resources, Inc, an independent oil and gas exploration and production company with operations concentrated in the Permian Basin of West Texas and New Mexico and in the Gulf of Mexico. Terms of the merger agreement provided that Magnum Hunter stockholders receive 0.415 shares of Cimarex common stock for each share of Magnum Hunter common stock. As a result of the merger, Cimarex issued 39.7 million common shares to Magnum Hunter's common stockholders. The merger was accounted for as a purchase of Magnum Hunter by Cimarex and the results of operations of Magnum Hunter are included in our consolidated statements of operations for the periods since the acquisition.

The following unaudited pro forma information has been prepared to give effect to the Magnum Hunter acquisition as if it had occurred at the beginning of the year. The unaudited pro forma data is presented for illustrative purposes only, based on estimates and assumptions deemed appropriate by

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

3. BUSINESS COMBINATION (Continued)

management, and should not be relied upon as an indication of the operating results that Cimarex would have achieved if the transaction had occurred on January 1, 2005.

For the year ended December 31, 2005:

Revenues	\$	1,393,715
Net income		403,925
Net income per share:		
Basic	\$	6.24
Diluted		6.03

4. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Cash and Cash Equivalents

Cash and cash equivalents consist of cash in banks and investments readily convertible into cash which have original maturities within three months at the date of acquisition. Cash equivalents are stated at cost, which approximates market value.

Short-term Investments

Our short-term investments consist of investments in an asset-backed securities fund. The investments are classified as available-for-sale and are carried at fair value in our balance sheet. Unrealized holding gains and losses are reported in other comprehensive income.

Inventories

Inventories, primarily materials and supplies, are valued at the lower of cost or market.

Oil and Gas Properties

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

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 an amount equal to 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. Increases and decreases in proved reserve estimates, due to quantity revisions or fluctuations in commodity prices, will result in corresponding changes to the full cost ceiling limitation. If net capitalized costs subject to amortization exceed this limit, the excess would be

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

charged to expense. However, if commodity prices increase after period end and before issuance of the financial statements, the higher commodity prices will be used to determine if the capital costs are in fact impaired as of the end of the period.

Depletion of proved oil and gas properties is computed on the units-of-production method, whereby capitalized costs, as adjusted for future development costs and asset retirement obligations, are amortized over the total estimated proved reserves. The costs of wells in progress and certain unevaluated properties are not being amortized. On a quarterly basis, we evaluate such costs for inclusion in the costs to be amortized resulting from the determination of proved reserves, impairments, or reductions in value. To the extent that the evaluation indicates these properties are impaired, the amount of the impairment is added to the capitalized costs to be amortized. Expenditures for maintenance and repairs are charged to production expense in the period incurred.

Goodwill

We account for goodwill in accordance with Statement of Financial Accounting Standard (SFAS) No. 142, *Goodwill and Other Intangible Assets*. SFAS No. 142 requires an annual impairment assessment. A more frequent assessment is required if certain events occur that reasonably indicate an impairment may have occurred. The volatility of oil and gas prices may cause more frequent assessments. The impairment assessment requires us to make estimates regarding the fair value of goodwill. The estimated fair value is based on numerous factors, including future net cash flows of our estimates of proved reserves as well as the success of future exploration for and development of unproved reserves. If the carrying amount exceeds the estimated fair value, then a measurement of the loss must be performed, with any deficiency recorded as an impairment. To date, no related impairment has been recorded.

Revenue Recognition

Oil and Gas Sales

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

Marketing Sales

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

Gas Imbalances

We use the sales method of accounting for gas imbalances. Under this method, revenue is recorded on the basis of gas actually sold. Oil and gas reserves are adjusted to the extent there are sufficient quantities of natural gas to make up an imbalance. In situations where there are insufficient reserves available to make-up an overproduced imbalance, then a liability is established. The natural gas imbalance liability at December 31, 2007 and 2006 was \$3.6 million and \$3.2 million, respectively. At December 31, 2007 and 2006, we were also in an under-produced position relative to certain other third parties.

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

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 we make every reasonable effort 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. Revisions of previous estimates increased our proved reserves by 57.5 Bcfe, or 4% of total proved reserves, at December 31, 2007. Estimations of proved undeveloped reserves can be subject to an even greater possibility of revision. At year-end, 21.4% of our total proved reserves are categorized as proved undeveloped. Of these proved undeveloped reserves, 62% are related to a project in Wyoming.

We use the units-of-production method to amortize our oil and gas properties. Changes in reserve quantities and commodity prices will cause corresponding changes in depletion expense in periods subsequent to these changes, or, in some cases, a full cost ceiling limitation charge in the period of the revision. To date, changes in expense resulting from changes in previous estimates of reserves have not been material.

Transportation Costs

We account for transportation costs under Emerging Issues Task Force ("EITF") 00-10 *Accounting for Shipping and Handling Fees and Costs*. Amounts paid for transportation are classified as an operating expense and are not netted against gas sales.

Derivatives

SFAS No.133, *Accounting for Derivative Instruments and Hedging activities*, requires that all derivatives be recorded on the balance sheet at fair value. We determine the fair value of derivative contracts based on the stated contract prices and current and projected market prices at the determination date discounted to reflect the time value of money until settlement. The accounting treatment for the changes in fair value is dependent upon whether or not a derivative instrument is designated as a hedge for accounting treatment purposes. Realized and unrealized gains and losses on derivatives that are not designated as hedges are recognized currently in costs and expenses associated with operating income in our consolidated statements of operations. For derivatives designated as cash flow hedges, changes in the fair value, to the extent the hedge is effective, are recognized in other comprehensive income until the hedged item is settled. Changes in the fair value of the hedge resulting from ineffectiveness are recognized currently as unrealized gains or losses in other income and expense in the consolidated statements of operations. Gains and losses upon settlement of the cash flow hedges will be recognized in gas revenues in the period the contracts are settled.

Existing commodity derivatives acquired in the Magnum Hunter merger did not qualify for hedge accounting treatment. As of December 31, 2006, all of the contracts assumed with the merger have expired.

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

To mitigate a portion of our potential exposure to adverse market changes in an environment of volatile gas prices, we entered into additional derivative contracts in 2006. These contracts were designated as cash flow hedges for accounting treatment purposes.

Depending on changes in oil and gas futures markets and management's view of underlying oil and natural gas supply and demand trend, we may increase or decrease our current hedging positions. See Note 5 to the Consolidated Financial Statements and Item 7 of this report for additional information regarding our derivative instruments.

Income Taxes

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

We adopted the provisions of Financial Accounting Standards Board Interpretation No. 48 "Accounting for Uncertainty in Income Taxes" ("FIN 48") an interpretation of FASB Statement No. 109 "Accounting for Income Taxes", on January 1, 2007. The interpretation clarifies the accounting for uncertainty in income taxes recognized in our financial statements and provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. The adoption of FIN 48 resulted in no impact to our consolidated financial statements and we have no unrecognized tax benefits that would impact our effective rate.

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.

At December 31, 2006, we had accrued \$8.6 million for mediated litigation settlements which were paid in 2007 with associated interest. In the normal course of business, we have various other litigation related matters and associated accruals, the resolution of which we believe, individually or in aggregate, would not have a material adverse effect on our company.

Asset Retirement Obligations

The Company recognizes the fair value of a liability for an asset retirement obligation in the period in which it is incurred if a reasonable estimate of fair value can be made, and the associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. Oil and gas producing companies incur this liability which includes costs related to the plugging of wells, the removal of facilities and equipment, and site restorations, upon acquiring or drilling a successful well. Subsequent to initial measurement, the asset retirement liability is required to be accreted each period. Capitalized costs are depleted as a component of the full cost pool.

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Stock Options

Effective January 1, 2005, we adopted the provisions of Statement of Financial Accounting Standards ("SFAS") No. 123R, *Share Based Payment* on a modified prospective basis. SFAS No. 123R requires companies to recognize in the income statement the grant-date fair value of stock options and other equity-based compensation to employees.

Earnings per Share

Basic earnings per share includes no dilution and is computed by dividing net income available to common stockholders by the weighted average number of common shares outstanding for the period. Diluted earnings per share reflect the impact of potentially dilutive securities on weighted average number of shares.

Comprehensive Income

Comprehensive income is a term used to refer to net income plus other comprehensive income. Other comprehensive income is comprised of revenues, expenses, gains, and losses that under generally accepted accounting principles are reported as separate components of shareholders' equity instead of net income.

The components of other comprehensive income are as follows (in 000's):

	Net Unrealized Gain on Derivative Instruments(1)	Net Unrealized Gain (Loss) On Short-Term Investments and Other(1)	Accumulated Other Comprehensive Income
Balance at January 1, 2005	\$	\$ 88	\$ 88
2005 activity		(7)	(7)
Balance at December 31, 2005		81	81
2006 activity	30,954	46	31,000
Balance at December 31, 2006	30,954	127	31,081
2007 activity	(23,302)	(153)	(23,455)
Balance at December 31, 2007	\$ 7,652	\$ (26)	\$ 7,626

(1)
Net of tax

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

The table below sets forth the changes in the Company's unrealized gains on derivative instruments included as a component of comprehensive income for the years ended December 31, 2007 and 2006 (in 000's):

	2007	2006
Unrealized derivative gain in comprehensive income, at January 1	\$ 49,009	\$ 48,996
Change in fair value	(9,043)	48,996
Reclassification of net gains to income	(27,829)	13
Net ineffectiveness	(49)	13
	12,088	49,009
Related income tax effect	(4,436)	(18,055)
Unrealized derivative gain in comprehensive income at December 31	\$ 7,652	\$ 30,954

Segment Information

Cimarex has one reportable segment (exploration and production).

Recently Issued Accounting Standards

In December 2007, the Financial Accounting Standards Board ("FASB") issued two new Statements. FASB Statement 141R, *Business Combinations*, requires most identifiable assets, liabilities, noncontrolling interests, and goodwill acquired in a business combination to be recorded at "full fair value". The Statement redefines various aspects related to the accounting for a business combination, by now applying the acquisition method of accounting (previously referred to as the purchase method). FASB Statement 160, *Noncontrolling Interests in Consolidated Financial Statements*, requires noncontrolling interests (previously referred to as minority interests) to be reported as a component of equity, which changes the accounting for transactions with noncontrolling interest holders. Both Statements are effective for periods beginning on or after December 15, 2008, and earlier adoption is prohibited. We do not expect the adoption of either Statement to have a material impact on our financial statements.

5. FINANCIAL INSTRUMENTS

Derivatives

In connection with the Magnum Hunter merger, Cimarex acquired Magnum Hunter's existing commodity derivatives. These derivative instruments were not designated for hedge accounting treatment. During 2006, Cimarex recognized a net gain of \$23.0 million. In 2005, we recorded a net loss of \$67.8 million. Activity in both years included non-cash mark-to-market derivative gains and losses as well as cash settlements. Cash payments related to these contracts for 2006 totaled \$19.0 million, and \$83.4 million from the date of the merger through the fourth quarter of 2006. As of December 31, 2006, all derivative contracts assumed with the merger had expired.

In 2006, we entered into additional derivative contracts to mitigate a portion of our potential exposure to adverse market changes in an environment of volatile gas prices. Using zero-cost collars with

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. FINANCIAL INSTRUMENTS (Continued)

Mid-Continent weighted average floor and ceiling prices of \$7.00 to \$10.17 for 2007 and \$7.00 to \$9.90 for 2008, we hedged 29.2 million MMBtu and 14.6 million MMBtu of our anticipated Mid-Continent gas production for 2007 and 2008, respectively. At December 31, 2007, the remaining contracts outstanding represented approximately 24% of our current anticipated Mid-Continent gas production for 2008.

Under the collar agreements, we receive the difference between an agreed upon index price and a floor price if the index price is below the floor price. We pay the difference between the agreed upon contracted ceiling price and the index price only if the index price is above the contracted ceiling price.

No amounts are paid or received if the index price is between the contracted floor and ceiling prices. These contracts have been designated for hedge accounting treatment as cash flow hedges.

Settlements received during the year ended December 31, 2007 equaled \$27.8 million which were recorded in gas sales and increased the average realized price for the year by \$0.23 per Mcf. During the periods ended December 31, 2007 and 2006, we recognized an unrealized gain of \$49 thousand and an unrealized loss of \$13 thousand, respectively, related to the ineffective portion of the derivative contracts.

At December 31, 2006, the fair value of \$41.9 million and \$7.1 million of the contracts were recorded as current and long-term assets, respectively, and an unrealized gain (net of deferred income taxes) of \$31 million was recorded in other comprehensive income.

At December 31, 2007, the fair value of the remaining contracts was approximately \$12.1 million and was recorded as a current asset. An unrealized gain (net of deferred income taxes) of \$7.7 million was recorded in other comprehensive income. Based on the estimated fair values of the derivative contracts at December 31, 2007, the amount of unrealized gain (net of deferred income taxes) to be reclassified from accumulated other comprehensive income to gas revenue in the next twelve months would be approximately \$7.7 million. We believe that we have sufficient production volumes such that the hedge contract transactions will occur as expected.

Short-term Investments

In the fourth quarter of 2007 we invested \$16 million in an asset-backed securities fund. The investments, which are expected to be liquidated in 2008, are classified as available-for-sale and marked-to-market at the end of each period, through other comprehensive income. As of December 31, 2007, we had liquidated \$1.4 million of the investments with a realized loss of \$17 thousand. We also recorded an unrealized loss of \$183 thousand in other comprehensive income, resulting in a fair value attributable to the investments of \$14.4 million.

Debt

Our revolving credit facility provides for \$500 million of long-term committed credit. The carrying amount of the credit facility approximates the fair value because the interest rates on the credit facility are variable. At December 31, 2007, there were no outstanding borrowings under the credit facility. At December 31, 2006, the carrying amount of the outstanding borrowings was \$95 million.

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. FINANCIAL INSTRUMENTS (Continued)

The following table presents the carrying amounts and estimated fair values of our other debt instruments at December 31, 2007 and 2006.

	2007		2006	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In thousands)			
7.125% Notes due 2017(1)	\$ 350,000	\$ 346,504	\$	\$
9.6% Notes due 2012 (face value \$195,000)(1)			210,746	205,238
Floating rate convertible notes due 2023 (face value \$125,000)	137,159	183,395	137,921	157,393

(1)

The fair values for the fixed rate notes were based on their last traded value before year end.

The carrying amounts for the convertible notes do not reflect \$49.6 million of Paid in Capital attributable to the fair value of our common stock at the time we acquired the convertible notes in the Magnum Hunter merger. There is not an observable market for the convertible notes. The fair values of the convertible notes were based on the December 31st closing price per share for our common stock, which was \$42.53 and \$36.50 for 2007 and 2006, respectively. Therefore, the calculated fair value includes value attributable to both the face amount of the notes and the conversion feature.

Other Financial Instruments

The carrying amounts of our cash, accounts receivable, accounts payable, and accrued liabilities approximate fair value because of the short-term maturities of these assets and liabilities. At December 31, 2007, the allowance for doubtful accounts for trade, oil and gas sales, and gas gathering, processing, and marketing receivables was \$5.6 million, \$0.2 million, and zero, respectively. At December 31, 2006, the allowance for doubtful accounts for trade, oil and gas sales, and gas gathering, processing, and marketing receivables was \$5.7 million, \$0.3 million, and zero, respectively.

Most of our accounts receivable balances are uncollateralized and result from transactions with other companies in the oil and gas industry. Concentration of customers may impact our overall credit risk because our customers may be similarly affected by changes in economic or other conditions within the industry.

6. ASSET RETIREMENT OBLIGATIONS

The Company recognizes the fair value of a liability for an asset retirement obligation in the period in which it is incurred if a reasonable estimate of fair value can be made, and the associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. Oil and gas producing companies incur this liability which includes costs related to the plugging of wells, the removal of facilities and equipment, and site restorations, upon acquiring or drilling a successful well.

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

6. ASSET RETIREMENT OBLIGATIONS (Continued)

The following table reflects the components of the change in the carrying amount of the asset retirement obligation for the years ended December 31, 2007 and 2006 (in thousands):

	2007	2006
	<u> </u>	<u> </u>
Asset retirement obligation at January 1	\$ 129,141	\$ 101,128
Liabilities incurred	5,063	15,318
Liability settlements and disposals	(25,880)	(4,337)
Accretion expense	6,628	6,391
Revisions of estimated liabilities	(1,898)	10,641
	<u> </u>	<u> </u>
Asset retirement obligation at December 31	113,054	129,141
Less: Current asset retirement obligation	7,270	4,320
	<u> </u>	<u> </u>
Long-term asset retirement obligation	\$ 105,784	\$ 124,821
	<u> </u>	<u> </u>

7. LONG-TERM DEBT

Debt at December 31, 2007 and 2006 consisted of the following (in thousands):

	2007	2006
	<u> </u>	<u> </u>
Bank debt	\$	\$ 95,000
9.6% Notes due 2012 (face value \$195,000)		210,746
7.125% Notes due 2017	350,000	
Floating rate convertible notes due 2023 (face value \$125,000)	137,159	137,921
	<u> </u>	<u> </u>
Total long-term debt	\$ 487,159	\$ 443,667
	<u> </u>	<u> </u>

Our revolving credit facility provides for \$500 million of long-term committed credit. The facility is scheduled to mature on July 1, 2010 and is secured by mortgages on certain oil and gas properties and the stock of certain wholly-owned operating subsidiaries. At December 31, 2007, there were no outstanding borrowings under the revolving credit facility. We also had letters of credit for approximately \$2.7 million posted against the borrowing base, leaving an unused borrowing amount of approximately \$497.3 million at December 31, 2007.

The credit facility agreement contains both financial and non-financial covenants which we do not view as materially restrictive.

The 9.6% notes, which were assumed in the Magnum Hunter merger, were redeemed on May 18, 2007. The notes were redeemed at 104.8% of the principal amount plus accrued interest of \$3.3 million through the redemption date, for a total of \$207.6 million. At acquisition, the notes were recorded at a fair market value of \$215.5 million. We recognized a gain on the early extinguishment of this debt of \$5.1 million which is reflected on the income statement under Other income and expense.

In May, 2007 we also sold \$350 million of 7.125% senior unsecured notes that will mature May 1, 2017. The notes were sold to the public at par. Net proceeds from the sale were used to redeem the 9.6% notes and reduce borrowings under our credit facility. Interest on the notes is payable May 1 and November 1 of each year. The first interest payment was made on November 1, 2007. The notes are redeemable at our option, in whole or in part, at any time on and after May 1, 2012 at the following

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

7. LONG-TERM DEBT (Continued)

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 equal to 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.

The floating rate convertible senior notes were assumed in the Magnum Hunter merger and mature on December 15, 2023. At acquisition, the notes were recorded at a fair market value of \$144.7 million, with an additional \$49.6 million attributable to the conversion feature of the notes recorded in Paid in Capital. The notes are senior unsecured obligations and bear interest at an annual rate equal to three-month LIBOR, reset quarterly. On December 31, 2007, the interest rate equaled 4.99%.

Holder 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 fixed conversion price of \$28.99 per share. On December 31, 2007, the closing price of our common stock traded on the New York Stock Exchange was \$42.53. To date, no holders have surrendered their notes for conversion. In addition to the holders' right to redeem the notes if our common stock price is above the conversion price, the holders also have the right to require Cimarex to repurchase all or a portion of the notes at a repurchase price equal to 100% of the principal amount (plus accrued interest) on December 15, 2008, 2013, and 2018. The indenture agreement also provides Cimarex with an option to redeem some or all of the notes at a redemption price equal to 100% of the principal amount (plus accrued interest) anytime after December 22, 2008.

8. INCOME TAXES

Federal income tax expense for the years ended December 31, 2007, 2006, and 2005 differ from the amounts that would be provided by applying the U.S. Federal income tax rate, due to the effect of state

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. INCOME TAXES (Continued)

income taxes, and the Domestic Production Activities deduction. The components of the provision for income taxes are as follows (in thousands):

	Years Ended December 31,		
	2007	2006	2005
Current taxes:			
Federal	\$ 26,993	\$ (20,672)	\$ 66,994
State	3,656	(1,262)	8,246
	<u>30,649</u>	<u>(21,934)</u>	<u>75,240</u>
Deferred taxes:			
Federal	162,122	211,534	108,487
State	5,385	9,005	4,403
	<u>167,507</u>	<u>220,539</u>	<u>112,890</u>
	<u>\$ 198,156</u>	<u>\$ 198,605</u>	<u>\$ 188,130</u>

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

	Years Ended December 31,		
	2007	2006	2005
Provision at statutory rate	\$ 190,619	\$ 190,513	\$ 180,759
Effect of state taxes	9,041	7,564	9,301
Domestic Production Activities deduction	(1,723)		(2,095)
Other	219	528	165
	<u>\$ 198,156</u>	<u>\$ 198,605</u>	<u>\$ 188,130</u>

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. INCOME TAXES (Continued)

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

	December 31,	
	2007	2006
Long-term:		
Assets:		
Net operating loss carryforwards	\$	\$ 24,176
Credit carryforwards	3,587	1,627
Merger related accruals		25,762
Other	1,474	23,723
	<u>5,061</u>	<u>75,288</u>
Liabilities:		
Property, plant and equipment	(1,081,284)	(996,953)
Net, long-term deferred tax liability	(1,076,223)	(921,665)
Current:		
Assets:		
Derivative instruments	4,445	
Other	1,252	1,498
	<u>5,697</u>	<u>1,498</u>
Net deferred tax liabilities	<u>\$ (1,070,526)</u>	<u>\$ (920,167)</u>

We have recorded deferred tax assets of \$10.8 million of which \$3.6 million is attributable to the alternative minimum credit carryforward which does not expire. The realization is dependent on generating sufficient taxable income in the future.

We adopted the provisions of Financial Accounting Standards Board Interpretation No. 48 "Accounting for Uncertainty in Income Taxes" ("FIN 48") an interpretation of FASB Statement No. 109 "Accounting for Income Taxes", on January 1, 2007. The interpretation clarifies the accounting for uncertainty in income taxes recognized in our financial statements and provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. The adoption of FIN 48 resulted in no impact to our consolidated financial statements and we have no unrecognized tax benefits that would impact our effective rate.

As of December 31, 2007, we made no provisions for interest or penalties related to uncertain tax positions. The tax years 2004 - 2006 remain open to examination by the Internal Revenue Service of the United States. We file tax returns with various state taxing authorities which remain open for tax years 2003 - 2006 for examination.

9. CAPITAL STOCK

Stock-based Compensation

Our 2002 Stock Incentive Plan was approved by stockholders in May 2003 and is effective until October 1, 2012. The plan provides for grants of stock options, restricted stock and restricted stock units to non-employee directors, officers and other eligible employees. A total of 12.7 million shares of common stock may be issued under the Plan.

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

9. CAPITAL STOCK (Continued)

Restricted Stock and Units

During 2007 we issued a total of 572,009 restricted shares and 5,274 restricted units to non-employee directors, officers, and other employees. Included in that amount are 228,000 shares issued to certain executives that are subject to market condition-based vesting determined by our stock price performance relative to a defined peer group's stock price performance. After three years of continued service, the executive will be entitled to vest in 50% to 100% of the award. The material terms of performance goals applicable to these awards were approved by stockholders in May 2006. The remaining shares and units granted in 2007 have requisite service-based vesting schedules ranging from one to five years.

The following table presents restricted stock activity during the last three years:

	Years Ended December 31,		
	2007	2006	2005
Outstanding beginning of period	792,779	249,905	14,145
Vested	(13,693)	(7,915)	(11,248)
Granted	572,009	600,589	249,008
Canceled	(61,400)	(49,800)	(2,000)
Outstanding end of period	1,289,695	792,779	249,905

The following table presents restricted unit activity during the last three years:

	Years Ended December 31,		
	2007	2006	2005
Outstanding beginning of period	696,641	697,937	780,787
Converted to Stock			(154,600)
Granted	5,274	4,954	71,750
Canceled		(6,250)	
Outstanding end of period	701,915	696,641	697,937
Vested included in outstanding	559,839	172,617	128,550

Vesting of restricted stock and units granted in years before 2006 is exclusively related to continued service of the grantee for one to five years. In certain cases, a three year required holding period following vesting also applies. A restricted unit represents a right to an unrestricted share of common stock upon completion of defined vesting and holding periods. The restricted stock and stock unit agreements provide that grantees are entitled to receive dividends on unvested shares.

Compensation expense for service-based vesting restricted shares or units is based upon amortization of the grant-date market value of the award. The fair value of the market condition-based restricted stock is based on the grant-date market value of the award utilizing a Monte Carlo simulation model to estimate the percentage of awards that will vest at the end of the three-year period. Compensation expense related

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

9. CAPITAL STOCK (Continued)

to the restricted stock and unit awards is recognized ratably over the applicable vesting period. We recorded compensation costs related to the restricted stock and units as follows (in thousands):

	Years Ended December 31,		
	2007	2006	2005
Compensation costs:			
Recorded as expense	\$ 8,875	\$ 5,913	\$ 5,177
Capitalized to oil and gas properties	\$ 3,863	\$ 3,320	\$ 1,725

Unamortized compensation costs related to unvested restricted shares and units at December 31, 2007, 2006, and 2005 was \$31.7 million, \$30.6 million, and \$39.8 million, respectively.

Stock Options

Options granted under our plan expire ten years from the grant date and vest in one-fifth increments on each of the first five anniversaries of the grant date. The plan provides that all grants have an exercise price equal to the average of the high and low prices of our common stock as reported by the New York Stock Exchange on the date of grant. Upon the exercise of stock options granted after October 1, 2002, grantees are required to hold at least 50% of the profit shares, as defined in the plan, until the eighth anniversary of the grant date.

There were no stock options granted during 2007. Information about outstanding stock options is summarized below:

	Shares	Weighted Average Exercise Price	Weighted Average Remaining Term	Aggregate Intrinsic Value (000)
Outstanding as of January 1, 2007	1,913,529	\$ 16.23		
Exercised	(454,263)	12.90		
Granted				
Canceled	(1)	7.91		
Outstanding as of December 31, 2007	1,459,265	\$ 17.26	4.5 Years	\$ 36,919
Exercisable as of December 31, 2007	1,387,805	\$ 16.29	4.3 Years	\$ 36,430

The total intrinsic value of stock options exercised during 2007 was \$11.0 million. In 2006 and 2005 the intrinsic value of stock options exercised was \$4.4 million and \$17.7 million, respectively.

During 2007 compensation expense related to stock options was approximately \$1.9 million. In 2006 and 2005 compensation expense was \$2.3 million and \$3.4 million, respectively. Compensation cost for stock options is determined pursuant to SFAS No. 123R. Historical amounts may not be representative of future amounts as additional options may be granted.

The weighted-average grant-date fair value of stock options granted during the years ended December 31, 2006 and 2005 was \$15.75 and \$17.20, respectively. The fair value of options is estimated as of the date of grant using the Black-Scholes option-pricing model. Expected volatilities are based on the historical volatility of our common stock. Historical data is also used to estimate the probability of option

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

9. CAPITAL STOCK (Continued)

exercise, expected years until exercise and potential forfeitures. The risk-free interest rate used is the five-year U.S. Treasury bond in effect at the date of the grant.

The following summarizes the assumptions used to determine the fair market value of options issued during the last three years:

	Years Ended December 31,		
	2007	2006	2005
Expected years until exercise	N/A	7.5	7.5
Expected stock volatility	N/A	32.2%	25.5%
Dividend yield	N/A	0.1%	0.0%
Risk-free interest rate	N/A	4.8%	4.1%

Cash received from option exercises during the years ended December 31, 2007, 2006, and 2005 was approximately \$5.9 million, \$2.7 million, and \$9.3 million, respectively. The related tax benefits realized from option exercises totaled approximately \$4.0 million, \$1.6 million, and \$6.4 million, respectively, and were recorded to paid-in capital.

The following summary reflects the status of non-vested stock options granted to employees and directors as of December 31, 2007 and changes during the year:

	Shares	Weighted Average Grant Date Fair Value
Non-vested as of January 1, 2007	300,220	\$ 10.41
Vested	(228,760)	8.80
Granted		
Forfeited		
Non-vested as of December 31, 2007	71,460	\$ 15.57

As of December 31, 2007 there was \$1.0 million of unrecognized compensation cost related to non-vested stock options granted under our stock incentive p