CIMAREX ENERGY CO
Form S-3ASR
April 11, 2007

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As filed with the United States Securities and Exchange Commission on April 11, 2007

Registration No. 333-

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM S-3

Registration Statement
Under
the Securities Act of 1933

CIMAREX ENERGY CO.*

(Exact name of registrant as specified in its charter)

Delaware	**45-0466694**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1700 Lincoln Street, Suite 1800
Denver, Colorado 80203-4518
(303) 295-3995
(Address, including zip code, and telephone number, including area code, of registrant's principal executive offices)

Paul Korus
Cimarex Energy Co.
1700 Lincoln Street, Suite 1800
Denver, Colorado 80203-4518
(303) 295-3995
(Name, address, including zip code, and telephone number, including area code, of agent for service)

With copies to:

Thomas A. Richardson **Charles D. Maguire, Jr.** **Holme Roberts & Owen LLP** **1700 Lincoln Street, Suite 4100** **Denver, Colorado 80203** **(303) 861-7000**	**Stephan J. Feder** **Simpson Thacher & Bartlett LLP** **425 Lexington Avenue** **New York, NY 10017** **(212) 455-2000**

Approximate date of commencement of proposed sale to the public:
From time to time after the effective date of this Registration Statement.

If the only securities being registered on this Form are being offered pursuant to dividend or interest reinvestment plans, please check the following box. o

If any of the securities being registered on this Form are to be offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act of 1933, please check the following box. ý

If this Form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act, check the following box and list the Securities Act registration statement number of earlier effective registration statement for the same offering. o

If this Form is a post-effective amendment filed pursuant to Rule 462(c) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

If this Form is a registration statement pursuant to General Instruction I.D. or a post-effective amendment thereto that shall become effective upon filing with the Commission pursuant to Rule 462(e) under the Securities Act, check the following box. ý

If this Form is a post-effective amendment to a registration statement filed pursuant to General Instruction I.D. filed to register additional securities or additional classes of securities pursuant to Rule 413(b) under the Securities Act, check the following box. o

CALCULATION OF REGISTRATION FEE

Title of each class of securities to be registered	**Proposed maximum aggregate offering price**	**Amount of registration fee**
Senior Notes due 2017	$300,000,000	$9,210
Subsidiary Guarantees	(1)	(1)

(1) In accordance with Rule 457(n), no separate fee is payable with respect to the Subsidiary Guarantees.

* Includes certain subsidiaries of Cimarex Energy Co. identified on the following page.

Table of additional registrant guarantors

Exact name of registrant guarantors as specified in its charter(1)	State or other jurisdiction of incorporation or organization	I.R.S. Employer Identification Number
Brock Gas Systems & Equipment, Inc.	Texas	84-1438790
Cimarex California Pipeline LLC	Colorado	20-8785697
Cimarex Energy Co. of Colorado	Texas	75-1074365
Cimarex Texas LLC	Colorado	20-2424750
Cimarex Texas L.P.	Texas	20-2424688
Columbus Energy Corp.	Colorado	84-0891713
Columbus Energy L.P.	Texas	84-1473120
Columbus Gas Services, Inc.	Delaware	84-0396094
Columbus Texas, Inc.	Nevada	84-1472414
Conmag Energy Corporation	Texas	20-8596953
Hunter Gas Gathering, Inc.	Texas	73-1222501
Key Production Company, Inc.	Delaware	84-1089744
Key Production Texas L.P.	Texas	20-2424799
Key Texas LLC	Colorado	20-2424839
Magnum Hunter Production, Inc.	Texas	75-2589131
Oklahoma Gas Processing, Inc.	Delaware	73-1566476
PEC (Delaware), Inc.	Delaware	73-1567808
Pintail Energy, Inc.	Delaware	01-0615093
Prize Energy Resources, L.P.	Delaware	73-1565425
Prize Operating Company	Delaware	73-1565426
Trapmar Properties, Inc.	Texas	75-1896997

(1) The address for each registrant guarantor is 1700 Lincoln Street, Suite 1800, Denver, Colorado 80203-4518, telephone (303) 295-3995.

Subject to completion, dated April 11, 2007

The information in this prospectus is not complete and may be changed. This prospectus is not an offer to sell these securities and it is not soliciting offers to buy these securities in any state where the offer or sale is not permitted.

Preliminary prospectus

Cimarex Energy Co.

$300,000,000

% Senior Notes due 2017
Interest payable and

The notes will mature on , 2017. Interest will accrue from , 2007, and the first interest payment will be due , 2007.

We may redeem the notes, in whole or in part, on and after , 2012 at the redemption prices described in this prospectus. In addition, at any time prior to , 2012, we may redeem all, but not part, of the notes at a price equal to 100% of the principal amount plus accrued and unpaid interest plus a "make-whole" premium. Prior to , 2010, we may, at our option, also redeem up to 35% of the notes using the proceeds of certain equity offerings. The redemption provisions are more fully described in this prospectus under "Description of notes Optional redemption." If we sell certain of our assets or experience specific kinds of change of control, we may be required to offer to purchase the notes.

The notes will be our general unsecured, senior obligations, will be equal in right of payment with any of our existing and future unsecured senior indebtedness that is not by its terms subordinated to the notes, and will be effectively junior to our existing and future secured indebtedness to the extent of collateral securing that debt. The notes will initially be guaranteed on a senior unsecured basis by all of our current and future subsidiaries that guarantee our senior revolving credit facility. The notes will be effectively junior to the indebtedness and other liabilities of any non-guarantor subsidiaries.

Investing in the notes involves risks. See "Risk factors" beginning on page 12.

	Public offering price(1)	**Underwriting discounts and commissions**	**Proceeds to Cimarex Energy Co.**
Per note	%	%	%
Total	$	$	$

(1) Plus accrued interest, if any, from April , 2007.

The notes will not be listed on any securities exchange. Currently, there is no public market for the notes. Delivery of the notes, in book-entry form, will be made on or about April , 2007 through The Depository Trust Company.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or passed on the adequacy or accuracy of this prospectus. Any representation to the contrary is a criminal offense.

Joint book-running managers

JPMorgan **Lehman Brothers**

Co-managers

Deutsche Bank Securities **Merrill Lynch & Co.**

Calyon Securities (USA) **Raymond James** **UBS Investment Bank**

April , 2007

You should rely only on the information included or incorporated by reference in this prospectus or to which this prospectus refers or that is contained in any free writing prospectus relating to the notes. We have not, and the underwriters have not, authorized any other person to provide you with different information. If anyone else provides you with different or inconsistent information, you should not rely on it.

We and the underwriters are not making an offer to sell the notes in any jurisdiction where the offer or sale is not permitted.

You should assume that the information contained in this prospectus and the documents incorporated by reference is accurate only as of their respective dates. Our business, results of operations, financial condition and prospects may have changed since those dates.

Table of contents

Glossary of oil and gas terms

In this prospectus, the following terms have the meanings specified below.

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.

Summary

This summary highlights selected information contained elsewhere in this prospectus and in the documents we incorporate by reference. This summary is not complete and does not contain all of the information that you should consider before deciding whether or not to invest in the notes. For a more complete understanding of our company and this offering, we encourage you to read this entire document, including "Risk factors," the financial and other information included and incorporated by reference in this prospectus and the other documents to which we have referred you. Unless otherwise indicated or required by the context, as used in this prospectus, the terms "the Company," "we," "our" and "us" refer to Cimarex Energy Co. and its subsidiaries. The term "Magnum Hunter" refers to Magnum Hunter Resources, Inc., which we acquired on June 7, 2005. Some of the oil and gas terms we use are defined under "Glossary of oil and gas terms" on page ii. Our fiscal year ends on December 31 of each year.

Our company

We are an independent oil and gas exploration and production company. Our core areas of operation are in the Mid-Continent, Permian Basin and onshore Gulf Coast regions of the United States. We also have a small presence in the Gulf of Mexico and are expanding our operations in Wyoming. As of December 31, 2006, our estimated proved reserves were 1,449 Bcfe, of which 80% were proved developed and 75% were gas. During 2006, our net production averaged 449 MMcfe per day, which implies a reserve life of approximately 8.8 years. For the year ended December 31, 2006, we generated revenues and EBITDA of $1,267 million and $943 million, respectively. See "   Summary historical consolidated financial data" for a reconciliation of EBITDA to net income.

On June 7, 2005, we acquired Magnum Hunter Resources, Inc., which significantly increased our presence in the Permian Basin and enhanced our Mid-Continent operations in the Texas Panhandle. Magnum Hunter also had a small presence in the Gulf of Mexico and a large acreage position in several western states. The acquisition increased our proved reserves by 887 Bcfe (60% gas and 73% proved developed), which effectively tripled our proved reserves and doubled our production.

The following table summarizes our estimated proved oil and gas reserves by region as of December 31, 2006 and our average daily production by region for 2006.

					2006 average daily production		
	Oil (MBbl)	**Gas (MMcf)**	**Equivalent (MMcfe)**	**Percent of proved reserves**	**Oil (MBbl/d)**	**Gas (MMcf/d)**	**Total (MMcfe/d)**
Mid-Continent	8,709	542,447	594,701	41%	4.7	152.5	180.7
Permian Basin	44,351	296,969	563,076	39%	8.1	83.8	132.4
Gulf Coast	4,671	76,640	104,663	7%	3.2	61.8	80.7
Gulf of Mexico	964	38,111	43,895	3%	1.6	36.2	45.9
Western/Other	1,102	136,195	142,811	10%	0.3	7.4	9.4
	59,797	1,090,362	1,449,146	100%	17.9	341.7	449.1

Business strengths

Solid base of onshore proved reserves and production. At year-end 2006, we had nearly 1.45 Tcfe of proved oil and gas reserves, 80% of which were classified as proved developed. Approximately 80% of our total proved reserves are concentrated in the Mid-Continent and Permian Basin regions. Wells in these areas generally have stable production, reliable reserve estimates and low production decline rates. The Mid-Continent and Permian Basin regions also accounted for 70% of our total 2006 production.

Blended portfolio of low-risk development and potentially high-return exploration projects. We maintain a geographically and geologically diverse portfolio of low-to-moderate risk development and higher risk exploration projects. The low-risk, repeatable results we achieve in our Mid-Continent and Permian Basin regions provide moderate and predictable production and reserve growth. Our higher-risk drilling locations along the Gulf Coast and in the Gulf of Mexico are characterized by higher reserves per well and potentially higher economic returns. We believe that this blend of low-risk Mid-Continent and Permian Basin drilling combined with higher-potential Gulf Coast exploration allows us to achieve consistent, profitable results while also enabling us to pursue larger growth opportunities.

Large undeveloped acreage position with an active drilling program. As of December 31, 2006, we owned leases covering more than 4.4 million net acres, of which 80% were undeveloped. In 2006, we drilled more than 550 gross wells completing 91% as producers. More than 80% of this drilling occurred in the Mid-Continent and Permian Basin, where we achieved drilling success rates of 97% and 96%, respectively. Our technical teams and operating managers continue to generate projects on our existing acreage inventory and also seek to identify new areas for exploration and development.

Proven track record of reserve and production growth. We have increased our proved reserves and production each year since 2002 at average annual growth rates of 37% and 36%, respectively. We have achieved these results from a combination of organic growth through drilling and opportunistic mergers that have enhanced our competitive position.

Experienced management and operational teams. Our financial and operations executives, led by F.H. Merelli, each have over 25 years of experience in the oil and gas industry. Mr. Merelli has over 47 years of oil and gas industry experience. Our executive management team is supported by technical and operating managers who also have substantial industry experience and expertise within the basins in which we operate.

Business strategy

Consistently grow proved reserves and production. We seek to reinvest the cash flow generated by our producing properties into drilling new wells that have the potential to profitably grow our production and proved reserves. From time to time, we also consider supplementing our drill-bit driven growth through selective mergers and acquisitions.

Focus on blended portfolio. We seek to maintain a diverse portfolio of prospects that is underpinned by approximately 70%-80% low-to-moderate risk projects combined with a smaller percentage of higher risk/higher potential prospects. Our objective is to achieve consistent, profitable growth, while still preserving opportunities for potentially meaningful new discoveries. We also seek to maintain geographic diversification so as to mitigate certain operational and market risks and to position us to benefit from emerging plays.

Employ a disciplined approach to capital investment decision making. Each drilling decision is based on a detailed evaluation of its risk-adjusted, discounted cash flow rate of return on investment. Our comprehensive analysis includes estimates and assessments of potential reserve size, geologic and mechanical risks, expected costs and future production profiles. Our integrated teams of geoscientists, landmen and petroleum engineers seek to continually generate new prospects to maintain a rolling inventory of drilling opportunities. We have a centralized management system that measures actual results and provides feedback to the originating teams in order to help them improve and refine future investment decisions.

Control our drilling inventory. We will continue to seek to exercise control over the majority of our properties and investment decisions. At December 31, 2006, we operated the wells that accounted for approximately 73% of our total proved reserves and approximately 70% of our production. We believe our ability to control our drilling inventory will allow us to more effectively control operating costs, timing of development activities and technological enhancements, marketing of production and allocation of our capital budget.

Maintain financial flexibility and a conservative capital structure. We believe that maintaining a conservative capital structure will provide us with the flexibility needed to capitalize on future growth opportunities, while limiting our financial risk. We have historically used leverage conservatively, funding our development and growth activity through a combination of internally generated cash flow, bank borrowings and stock-for-stock mergers. Prior to our 2005 acquisition of Magnum Hunter and the assumption of its debt, we had no debt outstanding at year-end 2003 and 2004, and our 2006 year-end debt-to-capitalization ratio was 13%. Based on expected cash flow provided by operating activities and available liquidity under our senior revolving credit facility, we believe we are well positioned to fund our identified drilling opportunities for the foreseeable future.

Corporate information

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 website address is *www.cimarex.com*. The information on our website is not incorporated into this prospectus, and you should rely only on the information contained in this prospectus and in the documents we incorporate by reference when making a decision whether to invest in the notes.

The offering

The following summary contains basic information about the notes and is not intended to be complete. For a more complete understanding of the notes, please refer to the section entitled "Description of notes" in this prospectus. For purposes of the description of notes included in this prospectus, references to "the Company," "issuer," "us," "we" and "our" refer only to Cimarex Energy Co. and do not include our subsidiaries.

Issuer	Cimarex Energy Co.
Securities offered	$300,000,000 aggregate principal amount of % Senior Notes due 2017.
Maturity	, 2017.
Interest payment dates	Interest is payable on the notes on and of each year, commencing , 2007. Interest will accrue from , 2007.
Optional redemption	The notes will be redeemable at our option, in whole or in part, at any time on and after , 2012 at the redemption prices described in this prospectus, together with accrued and unpaid interest, if any, to the date of redemption. At any time prior to , 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 % 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 , 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.
Mandatory offers to repurchase	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. See "Description of notes Change of control." Certain asset dispositions will be triggering events that may require us to use the net proceeds from those asset dispositions to make an offer to purchase the notes at 100% of their principal amount, together with accrued and unpaid interest, if any, to the date of purchase if such proceeds are not otherwise used within 365 days to repay indebtedness (with a corresponding permanent reduction in commitment, if applicable) or to invest in capital assets related to our business or capital stock of a restricted subsidiary (as defined under the heading "Description of notes"). See "Description of notes Covenants Limitation on sales of assets and subsidiary stock."

Ranking	The notes will be our unsecured senior obligations and will rank:

- equal in right of payment to all of our existing and future senior indebtedness including our senior revolving credit facility without giving effect to collateral arrangements;
- senior in right of payment with any of our existing and future senior subordinated indebtedness; and
- senior in right of payment to any of our existing and future subordinated obligations. As of December 31, 2006, after giving pro forma effect to this offering and the application of the net proceeds from this offering, as more fully described in "Use of proceeds":
- we would have had approximately $442.9 million of total indebtedness (including the notes), all of which would have ranked equally in right of payment with the notes;
- we would have had approximately $5.0 million of secured indebtedness under our senior revolving credit facility excluding an additional $5.0 million represented by letters of credit under the senior revolving credit facility, to which the notes would have been effectively subordinated, and would have had additional commitments under our senior revolving credit facility available to us of $490.0 million, all of which would be secured if borrowed; and
- our non-guarantor subsidiaries would not have had any obligations or liabilities (other than inter-company obligations).

Subsidiary guarantees	The notes will be guaranteed on a senior basis by all of our current and future subsidiaries that guarantee our obligations under our senior revolving credit facility. The guarantees will be released when the guarantees of our indebtedness, including indebtedness under our senior revolving credit facility, and the guarantees of indebtedness of our restricted subsidiaries are released.

The guarantees will be unsecured senior indebtedness of our subsidiary guarantors and will rank:

- equal in right of payment to all of the subsidiary guarantors' existing and future senior indebtedness;
- senior in right of payment with any of the subsidiary guarantors' existing and future senior subordinated indebtedness; and
- senior in right of payment to any of the subsidiary guarantors' existing and future subordinated obligations.

For the twelve months ended December 31, 2006, on a pro forma basis, our non-guarantor subsidiaries had no net sales, operating income, EBITDA, and cash flows from operating activities.

Covenants	We will issue the notes under an indenture with U.S. Bank National Association, as trustee. The indenture will, among other things, limit our ability and the ability of our restricted subsidiaries to: incur, assume or guarantee additional indebtedness; issue redeemable stock and preferred stock; pay dividends or distributions or redeem or repurchase capital stock; prepay, redeem or repurchase debt that is junior in right of payment to the notes; make loans, investments and capital expenditures; incur liens; engage in sale/leaseback transactions; restrict dividends, loans or asset transfers from our subsidiaries; sell or otherwise dispose of assets, including capital stock of subsidiaries; consolidate or merge with or into, or sell substantially all of our assets to, another person; enter into transactions with affiliates; and enter into new lines of business. These covenants are subject to important exceptions and qualifications, which are described under the caption "Description of notes Certain covenants." In addition, if and for as long as the notes have an investment grade rating from both Standard & Poor's Ratings Group, Inc. and Moody's Investors Service, Inc., and no default exists under the indenture, we will not be subject to certain of the covenants listed above.
Use of proceeds	We intend to use approximately $204 million of the net proceeds from this offering to redeem the outstanding 9.6% senior notes due 2012 assumed in the acquisition of Magnum Hunter. Certain of the underwriters and their affiliates are lenders to us under our senior revolving credit facility. We intend to use the remainder of the proceeds to reduce outstanding borrowings under our senior revolving credit facility. See "Use of proceeds."

Risk factors

Investing in the notes involves substantial risk. You should carefully consider the risk factors set forth under "Risk factors" and the other information contained and incorporated in this prospectus prior to making an investment in the notes. See "Risk factors" beginning on page 12.

Summary historical consolidated financial data

The following table shows our summary consolidated historical financial data as of and for the periods indicated. Our summary historical financial data as of and for the fiscal years ended December 31, 2006, 2005 and 2004 have been derived from our audited financial statements. Certain historical amounts have been reclassified to conform to the current presentation.

You should read the summary consolidated historical financial data below in conjunction with our consolidated financial statements and the accompanying notes which are contained elsewhere in this prospectus. You should also read the sections entitled "Selected historical consolidated financial information" and "Management's discussion and analysis of financial condition and results of operations."

	Year ended December 31,		
(Dollars in thousands)	**2006**	**2005**	**2004**
Statement of operations data:			
Revenues:			
Gas sales	$ 810,894	$ 807,007	$ 366,260
Oil sales	404,517	265,415	106,129
Gas gathering and processing	47,879	44,238	101
Gas marketing, net of related costs	3,854	1,962	2,674
Total revenues	$ 1,267,144	$ 1,118,622	$ 475,164
Expenses:			
Depreciation, depletion and amortization	$ 396,394	$ 258,287	$ 124,251
Asset retirement obligation accretion	7,018	3,819	1,241
Production	176,833	104,067	37,476
Transportation	21,157	15,338	10,003
Gas gathering and processing	27,410	31,890	284
Taxes other than income	91,066	73,360	37,761
General and administrative	42,288	33,497	22,483
Stock compensation	8,243	4,959	1,957
(Gain)/Loss on derivative instruments	(22,970)	67,800	
Other operating, net	2,064	15,897	(3,394)
Total expenses	$ 749,503	$ 608,914	$ 232,062
Income from operations	$ 517,641	$ 509,708	$ 243,102
Interest expense net of capitalized interest	5,692	7,921	1,075
Amortization of fair value of debt	(3,784)	(2,132)	
Other, net	(28,591)	(12,536)	(4,291)
Income before income tax expense	$ 544,324	$ 516,455	$ 246,318
Income tax expense	198,605	188,130	92,726
Net income	$ 345,719	$ 328,325	$ 153,592

Balance sheet data (as of period end):			
Cash and cash equivalents	$ 5,048	$ 61,647	$ 115,746
Net oil and gas properties	3,587,710	2,876,959	802,293
Total assets	4,829,750	4,180,335	1,105,446
Total debt	443,667	352,451	
Stockholders' equity	2,976,143	2,595,453	700,712
Cash flows data:			
Net cash flow provided by (used in):			
Operating activities	$ 878,419	$ 704,734	$ 355,853
Investing activities	(1,009,802)	(497,453)	(293,101)
Financing activities	74,784	(261,380)	12,574
Other financial data:			
EBITDA(1)	$ 942,626	$ 780,531	$ 371,644
Total interest(2)	29,940	19,607	1,075
Oil and gas expenditures(3)	1,030,791	631,549	281,407
Ratio of total debt to EBITDA	0.5x	0.5x	
Ratio of EBITDA to total interest(4)	31.5x	39.8x	345.7x
Ratio of earnings to fixed charges(5)	19.8x	27.2x	130.6x

(1)

EBITDA represents net earnings before income taxes, interest expense and depreciation, depletion and amortization. EBITDA is not a measure calculated in accordance with generally accepted accounting principles (GAAP). EBITDA should not be considered as an alternative to net income, income before taxes, net cash flow from operating activities or any other measure of financial performance presented in accordance with GAAP. We believe that EBITDA is a widely accepted financial indicator of a company's ability to incur and service debt and to fund capital expenditures. Because EBITDA is commonly used in the oil and gas industry, we believe it is useful in evaluating our ability to meet our interest obligations in connection with this offering. EBITDA calculations may vary among entities, so our computation of EBITDA may not be comparable to EBITDA or similar measures of other entities. In evaluating EBITDA, we believe that investors should consider, among other things, the amount by which EBITDA exceeds interest costs, how EBITDA compares to principal payments on debt and how EBITDA compares to capital expenditures for each period.

The following table provides a reconciliation of net income to EBITDA:

	Year ended December 31,		
(in thousands)	**2006**	**2005**	**2004**
Net income	$ 345,719	$ 328,325	$ 153,592
Income tax expense	198,605	188,130	92,726
Interest expense	5,692	7,921	1,075
Amortization of fair value of debt	(3,784)	(2,132)	
Depreciation, depletion and amortization	396,394	258,287	124,251
EBITDA	$ 942,626	$ 780,531	$ 371,644

(2)

Includes capitalized interest of $24,248, $11,686 and $0 for the years ended December 31, 2006, 2005 and 2004, respectively.

(3)

From Statements of Cash Flows.

(4)

Represents EBITDA divided by total interest. The ratio of net income to total interest for the years ended December 31, 2006, 2005 and 2004 were 11.5x, 16.7x and 142.9x, respectively.

(5)

The ratio of earnings to fixed charges was computed by dividing earnings by fixed charges. Earnings consist of income from continuing operations before income taxes and cumulative change in accounting principle plus distributions received from equity investments, and fixed charges, minus income from equity investees and capitalized interest. Fixed charges consist of interest expensed, which includes amortization of the premium of fair market value over the face value of debt, an estimated interest component in net rental expense, and interest capitalized.

Summary reserve, production and operating data

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 the proved reserve estimates associated with at least 80 percent of the discounted future net cash flows before income taxes for the year ended December 31, 2006. Ryder Scott Company, L.P., independent petroleum engineers, and DeGolyer and MacNaughton collectively reviewed the proved reserve estimates associated with at least 80 percent of the discounted future net cash flows before income taxes for the year ended December 31, 2005. Ryder Scott Company, L.P. reviewed the proved reserve estimates associated with at least 80 percent of the discounted future net cash flows before income taxes for the year ended December 31, 2004. All information in this prospectus relating to oil and gas reserves is net to our interest unless stated otherwise. The following table sets forth the present value and estimated volume of our oil and gas proved reserves:

	As of December 31,		
	2006	**2005**	**2004**
Total proved reserves:			
Gas (MMcf)	1,090,362	1,004,482	364,641
Oil, condensate and NGLs (MBbls)	59,797	64,710	14,063
Equivalent (MMcfe)	1,449,146	1,392,742	449,020
% gas	75%	72%	81%
% proved developed	80%	81%	99%
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves (in thousands)	$ 2,200,889	$ 3,028,100	$ 798,033
Average price used in calculation of future net cash flow:			
Gas ($/Mcf)	$ 5.54	$ 7.89	$ 5.58
Oil ($/Bbl)	$ 56.91	$ 57.65	$ 40.76

The following table sets forth certain information regarding our production volumes and the average oil and gas prices received and operating expenses per Mcfe of production:

	Years ending December 31,		
	2006	2005	2004
Production volumes:			
Gas (MMcf)	124,733	100,272	63,611
Oil (MBbls)	6,529	4,804	2,641
Equivalent (MMcfe)	163,907	129,096	79,457
Average sales price(1):			
Gas ($/Mcf)	$ 6.50	$ 8.05	$ 5.76
Oil ($/Bbl)	$ 61.96	$ 55.25	$ 40.19
Operating expenses per Mcfe:			
Production	$ 1.08	$ 0.81	$ 0.47
Transportation	0.13	0.12	0.13
Gas gathering and processing	0.17	0.25	
Taxes other than income	0.56	0.57	0.48
DD&A	2.42	2.00	1.56
G&A	0.26	0.26	0.28
Interest expense net of capitalized interest	0.03	0.06	0.01
Total	$ 4.65	$ 4.07	$ 2.93

(1) We assumed Magnum Hunter's oil and gas commodity swap and collar contracts as part of the merger. These instruments did not qualify for hedge accounting treatment and, as such, they are not included in the above average sales prices.

The following table summarizes daily production by region for 2006 and the second-half of 2005. The second-half 2005 volumes reflect the production increases as a result of the Magnum Hunter acquisition.

	Average daily production	
	Year ended 2006 (MMcfe/d)	Second-half 2005 (MMcfe/d)
Mid-Continent	180.7	175.3
Permian Basin	132.4	130.1
Gulf Coast	80.7	84.4
Gulf of Mexico	45.9	37.9
Other	9.4	10.5
Total	449.1	438.2

Risk factors

You should carefully consider the risks described below before making an investment decision. The risks and uncertainties described below are not the only ones we face. Additional risks and uncertainties not presently known to us or that we currently deem immaterial may also impair our business operations. If any of the following risks actually occurs, our business, financial condition or results of operations could be materially adversely affected.

This prospectus and the documents incorporated by reference also contain forward-looking statements that involve risks and uncertainties. Our actual results could differ materially from those anticipated in the forward-looking statements as a result of a number of factors, including the risks described below and elsewhere in this prospectus.

Risks relating to our business

Low oil and gas 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 2006 we sold our gas at an average price of $6.50 per Mcf, which was 19 percent lower than our 2005 average sales price of $8.05 per Mcf. Conversely, our average 2006 oil price of $61.96 per barrel was 12 percent higher than the price we received in 2005 of $55.25 per barrel.

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 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. Because low oil and gas prices would negatively affect the amount of cash flow available to fund these capital investments, they could also affect our future rate of growth. 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, we have entered into hedging arrangements for a portion of our natural gas production. These hedging arrangements 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.

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 levels of initial production. Production from these wells declines and stabilizes 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 and reduce our ability to raise capital.

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.

We often are uncertain as to the future cost or timing of drilling, completing and producing wells. 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 us 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 proved oil and gas reserves and their associated future net cash flow necessarily 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.

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, 2006.

The values referred to in this prospectus 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 unavailability of or 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 30 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 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. 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.

Risks relating to our indebtedness and the notes

The level of our indebtedness could adversely affect our financial condition and prevent us from fulfilling our obligations on the notes.

At December 31, 2006, after giving pro forma effect to this offering and the application of the net proceeds from the sale of the notes as set forth under "Use of proceeds," we would have had total consolidated debt of $442.9 million, plus $355 million in current liabilities. 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, 2006, only $500 million of which is currently committed. We have demands on our cash resources in addition to interest expense and principal on the notes, including, among others, operating expenses, capital expenditures and interest and principal payments under our senior revolving credit facility and our floating rate convertible senior notes due 2023. Our level of indebtedness could have important effects on our business and on your investment in the notes, including:

- making it more difficult for us to satisfy our obligations with respect to the notes and our other debt;
- requiring us to dedicate a substantial portion of our cash flow from operations to payments on our debt, thereby reducing the amount of our cash flow available for working capital, capital expenditures, acquisitions and other general corporate purposes;
- limiting our flexibility in planning for, or reacting to, changes in the oil and gas industry;
- placing us at a competitive disadvantage compared to our competitors that have lower debt service obligations and significantly greater operating and financing flexibility than we do;
- limiting our financial flexibility, including our ability to borrow additional funds;
- increasing our interest expense if interest rates increase, because approximately $130 million of our borrowings as of December 31, 2006, pro forma for this offering, are at variable rates of interest;
- increasing our vulnerability to general adverse economic and industry conditions; and
- resulting in an event of default upon a failure to comply with financial covenants contained in our senior revolving credit facility which, if not cured or waived, could have a material adverse effect on our business, financial condition or results of operations.

We may not be able to generate enough cash flow to meet our debt obligations, including the notes.

Our ability to pay the principal and interest on our long-term debt, including the notes, 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 markets 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 borrowings under our existing senior revolving credit facility bear interest at floating rates. See "Capitalization."

We also 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.

Our business may not generate sufficient cash flow from operations. Future sources of capital may not be available to us in an amount sufficient to enable us to service our indebtedness, including the notes, or to fund our other liquidity needs. If we are unable to service our indebtedness and fund our operating costs, we will be forced to adopt alternative strategies that may include:

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

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

Our senior revolving credit facility restricts and the indenture will restrict us from engaging in some business activities.

The credit agreement governing our senior revolving credit facility restricts and the indenture governing the notes will restrict our ability to, among other things:

- incur additional debt and guarantees;
- pay dividends on or redeem or repurchase capital stock;
- make certain investments;
- incur or permit to exist certain liens;
- enter into transactions with affiliates;
- merge, consolidate or amalgamate with another company; and
- transfer or otherwise dispose of assets, including capital stock of subsidiaries.

The credit agreement for our senior revolving credit facility contains both financial and non-financial covenants, including limitations on share repurchases, dividends and other restricted payments. The financial covenants require us to maintain a minimum ratio of funded indebtedness to trailing twelve-month EBITDA (earnings before interest, taxes and depreciation, depletion and amortization (DD&A) adjusted for non-cash items associated with mark-to-market accounting, stock-based compensation and impairment of goodwill) of less than three times and a ratio of current assets plus unused commitments for borrowing to current liabilities of greater than one. Our ability to meet these covenants or requirements may be affected by events beyond our control, and we may be unable to satisfy such covenants and requirements.

The covenants contained in the agreements governing our debt may affect our flexibility in planning for, and reacting to, changes in business conditions. In addition, a breach of the restrictive covenants in our credit agreement, the indenture or any instrument governing future indebtedness or our inability to maintain the financial ratios described above could result in an event of default under the applicable instrument or inability to borrow additional funds. Upon the occurrence of such an event of default, the applicable creditors could, subject to the terms and conditions of the applicable instrument, elect to declare the outstanding principal of that debt, together with accrued interest, to be immediately due and payable. Moreover, any of our other debt agreements that contain a cross-default or cross-acceleration provision that would be triggered by such default or acceleration would also be subject to acceleration upon the occurrence of such default or acceleration. The accelerated debt would become immediately due and payable. If that should occur, we may not be able to make all of the required payments or borrow sufficient funds to refinance it. Even if new financing were then available, it may not be on terms that are acceptable to us. See "Description of other indebtedness" and "Description of notes Events of default." If we were unable to repay amounts due under our senior revolving credit facility, the lenders could proceed against the collateral granted to them to secure such indebtedness. If the payment of our indebtedness is accelerated, our assets may not be sufficient to repay in full that indebtedness and our other indebtedness that would become due as a result of any acceleration. The above restrictions could limit our ability to obtain future financing and may prevent us from taking advantage of attractive business opportunities.

The notes and the guarantees will be unsecured and effectively subordinated to our and our subsidiary guarantors' existing and future secured indebtedness and other liabilities of our non-guarantor subsidiaries.

The notes will be our general unsecured obligations and will be effectively subordinated to claims of our secured creditors and the subsidiary guarantees will be effectively subordinated to the claims of our secured creditors as well as the secured creditors of our subsidiary guarantors. Holders of our secured obligations, including obligations under our existing senior revolving credit facility, will have claims that are prior to claims of the holders of the notes with respect to the assets securing those obligations. In the event of a liquidation, dissolution, reorganization, bankruptcy or any similar proceeding, our assets and those of our current subsidiaries will be available to pay obligations on the notes and the guarantees only after holders of our senior secured debt have been paid the value of the assets securing such debt. At December 31, 2006, after giving pro forma effect to this offering and the application of the net proceeds from the sale of the notes as set forth under "Use of proceeds," the aggregate amount of our secured indebtedness was approximately $5.0 million, and approximately $490.0 million was available for additional borrowing under our senior revolving credit facility, all of which would rank senior to your claims as holders of the notes.

Although all of our current and future subsidiaries that guarantee our senior revolving credit facility will initially provide guarantees of the notes, under certain circumstances, the guarantees are subject to release. In that case, the notes would be effectively subordinated to the claims of all creditors, including trade creditors and tort claimants, of our subsidiaries that are not guarantors. In the event of the liquidation, dissolution, reorganization, bankruptcy or similar proceeding of the business of a subsidiary that is not a guarantor, creditors of that subsidiary would generally have the right to be paid in full before any distribution is made to us or the holders of the notes. Accordingly, there may not be sufficient funds remaining to pay amounts due on all or any of the notes.

We may be able to incur substantially more debt, which could increase the risks associated with our indebtedness.

We and our subsidiaries may be able to incur substantial additional indebtedness in the future. The terms of our new indenture do not prohibit us or our subsidiaries from doing so. As of December 31, 2006, on a pro forma basis after giving effect to this offering and the application of the net proceeds from the sale of the notes as set forth under "Use of proceeds," our senior revolving credit facility provided commitments of up to $500 million, of which approximately $5.0 million of borrowings were outstanding, approximately $5.0 million of letters of credit were outstanding and $490 million was immediately available for future borrowings. These borrowings would be secured, and as a result, effectively senior to the notes and the guarantees of the notes by our subsidiary guarantors, to the extent of the value of the collateral securing that indebtedness. In addition, our senior revolving credit facility and the indenture governing the notes would permit us to borrow up to $1 billion of debt, only $500 million of which is currently committed. If we incur any additional indebtedness that ranks equally with the notes, the holders of that debt will be entitled to share ratably with the holders of these notes in any proceeds distributed in connection with any insolvency, liquidation, reorganization, dissolution or other winding-up of us. This may have the effect of reducing the amount of proceeds paid to you.

If new debt is added to our current debt levels, the related risks that we and our subsidiaries now face could intensify. At December 31, 2006, on a pro forma basis after giving effect to this offering, and the application of the net proceeds from the sale of the notes as set forth under "Use of proceeds," we would have had total consolidated long-term debt of approximately $442.9 million, excluding approximately $5.0 million in outstanding letters of credit. Our level of indebtedness may prevent us from engaging in certain transactions that might otherwise be beneficial to us by limiting our ability to obtain additional financing, limiting our flexibility in operating our business or otherwise. In addition, we could be at a competitive disadvantage against other less leveraged competitors that have more cash flow to devote to their business. Any of these factors could result in a material adverse effect on our business, financial condition, results of operations, business prospects and ability to satisfy our obligations under the notes.

If we undergo a change of control, we may not have the ability to raise the funds necessary to finance the change of control offer required by the indenture governing the notes, which would violate the terms of the notes.

Upon the occurrence of a change of control, holders of the notes will have the right to require us to purchase all or any part of such holders' notes at a price equal to 101% of the principal amount thereof, plus accrued and unpaid interest, if any, to the date of purchase. A change of control also would constitute a default under our senior revolving credit facility, which would allow the lenders to require us to repay our indebtedness under the senior revolving credit facility in full. We and our subsidiary guarantors may not have sufficient financial resources available to satisfy all of our or their obligations under our senior revolving credit facility and the notes in the event of a change in control, or our senior revolving credit facility or other future debt agreements may prohibit us from fulfilling our repurchase obligations. Our failure to purchase the notes as required under the indenture governing the notes would result in a default under the indenture and under our senior revolving credit facility, each of which could have material adverse consequences for us and the holders of the notes. See "Description of notes Change of control."

A subsidiary guarantee could be voided if it constitutes a fraudulent transfer under U.S. bankruptcy or similar state law, which would prevent the holders of the notes from relying on that subsidiary to satisfy claims.

Under U.S. bankruptcy law and comparable provisions of state fraudulent transfer laws, a guarantee can be voided, or claims under the guarantee may be subordinated to all other debts of that guarantor if, among other things, the guarantor, at the time it incurred the indebtedness evidenced by its guarantee or, in some states, when payments become due under the guarantee, received less than reasonably equivalent value or fair consideration for the incurrence of the guarantee and:

- was insolvent or rendered insolvent by reason of such incurrence;
- was engaged in a business or transaction for which the guarantor's remaining assets constituted unreasonably small capital; or
- intended to incur, or believed that it would incur, debts beyond its ability to pay those debts as they mature.

A guarantee may also be voided, without regard to the above factors, if a court found that the guarantor entered into the guarantee with the actual intent to hinder, delay or defraud its creditors. A court would likely find that a guarantor did not receive reasonably equivalent value or fair consideration for its guarantee if the guarantor did not substantially benefit directly or indirectly from the issuance of the notes. If a court were to void a guarantee, you would no longer have a claim against the guarantor. Sufficient funds to repay the notes may not be available from other sources, including the remaining guarantors, if any. In addition, the court might direct you to repay any amounts that you already received from the subsidiary guarantor.

The measures of insolvency for purposes of fraudulent transfer laws vary depending upon the governing law. Generally, a guarantor would be considered insolvent if:

- the sum of its debts, including contingent liabilities, was greater than the fair saleable value of all its assets;
- the present fair saleable value of its assets was less than the amount that would be required to pay its probable liability on its existing debts, including contingent liabilities, as they became absolute and mature; or
- it could not pay its debts as they became due.

Each subsidiary guarantee will contain a provision intended to limit the guarantor's liability to the maximum amount that it could incur without causing the incurrence of obligations under its subsidiary guarantee to be a fraudulent transfer. This provision may not be effective to protect the subsidiary guarantees from being voided under fraudulent transfer law.

Your ability to transfer the notes may be limited by the absence of an active trading market, and an active trading market may not develop for the notes.

The notes are a new issue of securities for which there is no established public market. Although the underwriters have informed us that they intend to make a market in the notes, they have no obligation to do so and may discontinue making a market at any time without notice. Accordingly, a liquid market may not develop for the notes, you may not be able to sell your notes at a particular time and the prices that you receive when you sell the notes may not be favorable.

We do not intend to apply for the notes to be listed on any securities exchange or to arrange for the notes to be quoted on any quotation system. Notes that are sold to qualified institutional buyers will be eligible for trading on PORTAL.

Historically, the market for non-investment grade debt has been subject to disruptions that have caused substantial volatility in the prices of securities similar to the notes. The market, if any, for the notes may not be free from similar disruptions and any such disruptions may adversely affect the prices at which you may sell your notes. In addition, subsequent to their initial issuance, the notes may trade at a discount from their initial offering price, depending upon prevailing interest rates, the market for similar notes, our operating performance and financial condition and other factors.

Disclosure regarding forward-looking statements

Throughout this prospectus, we make statements that may be deemed "forward-looking" statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. 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 prospectus. 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 prospectus 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 prospectus 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 the registration statement of which this prospectus is a part with the Securities and Exchange Commission, except as required by law.

Use of proceeds

We estimate that the net proceeds from this offering will be approximately $295 million after deducting underwriting discounts and commissions and estimated expenses of the offering. We intend to use approximately $204 million of the net proceeds from this offering to redeem the outstanding 9.6% senior notes due 2012 assumed in the acquisition of Magnum Hunter. The 9.6% senior notes due 2012 have a face value of $195 million and are due March 15, 2012. As of December 31, 2006, the fair market value of the 9.6% senior notes due 2012 was approximately $210.7 million. Certain of the underwriters and their affiliates are lenders to us under our senior revolving credit facility. We intend to use the remainder of the proceeds to reduce outstanding borrowings under our senior revolving credit facility by approximately $90 million. Our senior revolving credit facility matures on July 1, 2010 and bore interest at a weighted average rate of approximately 6.75% as of December 31, 2006.

Capitalization

The following table sets forth our capitalization as of December 31, 2006 on a historical basis and on an as adjusted basis to give pro forma effect to this offering and the application of the net proceeds from the offering as described in "Use of proceeds."

You should read this table along with our audited consolidated financial statements and related notes and the other financial information contained in this prospectus.

(Dollars in thousands)	As of December 31, 2006 Actual	As of December 31, 2006 As adjusted
		(unaudited)
Cash and cash equivalents	$ 5,048	$ 5,048
Long-term debt:		
Senior revolving credit facility(1)	$ 95,000	$ 5,000
9.6% senior notes due 2012 (face value $195,000)(2)	210,746	
% Senior Notes due 2017		300,000
Floating rate convertible senior notes due 2023, 5.36% at December 31, 2006 (face value $125,000)(3)	137,921	137,921
Total long-term debt	443,667	442,921
Total stockholders' equity(4)	2,976,143	2,979,793
Total capitalization	$ 3,419,810	$ 3,422,714

(1) As of March 31, 2007, we had $161.0 million outstanding under our senior revolving credit facility. As of March 31, 2007, on a pro forma basis after giving effect to this offering and the application of the net proceeds from the offering as described in "Use of proceeds", we would have had $71.0 million outstanding.

(2) 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.

(3) 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.

(4) The change in stockholders' equity results from an estimated pre-tax gain of $5.7 million (after tax gain of $3.7 million) to be realized from the redemption of our outstanding 9.6% senior notes due 2012. The book value of the senior notes at December 31, 2006 was $210.7 million. The estimated amount to redeem the senior notes is approximately $204 million ($195 million at a redemption price of 104.8% plus estimated costs).

Ratio of earnings to fixed charges

The following table sets forth our ratio of earnings to fixed charges:

	Year ended December 31,				
(Dollars in thousands)	2006	2005	2004	2003	2002
Earnings:					
Income from continuing operations before income taxes and cumulative change in accounting principle	$ 544,324	$ 516,455	$ 246,318	$ 148,169	$ 61,379
Additions:					
Fixed charges as shown below	29,795	19,262	1,900	1,977	820
Distributions received from equity-method investees	59,823	302			
	89,618	19,564	1,900	1,977	820
Subtractions:					
Equity in income of investees	17,712	473			
Interest capitalized	25,478	12,315		304	206
	43,190	12,788		304	206
Earnings as adjusted	$ 590,752	$ 523,231	$ 248,218	$ 149,842	$ 61,993
Fixed charges:					
Interest on indebtedness, expensed or capitalized	31,829	20,236	1,075	1,285	620
Amortization of premium on indebtedness, expensed or capitalized	(3,784)	(2,132)			
Interest within rent expense	1,750	1,158	825	692	200
Total fixed charges	$ 29,795	$ 19,262	$ 1,900	$ 1,977	$ 820
Ratio of earnings to fixed charges	**19.8**	**27.2**	**130.6**	**75.8**	**75.6**

The ratio of earnings to fixed charges was computed by dividing earnings by fixed charges. Earnings consist of income from continuing operations before income taxes and cumulative change in accounting principle plus distributions received from equity investments, and fixed charges, minus income from equity investments and capitalized interest. Fixed charges consist of interest expensed, which includes amortization of the premium of fair market value over the face value of debt, an estimated interest component in net rental expense, and interest capitalized.

Selected historical consolidated financial data

The following table sets forth selected financial information as of the dates and for the periods indicated. This financial information is derived from our consolidated financial statements as of such dates and for such periods. This information should be read in conjunction with "Management's discussion and analysis of financial condition and results of operations" and our consolidated financial statements and notes thereto included elsewhere in this prospectus. The following information is not necessarily indicative of our future results.

	Year ended December 31,				
(in thousands)	**2006**	**2005**	**2004**	**2003**	**2002**
Statement of operations data:					
Revenues:					
Gas sales	$ 810,894	$ 807,007	$ 366,260	$ 250,764	$ 128,060
Oil sales	404,517	265,415	106,129	73,355	29,239
Gas gathering and processing	47,879	44,238	101	679	1,067
Gas marketing, net of related costs	3,854	1,962	2,674	823	2,254
Total revenues	$ 1,267,144	$ 1,118,622	$ 475,164	$ 325,621	160,620
Expenses:					
Depreciation, depletion and amortization	$ 396,394	$ 258,287	$ 124,251	$ 88,774	$ 49,231
Asset retirement obligation accretion	7,018	3,819	1,241	1,009	
Production	176,833	104,067	37,476	31,801	19,427
Transportation	21,157	15,338	10,003	7,472	7,918
Gas gathering and processing	27,410	31,890	284	849	642
Taxes other than income	91,066	73,360	37,761	27,485	13,154
General and administrative	42,288	33,497	22,483	17,526	8,568
Stock compensation	8,243	4,959	1,957	1,824	125
(Gain)/Loss on derivative instruments	(22,970)	67,800			
Other operating, net	2,064	15,897	(3,394)		
Total expenses	$ 749,503	$ 608,914	$ 232,062	176,740	99,065
Income from operations	$ 517,641	$ 509,708	$ 243,102	148,881	61,555
Interest expense net of capitalized interest	5,692	7,921	1,075	981	414
Amortization of fair value of debt	(3,784)	(2,132)			
Other, net	(28,591)	(12,536)	(4,291)	(269)	(238)
Income before income tax expense and cumulative effect of a change in accounting principle	$ 544,324	$ 516,455	$ 246,318	$ 148,169	$ 61,379
Income tax expense	198,605	188,130	92,726	55,141	21,560
Income before cumulative effect of a change in accounting principle	$ 345,719	$ 328,325	$ 153,592	$ 93,028	$ 39,819
Cumulative effect of a change in accounting principle				1,605	
Net Income	$ 345,719	$ 328,325	$ 153,592	$ 94,633	$ 39,819
Balance sheet data (as of period end):					
Cash and cash equivalents	$ 5,048	$ 61,647	$ 115,746	$ 40,420	$ 22,327
Net oil and gas properties	3,587,710	2,876,959	802,293	624,304	530,718
Total assets	4,829,750	4,180,335	1,105,446	805,508	674,286
Total debt	443,667	352,451			32,000
Stockholders' equity	2,976,143	2,595,453	700,712	534,740	444,880

Cash flows data:					
Net cash flow provided by (used in):					
Operating activities	$ 878,419	$ 704,734	$ 355,853	$ 205,110	$ 104,455
Investing activities	(1,009,802)	(497,453)	(293,101)	(159,641)	(71,685)
Financing activities	74,784	(261,380	12,574	(27,376)	(17,613)

	Year ended December 31,				
(Dollars in thousands)	**2006**	**2005**	**2004**	**2003**	**2002**
Other financial data:					
EBITDA(1)	$ 942,626	$ 780,531	$ 371,644	$ 239,529	$ 111,024
Total interest(2)	29,940	19,607	1,075	1,285	620
Oil and gas expenditures(3)	1,030,791	631,549	281,407	150,501	66,458
Ratio of total debt to EBITDA	0.5x	0.5x			0.3x
Ratio of EBITDA to total interest(4)	31.5x	39.8x	345.7x	186.4x	179.1x

(1) EBITDA represents net earnings before income taxes, interest expense and depreciation, depletion and amortization. EBITDA is not a measure calculated in accordance with generally accepted accounting principles (GAAP). EBITDA should not be considered as an alternative to net income, income before taxes, net cash flow from operating activities or any other measure of financial performance presented in accordance with GAAP. We believe that EBITDA is a widely accepted financial indicator of a company's ability to incur and service debt and to fund capital expenditures. Because EBITDA is commonly used in the oil and gas industry, we believe it is useful in evaluating our ability to meet our interest obligations in connection with this offering. EBITDA calculations may vary among entities, so our computation of EBITDA may not be comparable to EBITDA or similar measures of other entities. In evaluating EBITDA, we believe that investors should consider, among other things, the amount by which EBITDA exceeds interest costs, how EBITDA compares to principal payments on debt and how EBITDA compares to capital expenditures for each period.

The following table provides a reconciliation of net income to EBITDA:

	Year ended December 31,				
(in thousands)	**2006**	**2005**	**2004**	**2003**	**2002**
Net income	$ 345,719	$ 328,325	$ 153,592	$ 94,633	$ 39,819
Income tax expense	198,605	188,130	92,726	55,141	21,560
Interest expense	5,692	7,921	1,075	981	414
Amortization of fair value of debt	(3,784)	(2,132)			
Depreciation, depletion and amortization	396,394	258,287	124,251	88,774	49,231
EBITDA	$ 942,626	$ 780,531	$ 371,644	$ 239,529	$ 111,024

(2) Includes capitalized interest of $24,248, $11,686, $0, $304 and $206 for the years ended December 31, 2006, 2005, 2004, 2003 and 2002, respectively.

(3) From Statements of Cash Flows.

(4) Represents EBITDA divided by total interest. The ratio of net income to total interest for the years ended December 31, 2006, 2005, 2004, 2003 and 2002 were 11.5x, 16.7x, 142.9x, 73.6x and 64.2x, respectively.

Management's discussion and analysis of financial condition and results of operations

Introduction

Cimarex Energy Co. is an independent oil and gas exploration and production company, with operations focused mainly in Oklahoma, Texas, New Mexico, Kansas, Louisiana, and the Gulf of Mexico.

Our primary focus is exploration and development drilling for new reserves. To supplement our growth, we also consider mergers and acquisitions. On June 7, 2005, we acquired Magnum Hunter Resources, Inc, 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. Terms of the merger agreement provided that Magnum Hunter stockholders receive 0.415 shares of our common stock for each share of Magnum Hunter common stock. As a result of the merger, we issued 39.7 million common shares to Magnum Hunter's common stockholders and assumed $633 million of debt. The merger was accounted for as a purchase of Magnum Hunter by Cimarex. Results of operations from Magnum Hunter's properties are included in our consolidated statements of operations beginning June 7, 2005.

Our exploration and development expenditures totaled $1,049 million for 2006, up from $642 million in 2005. Operationally, we now have a large base of properties in the Permian Basin with operational characteristics similar to our Mid-Continent assets. The merger also extended our onshore Gulf Coast activities into the Gulf of Mexico. Overall, about 39 percent of our proved reserves are in the Permian Basin and 41 percent are in our Mid-Continent region. Our onshore Gulf Coast and Gulf of Mexico operations collectively make up 10 percent of our proved reserves.

Industry and economic factors

In managing our business we must deal with many factors inherent in our industry. First and foremost is wide fluctuation of oil and gas prices. Oil and gas markets are cyclical and volatile, with future price movements difficult to predict. While our revenues are a function of both production and prices, wide swings in prices often have the greatest impact on our results of operations.

Our operations entail significant complexities. Advanced technologies requiring highly trained personnel are utilized in both exploration and production. Even when the technology is properly used, the interpreter still may not know conclusively if hydrocarbons will be present or the rate at which they will be produced. Exploration is a high-risk activity, often times resulting in no commercially productive reservoirs being discovered. Moreover, costs associated with operating within the industry are substantial and usually move up and down together with prices.

The oil and gas industry is highly competitive. We compete with major and diversified energy companies, independent oil and gas companies, and individual operators. In addition, the industry as a whole competes with other businesses that supply energy to industrial, commercial, and residential end users.

Extensive federal, state, and local regulation of the industry significantly affects our operations. In particular, our activities are subject to comprehensive environmental regulations. Compliance with these regulations increases the cost of planning, designing, drilling, installing, operating, and abandoning oil and gas wells and related facilities. These regulations may become more demanding in the future.

Approach to the business

Profitable growth largely depends upon our ability to successfully find and develop new proved reserves. To achieve an overall acceptable rate of growth, we maintain a blended portfolio of low, moderate, and higher risk exploration and development projects. We believe that this approach allows for consistent increases in our oil and gas reserves, while minimizing the chance of failure. To further mitigate risk, we have chosen to seek geologic and geographic diversification by operating in multiple basins. We may also consider the use of transaction-specific hedging of oil and gas prices to reduce price risk. In connection with the acquisition of Magnum Hunter, we acquired existing commodity derivatives, as well as in the third quarter of 2006 we entered into additional derivative contracts as discussed more fully below.

Implementation of our business approach relies on our ability to fund ongoing exploration and development projects with cash flow provided by operating activities, periodic sales of non-core properties, and external sources of capital.

We project that 2007 exploration and development expenditures will range from $800 million to $1 billion. Approximately 37 percent of the expenditures will be in the Mid-Continent area, 28 percent in the Permian Basin, 24 percent in the Gulf Coast area, and 8 percent in the Gulf of Mexico.

Cash flow from operating activities for 2006 totaled $878.4 million, which helped to fund our drilling program. Based on expected cash provided by operating activities and monies available under our senior revolving credit facility, we believe we are well positioned to fund the projects identified for 2007 and beyond.

Critical accounting policies and estimates

Our discussion and analysis of our financial condition and results of operation are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States of America, or GAAP. The preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. In response to SEC Release No. 33-8040, *Cautionary Advice Regarding Disclosure about Critical Accounting Policies*, 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, 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. We believe the following critical accounting policies affect our more significant judgments and estimates used in the preparation of our consolidated financial statements.

Revenue recognition

Oil and gas sales. Revenue from the sale of oil and gas is recognized when title passes, net of royalties. This is known as the sales method (versus the entitlement method). Under the sales method, revenue is 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 earns a fee for such services. Revenues are recognized as gas is delivered and are reflected net of gas purchases on the accompanying 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, 2006 and 2005 was $3.2 million and $2.7 million, respectively. At December 31, 2006 we are also in an under-produced position relative to certain other third parties.

Oil and gas reserves

The process of estimating quantities of oil and gas reserves is complex, requiring significant decisions in the evaluation of all available geological, geophysical, engineering and economic data. The data for a given field may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. As a result, material revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure that 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. For 2006, revisions of reserve estimates equaled a decrease of 3.7 MBbls of oil and 14.5 Bcf of gas (due to lower oil and gas prices), representing two and one half percent of proved oil and gas reserves as of December 31, 2006.

We use the units-of-production method to amortize our oil and gas properties. Changes in reserve quantities will cause corresponding changes in depletion expense in periods subsequent to the quantity revision 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.

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.

At the end of each quarter, a full cost ceiling limitation calculation is made 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 if it is determined that net capitalized costs exceed the full cost ceiling limit. If net capitalized costs subject to amortization were to exceed this limit, the excess would be charged to expense. However, if commodity prices increase subsequent to period end and prior to 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 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 estimated fair value exceeds its carrying amount, goodwill is considered not impaired. 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.

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.

In connection with the Magnum Hunter merger, we recognized a $39.3 million net 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, we recognized a net gain for the year ended December 31, 2006 of $23 million. Activity included both non-cash mark-to-market derivative gains and losses as well as cash settlements. Cash payments related to these contracts that settled in the year ended December 31, 2006 was

$19 million. As of December 31, 2006, all derivative contracts assumed with the Magnum Hunter merger had matured.

In the third quarter of 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 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, 2006, this represented approximately 51% and 31% of our current anticipated Mid-Continent gas production for 2007 and 2008, respectively.

Under the collar agreements, we will receive the difference between an agreed upon Mid-Continent index price and floor price if the index price is below the floor price. We will 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 hedges have been designated for hedge accounting treatment as cash flow hedges.

For the year ended December 31, 2006, we recorded an unrealized loss of $13 thousand related to the ineffective portion of the hedges. At December 31, 2006, $41.9 million and $7.1 million of the hedges 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.

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.

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. As of December 31, 2006, we have accrued $7.1 million for a mediated litigation settlement pertaining to post-production deductions on properties operated by us. We have also accrued an additional $1.5 million for a mediated litigation settlement pertaining to oil and gas property title issues. We anticipate payment of both settlements during 2007. We have other various litigation related matters in the normal course of business, none of which that can be estimated are deemed to be material, individually or in aggregate.

Asset retirement obligations

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

Recent accounting developments

In July 2006, the FASB issued Interpretation 48, *Accounting for Uncertainty in Income Taxes*, which clarifies the accounting for uncertainty in income taxes recognized in our financial statements in accordance with SFAS 109, *Accounting for Income Taxes*. The interpretation also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. Along with these disclosures, a tabular presentation of significant changes during each period will be required. The Interpretation is effective as of the beginning of the first fiscal year beginning after December 15, 2006 (January 1, 2007 for calendar-year companies). We are currently evaluating the effects of implementing this interpretation and do not believe the adoption of this interpretation will have a material impact on our financial statements.

In September 2006, the Securities and Exchange Commission issued Staff Accounting Bulletin No. 108 regarding the process of quantifying misstatements within a financial statement, addressing in particular materiality analysis related to the correction of errors. The impact on the current year financial statements of correcting all misstatements, including both the carryover and reversing effects of prior year misstatements, must be quantified. Adjustment would be required if the misstatement is deemed material, after considering all relevant quantitative and qualitative factors. The periods in which the correction would be recorded would be dependent on the materiality considerations for each affected period. This did not have a material impact on our financial statements.

Also in September 2006, the Financial Accounting Standards Board issued Statement No. 157, *Fair Value Measurements*, which establishes a single authoritative definition of fair value, sets out a framework for measuring fair value, and requires additional disclosures about fair-value measurements. The Statement applies only to fair-value measurements that are already required or permitted by other accounting standards and is expected to increase the consistency of those measurements. The Statement is effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. We do not expect the adoption of Statement No. 157 to have a material impact on our financial statements.

Overview

Our results of operations are primarily impacted by changes in oil and gas prices and changes in our production volumes. Realized gas prices decreased from $8.05 per Mcf in 2005 to $6.50 per Mcf in 2006, and oil prices increased from $55.25 per barrel in 2005 to $61.96 per barrel in 2006. We also sell gas on behalf of third parties that are incidental to sales of our own production. Sales and costs associated with our production are reflected in gas sales and transportation expense.

We also own interests in gas gathering systems and gas processing plants that are connected to our production operations. We transport and process third party gas that is associated with our gas.

Transportation expenses are comprised of costs paid to carry and deliver oil and gas to a specified delivery 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.

Production costs are composed of lease operating expenses, which generally consist of pumpers' salaries, utilities, water disposal, maintenance and other costs necessary to operate our producing properties.

Taxes, other than income, are taxes 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.

Depreciation, depletion and amortization 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. While we expect such costs to increase with our growth, we expect such increases to be proportionately smaller than our production growth.

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.

Basis of presentation

In June 2005, we acquired Magnum Hunter Resources, Inc, by issuing 0.415 shares of our common stock for each share of outstanding Magnum Hunter common stock, resulting in the issuance of 39.7 million Cimarex common shares. At December 31, 2005, we had 82.4 million shares outstanding. The merger was accounted for as a purchase of Magnum Hunter by Cimarex. The results of operations of Magnum Hunter were included in our consolidated statements of operations beginning June 7, 2005.

Certain amounts in prior years' financial statements have been reclassified to conform to the 2006 financial statement presentation.

Results of operations

Year ended December 31, 2006 compared with year ended December 31, 2005

Summary data

(in thousands or as indicated)	For the years ended December 31, 2006	2005
Net income	$ 345,719	$ 328,325
Per share basic	4.21	5.07
Per share diluted	4.11	4.90
Gas sales	$ 810,894	$ 807,007
Oil sales	404,517	265,415
Total oil and gas sales	$ 1,215,411	$ 1,072,422
Total gas volume Mcf	124,733	100,272
Gas volume MMcf per day	341.7	274.7
Average gas price per Mcf	$ 6.50	$ 8.05
Total oil volume thousand barrels	6,529	4,804
Oil volume barrels per day	17,887	13,162
Average oil price per barrel	$ 61.96	$ 55.25
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
Expenses and other income:		
Depreciation, depletion and amortization	$ 396,394	$ 258,287
Production	176,833	104,067
Transportation	21,157	15,338
Taxes other than income	91,066	73,360
General and administrative	42,288	33,497
Stock compensation	8,243	4,959
Other operating, net	2,064	15,897
(Gain) Loss on derivative instruments	(22,970)	67,800
Int. exp., net of cap. int. & amort. of F.V. of debt	1,908	5,789
Asset retirement obligation accretion	7,018	3,819
Other, net	(28,591)	(12,536)

Net income for the year of 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. The results of operations of Magnum Hunter are included in our consolidated statements of operations only for the period since the acquisition on June 7, 2005.

Oil and gas sales for the year of 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 percent 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 percent improvement in oil prices totaled $44.0 million. Changes in realized prices were the direct result of overall market conditions.

Gas gathering and processing revenues, net of related costs, equaled $20.5 million in 2006, compared to $12.4 million in 2005. The increase is due to the inclusion of related activities from Magnum Hunter operations from June 7, 2005. We own interests in gas gathering systems and gas processing plants that are connected to our production operations. We transport and process third party gas that is associated with our gas.

Gas marketing net revenues increased to $3.9 million from $2 million, net of related costs of $144.7 million and $213.7 million for 2006 and 2005, respectively. Gas marketing revenues, net of related costs, pertain to sales of gas on behalf of third parties that is incidental to sales of our own production.

Costs and expenses

Net costs and expenses (not including gas gathering, marketing and processing costs, as well as income tax expense) were $695.4 million in 2006 compared to $570.3 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.

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.

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 us. 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 net costs and expenses for 2006 and 2005 was the gain and loss on derivative instruments. In connection with the Magnum Hunter merger, we 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, we 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. Theses contracts expired December 31, 2006.

To mitigate a portion of the potential exposure to adverse market changes in an environment of volatile gas prices, we entered into additional derivative contracts in third quarter of 2006. These derivatives have been designated for hedge accounting treatment as cash flow hedges. Changes in the fair value of the hedges, 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. During 2006, we recognized an unrealized loss of $13 thousand related to the ineffective portion of the derivative contracts.

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, we had no outstanding debt.

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

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 our 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. Our 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 our 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 percent and 36.4 percent in 2006 and 2005, respectively. Included in the 2006 income tax expense of $198.6 million is a current benefit of $21.9 million.

Year ended December 31, 2005 compared with year ended December 31, 2004

Summary data

	For the years ended December 31,	
(in thousands or as indicated)	**2005**	**2004**
Net income	$ 328,325	$ 153,592
Per share basic	5.07	3.70
Per share diluted	4.90	3.59
Gas sales	$ 807,007	$ 366,260
Oil sales	265,415	106,129
Total oil and gas sales	$ 1,072,422	$ 472,389
Total gas volume MMcf	100,272	63,611
Gas volume MMcf per day	274.7	173.8
Average gas price per Mcf	$ 8.05	$ 5.76
Total oil volume thousand barrels	4,804	2,641
Oil volume barrels per day	13,162	7,215
Average oil price per barrel	$ 55.25	$ 40.19
Gas gathering and processing revenues	$ 44,238	$ 101
Gas gathering and processing costs	(31,890)	(284)
Gas gathering and processing margin	$ 12,348	$ (183)
Gas marketing revenues, net of related costs	$ 1,962	$ 2,674
Costs and expenses:		
Depreciation, depletion and amortization	$ 258,287	$ 124,251
Production	104,067	37,476
Transportation	15,338	10,003
Taxes other than income	73,360	37,761
General and administrative	33,497	22,483
Stock compensation	4,959	1,957
Other operating, net	15,897	(3,394)
Loss on derivative instruments	67,800	
Int. exp., net of cap. int. & amort. of F.V. of debt	5,789	1,075
Asset retirement obligation accretion	3,819	1,241
Other, net	(12,536)	(4,291)

Net income for the year of 2005 was $328.3 million, or $4.90 per diluted share, compared to net income of $153.6 million, or $3.59 per diluted share in 2004. The change in net income results from the effect of changes in revenues and costs, as discussed further. The results of operations of Magnum Hunter are included in our consolidated statements of operations only for the period since the acquisition on June 7, 2005.

Oil and gas sales for the year of 2005 totaled $1.1 billion, compared to $472.4 million for 2004. The $600.0 million increase in sales between the two periods results from $302.0 million related to higher commodity prices and $298.0 million due to higher production volumes (due primarily to increased production resulting from the acquisition of Magnum Hunter).

Realized gas prices averaged $8.05 per Mcf for 2005, compared to $5.76 per Mcf for 2004. This 40 percent change increased sales by $230.0 million between the two periods. Realized oil prices averaged $55.25 per barrel for 2005, compared to $40.19 per barrel for 2004. The increase in sales between periods resulting from this 37 percent improvement in oil prices totaled $72.0 million. Changes in realized prices were the direct result of overall market conditions.

Sales also benefited from higher production volumes. Average gas volumes rose 100.9 MMcf per day in 2005 to 274.7 MMcf per day from 173.8 MMcf per day in 2004, resulting in $211.1 million of incremental revenues. Oil volumes averaged 13,162 barrels per day for 2005, compared to 7,215 barrels per day in 2004, resulting in increased revenues of $86.9 million. The increase in sales volumes between the periods of 2005 and 2004 is due to positive drilling results during 2004 and 2005, and the inclusion of production from Magnum Hunter operations from June 7, 2005. Production volumes in the Gulf of Mexico and along the Texas and Louisiana Gulf Coast area were negatively impacted during the third and fourth quarters 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 and full-year volumes by 17 to 20 MMcf equivalent per day. At year-end 2005, approximately 20 MMcf equivalent was still shut-in. It is anticipated that most of the remaining shut-in volumes will be restored by the end of the first quarter of 2006. The timetable to restore full production largely depends on the startup of refineries, gas processing plants, platforms, facilities and pipelines owned and operated by others. No oil and gas reserves have been lost as a result of the storms and essentially all associated repair costs will be covered by insurance.

Gas gathering and processing revenues, net of related costs, equaled $12.4 million in 2005, compared to a loss of $0.2 million in 2004. The increase is due to the inclusion of related activities from Magnum Hunter operations from June 7, 2005. We own interests in gas gathering systems and gas processing plants that are connected to our production operations. We transport and process third party gas that is associated with our gas.

Gas marketing net revenues decreased to $2 million from $2.7 million, net of related costs of $213.7 million and $193.0 million for 2005 and 2004, respectively. Gas marketing revenues, net of related costs, pertain to sales of gas on behalf of third parties that is incidental to sales of our own production.

Costs and expenses

Costs and expenses (not including gas gathering, marketing and processing costs as well as income tax expense) were $570.3 million in 2005 compared to $228.6 million in 2004. Depreciation, depletion and amortization (DD&A) was the largest component of the increase between periods. DD&A equaled $258.3 million in 2005 compared to $124.3 million in 2004. On a unit of production basis, DD&A was $2.00 per Mcfe in 2005 compared to $1.56 per Mcfe for 2004. The increase largely stems from costs associated with Magnum Hunter operations and higher costs for reserves added during 2004 and 2005.

Production costs rose $66.6 million from $37.5 million ($.47 per Mcfe) in 2004 to $104.1 million ($.81 per Mcfe) in 2005. The higher costs in 2005 resulted primarily from the inclusion of costs associated with Magnum Hunter operations, higher field operating expenses from an expanded number of properties and higher maintenance costs.

Transportation costs increased from $10.0 million in 2004 to $15.3 million in 2005. The increase is the result of expiring contracts being renewed with increased current market rates and the inclusion of transportation costs associated with Magnum Hunter operations.

Taxes other than income were $35.6 million greater, rising from $37.8 million in 2004 to $73.4 million in 2005. The increase between periods resulted from increases in oil and gas sales stemming from inclusion of Magnum Hunter operations, higher production volumes and commodity prices.

General and administrative (G&A) expenses increased $11.0 million from $22.5 million in 2004 to $33.5 million in 2005. 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 $2.0 million in 2004 to $5.0 million in 2005 due primarily to the $3.4 million expensing of stock options resulting from the adoption of SFAS No. 123R as of January 1, 2005.

Other operating, net totaled an expense of $15.9 million in 2005 and income of $3.4 million in 2004. The 2005 expenses 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 consisted 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 us. The income reflected in 2004 consisted of miscellaneous litigation settlements in our favor.

Another large component of the increase in costs and expenses between periods was the loss on derivative instruments. Prior to the acquisition of Magnum Hunter, we did not use financial instruments to mitigate commodity price changes. In connection with the merger, we recognized a $39.3 million liability associated with Magnum Hunter's existing commodity derivatives at the merger date (June 7, 2005). These derivative instruments have not been designated for hedge accounting treatment. As a result, we recognized in earnings during 2005 a net loss of $67.8 million. The charge includes both non-cash mark-to-market derivative losses as well as cash settlements. Cash payments related to these contracts that settled in 2005 totaled $64.3 million. The net derivative liability at December 31, 2005 equals $41.9 million. We will continue to recognize mark-to-market gains and losses as well as amortization of these contracts in future earnings until the derivative instruments mature.

Net interest expense in 2005 of $5.8 million is comprised of $19.6 million of interest expense, offset by $11.7 million of capitalized interest resulting from interest recognized on borrowings associated with costs incurred to bring properties under development, not being amortized, to their intended use and $2.1 million of amortization of fair value of debt. This has increased from $1.1 million of interest expense in 2004. The additional components of the 2005 net interest amount and the increase from 2004 results from amounts associated with the debt assumed in the Magnum Hunter merger. Prior to the Magnum Hunter merger, we had no outstanding debt.

Asset retirement obligation accretion increased $2.6 million from $1.2 million in 2004 to $3.8 million in 2005. We recognize the fair value of a liability for an asset retirement obligation in the period in which it is incurred if a reasonable estimate of fair value can be made, and the associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. Oil and gas producing companies incur this liability which includes costs related to the plugging of wells, the removal of facilities and equipment, and site restorations, upon acquiring or drilling a successful well. Since 2004 the liability has increased $81.3 million from $19.8 million in 2004 to $101.1 million in 2005.

Other, net increased from $4.3 million of income in 2004 to $12.5 million of income in 2005. The components of this other income net of other expenses consist of miscellaneous items that will vary from period to period. The increase from 2004 to 2005 is due primarily to additional gains on the sale of miscellaneous equipment inventory.

Income tax expense

Income tax expense totaled $188.1 million for 2005 versus $92.7 million for 2004. Tax expense equaled a combined federal and state effective income tax rate of 36.4 percent and 37.6 percent in 2005 and 2004, respectively.

Liquidity and capital resources

Cash flows

Our primary source of capital is cash flow generated from operating activities. Prices we receive for oil and gas sales and our level of production will impact these future cash flows. No prediction can be made as to the prices we will receive. Production volumes will in large part be dependent upon the amount and results of future capital expenditures. In turn, actual levels of capital expenditures may vary due to many factors, including drilling results, oil and gas prices, industry conditions, prices and availability of goods and services, and the extent to which proved properties are acquired.

Cash flow provided by operating activities for 2006 was $878.4 million, compared to $704.7 million for 2005. The increase in 2006 from the earlier period resulted primarily from higher oil and gas production and higher oil prices.

Cash flow used in investing activities for 2006 was $1.0 billion, compared to $497.5 million for 2005. The increase in 2006 stemmed from a larger exploration and development program.

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.

Financial condition

As of December 31, 2006, stockholders' equity totaled $3.0 billion, up from $2.6 billion at December 31, 2005. The increase resulted primarily from 2006 net income of $345.7 million. At December 31, 2006, our cash balance equaled $5.0 million.

In December 2005, our Board of Directors declared our first quarterly cash dividend of $.04 per share payable to shareholders. A $.04 per share dividend has been authorized in every quarter of 2006. Also in December 2005, our Board of Directors authorized the repurchase of up to four million shares of common stock. Through December 31, 2005, 68,000 shares had been repurchased at an average price of $43.03. Since December 31, 2005 and through December 31, 2006, an additional 182,100 shares have been repurchased for an average price of $44.43 per share.

Working capital

Working capital at December 31, 2006 totaled $62.2 million, compared to $31.6 million at December 31, 2005. The increase is primarily the result of settlement of the liability associated with derivative contracts outstanding at December 31, 2005 and entering into new derivative contracts in the third quarter for which a current asset was recorded at December 31, 2006.

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

Pre-offering

Debt at December 31, 2005 consisted of the following (in thousands):

Bank debt	$	
9.6% senior notes due 2012 (face value $195,000)(1)		213,770
Floating rate convertible senior notes due 2023 (face value $125,000)(2)		138,681
Total long-term debt	$	352,451

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

Bank debt	$	95,000
9.6% senior notes due 2012 (face value $195,000)(1)		210,746
Floating rate convertible senior notes due 2023, 5.36% at December 31, 2006 (face value $125,000)(2)		137,921
Total long-term debt	$	443,667

(1) Fair market value at June 7, 2005 (date of acquisition of Magnum Hunter) equaled $215.5 million. The subsequent noted balance represents the fair market value at date of acquisition less amortization of the premium of fair market value over face value.

(2) Fair market value at June 7, 2005 equaled $144.75 million. The subsequent noted balance represents the fair market value at date of acquisition less amortization of the premium of fair market value over face value.

Our senior 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, 2006, there were outstanding borrowings of $95 million under the senior revolving credit facility at a weighted average interest rate of approximately 6.75%. We also had outstanding letters of credit of approximately $5 million, leaving an unused borrowing capacity of approximately $400 million at December 31, 2006.

The credit facility agreement contains both financial and non-financial covenants. We continue to comply with these covenants and do not view them as materially restrictive.

The 9.6% senior notes due 2012 assumed in the Magnum Hunter merger have a face value of $195 million and are due March 15, 2012. The notes are unsecured and are redeemable, as a whole or in part, at our option, on and after March 15, 2007 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**
2007	104.8%
2008	103.2%
2009	101.6%
2010 and thereafter	100.0%

We intend to redeem the 9.6% senior notes due 2012 in full with the proceeds of this offering.

The floating rate convertible senior notes due 2023 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, 2006, the interest rate equaled 5.36%.

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 29, 2006, the closing price of our common stock traded on the New York Stock Exchange was $36.50. There is not an observable market for the notes. Based on an average common stock price of $36.50, management estimates the fair value of the notes at December 31, 2006 was approximately $157.4 million (or $1,259 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 (plus accrued interest) anytime after December 22, 2008.

Post-offering

Debt at December 31, 2006, as adjusted to give pro forma effect to the offering and the application of the net proceeds from the sale of the notes as set forth under "Use of Proceeds," would have consisted of the following (in thousands):

Bank debt	$	5,000
9.6% senior notes due 2012 (face value $195,000)		
% Senior Notes due 2017		300,000
Floating rate convertible senior notes due 2023 (face value $125,000)		137,921
Total long-term debt	$	442,921

As of December 31, 2006, on a pro forma basis, after giving effect to the offering of the notes offered hereby, we would have had outstanding $442.9 million in aggregate indebtedness, with an additional $490.0 million of borrowing capacity available under our senior revolving credit facility. Our liquidity requirements will be significant, primarily due to funding our operation, exploration and development activities and debt service requirements.

At December 31, 2006, on a pro forma basis, we would have had $130 million face value of debt subject to variable interest rates. A 1% increase in the average interest rate would increase annual interest expense by approximately $1.3 million.

We intend to use a portion of the proceeds of the offering to reduce outstanding borrowings under our senior revolving credit facility by approximately $90 million. Our senior revolving credit facility matures on July 1, 2010 and bore interest at a weighted average rate of approximately 6.75% as of December 31, 2006. Reductions of outstanding borrowings under our senior revolving credit facility can be temporary, as additional borrowing capacity is available under the facility.

In addition, the indenture governing the notes being offered hereby will limit our (and our subsidiary guarantors') ability to:

- incur additional debt or issue certain preferred shares;
- pay dividends on or make other distributions in respect of our capital stock or make other restricted payments;
- make certain investments;
- enter into certain types of transactions with affiliates;
- sell certain assets;
- create liens on certain assets to secure debt; and
- consolidate, merge, sell or otherwise dispose of all or substantially all of our assets.

Subject to certain exceptions, the indenture governing the notes will permit us and our restricted subsidiaries to incur additional indebtedness, including secured indebtedness. See "Description of notes."

Contractual obligations and material commitments

The following table sets forth our contractual obligations and material commitments as of December 31, 2006 on a historical basis:

	Payments due by period				
Contractual obligations (in thousands)	**Total**	**Less than 1 year**	**1-3 years**	**3-5 years**	**More than 5 years**
Long-term debt(1)	$ 415,000	$	$	$ 95,000	$ 320,000
Fixed-rate interest payments(1)	102,960	18,720	37,440	37,440	9,360
Operating leases	31,278	5,158	10,074	7,868	8,178
Drilling commitments	55,322	55,322			
Asset retirement obligation(2)	129,141	4,320			
Other liabilities	5,932	202	67	51	5,612

(1) These amounts do not include interest on the $95 million of bank debt outstanding at December 31, 2006. The weighted average interest rate at December 31, 2006 on the bank debt was approximately 6.75%.

(2) 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, 2006, we had a firm sales contract to deliver approximately four Bcf of natural gas over the next eight months. If this gas is not delivered, our financial commitment would be approximately $22.3 million. This commitment will fluctuate due to price volatility and actual volumes delivered. However, we believe no financial commitment will be due based on our reserves and current production levels.

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 $2.8 million.

All of the 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 line of credit will be adequate to meet future liquidity needs, including satisfying our financial obligations and funding our operations and exploration and development activities.

2007 outlook

Our projected 2007 exploration and development expenditure program ranging from $800 million to $1 billion will require a great deal of coordination and effort. Though there are a variety of factors that could curtail, delay or even cancel some of our drilling operations, we believe our projected program has a high degree of occurrence. The majority of projects are in hand, drilling rigs are being scheduled, and the historical results of our drilling efforts in these areas warrant pursuit of the projects.

Costs of operations on a per Mcfe basis for 2007 are estimated to approximate levels realized in late 2006. Should factors beyond our control change, our program and realized costs will vary from current projections. These factors could include volatility in commodity prices, changes in the supply of and demand for oil and gas, weather conditions, governmental regulations and more.

Production estimates for 2007 range from 450 to 470 MMcfe per day. Revenues will be dependent not only on the level of oil and gas actually produced, but also the prices that will be realized. During 2006, our realized prices averaged $6.50 per Mcf of gas and $61.96 per barrel of oil. Prices can be very volatile and the possibility of 2007 realized prices being different than they were in 2006 is high.

Qualitative and quantitative disclosures about market risk

Price fluctuations

Our results of operations are highly dependent upon the prices we receive for oil and gas production, and those prices are constantly changing in response to market forces. Nearly all of our revenue is from the sale of oil and gas, so these fluctuations, positive and negative, can have a significant impact on our results of operations and cash flows.

Monthly gas price realizations during 2006 ranged from $4.23 per Mcf to $8.43 per Mcf. Oil prices ranged from $54.85 per barrel to $70.61 per barrel. It is impossible to predict future oil and gas prices with any degree of certainty.

In third quarter 2006, we entered into derivative contracts to mitigate a portion of our potential exposure to adverse market changes in the Mid-Continent region, in an environment of volatile gas prices. These arrangements, which were based on prices available in the financial markets at the time the contracts were entered into, will be settled in cash and will not require physical delivery of hydrocarbons. These hedges have been designated for hedge accounting treatment as cash flow hedges under SFAS No. 133 and therefore, gains and losses upon settlement of the hedges will be recognized in gas revenue in the period the contracts are settled. We believe that we have sufficient production volumes such that the hedge contract transactions will occur as expected.

The following tables reflect the volumes, weighted average contract prices and fair values of the contracts we have in place as of December 31, 2006. We are exposed to risks associated with these contracts arising from volatility in commodity prices and the unlikely event of non-performance by the counterparties to the agreements.

Commodity	Type	Volume/day	Duration	Mid-continent weighted average price	Fair value (000's)
Natural Gas	Collars	80,000 MMBTU	Jan 07-Dec 07	$ 7.00-$10.17	$ 41,945
Natural Gas	Collars	40,000 MMBTU	Jan 08-Dec 08	$ 7.00-$9.90	7,051
					$ 48,996

At December 31, 2006, the weighted average Mid-Continent prices for the 2007 and 2008 contracts approximated $6.13 and $7.02, respectively.

Interest rate risk

Fixed and variable rate debt. We assumed fixed and variable rate debt as part of the acquisition of Magnum Hunter. These agreements expose us to market risk related to changes in interest rates. We have a credit facility that bears interest at either a Base rate or a Eurodollar rate at our option.

The following table presents the carrying and fair value of our debt along with average interest rates as of December 31, 2006. The fair value for the convertible notes was based on an average price per share of $36.50 for our common stock. The fair value for the existing fixed rate senior notes that will be redeemed in connection with this offering was valued at their last traded value before December 31, 2006.

Expected maturity dates (in thousands)	2010	2012	2017	2023	Total	Book value	Fair value
Pre-offering:							
Variable Rate Debt:							
Bank debt(a)	$ 95,000	$	$	$	$ 95,000	$ 95,000	$ 95,000
Convertible notes(b)	$	$	$	$ 125,000	$ 125,000	$ 137,921	$ 157,393
Fixed Rate Debt:							
9.6% senior notes due 2012(c)	$	$ 195,000	$	$	$ 195,000	$ 210,746	$ 205,238
Post-offering(d):							
Variable Rate Debt:							
Bank debt(a)	$ 5,000	$	$	$	$ 5,000	$ 5,000	$ 5,000
Convertible notes(b)	$	$	$	$ 125,000	$ 125,000	$ 137,921	$ 157,393
Fixed Rate Debt:							
9.6% senior notes due 2012	$	$	$	$	$	$	$
% Senior Notes due 2017	$	$	$ 300,000	$	$ 300,000	$ 300,000	$ 300,000

(a) At December 31, 2006, the weighted average interest rate on outstanding borrowings under the credit facility was approximately 6.75%.

(b) The interest rate on the convertible notes is 5.36%. The rate on these notes is equal to the three month LIBOR, adjusted quarterly. A holder of these notes has the right to require us to repurchase all or a portion of these notes on December 15, 2008, 2013, and 2018. The repurchase will be equal to the face value of the notes plus accrued and unpaid interest up to the date of repurchase.

(c) The interest rate on the senior notes due 2012 is a fixed 9.6%.

(d) As adjusted to give pro forma effect to this offering and the application of the net proceeds from the sale of the notes as set forth under "Use of proceeds."

Business

Our company

We are an independent oil and gas exploration and production company. Our core areas of operation are in the Mid-Continent, Permian Basin and onshore Gulf Coast regions of the U.S. We also have a small presence in the Gulf of Mexico and are expanding our operations in Wyoming. As of December 31, 2006 our estimated proved reserves were 1,449 Bcfe, of which 80% were proved developed and 75% were gas. During 2006, our net production averaged 449 MMcfe per day, which implies a reserve life of approximately 8.8 years. For the year ended December 31, 2006, we generated revenues and EBITDA of $1,267 million and $943 million, respectively. See "Summary Summary historical consolidated financial data" for reconciliation of EBITDA to net income.

On June 7, 2005, we acquired Magnum Hunter Resources, Inc., which significantly increased our presence in the Permian Basin and enhanced our Mid-Continent operations in the Texas Panhandle. Magnum Hunter also had a small presence in the Gulf of Mexico and a large acreage position in several western states. The acquisition increased our proved reserves by 887 Bcfe (60% gas and 73% proved developed), which effectively tripled our proved reserves and doubled our production.

The following table summarizes our estimated proved oil and gas reserves by region as of December 31, 2006 and our average daily production by region for 2006.

					2006 average daily production		
	Oil (MBbl)	Gas (MMcf)	Equivalent (MMcfe)	Percent of proved reserves	Oil (MBbl/d)	Gas (MMcf/d)	Total (MMcfe/d)
Mid-Continent	8,709	542,447	594,701	41%	4.7	152.5	180.7
Permian Basin	44,351	296,969	563,076	39%	8.1	83.8	132.4
Gulf Coast	4,671	76,640	104,663	7%	3.2	61.8	80.7
Gulf of Mexico	964	38,111	43,895	3%	1.6	36.2	45.9
Western/Other	1,102	136,195	142,811	10%	0.3	7.4	9.4
	59,797	1,090,362	1,449,146	100%	17.9	341.7	449.1

Business strengths

Solid base of onshore proved reserves and production. At year-end 2006, we had nearly 1.45 Tcfe of proved oil and gas reserves, 80% of which were classified as proved developed. Approximately 80% of our total proved reserves are concentrated in the Mid-Continent and Permian Basin regions. Wells in these areas generally have stable production, reliable reserve estimates and low production decline rates. The Mid-Continent and Permian Basin regions also accounted for 70% of our total 2006 production.

Blended portfolio of low-risk development and potentially high-return exploration projects. We seek to maintain a geographically and geologically diverse portfolio of low-to-moderate risk development and higher risk exploration projects. The low-risk, repeatable results we achieve in our Mid-Continent and Permian Basin regions provide moderate and predictable production and reserve growth. Our higher-risk drilling locations along the Gulf Coast and in the Gulf of Mexico are characterized by higher reserves per well and potentially higher economic returns. We believe that this blend of low-risk Mid-Continent and Permian Basin drilling combined with higher-potential Gulf Coast exploration allows us to achieve consistent, profitable results while also enabling us to pursue larger growth opportunities.

Large undeveloped acreage position with an active drilling program. As of December 31, 2006, we owned leases covering more than 4.4 million net acres, of which 80% were undeveloped. In 2006, we drilled more than 550 gross wells completing 91% as producers. More than 80% of this drilling occurred in the Mid-Continent and Permian Basin where we achieved drilling success rates of 97% and 96%, respectively. Our technical teams and operating managers continue to generate projects on our existing acreage inventory and also seek to identify new areas for exploration and development.

Proven track record of reserve and production growth. We have increased our proved reserves and production each year since 2002 at average annual growth rates of 37% and 36%, respectively. We have achieved these results from a combination of organic growth through drilling and opportunistic mergers that have enhanced our competitive position.

Experienced management and operational teams. Our financial and operations executives, led by F.H. Merelli, each have over 25 years of experience in the oil and gas industry. Mr. Merelli has over 47 years of oil and gas industry experience. Our executive management team is supported by technical and operating managers who also have substantial industry experience and expertise within the basins in which we operate.

Business strategy

Consistently grow proved reserves and production. We seek to reinvest the cash flow generated by our producing properties into drilling new wells that have the potential to profitably grow our production and proved reserves. From time to time, we also consider supplementing our drill-bit driven growth through selective mergers and acquisitions.

Focus on blended portfolio. We maintain a diverse portfolio of prospects that is underpinned by approximately 70%-80% low-to-moderate risk projects combined with a smaller percentage of higher risk/higher potential prospects. Our objective is to achieve consistent, profitable growth while still preserving opportunities for potentially meaningful new discoveries. We also seek to maintain geographic diversification so as to mitigate certain operational and market risks and to position us to benefit from emerging plays.

Employ a disciplined approach to capital investment decision making. Each drilling decision is based on a detailed evaluation of its risk-adjusted, discounted cash flow rate of return on investment. Our comprehensive analysis includes estimates and assessments of potential reserve size, geologic and mechanical risks, expected costs and future production profiles. Our integrated teams of geoscientists, landmen and petroleum engineers seek to continually generate new prospects to maintain a rolling inventory of drilling opportunities. We have a centralized management system that measures actual results and provides feedback to the originating teams in order to help them improve and refine future investment decisions.

Control our drilling inventory. We will continue to seek to exercise control over the majority of our properties and investment decisions. At December 31, 2006, we operated the wells that accounted for approximately 73% of our total proved reserves and approximately 70% of our production. We believe our ability to control our drilling inventory will allow us to more effectively control operating costs, timing of development activities and technological enhancements, marketing of production and allocation of our capital budget.

Maintain financial flexibility and a conservative capital structure. We believe that maintaining a conservative capital structure will provide us with the flexibility needed to capitalize on future growth opportunities while limiting our financial risk. We have historically used leverage conservatively, funding our development and growth activity through a combination of internally generated cash flow, bank borrowings and stock-for-stock mergers. Prior to our 2005 acquisition of Magnum Hunter and the assumption of its debt, we had no debt outstanding at year-end 2003 and 2004 and our 2006 year-end debt-to-capitalization ratio was 13%. Based on expected cash flow provided by operating activities and available liquidity under our senior revolving credit facility, we believe we are well positioned to fund our identified drilling opportunities for the foreseeable future.

Business segments

We have 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; the upper Gulf Coast areas of Texas, south Louisiana and Mississippi; and the Gulf of Mexico.

A summary of our 2006 exploration and development activity by region is as follows.

(Dollars in millions)	Exploration and development capital	Gross wells drilled	Net wells drilled	Completion rate	12/31/06 proved reserves (Bcfe)
Mid-Continent	$350	302	186	97%	595
Permian Basin	331	167	119	96%	563
Gulf Coast	211	49	28	65%	105
Gulf of Mexico	128	16	6	44%	44
Western/Other	29	24	7	71%	142
	$1,049	558	346	91%	1,449

Company-wide, we participated in drilling 558 gross wells during 2006, with an overall completion rate of 91 percent. On a net basis, 316 of 346 total wells drilled during 2006 were completed as producers.

Our 2006 exploration and development expenditures (E&D) totaled $1,049 million and resulted in 201 Bcfe of proved reserve additions from drilling. Of total expenditures, 33 percent were invested in projects located in the Mid-Continent area; 32 percent in the Permian Basin; 20 percent in the Gulf Coast; and 12 percent in the Gulf of Mexico.

Mid-Continent

Our Mid-Continent operations cover the Anadarko and Arkoma basins of central and southeastern Oklahoma, the Hugoton Basin of southwest Kansas and the Texas Panhandle. We drilled 302 gross (186 net) Mid-Continent wells during 2006, completing 97 percent as producers. The bulk of this activity occurred in the Texas Panhandle and the Anadarko Basin. Full-year 2006 drilling investment in this area totaled $350 million, or 33% of total E&D capital.

We drilled 86 gross (59 net) Texas Panhandle wells with 98 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 75-100 wells planned for 2007.

We drilled 92 gross (18 net) Anadarko Basin wells, of which 98 percent were completed as producers. The drilling activity mainly targets the Red Fork and Clinton Lake/Atoka formations at depths ranging from 12,000-15,000 feet. Gross proved reserves for these wells averaged 1.3 Bcfe. We expect to continue an active program in this area, drilling a similar number of wells in 2007 as in 2006.

We have a large inventory of recompletion and in-fill drilling locations in several exploitation projects, including the Cumberland, Madill and Caddo fields in southern Oklahoma and the Panoma field in the Texas Panhandle. The Panoma field area targets the Brown Dolomite formation at depths of approximately 2,200 feet. In 2006 we drilled 80 gross (79 net) wells at Panoma with a 100% success rate, increasing field production by 3.2 MMcfe/d.

Permian Basin

In the Permian Basin our operations cover both west Texas and southeast New Mexico. In total, we drilled 167 gross (119 net) wells completing 161 gross (115 net) as producers in the Permian Basin during 2006. Full-year 2006 drilling investment in this area totaled $331 million, or 32% of total E&D capital.

Southeast New Mexico drilling totaled 69 gross (47 net) wells with 94% being completed as producers. The primary formations we target in this area are comprised of Pennsylvanian-aged Morrow, Atoka and Strawn sandstones and conglomerate gas reservoirs at depths ranging from 11,500-14,000 feet.

In West Texas, a total of 98 gross (72 net) wells were drilled, of which 98% were successful. Included in the West Texas program is exploitation of the Westbrook Unit (90% working interest) where 44 infill wells have been drilled and completed in the Clearfork formation at 3,200 feet.

Other geologic targets in West Texas include the Devonian, Ellenburger, Bone Spring and Spraberry. We drilled or participated in 21 (seven net) Devonian wells in the Arbol de Nada field in Winkler and Ector Counties, Texas; five gross (five net) Ellenburger wells in the Will-O field in Val Verde County, Texas; and six gross (2.7 net) Bone Spring wells in the War-Wink field in Ward County, Texas.

Gulf Coast /Gulf of Mexico

Our onshore Gulf Coast focus area generally encompasses coastal Texas, south Louisiana and Mississippi. Our Gulf of Mexico operations are primarily located in offshore Louisiana in water depths less than 300 feet and covering approximately one million gross acres. We obtained all of our offshore position through the Magnum Hunter acquisition. Our Gulf Coast and Gulf of Mexico effort is generally characterized by a greater reliance on 3-D seismic information for prospect generation, larger potential reserves per well, greater drilling depths and lower success rates.

During 2006 we drilled 49 gross (28 net) Gulf Coast wells, realizing a 65 percent success rate. A significant portion of the drilling occurred in Liberty County, Texas. Targeting the Yegua and Cook Mountain formations at 10,500 feet, we drilled 14 gross (nine net) Liberty County wells with a success rate of 64 percent. Gulf of Mexico 2006 drilling consisted of 16 gross (6.7 net) wells, of which 44% were successful.

Western/other

Our Western/Other region principally includes operations in California, Michigan, North Dakota and Wyoming. We drilled 24 gross (7.2 net) wells in the Western/Other region completing only 17 gross (0.2 net) as producers. Included in this area is the Riley Ridge Unit gas development project in Sublette County, Wyoming.

Production and pricing information

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

	Years ended December 31,		
	2006	2005	2004
Production Volumes			
Gas (MMcf)	124,733	100,272	63,611
Oil (MBbls)	6,529	4,804	2,641
Equivalent (MMcfe)	163,907	129,096	79,457
Net Average Daily Volumes:			
Gas (MMcf)	341.7	274.7	173.8
Oil (MBbl)	17.9	13.2	7.2
Equivalent (MMcfe)	449.1	353.7	217.1
Average Sales Price			
Gas ($/Mcf)	$ 6.50	$ 8.05	$ 5.76
Oil ($/Bbl)	$ 61.96	$ 55.25	$ 40.19

Combined oil and gas production volumes increased 27 percent to 449.1 MMcfe per day. Gas production in 2006 rose 24 percent to 341.7 MMcf per day and oil production increased 36 percent to 17,887 barrels per day. The increase in volumes primarily stems from the inclusion of production from Magnum Hunter operations beginning June 7, 2005 and exploration and development drilling.

The weighted-average gas price we received during 2006 was $6.50 per Mcf, which was 19 percent lower than the $8.05 per Mcf average price we received during 2005. Our annual average realized oil price during 2006 increased by 12 percent to $61.96 per barrel from $55.25 per barrel in 2005. Gas prices fell in 2006 as compared to 2005 as a result of a number of factors including lower demand because of warm winter weather, no significant hurricane activity causing supply disruptions in the Gulf of Mexico and rising storage levels relative to historic averages.

We assumed Magnum Hunter's oil and gas commodity swap and collar contracts as part of the merger. These instruments did not qualify for hedge accounting treatment and as such they are not included in the above average sales prices. In third quarter of 2006, we entered into natural gas collars for calendar 2007 and 2008 for 80,000 and 40,000 MMBtu per day, respectively. The collars have been executed to settle against regional delivery points that correspond with our Mid-Continent production. Beginning in January 2007, these instruments will affect average sales prices to the extent that the benchmark prices fall outside the collar range.

The following table summarizes daily production by region for 2006 and the second-half of 2005. The second-half 2005 volumes reflect the production increases as a result of the Magnum Hunter acquisition.

	2006 average daily production			
	Oil (MBbl/d)	Gas (MMcf/d)	Total (MMcfe/d)	Second-half 2005 avg. (MMcfe/d)
Mid-Continent	4.7	152.5	180.7	175.3
Permian Basin	8.1	83.8	132.4	130.1
Gulf Coast	3.2	61.8	80.7	84.4
Gulf of Mexico	1.6	36.2	45.9	37.9
Western/Other	0.3	7.4	9.4	10.5
	17.9	341.7	449.1	438.2

Our largest producing area is the Mid-Continent region which averaged 180.7 MMcfe per day making-up 40 percent of our total 2006 production. We grew our 2006 production in this region as a result of successful drilling programs in the Texas Panhandle and the Anadarko Basin. The Permian Basin contributed 132.4 MMcfe per day in 2006, which was 29 percent of our total production for this period. The current year production increased as a result of successful Morrow drilling in southeast New Mexico and West Texas secondary oil projects and development drilling. Gulf Coast production was 80.7 MMcfe per day during 2006, or 18 percent of total production. Gulf Coast volumes decreased in 2006 as a result of natural decline in our wells which were only partially offset by exploration success. Production from the Gulf of Mexico totaled 45.9 MMcfe per day, or 10 percent of our total 2006 production. Our second-half 2005 Gulf of Mexico production rate of 37.9 MMcfe per day was negatively impacted by hurricanes.

We have field offices located near our major concentrations of operated properties and have a centralized production management team in our Tulsa office.

Acquisitions and divestitures

We completed our acquisition of 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 of West Texas and southeast New Mexico and in 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 (73 percent proved developed).

Various interests in oil and gas properties were sold during 2006, with proceeds totaling $4.5 million. Proceeds from the sales were recorded as a reduction to oil and gas properties, as prescribed under the full cost method of accounting. Proved reserves associated with the sold properties approximated 2.5 billion cubic feet equivalent. We also recognized a $19.8 million gain on sale of certain limited partnership interests in oil and gas properties. Net sales consideration received via distributions from these affiliated partnerships totaled $59.3 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. Revenues are recognized as gas is delivered and are reflected in our income statement net of gas purchases.

We sell our oil and gas to a broad portfolio of customers. Our largest customer accounted for 11 percent of 2006 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 734 people on December 31, 2006. 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 financial and human resources substantially larger than ours. The effect of these competitive factors on our business 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. Our oil and gas properties are subject to customary royalty interests contracted for in connection with the acquisition of title, 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 many varying and complex federal and state regulations. In recent years, we have been most directly affected by federal and state environmental regulations and energy conservation rules. We are indirectly affected by federal and state regulation of pipelines and other oil and gas transportation systems. Compliance with such laws and regulations increases our overall cost of business, but has not had a material adverse effect on our operations or financial condition.

Most of the states in which we conduct operations regulate the size of well spacing units, drilling density within productive formations and the unitization or pooling of properties. In addition, state conservation laws 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. To date, we have not expended any material amounts to comply with such regulations, and our management does not currently anticipate that future compliance will have a materially adverse effect on our consolidated financial position or results of operations.

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.

Gas gathering and transportation. The Federal Energy Regulatory Commission (FERC) requires interstate gas pipelines to provide open access transportation. Interstate pipelines have implemented this requirement by modifying their tariffs and implementing new services and rates. These changes have provided 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 federal regulatory oversight, our natural gas gathering systems and services may receive regulatory scrutiny by state agencies.

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.

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.

Federal and state income taxation

Cimarex and the petroleum industry in general are affected by both federal and state income tax laws. 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.

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 73 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, 2006. All information in this prospectus relating to oil and gas reserves is net to our interest unless stated otherwise. The following table sets forth the present value and estimated volume of our oil and gas proved reserves:

	Years ended December 31,		
	2006	2005	2004
Total Proved Reserves			
Gas (MMcf)	1,090,362	1,004,482	364,641
Oil, condensate and NGLs (MBbls)	59,797	64,710	14,063
Equivalent (MMcfe)	1,449,146	1,392,742	449,020
Standardized measure of discounted future net cash flow after-tax, discounted at 10 percent (in thousands)	$ 2,200,889	$ 3,028,100	$ 798,033
Average price used in calculation of future net cash flow			
Gas ($/Mcf)	$ 5.54	$ 7.89	$ 5.58
Oil ($/Bbl)	$ 56.91	$ 57.65	$ 40.76

Significant properties

As of December 31, 2006, 90 percent of proved reserves were located in the Mid-Continent, Permian Basin, Gulf Coast and Gulf of Mexico regions. In total we owned an interest in 13,194 gross (4,757 net) productive oil and gas wells.

The following table summarizes our estimated proved oil and gas reserves by region as of December 31, 2006.

	Oil (MBbl)	Gas (MMcf)	Equivalent (MMcfe)	Percent of proved reserves
Mid-Continent	8,709	542,447	594,701	41%
Permian Basin	44,351	296,969	563,076	39%
Gulf Coast	4,671	76,640	104,663	7%
Gulf of Mexico	964	38,111	43,895	3%
Western/Other	1,102	136,195	142,811	10%
	59,797	1,090,362	1,449,146	100%

Our ten largest fields hold 30 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**
Hugoton	Mid-Continent	4.3%	59%	2,600	Chase
Hemphill	Mid-Continent	4.1%	95%	11,000	Granite Wash
Panhandle East	Mid-Continent	3.5%	98%	2,400	Brown Dolomite
Eola-Robberson	Mid-Continent	3.2%	95%	5,500-11,000	Bromide/McLish/Oil Creek
Carlsbad South	Permian	2.8%	58%	11,500	Morrow/Atoka
Red Deer Creek	Mid-Continent	2.8%	47%	11,000	Granite Wash
Quail Ridge	Permian	2.6%	59%	13,000	Morrow
Jo-Mill	Permian	2.5%	13%	7,500	Spraberry
Mendota NW	Mid-Continent	2.3%	71%	11,000	Granite Wash
Westbrook	Permian	2.1%	90%	3,500	Clearfork
		30.2%			

Acreage

The following table sets forth as of December 31, 2006, the gross and net acres of both developed and undeveloped leases held by us. 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	3,480	2,415	158,391	105,601	161,871	108,016
Oklahoma	103,772	85,182	395,645	168,255	499,417	253,437
Texas	144,826	106,218	232,402	110,785	377,228	217,003
	252,078	193,815	786,438	384,641	1,038,516	578,456
Permian Basin						
New Mexico	86,178	64,943	144,645	94,115	230,823	159,058
Texas	53,794	37,850	232,664	156,045	286,458	193,895
	139,972	102,793	377,309	250,160	517,281	352,953
Gulf Coast						
Louisiana	22,063	17,114	21,521	6,356	43,584	23,470
Texas	81,473	33,938	164,734	61,674	246,207	95,612
Mississippi	6,027	3,779	25,583	6,539	31,610	10,318
	109,563	54,831	211,838	74,569	321,401	129,400
Gulf of Mexico	711,140	438,125	324,614	110,709	1,035,754	548,834
Western/Other						
Arkansas			6,719	2,115	6,719	2,115
Arizona	914,695	914,695			914,695	914,695
California	35,715	30,678	8,770	6,752	44,485	37,430
Colorado	96,690	6,759	26,497	6,498	123,187	13,257
Illinois	1,782	1,191	554	183	2,336	1,374
Indiana	175	175	344	310	519	485
Michigan	31,803	31,686	549	549	32,352	32,235
Montana	49,449	16,298	18,858	7,735	68,307	24,033
Nebraska	4,560	116	2,118	168	6,678	284
Nevada	160	1	560	1	720	2
New Mexico	1,649,340	1,621,646	13,574	2,281	1,662,914	1,623,927
North Dakota	64,741	18,152	25,818	2,706	90,559	20,858
South Dakota	10,583	9,329	2,420	379	13,003	9,708
Utah	120,625	63,621	20,159	2,223	140,784	65,844
Wyoming	252,551	31,542	118,416	24,239	370,967	55,781
	3,232,869	2,745,889	245,356	56,139	3,478,225	2,802,028
	4,445,622	3,535,453	1,945,555	876,218	6,391,177	4,411,671

Gross wells drilled

We participated in drilling the following number of gross wells during calendar years 2006, 2005, and 2004:

	Exploratory			Developmental		
	Productive	Dry	Total	Productive	Dry	Total
Year ended December 31, 2006	20	32	52	490	16	506
Year ended December 31, 2005	55	20	75	283	24	307
Year ended December 31, 2004	12	11	23	177	21	198

We were in the process of drilling 30 gross (16 net) wells at December 31, 2006.

Net wells drilled

The number of net wells we drilled during calendar years 2006, 2005, and 2004 are shown below:

	Exploratory			Developmental		
	Productive	Dry	Total	Productive	Dry	Total
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
Year ended December 31, 2004	6.8	6.5	13.3	78.8	12.1	90.9

Productive wells

We have working interests in the following productive wells as of December 31, 2006:

	Gas		Oil	
	Gross	Net	Gross	Net
Mid-Continent	3,396	1,721	1,017	529
Permian	1,023	557	6,109	1,629
Gulf Coast	525	138	186	91
Gulf of Mexico	124	27	38	6
Western/Other	144	24	632	35
	5,212	2,467	7,982	2,290

Management

Our directors and executive officers as of March 21, 2007 were:

Name	Age	Office
F.H. Merelli	70	Chairman of the Board, Chief Executive Officer and President
Joseph R. Albi	48	Executive Vice President-Operations
Thomas E. Jorden	49	Executive Vice President-Exploration
Stephen P. Bell	52	Senior Vice President, Business Development and Land
Paul Korus	50	Vice President, Chief Financial Officer, and Treasurer
Gary R. Abbott	34	Vice President, Corporate Engineering
Richard S. Dinkins	62	Vice President, Human Resources
James H. Shonsey	55	Vice President, Chief Accounting Officer and Controller
Jerry Box	68	Director
Glenn A. Cox	77	Director
Cortlandt S. Dietler	85	Director
Hans Helmerich	48	Director
David A. Hentschel	73	Director
Paul D. Holleman	75	Director
Monroe W. Robertson	57	Director
Michael J. Sullivan	66	Director
L. Paul Teague	72	Director

There are no family relationships by blood, marriage, or adoption among any of the above directors or executive officers. Our board of directors consists of ten members and is divided into three classes: Class I, Class II and Class III directors. At each annual meeting of stockholders, a class of directors is elected for a term expiring at the annual meeting in the third year following the year of election. Each director holds office until his successor is elected and qualifies. 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 directors or executive officers and any other person pursuant to which he was selected as a director or executive officer.

Executive officers

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.

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.

Directors

Jerry Box has served as our director since 2005. He served as Chairman of Magnum Hunter Resources, Inc. from October 2004 until June 2005, and as a director of Magnum Hunter Resources from March 1999 to June 2005. Mr. Box served as President, COO and a director of Oryx Energy Company from February 1998 to March 1999. He had previously held a number of managerial and executive positions with Oryx Energy and its predecessor company, Sun Oil Company. Currently, Mr. Box is a director and chairman of the compensation committee and member of the nominating and governance committee of Newpark Resources, Inc., a Houston, Texas based oilfield services company traded on the NYSE.

Glenn A. Cox has served as our director since 2002. He served as President and Chief Operating Officer of Phillips Petroleum Company from June 1985 until his retirement in 1991. He also served as Chief Financial Officer of Phillips Petroleum Company from June 1980 to May 1985. Mr. Cox is currently a director and chairman of audit committee of Helmerich & Payne, Tulsa, Oklahoma, and previous director and member of audit committees of The Williams Companies, a gas gathering and exploration and production company located in Tulsa, Oklahoma, and Union Texas Petroleum, an exploration and production company located in Houston, Texas.

Cortlandt S. Dietler has served as our director since 2002. He currently serves as the owner of Poison Spider Oil Company LLC. From April 1995 through September 1, 2006, he was Chairman of the Board of TransMontaigne, Inc. He also served as Chief Executive Officer of TransMontaigne from April 1995 through September 1999. Mr. Dietler is currently a director of Hallador Petroleum Company, a Denver, Colorado exploration and production company traded on the OTC Bulletin Board, and Forest Oil Corporation, a Denver, Colorado exploration and production company traded on the NYSE. He also serves as chairman of the nominating and corporate governance committee and the compensation committee of Forest Oil.

Hans Helmerich has served as our director since 2002. He has served as a director of Helmerich & Payne since 1987, and as President and Chief Executive Officer of Helmerich & Payne since 1989. Mr. Helmerich also serves as a director of Atwood Oceanics, Inc., Houston, Texas, an international offshore drilling company, and as trustee of The Northwestern Mutual Life Insurance Company.

David A. Hentschel has served as our director since 2002. He served as Chairman and Chief Executive Officer of Occidental Oil and Gas Corporation from 1997 until 1999, when he retired. He also served as President and Chief Executive Officer of Canadian Occidental Petroleum, Ltd, now known as Nexen, from 1995 until 1997. Mr. Hentschel is currently a director of Nexen Inc., a global energy company located in Calgary, Alberta, Canada.

Paul D. Holleman has served as our director since 2002. He served as senior partner of Holme Roberts & Owen LLP, a Denver law firm, until 2000, when he retired. At Holme Roberts, he served as legal counsel to Key Production Company, Inc. and other oil and gas companies. Other positions in his 40 years with Holme Roberts included Chairman of the Natural Resources Department and member of the executive committee.

Monroe W. Robertson has served as our director since 2005. He is currently a private investor. Mr. Robertson was with Key Production Company, Inc., a company acquired by Cimarex in 2002, for 10 years until retirement in March 2002. He held the positions of President, Chief Operating Officer, Senior Vice President and Principal Financial Officer.

Michael J. Sullivan has served as our director since 2002. He has been a member of the Denver law firm, Rothgerber Johnson & Lyons LLP, since 2001, most recently as partner of the Casper office. He served as United States Ambassador to Ireland from 1998 until 2001. Prior to that, he practiced law with Brown, Drew, Apostolos, Massey & Sullivan from 1964 to 1986 and from 1995 until 1998. Mr. Sullivan was Governor of Wyoming from 1987 through 1995. He currently serves as a director of Kerry Group plc, a global food and food ingredients producer headquartered in Tralee, Ireland; director and member of audit committee and governance committee of Allied Irish Bank Group, Dublin, Ireland; director and member of the governance committee of First Interstate BancSystem, Billings, Montana and director and member of the governance and audit committee of Slatten Construction, Inc., Great Falls, Montana.

L. Paul Teague has served as our director since 2002. He was with Texaco Exploration & Producing Inc. for 35 years until his retirement in 1994. He held the positions of Vice President, Western Region; Division Manager of the New Orleans Division, Eastern Producing Department; Vice President, New Orleans Producing Division of Texaco USA; and Vice President, Producing Department, Texaco USA in Houston.

Stock ownership of directors, management and certain beneficial owners

We have one class of voting securities outstanding. On March 21, 2007, there were 83,444,376 shares of common stock outstanding, with each share entitled to one vote.

Beneficial ownership by executive officers and directors

The following table shows, as of March 21, 2007, the number of shares of common stock "beneficially owned," as determined in accordance with Rule 13d-3 under the Securities Exchange Act of 1934, by our named executive officers, the directors, and all executive officers and directors, as a group:

Name of beneficial owner	Shares owned(1)	Option shares(2)	Beneficial ownership total	Percent of class
Named executive officers				
F. H. Merelli (also director)	511,029	462,920	973,949	1%
Joseph R. Albi	67,371	71,100	138,471	<1%
Stephen P. Bell	64,500	72,800	137,300	<1%
Thomas E. Jorden	71,130	54,600	125,730	<1%
Paul Korus	83,515	0	83,515	<1%
Directors				
Jerry Box	10,901		10,901	<1%
Glenn A. Cox	9,472	10,000	19,472	<1
Cortlandt S. Dietler	132,285	30,000	162,285	<1%
Hans Helmerich	84,670(3)	10,000	94,670(3)	<1%
David A. Hentschel	8,285	10,000	18,285	<1%
Paul D. Holleman	8,285	35,000	43,285	<1%
Monroe W. Robertson	5,862		5,862	<1%
Michael J. Sullivan	4,479	10,000	14,479	<1%
L. Paul Teague	48,667	16,667	65,334	<1%
All executive officers & directors as a group (17 persons)	1,233,099	852,087	2,085,186	2%

(1) Includes restricted stock, direct and indirect ownership of common stock and equivalent shares of common stock held by the trustee for the benefit of the named individual in the Cimarex Energy Co. 401(k) Plan. Does not include restricted stock units held by executive officers or deferred compensation units held by some directors. See Equity-Related Interests table below.

(2) Shares of common stock that could be purchased by the exercise of vested stock options within the 60-day period following March 21, 2007 under the Cimarex Energy Co. 2002 Stock Incentive Plan.

(3) Includes 7,865 shares held for various trusts for immediate family members of which Mr. Helmerich is trustee and 1,072 shares held by a family trust of which Mr. Helmerich is a co-trustee. Also includes 11,450 shares owned by Mr. Helmerich's wife, and Mr. Helmerich disclaims beneficial ownership of these shares.

Beneficial owners of more than five percent

Third Avenue Management LLC is the only stockholder who beneficially owns more than five percent of our outstanding shares of common stock. The following table provides information

regarding Third Avenue Management's stock ownership and is based on its filing with the Securities and Exchange Commission.

Name and address	Voting authority		Dispositive authority		Total amount of beneficial ownership	Percent of class
	Sole	Shared	Sole	Shared		
Third Avenue Management LLC 622 Third Avenue New York, NY 10017	4,587,179	0	4,608,879	0	4,608,879	5.56%

Equity and equity-related interests held by executive officers and directors

The following table shows, as of March 21, 2007, vested and unvested equity interests and common stock held by each of our named executive officers, the directors and all of the executive officers and directors as a group:

	Unvested restricted stock(1)(2)	Restricted stock units/deferred comp units(3)(4)		Shares underlying stock options		401(k)	Common stock	Total
		Vested	Unvested	Vested	Unvested			
Named executive officers								
F. H. Merelli (also director)	120,000	168,960	42,240	462,920	84,480	13,400	377,629	1,269,366
Joseph R. Albi	60,000		45,500	71,100	18,200	5,112	2,259	202,171
Stephen P. Bell	60,000		45,500	72,800	18,200		4,500	201,000
Thomas E. Jorden	60,000		45,500	54,600	18,200	7,308	3,822	189,430
Paul Korus	60,000		45,500	0	18,200	0	23,515	147,215
Directors								
Jerry Box	3,639						7,262	10,901
Glenn A. Cox	4,406			10,000			5,066	19,472
Cortlandt S. Dietler	4,406			30,000			127,879	162,285
Hans Helmerich	1,319	1,219	3,087	10,000			83,351	98,976
David A. Hentschel	4,406			10,000			3,879	18,285
Paul D. Holleman	4,406			35,000			3,879	43,285
Monroe W. Robertson	3,302						2,830	5,862
Michael J. Sullivan	1,319	1,219	3,087	10,000			3,160	18,785
L. Paul Teague	3,796	1,219	610	16,667			44,871	67,163
All executive officers & directors as a group (17 persons)	507,459	172,617	312,774	852,087	185,080	28,387	697,233	2,755,657

(1) The restricted stock held by the executive officers is subject to three-year cliff vesting and the satisfaction of performance goals.

(2) The restricted stock held by the directors vests in three equal annual installments, beginning with the first anniversary from the grant date.

(3) The restricted stock units vest five years from the date of grant and are payable in shares of common stock on the eighth anniversary of the date of grant.

(4)

The deferred compensation units held by certain directors vest in three equal annual installments and represent the right to receive one share of Cimarex common stock at the time provided in the director's deferred compensation election.

Transactions with related persons

During 2006, no related person had a direct or indirect material interest in any transaction with Cimarex.

Description of other indebtedness

Senior revolving credit facility

Our senior 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, 2006, there were outstanding borrowings of $95 million under the senior revolving credit facility at a weighted average interest rate of approximately 6.75%. We also had letters of credit for approximately $5 million posted against the borrowing base, leaving an unused borrowing amount of approximately $400 million at December 31, 2006.

The credit facility agreement contains both financial and non-financial covenants. We continue to comply with these covenants and do not view them as materially restrictive.

9.6% senior notes due 2012

The 9.6% senior notes due 2012 assumed in the Magnum Hunter merger have a face value of $195 million and are due March 15, 2012. The notes are unsecured and are redeemable, as a whole or in part, at our option, on and after March 15, 2007 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
2007	104.8%
2008	103.2%
2009	101.6%
2010 and thereafter	100.0%

Floating rate convertible senior notes due 2023

The floating rate convertible senior notes due 2023 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, 2006, the interest rate equaled 5.36%.

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 29, 2006, the closing price of our common stock traded on the New York Stock Exchange was $36.50. There is not an observable market for the notes. Based on an average common stock price of $36.50, management estimates the fair value of the notes at December 31, 2006 was approximately $157.4 million (or $1,259 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 (plus accrued interest) anytime after December 22, 2008.

Description of notes

The Company will issue the Notes under the Indenture (the "Indenture") among itself, the Subsidiary Guarantors and U.S. Bank National Association, as trustee (the "Trustee"). The terms of the Notes include those expressly set forth in the Indenture and those made part of the Indenture by reference to the Trust Indenture Act of 1939, as amended (the "Trust Indenture Act"). The Indenture is unlimited in aggregate principal amount, although the issuance of notes in this offering will be limited to $300 million. We may issue an unlimited principal amount of additional notes having identical terms and conditions as the Notes other than issue date, issue price and the first interest payment date (the "Additional Notes"). We will only be permitted to issue such Additional Notes if at the time of such issuance, we are in compliance with the covenants contained in the Indenture. Any Additional Notes will be part of the same issue as the Notes that we are currently offering and will vote on all matters with the holders of the Notes.

This description of notes is intended to be a useful overview of the material provisions of the Notes and the Indenture. Since this description of notes is only a summary, you should refer to the Indenture for a complete description of the obligations of the Company and your rights. We have filed a copy of the Indenture as an exhibit to the registration statement which includes this Prospectus.

You will find the definitions of capitalized terms used in this description under the heading " Certain definitions." For purposes of this description, references to "the Company," "we," "our" and "us" refer only to Cimarex Energy Co. and not to its subsidiaries. Certain defined terms used in this description but not defined herein have the meanings assigned to them in the Indenture.

General

The notes. The Notes:

- are general unsecured, senior obligations of the Company;
- are limited to an aggregate principal amount of $300 million, subject to our ability to issue Additional Notes;
- mature on , 2017;
- will be issued in denominations of $2,000 and integral multiples of $1,000 in excess thereof;
- will be represented by one or more registered Notes in global form, but in certain circumstances may be represented by Notes in definitive form. See "Book-entry, delivery and form;"
- rank equally in right of payment to any future senior Indebtedness of the Company, without giving effect to collateral arrangements;
- are unconditionally guaranteed on a senior unsecured basis by each Subsidiary Guarantor. See "Subsidiary guarantees;" and

are expected to be eligible for trading in The PORTAL Market.

Interest. Interest on the Notes will compound semi-annually and:

accrue at the rate of % per annum;

accrue from the date of original issuance or, if interest has already been paid, from the most recent interest payment date;

be payable in cash semi-annually in arrears on and , commencing on , 2007;

be payable to the holders of record on the and immediately preceding the related interest payment dates; and

be computed on the basis of a 360-day year comprised of twelve 30-day months.

Payments on the notes; paying agent and registrar

We will pay principal of, premium, if any, and interest on the Notes at the office or agency designated by the Company in the Borough of Manhattan, The City of New York, except that we may, at our option, pay interest on the Notes by check mailed to holders of the Notes at their registered address as it appears in the Registrar's books. We have initially designated the corporate trust office of the Trustee in New York, New York to act as our Paying Agent and Registrar. We may, however, change the Paying Agent or Registrar without prior notice to the holders of the Notes, and the Company or any of its Restricted Subsidiaries may act as Paying Agent or Registrar.

We will pay principal of, premium, if any, and interest on, Notes in global form registered in the name of or held by The Depository Trust Company or its nominee in immediately available funds to The Depository Trust Company or its nominee, as the case may be, as the registered holder of such global Note.

Transfer and exchange

A holder may transfer or exchange Notes in accordance with the Indenture. The Registrar and the Trustee may require a holder, among other things, to furnish appropriate endorsements and transfer documents. No service charge will be imposed by the Company, the Trustee or the Registrar for any registration of transfer or exchange of Notes, but the Company may require a holder to pay a sum sufficient to cover any transfer tax or other governmental taxes and fees required by law or permitted by the Indenture. The Company is not required to transfer or exchange any Note selected for redemption. Also, the Company is not required to transfer or exchange any Note for a period of 15 days before a selection of Notes to be redeemed.

The registered holder of a Note will be treated as the owner of it for all purposes.

Optional redemption

Except as described below, the Notes are not redeemable until , 2012. On and after , 2012, the Company may redeem all or, from time to time, a part of the Notes upon not less than 30 nor more than 60 days' notice, at the following redemption prices (expressed as a percentage of principal amount) plus accrued and unpaid interest on the Notes, if any, to the applicable redemption date (subject to the right of holders of record on the relevant record date to receive interest due on the relevant interest payment date), if redeemed during the twelve-month period beginning on of the years indicated below:

Year	Percentage
2012	%
2013	%
2014	%
2015 and thereafter	100.00%

Prior to , 2010, the Company may on any one or more occasions redeem up to 35% of the original principal amount of the Notes (including the original principal amount of any Additional Notes) with the Net Cash Proceeds of one or more Equity Offerings at a redemption price of % of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date (subject to the right of holders of record on the relevant record date to receive interest due on the relevant interest payment date); *provided* that

(1) at least 65% of the original principal amount of the Notes (including the original principal amount of any Additional Notes) remains outstanding immediately after each such redemption; and

(2) the redemption occurs within 60 days after the closing of such Equity Offering.

If the optional redemption date is on or after an interest record date and on or before the related interest payment date, the accrued and unpaid interest, if any, will be paid to the Person in whose name the Note is registered at the close of business, on such record date, and no additional interest will be payable to holders whose Notes will be subject to redemption by the Company.

In the case of any partial redemption, selection of the Notes for redemption will be made by the Trustee in compliance with the requirements of the principal national securities exchange, if any, on which the Notes are listed or, if the Notes are not listed, then on a pro rata basis, by lot or by such other method as the Trustee in its sole discretion will deem to be fair and appropriate, although no Note of $2,000 in original principal amount or less will be redeemed in part. If any Note is to be redeemed in part only, the notice of redemption relating to such Note will state the portion of the principal amount thereof to be redeemed. A new Note in principal amount equal to the unredeemed portion thereof will be issued in the name of the holder thereof upon cancellation of the original Note.

In addition, at any time prior to , 2012, the Notes may be redeemed, in whole but not in part, at the option of the Company upon not less than 30 nor more than 60 days' prior notice mailed by first-class mail to each holder of Notes at its registered address, at a redemption price equal to 100% of the principal amount of the Notes redeemed plus the Applicable Premium plus accrued and unpaid interest, if any, to the redemption date (subject to the right of holders of record on the relevant record date to receive interest due on the relevant interest payment date).

"Applicable Premium" means, with respect to a Note on any date of redemption prior to , 2012, the greater of (1) % of the principal amount of such Note and (2) the excess of (a) the present value at such time of (i) the redemption price of such Note on , 2012 (such redemption price being described under the first paragraph under "Optional redemption") plus (ii) all required interest payments due on such Note through , 2012 (but excluding accrued and unpaid interest to the redemption date), computed using a discount rate equal to the Treasury Rate plus basis points, over (b) the then-outstanding principal amount of such Note.

"Treasury Rate" means the yield to maturity at the time of computation of United States Treasury securities with a constant maturity (as compiled and published in the most recent Federal Reserve Statistical Release H.15 (519) that has become publicly available at least two business days prior to the redemption date (or, if such Statistical Release is no longer published, any publicly available source of similar market data)) most nearly equal to the period from the redemption date to , 2012; *provided*, *however*, that if the period from the redemption date to , 2012 is not equal to the constant maturity of a United States Treasury security for which a weekly average yield is given, the Treasury Rate shall be obtained by linear interpolation (calculated to the nearest one-twelfth of a year) from the weekly average yields of United States Treasury securities for which such yields are given, except that if the period from the redemption date to , 2012 is less than one year, the weekly average yield on actually traded United States Treasury securities adjusted to a constant maturity of one year shall be used.

The Company is not required to make mandatory redemption payments or sinking fund payments with respect to the Notes.

The Company and its Subsidiaries and Affiliates may acquire Notes by means other than a redemption, whether by tender offer, open market purchases, negotiated transactions or otherwise, in accordance with applicable securities laws, so long as such acquisition does not otherwise violate the terms of the Indenture.

Ranking

The Notes will be general unsecured obligations of the Company that rank senior in right of payment to all existing and future Indebtedness that is expressly subordinated in right of payment to the Notes. The Notes will rank equally in right of payment with all existing and future liabilities of the Company that are not so subordinated and will be effectively subordinated to all of our secured Indebtedness and liabilities of our Subsidiaries that do not guarantee the Notes. Each of the Subsidiary Guarantees will be effectively subordinated to all of the secured Indebtedness of the Subsidiary Guarantor. In the event of bankruptcy, liquidation, reorganization or other winding up of the Company or its Subsidiary Guarantors or upon a default in payment with respect to, or the acceleration of, any Indebtedness under the Senior Secured Credit Agreement or other senior secured Indebtedness, the assets of the Company and its Subsidiary Guarantors that secure such senior secured Indebtedness will be available to pay obligations on the Notes and the Subsidiary Guarantees only after all Indebtedness under such Senior Secured Credit Agreement and other senior secured Indebtedness has been repaid in full from such assets. However, payment from the money or the proceeds of U.S. Government Obligations held in any defeasance trust (as described under "Defeasance" below) will not be subordinated to any Senior Indebtedness or subject to these restrictions. We advise you that there may not be sufficient assets remaining to pay amounts due on any or all the Notes and the Subsidiary Guarantees then outstanding.

Assuming that we had completed the offering of the Notes and applied the net proceeds we receive therefrom in the manner described under "Use of proceeds," as of December 31, 2006:

- our outstanding Indebtedness (including, without limitation, Indebtedness under the Indenture and the Notes) would have been $443 million, $5 million of which would have been secured;

- Restricted Subsidiaries would have had approximately $82.6 million of liabilities (excluding intercompany liabilities and Guarantees of the Senior Secured Credit Agreement and the Indenture); and

- Non-Guarantor Restricted Subsidiaries would not have had any outstanding Indebtedness or liabilities (other than inter-company Indebtedness or liabilities).

Subsidiary guarantees

The Subsidiary Guarantors will, jointly and severally, unconditionally guarantee on a senior unsecured basis the Company's obligations under the Notes and all obligations under the Indenture. Such Subsidiary Guarantors will agree to pay, in addition to the amount stated above, any and all costs and expenses (including, without limitation, reasonable counsel fees and expenses) Incurred by the Trustee or the holders in enforcing any rights under the Subsidiary Guarantees. The obligations of the Subsidiary Guarantors under the Subsidiary Guarantees will rank equally in right of payment with all existing and future Indebtedness of such Subsidiary Guarantors that is not expressly subordinated to the obligations arising under the Subsidiary Guarantees and will be effectively subordinated to all of our Subsidiary Guarantors' secured Indebtedness.

Assuming that we had completed the offering of the Notes and applied the net proceeds we receive therefrom in the manner described under "Use of proceeds," as of December 31, 2006, there would have been no outstanding Indebtedness of Subsidiary Guarantors.

Although the Indenture will limit the amount of indebtedness that the Company and any Restricted Subsidiaries may Incur, such indebtedness may be substantial.

The obligations of each Subsidiary Guarantor under its Subsidiary Guarantee will be limited as necessary to prevent that Subsidiary Guarantee from constituting a fraudulent conveyance or fraudulent transfer under applicable law. See "Risk factors Risks relating to our indebtedness and the notes A subsidiary guarantee could be voided if it constitutes a fraudulent transfer under U.S. bankruptcy or similar state law, which would prevent the holders of the notes from relying on that subsidiary to satisfy claims."

In the event a Subsidiary Guarantor is sold or disposed of (whether by merger, consolidation, the sale of its Capital Stock or the sale of all or substantially all of its assets (other than by lease) and whether or not the Subsidiary Guarantor is the surviving corporation in such transaction) to a Person which is not the Company or a Restricted Subsidiary of the Company (after giving effect to the sale or other disposition), such Subsidiary Guarantor will be released from its obligations under its Subsidiary Guarantee if:

(1) the sale or other disposition is in compliance with the Indenture, including the covenants "Certain covenants Limitation on sales of assets and subsidiary stock" (it being understood that only such portion of the Net Available Cash as is required to be applied on or before the date of such release in accordance with the terms of the Indenture needs to be applied in accordance therewith at such time), "Certain covenants Limitation on sales of capital stock of restricted subsidiaries" and "Certain covenants Merger and consolidation;" and

(2) all the obligations of such Subsidiary Guarantor under all Credit Facilities and any other agreements evidencing any other Indebtedness of the Company or its Restricted Subsidiaries (after giving effect to the sale or other disposition) terminate upon consummation of such transaction.

In the event that a Subsidiary Guarantor is released and discharged in full from all of its obligations under its Guarantees of the Senior Secured Credit Agreement and all other Indebtedness of the Company and its other Restricted Subsidiaries, then such Subsidiary Guarantor will be released from its obligations under its Subsidiary Guarantee as specified under the covenant "Certain covenants Future subsidiary guarantors."

In addition, a Subsidiary Guarantor will be released from its obligations under the Indenture and its Subsidiary Guarantee if the Company designates such Subsidiary as an Unrestricted Subsidiary and such designation complies with the other applicable provisions of the Indenture or in connection with any legal defeasance of the Notes or upon satisfaction and discharge of the Indenture, each in accordance with the terms of the Indenture.

Book-entry, delivery and form

The Notes will be represented by one or more global notes in registered, global form without interest coupons (collectively, the "Global Notes"). The Global Notes initially will be deposited upon issuance with the Trustee as custodian for The Depository Trust Company, or DTC, in New York, New York, and registered in the name of DTC or its nominee, in each case for credit to an account of a direct or indirect participant as described below.

Except as set forth below, the Global Notes may be transferred, in whole and not in part, only to another nominee of DTC or to a successor of DTC or its nominee. Beneficial interests in the Global Notes may not be exchanged for Notes in certificated form except in the limited circumstances described below. See " Exchange of global notes for certificated notes." In addition, transfers of beneficial interests in the Global Notes will be subject to the applicable rules and procedures of DTC and its direct or indirect participants, which may change from time to time.

The Notes may be presented for registration of transfer and exchange at the offices of the Registrar.

Depository procedures

The following description of the operations and procedures of DTC is provided solely as a matter of convenience. These operations and procedures are solely within the control of the respective settlement systems and are subject to changes by them. We take no responsibility for these operations and procedures and urge investors to contact the system or their participants directly to discuss these matters.

DTC has advised us that DTC is a limited-purpose trust company organized under the laws of the State of New York, a "banking organization" within the meaning of the New York Banking Law, a member of the Federal Reserve System, a "clearing corporation" within the meaning of the Uniform Commercial Code and a "clearing agency" registered pursuant to the provisions of Section 17A of the Exchange Act. DTC was created to hold securities for its participating organizations (collectively, the "participants") and to facilitate the clearance and settlement of transactions in those securities between participants through electronic book-entry changes in accounts of its participants. The participants include securities brokers and dealers, banks, trust companies, clearing corporations and certain other organizations. Access to DTC's system is also available to other entities such as banks, brokers, dealers and trust companies that clear through or maintain a custodial relationship with a participant, either directly or indirectly (collectively, the "indirect participants"). Persons who are not participants may beneficially own securities held by or on behalf of DTC only through the participants or the indirect participants. The ownership interests in, and transfers of ownership interests in, each security held by or on behalf of DTC are recorded on the records of the participants and indirect participants.

DTC has also advised us that, pursuant to procedures established by it:

(1) upon deposit of the Global Notes, DTC will credit the accounts of participants designated by the underwriters with portions of the principal amount of the Global Notes; and

(2) ownership of these interests in the Global Notes will be shown on, and the transfer of ownership of these interests will be effected only through, records maintained by DTC (with respect to the participants) or by the participants and the indirect participants (with respect to other owners of beneficial interests in the Global Notes).

Investors in the Global Notes who are participants in DTC's system may hold their interests therein directly through DTC. Investors in the Global Notes who are not participants may hold their interests therein indirectly through organizations which are participants in such system. All interests in a Global Note may be subject to the procedures and requirements of DTC. The laws of some states require that certain persons take physical delivery in definitive form of securities that they own. Consequently, the ability to transfer beneficial interests in a Global Note to such persons will be limited to that extent. Because DTC can act only on behalf of participants, which in turn act on behalf of indirect participants, the ability of a person having beneficial interests in a Global Note to pledge such interests to persons that do not participate in the DTC system, or otherwise take actions in respect of such interests, may be affected by the lack of a physical certificate evidencing such interests.

Except as described below, owners of an interest in the Global Notes will not have Notes registered in their names, will not receive physical delivery of Notes in certificated form and will not be considered the registered owners or "holders" thereof under the Indenture for any purpose.

Payments in respect of the principal of, and interest and premium, if any, on a Global Note registered in the name of DTC or its nominee will be payable to DTC in its capacity as the registered holder under the Indenture. Under the terms of the Indenture, we and the Trustee will treat the persons in whose names the Notes, including the Global Notes, are registered as the owners of the Notes for the purpose of receiving payments and for all other purposes. Consequently, neither we, the Trustee nor any agent of us or the Trustee has or will have any responsibility or liability for:

(1) any aspect of DTC's records or any participant's or indirect participant's records relating to or payments made on account of beneficial ownership interests in the Global Notes or for maintaining, supervising or reviewing any of DTC's records or any participant's or indirect participant's records relating to the beneficial ownership interests in the Global Notes; or

(2) any other matter relating to the actions and practices of DTC or any of its participants or indirect participants.

DTC has advised us that its current practice, upon receipt of any payment in respect of securities such as the Notes (including principal and interest), is to credit the accounts of the relevant participants with the payment on the payment date unless DTC has reason to believe it will not receive payment on such payment date. Each relevant participant is credited with an amount proportionate to its beneficial ownership of an interest in the principal amount of the relevant security as shown on the records of DTC. Payments by the participants and the indirect participants to the beneficial owners of Notes will be governed by standing instructions and customary practices and will be the responsibility of the participants or the indirect participants and will not be the responsibility of DTC, the Trustee or us. Neither we nor the Trustee will be liable for any delay by DTC or any of its participants in identifying the beneficial owners of the Notes, and we and the Trustee may conclusively rely on and will be protected in relying on instructions from DTC or its nominee for all purposes.

Transfers between participants in DTC will be effected in accordance with DTC's procedures, and will be settled in same-day funds.

DTC has advised us that it will take any action permitted to be taken by a holder of Notes only at the direction of one or more participants to whose account DTC has credited the interests in the Global Notes and only in respect of such portion of the aggregate principal amount of the Notes as to which such participant or participants has or have given such direction. However, if there is an event of default under the Notes, DTC reserves the right to exchange the Global Notes for Legend Notes in certificated form, and to distribute such Notes to its participants.

Although DTC has agreed to the foregoing procedures in order to facilitate transfers of interests in the Global Notes among participants, it is under no obligation to perform such procedures, and such procedures may be discontinued or changed at any time. Neither we, the Trustee nor any agent of us or the Trustee will have any responsibility for the performance by DTC or its participants or indirect participants of their respective obligations under the rules and procedures governing their operations.

Exchange of Global Notes for Certificated Notes

A Global Note is exchangeable for definitive Notes in registered certificated form ("Certificated Notes") if:

(1) DTC (A) notifies us that it is unwilling or unable to continue as depositary for the Global Notes or (B) has ceased to be a clearing agency registered under the Exchange Act and, in each case, a successor depositary is not appointed;

(2) we, at our option, notify the Trustee in writing that we elect to cause the issuance of the Certificated Notes; or

(3) there has occurred and is continuing a default with respect to the Notes.

In addition, beneficial interests in a Global Note may be exchanged for Certificated Notes upon prior written notice given to the Trustee by or on behalf of DTC in accordance with the Indenture. In all cases, Certificated Notes delivered in exchange for any Global Note or beneficial interests in Global Notes will be registered in the names, and issued in any approved denominations, requested by or on behalf of the depositary (in accordance with its customary procedures).

Exchange of Certificated Notes for Global Notes

Certificated Notes may not be exchanged for beneficial interests in any Global Note unless the transferor first delivers to the Trustee a written certificate (in the form provided in the Indenture) to the effect that such transfer will comply with the appropriate transfer restrictions applicable to such Notes.

Same day settlement and payment

We will make payments in respect of the Notes represented by the Global Notes (including principal, premium, if any, and interest, if any) by wire transfer of immediately available funds to the accounts specified by the Global Note holder. We will make all payments of principal, interest and premium, if any, with respect to Certificated Notes by wire transfer of immediately available funds to the accounts specified by the holders of the Certificated Notes or, if no such account is specified, by mailing a check to each such holder's registered address. The Notes represented by the Global Notes are expected to be eligible to trade in DTC's Same-Day Funds Settlement System, and any permitted secondary market trading activity in such Notes will, therefore, be required by DTC to be settled in immediately available funds. We expect that secondary trading in any Certificated Notes will also be settled in immediately available funds.

Change of control

If a Change of Control occurs, unless the Company has exercised its right to redeem all of the Notes as described under " Optional redemption," each holder will have the right to require the Company to repurchase all or any part (equal to $2,000 or an integral multiple of $1,000 in excess thereof) of such holder's Notes at a purchase price in cash equal to 101% of the principal amount of such Notes plus accrued and unpaid interest, if any, to the date of purchase (subject to the right of holders of record on the relevant record date to receive interest due on the relevant interest payment date).

Within 30 days following any Change of Control, unless the Company has exercised its right to redeem all of the Notes as described under " Optional redemption," or at the Company's option, prior to such Change of Control but after it is publicly announced, the Company will mail a notice (the "*Change of Control Offer*") to each holder, with a copy to the Trustee, stating:

(1) that a Change of Control has occurred or will occur and that such holder has the right to require the Company to purchase such holder's Notes at a purchase price in cash equal to 101% of the principal amount of such Notes plus accrued and unpaid interest, if any, to the

date of purchase (subject to the right of holders of record on a record date to receive interest on the relevant interest payment date) (the "*Change of Control Payment*");

(2) the repurchase date (which shall be no earlier than 30 days nor later than 60 days from the date such notice is mailed, or such later date as is necessary to comply with the requirements under the Exchange Act) (the "*Change of Control Payment Date*"); *provided* that the Change of Control Payment Date may not occur prior to the Change of Control; and

(3) the procedures determined by the Company, consistent with the Indenture, that a holder must follow in order to have its Notes repurchased.

On the Change of Control Payment Date, the Company will, to the extent lawful:

(1) accept for payment all Notes or portions of Notes (of $2,000 or an integral multiple of $1,000 in excess thereof) properly tendered and not withdrawn pursuant to the Change of Control Offer;

(2) deposit, to the extent not previously deposited for such purpose, with the paying agent an amount equal to the Change of Control Payment in respect of all Notes or portions of Notes so tendered; and

(3) deliver or cause to be delivered to the Trustee the Notes, to the extent not previously delivered for such purpose, so accepted and an Officers' Certificate stating the aggregate principal amount of Notes or portions of Notes being purchased by the Company.

The paying agent will promptly mail to each holder of Notes so tendered the Change of Control Payment for such Notes, and the Trustee will promptly authenticate and mail or deliver (or cause to be transferred by book entry) to each holder a new Note equal in principal amount to any unpurchased portion of the Notes surrendered, if any; *provided* that each such new Note will be in a principal amount of $2,000 or an integral multiple of $1,000 in excess thereof. The paying agent will deliver the Change of Control Payment for such Notes in global form registered in the name of or held by The Depository Trust Company or its nominee in immediately available funds to The Depository Trust Company or its nominee, as the case may be, as the registered holder of such global Note.

If the Change of Control Payment Date is on or after an interest record date and on or before the related interest payment date, any accrued and unpaid interest, if any, will be paid to the Person in whose name a Note is registered at the close of business on such record date, and no additional interest will be payable to holders who tender pursuant to the Change of Control Offer.

The Change of Control provisions described above will be applicable whether or not any other provisions of the Indenture are applicable. Except as described above with respect to a Change of Control, the Indenture does not contain provisions that permit the holders to require that the Company repurchase or redeem the Notes in the event of a takeover, recapitalization or similar transaction.

The Company will not be required to make a Change of Control Offer upon a Change of Control if a third party makes the Change of Control Offer in the manner, at the times and otherwise in compliance with the requirements set forth in the Indenture applicable to a

Change of Control Offer made by the Company and purchases all Notes validly tendered and not withdrawn under such Change of Control Offer.

The Company will comply, to the extent applicable, with the requirements of Rule 14e-1 under the Exchange Act and any other securities laws or regulations in connection with the repurchase of Notes pursuant to this covenant. To the extent that the provisions of any securities laws or regulations conflict with provisions of the Indenture, the Company will comply with the applicable securities laws and regulations and will not be deemed to have breached its obligations described in the Indenture by virtue of the conflict.

The Company's ability to repurchase Notes pursuant to a Change of Control Offer may be limited by a number of factors. The occurrence of certain of the events that constitute a Change of Control would constitute a default under the Senior Secured Credit Agreement. In addition, certain events that may constitute a change of control under the Senior Secured Credit Agreement and cause a default under that agreement may not constitute a Change of Control under the Indenture. Future Indebtedness of the Company and its Subsidiaries may also contain prohibitions of certain events that would constitute a Change of Control or require such Indebtedness to be repurchased upon a Change of Control. Moreover, the exercise by the holders of their right to require the Company to repurchase the Notes could cause a default under such Indebtedness, even if the Change of Control itself does not, due to the financial effect of such repurchase on the Company. Finally, the Company's ability to pay cash to the holders upon a repurchase may be limited by the Company's then existing financial resources. There can be no assurance that sufficient funds will be available when necessary to make any required repurchases.

Even if sufficient funds were otherwise available, the terms of the Senior Secured Credit Agreement will, and other Indebtedness may, prohibit the Company's prepayment of Notes before their scheduled maturity. Consequently, if the Company is not able to prepay the Senior Secured Credit Agreement and any such other Indebtedness containing similar restrictions or obtain requisite waivers or consents, the Company will be unable to fulfill its repurchase obligations if holders of Notes exercise their repurchase rights following a Change of Control, resulting in a default under the Indenture. A default under the Indenture likely will result in a cross-default under the Senior Secured Credit Agreement and other Indebtedness.

The Change of Control provisions described above may deter certain mergers, tender offers and other takeover attempts involving the Company by increasing the capital required to effectuate such transactions. The definition of "Change of Control" includes a disposition of all or substantially all of the property and assets of the Company and its Restricted Subsidiaries taken as a whole to any Person. Although there is a limited body of case law interpreting the phrase "substantially all," there is no precise established definition of the phrase under applicable law. Accordingly, in certain circumstances there may be a degree of uncertainty as to whether a particular transaction would involve a disposition of "all or substantially all" of the property or assets of a Person. As a result, it may be unclear as to whether a Change of Control has occurred and whether a holder of Notes may require the Company to make an offer to repurchase the Notes as described above. Certain provisions under the Indenture relative to the Company's obligation to make an offer to repurchase the Notes as a result of a Change of Control may be waived or modified with the written consent of the holders of a majority in principal amount of the Notes.

Certain covenants

Effectiveness of covenants

Following the first day:

(1) the Notes have an Investment Grade Rating from both of the Rating Agencies; and

(2) no Default has occurred and is continuing under the Indenture;

the Company and its Restricted Subsidiaries will not be subject to the provisions of the Indenture summarized under the subheadings below:

" Limitation on indebtedness,"

" Limitation on restricted payments,"

" Limitation on restrictions on distributions from restricted subsidiaries,"

" Limitation on sales of assets and subsidiary stock,"

" Limitation on affiliate transactions,"

" Limitation on the sale of capital stock of restricted subsidiaries,"

" Limitation on lines of business," and

Clause (3) of " Merger and consolidation."

(collectively, the "Suspended Covenants"). If at any time the Notes' credit rating is downgraded from an Investment Grade Rating by any Rating Agency or a Default or Event of Default occurs and is continuing, then the Suspended Covenants will thereafter be reinstated as if such covenants had never been suspended (the "Reinstatement Date") and thereafter be applicable pursuant to the terms of the Indenture (including in connection with performing any calculation or assessment to determine compliance with the terms of the Indenture), unless and until the Notes subsequently attain an Investment Grade Rating (in which event the Suspended Covenants shall no longer be in effect for such time that the Notes maintain an Investment Grade Rating and no Default or Event of Default has occurred and is continuing); *provided, however*, that no Default, Event of Default or breach of any kind shall be deemed to exist under the Indenture, the Notes or the Subsidiary Guarantees with respect to the Suspended Covenants based on, and none of the Company or any of its Subsidiaries shall bear any liability for, any actions taken or events occurring after the Notes attain an Investment Grade Rating and before any reinstatement of such Suspended Covenants as provided above, or any actions taken at any time pursuant to any contractual obligation arising prior to such reinstatement, regardless of whether such actions or events would have been permitted if the applicable Suspended Covenants remained in effect during such period. The period of time between the date of suspension of the covenants and the Reinstatement Date is referred to as the "Suspension Period."

On the Reinstatement Date, all Indebtedness Incurred during the Suspension Period will be classified to have been Incurred pursuant to the first paragraph of "Limitation on indebtedness" or one of the clauses set forth in the second paragraph of "Limitation on indebtedness" (to the extent such Indebtedness would be permitted to be Incurred thereunder as of the Reinstatement Date and after giving effect to Indebtedness Incurred prior to the Suspension Period and outstanding on the Reinstatement Date). To the extent such Indebtedness would not be so permitted to be Incurred pursuant to the first or second paragraph of "Limitation on indebtedness," such Indebtedness will be deemed to have been outstanding on the Issue Date, so that it is classified as permitted under clause (4)(b) of the second paragraph of "Limitation on indebtedness." Calculations made after the Reinstatement Date of the amount available to be made as Restricted Payments under " Limitation on restricted payments" will be made as though the covenants described under " Limitation on restricted payments" had been in effect since the Issue Date and throughout the Suspension Period. Accordingly, Restricted Payments made during the Suspension Period will reduce the amount available to be made as Restricted Payments under the first paragraph of " Limitation on restricted payments."

During any period when the Suspended Covenants are suspended, the Board of Directors of the Company may not designate any of the Company's Subsidiaries as Unrestricted Subsidiaries pursuant to the Indenture.

Limitation on indebtedness

The Company will not, and will not permit any of its Restricted Subsidiaries to, Incur any Indebtedness (including, without limitation, Acquired Indebtedness); *provided, however,* that any of the Company and the Subsidiary Guarantors may Incur Indebtedness if on the date thereof:

(1) the Consolidated Coverage Ratio for the Company and its Restricted Subsidiaries is at least 2.25 to 1.00; and

(2) no Default or Event of Default will have occurred or be continuing or would occur as a consequence of Incurring the Indebtedness or transactions relating to such Incurrence.

The first paragraph of this covenant will not prohibit the Incurrence of the following Indebtedness:

(1) Indebtedness of any of the Company and the Subsidiary Guarantors at any time outstanding pursuant to a Credit Facility in an aggregate principal amount up to the greater of (a) $1.0 billion and (b) 30% of Adjusted Consolidated Net Tangible Assets determined as of the date of the Incurrence of such Indebtedness;

(2) Guarantees by (a) any of the Company and the Subsidiary Guarantors of Indebtedness Incurred by the Company or any Subsidiary Guarantor in accordance with the provisions of the Indenture; *provided* that in the event such Indebtedness that is being Guaranteed is a Subordinated Obligation or a Guarantor Subordinated Obligation, then the related Guarantee shall be subordinated in right of payment to the Notes or the Subsidiary Guarantee, as the case may be, and (b) Non-Guarantor Restricted Subsidiaries of Indebtedness Incurred by Non-Guarantor Restricted Subsidiaries in accordance with the provisions of the Indenture;

(3) Indebtedness of the Company owing to and held by any Restricted Subsidiary or Indebtedness of a Restricted Subsidiary owing to and held by the Company or any other Restricted Subsidiary; *provided, however,*

(a) if the Company is the obligor on such Indebtedness and such Indebtedness is owing to and held by a Restricted Subsidiary that is not a Subsidiary Guarantor, such Indebtedness is expressly subordinated to the prior payment in full in cash of all obligations with respect to the Notes;

(b) if a Subsidiary Guarantor is the obligor on such Indebtedness and the Company or a Subsidiary Guarantor is not the obligee, such Indebtedness is subordinated in right of payment to the Subsidiary Guarantees of such Subsidiary Guarantor; and

(c) (i) any subsequent issuance or transfer of Capital Stock or any other event which results in any such Indebtedness being beneficially held by a Person other than the Company or a Restricted Subsidiary of the Company; and

(ii) any sale or other transfer of any such Indebtedness to a Person other than the Company or a Restricted Subsidiary of the Company;

shall be deemed, in each case, to constitute an Incurrence of such Indebtedness by the Company or such Subsidiary, as the case may be;

(4) Indebtedness represented by (a) the Notes issued on the Issue Date and the Subsidiary Guarantees, (b) any Indebtedness (other than the Indebtedness described in clauses (1), (2), (3), (9) and (10) of this paragraph) outstanding on the Issue Date and (c) any Refinancing Indebtedness Incurred in respect of any Indebtedness described in this clause (4) or clause (5) of this paragraph or Incurred pursuant to the first paragraph of this covenant;

(5) Indebtedness of a Restricted Subsidiary Incurred and outstanding on the date on which such Restricted Subsidiary was acquired by, or merged into, the Company or any Restricted Subsidiary (other than Indebtedness Incurred (a) to provide all or any portion of the funds utilized to consummate the transaction or series of related transactions pursuant to which such Restricted Subsidiary became a Restricted Subsidiary or was otherwise acquired by the Company or (b) otherwise in connection with, or in contemplation of, such acquisition); *provided, however,* that at the time such Restricted Subsidiary is acquired by the Company, the Company would have been able to Incur $1.00 of additional Indebtedness pursuant to the first paragraph of this covenant after giving effect to the Incurrence of such Indebtedness pursuant to this clause (5);

(6) Indebtedness under Hedging Obligations that are Incurred in the ordinary course of business (a) for the purpose of fixing or hedging interest rate risk with respect to any Indebtedness Incurred in accordance with the Indenture; (b) for the purpose of fixing or hedging currency exchange rate risk with respect to any currency exchanges; or (c) for the purpose of fixing or hedging commodity price risk with respect to any commodities;

(7) the Incurrence by any of the Company and the Restricted Subsidiaries of Indebtedness represented by Capitalized Lease Obligations, mortgage financings, purchase money obligations or other payments, in each case Incurred to finance all or any part of the purchase price or cost of acquisition, construction, improvement or development of assets or property (other than Capital Stock or other Investments) acquired, constructed, improved or developed in the ordinary course of business of the Company or such Restricted Subsidiary, and Attributable Indebtedness, in an aggregate principal amount, including all Refinancing Indebtedness Incurred to refund, defease, renew, extend, refinance or replace any Indebtedness Incurred pursuant to this clause (7), not to exceed $20.0 million at any time outstanding;