Cimarex Energy Co. of Colorado
Form 424B5
April 18, 2007

Filed pursuant to Rule 424(b)(5)
Registration Nos. 333-142016
and 333-142168

Prospectus

Cimarex Energy Co.

$350,000,000

7 1/8% Senior Notes due 2017
Interest payable May 1 and November 1

The notes will mature on May 1, 2017. Interest will accrue from May 1, 2007, and the first interest payment will be due November 1, 2007.

We may redeem the notes, in whole or in part, on and after May 1, 2012 at the redemption prices described in this prospectus. In addition, at any time prior to May 1, 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 May 1, 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	100.0%	1.5%	98.5%
Total	$ 350,000,000	$ 5,250,000	$ 344,750,000

(1) Plus accrued interest, if any, from May 1, 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 May 1, 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 17, 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.

It is expected that delivery of the notes will be made against payment thereof on or about the date specified in the penultimate paragraph of the cover page hereof, which will be the tenth business day in the United States following the date hereof. Pursuant to Rule 15c6-1 under the Securities Exchange Act of 1934, or the "Exchange Act," trades in the secondary market generally are required to settle in three business days, unless the parties to any such trade expressly agree otherwise. Accordingly, purchasers who wish to trade notes on the date of pricing or the next six succeeding business days will be required to specify an alternative settlement cycle at the time of any such trade to prevent a failed settlement. Purchasers of notes who wish to trade notes on the date of pricing or the next six succeeding business days should consult their own advisors.

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	\$350,000,000 aggregate principal amount of $7^{1}/_{8}$% Senior Notes due 2017.
Maturity	May 1, 2017.
Interest payment dates	Interest is payable on the notes on May 1 and November 1 of each year, commencing November 1, 2007. Interest will accrue from May 1, 2007.
Optional redemption	The notes will be redeemable at our option, in whole or in part, at any time on and after May 1, 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 May 1, 2010, we may redeem up to 35% of the original principal amount of the notes with the proceeds of certain equity offerings of our shares of common stock at a redemption price of 107.125% of the principal amount of the notes, together with accrued and unpaid interest, if any, to the date of redemption. At any time prior to May 1, 2012, we may also redeem all, but not part, of the notes at a price equal to 100% of the principal amount of the notes plus accrued and unpaid interest plus a "make-whole" premium.
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 $487.9 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 no secured indebtedness under our senior revolving credit facility excluding $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 $495.0 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 abili; The Change in Control Severance Agreement provides that, upon the involuntary termination of Mr. F. A. Cappello other than for cause after a change in control has occurred, the Company is required to make the severance payments as outlined above. The Separation Pay Agreement provides that, upon the involuntary termination of Mr. F. A. Cappello other than for cause (regardless of whether a change in control has occurred), the Company is required to make the severance payment as outlined above.

The following table describes the potential payments upon termination of employment of Mr. F. A. Cappello. The table assumes the executives employment was terminated on September 30, 2009, the last business day of the Company s 2009 fiscal year.

Table of Contents

Potential Payments Upon Termination of Employment

Name and Principal Position	Voluntary Termination	Involuntary Not For Cause Termination without a Change in Control	Involuntary Not For Cause Termination with a Change in Control
Jeffrey P. Gotschall	-0-	-0-	-0-
Michael S. Lipscomb	-0-	-0-	-0-
Frank A. Cappello			
Severance	-0-	$ 505,500	$ 672,500
Performance Stock awards (1)	-0-	-0-	$ 51,450
Health & Welfare Insurance	-0-	$ 22,300	$ 29,700

(1) Based upon the closing market price of the Company s common shares on the NYSE Amex Exchange on September 30, 2009, which was $14.70.

DIRECTOR COMPENSATION

The following table sets forth information regarding fiscal 2009 compensation for each director other than Mr. J. P. Gotschall, whose compensation is set forth above under the heading Executive Compensation .

Director Compensation for Fiscal 2008

Name	Fees Earned or Paid in Cash ($)	All Other Compensation ($) (1)	Total Compensation ($)
Hudson D. Smith	$ 27,500	$ 363,800	$ 391,300
P. Charles Miller, Jr.	$ 32,500	-0-	$ 32,500
Frank N. Nichols	$ 32,500	-0-	$ 32,500
Alayne L. Reitman	$ 41,500	-0-	$ 41,500
J. Douglas Whelan	$ 37,000	-0-	$ 37,000

(1) All other compensation consists of (i) with respect to Mr. H. D. Smith,

payments made to Forged Aerospace Sales, LLC during fiscal 2009 under the Sales Representative Agreement, further described below, for services other than as director, and (ii) with respect to all directors, amounts contributed by the Company s charitable foundation to educational organizations on behalf of such directors.

Effective January 1, 2009, (i) each director of the Company (other than directors who are employed by the Company) receives an annual retainer fee of $30,000, (ii) the four independent directors receive an additional $4,000 per year for being members of the Audit and Compensation Committees, and (iii) the Audit and Compensation Committee Chairpersons receive $10,000 and

Table of Contents

$5,000, respectively, per year. The Company has determined its directors compensation structures based on targeting a competitive level of pay as measured against similarly situated companies.

Mr. H. D. Smith previously held the position of Executive Vice President and Treasurer of the Company. In connection with his resignation from the Company, Mr. Smith entered into a Sales Representative Agreement with the Company, the terms of which are substantially the same as the terms of other agreements the Company maintains with its third-party sales representatives. Compensation under the Sales Representative Agreement, which resulted in payments of $362,400 in fiscal 2009, is based strictly upon earned sales commissions with no guaranteed minimum obligation to Mr. Smith and/or to Forged Aerospace Sales, LLC.

COMPENSATION COMMITTEE REPORT

The Compensation Committee has reviewed and discussed with management the Compensation Discussion and Analysis included in this proxy statement. Based on such review and discussions, the Compensation Committee has recommended to the Board of Directors that such Compensation Discussion and Analysis be included in this proxy statement and in the Company s Annual Report on Form 10-K for the fiscal year ended September 30, 2009 to be filed with the SEC.

Compensation Committee
J. Douglas Whelan, Chairperson
Frank N. Nichols
P. Charles Miller, Jr.
Alayne L. Reitman

PRINCIPAL ACCOUNTING FEES AND SERVICES

Audit Fees

Fees paid or payable to Grant Thornton LLP for the audits of the annual financial statements included in the Company s Form 10-K and for the reviews of the interim financial statements included in the Company s Forms 10-Q for the years ended September 30, 2009 and 2008 were $149,750 and $150,500, respectively. The Audit Committee has sole responsibility for determining whether and under what circumstances an independent registered public accounting firm may be engaged to perform audit-related services and must pre-approve any non-audit related service performed by such firm. In fiscal 2009, audit and non-audit related fees, to the extent they were incurred, were pre-approved by the Audit Committee.

Audit-Related Fees

Fees paid or payable to Grant Thornton LLP for audit-related services for the years ended September 30, 2009 and 2008 were $0 and $6,000, respectively.

Table of Contents

Tax Fees

There were no fees paid or payable during fiscal 2009 or 2008 to Grant Thornton LLP for tax compliance or consulting services.

All Other Fees

There were no fees paid or payable during fiscal 2009 or 2008 to Grant Thornton LLP for products or services other than the professional services described above.

AUDIT COMMITTEE REPORT

The Audit Committee reviewed and discussed the audited financial statements of the Company, for the fiscal year ended September 30, 2009, with the Company s management and with the Company s independent registered public accounting firm, Grant Thornton LLP. The Audit Committee also has (i) discussed with Grant Thornton LLP the matters required to be discussed by the Statement of Auditing Standards No. 61, as amended (Communication with Audit Committees), (ii) received the written communications from Grant Thornton LLP pursuant to the applicable requirements of the Public Company Accounting Oversight Board certifying the firm s independence and (iii) the Audit Committee discussed the independence of Grant Thornton LLP with that firm. Grant Thornton LLP has confirmed to the Company that it is in compliance with all rules, standards and policies of the Independence Standards board and the SEC governing auditor independence.

The Audit Committee and the Board of Directors of the Company operate under a written charter as last amended in July 2004.

Based upon the Audit Committee s review and discussions noted above, the Audit Committee recommended to the Board of Directors that the Company s audited financial statements be included in the Company s Annual Report on Form 10-K for the fiscal year ended September 30, 2009 to be filed with the SEC.

Audit Committee
Alayne L. Reitman, Chairperson
Frank N. Nichols
P. Charles Miller, Jr.
J. Douglas Whelan

PROPOSAL 2 TO RATIFY THE DESIGNATION OF AUDITORS

The firm of Grant Thornton LLP has been the Company s independent registered public accounting firm since 2002. The Board of Directors has chosen that firm to audit the accounts of the Company and its consolidated subsidiaries for the fiscal year ending September 30, 2010, subject to the

Table of Contents

ratification of the shareholders for which the affirmative vote of a majority of the Common Shares present and voting at the 2010 Annual Meeting (in person or by proxy) is required. Grant Thornton LLP has advised the Company that neither the firm nor any of its members or associates has any direct or indirect financial interest in the Company or any of its affiliates other than as auditors.

Board Recommendation - the Board of Directors recommends that you vote **FOR** the ratification of the selection of Grant Thornton LLP as the independent registered public accounting firm of the Company for the year ending September 30, 2010. Unless you instruct otherwise on your proxy card or in person, your proxy will be voted in accordance with the Board s recommendation.

Representatives of Grant Thornton LLP are expected to be present at the 2010 Annual Meeting with the opportunity to make a statement if they desire to do so and to be available to respond to appropriate questions.

SHAREHOLDER PROPOSALS FOR THE 2011 ANNUAL MEETING OF SHAREHOLDERS

A shareholder who intends to present a proposal at the 2011 Annual Meeting, and who wishes to have the proposal included in the Company s proxy statement and form of proxy for that meeting, must deliver the proposal to the Company no later than August 16, 2010. Any shareholder proposal submitted other than for inclusion in the Company s proxy materials for the 2011 Annual Meeting must be delivered to the Company no later than October 31, 2010 or such proposal will be considered untimely. If a shareholder proposal is received after October 31, 2010, the Company may vote, in its discretion as to the proposal, all of the Common Shares for which it has received proxies for the 2010 Annual Meeting.

OTHER MATTERS

The Company does not know of any other matters that will come before the meeting. In case any other matter should properly come before the 2010 Annual Meeting, it is the intention of the persons named in the enclosed proxy or their substitutions to vote in accordance with their best judgment in accordance with the recommendation of the Board of Directors or, in the absence of such a recommendation, in accordance with their judgment pursuant to the discretionary authority conferred by the enclosed proxy.

By order of the Board of Directors.

SIFCO Industries, Inc.

Daniel G. Berick, Secretary

December 15, 2009

SIFCO Industries, Inc.

THIS PROXY IS SOLICITED ON BEHALF OF THE BOARD OF DIRECTORS

The undersigned hereby appoints JEFFREY P. GOTSCHALL and HUDSON D. SMITH, and each of them, the proxies of the undersigned to vote the shares of the undersigned at the Annual Meeting of Shareholders of SIFCO Industries, Inc., to be held on January 26, 2010, and at any and all adjournments thereof.

Signature

Signature if held jointly

Dated:

NOTE: The signature of this proxy should correspond with the name (or names), as shown hereon, in which your stock is registered. Where stock is registered jointly in the name of two or more persons, all should sign.

(Proxy continued on other side)

Table of Contents

SIFCO Industries, Inc. Proxy IF NO INSTRUCTION IS INDICATED, THIS PROXY WILL BE VOTED FOR THE ELECTION OF THE NOMINEES FOR DIRECTORS, FOR THE PROPOSAL TO RATIFY THE DESIGNATION OF THE INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM AND, IN THE DISCRETION OF THE PROXIES, ON SUCH OTHER BUSINESS AS MAY COME BEFORE THE MEETING OR ANY ADJOURNMENT. ELECT SIX (6) DIRECTORS. To elect the following persons for one-year terms expiring at the 2011 Annual Meeting of Shareholders: Nominees: Jeffrey P. Gotschall Alayne L. Reitman Frank N. Nichols Hudson D. Smith P. Charles Miller, Jr. J. Douglas Whelan FOR all nominees listed above WITHHOLD AUTHORITY (except as noted below) To vote for all nominees (INSTRUCTIONS: If you wish to withhold authority to vote for any individual nominee, write that nominee s name in the space below.) (1) RATIFY THE DESIGNATION OF GRANT THORNTON LLP as the independent registered public accounting firm for the year ending September 30, 2010. FOR AGAINST ABSTAIN (2) Consider and take action upon such other matters as may properly come before the meeting or any adjournment thereof. GRANT AUTHORITY WITHHOLD AUTHORITY (continued from other side)