CONTINENTAL RESOURCES INC
Form S-1/A
May 12, 2006
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As filed with the Securities and Exchange Commission on May 12, 2006

Registration No. 333-132257

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Amendment No. 2

to

FORM S-1

REGISTRATION STATEMENT

UNDER

THE SECURITIES ACT OF 1933

Continental Resources, Inc.

(Exact name of registrant as specified in charter)

Oklahoma	**1311**	**73-0767549**
(State or other jurisdiction of incorporation or organization)	**(Primary Standard Industrial Classification Code Number)**	**(I.R.S. Employer Identification Number)**

302 N. Independence

Enid, Oklahoma 73701

(580) 233-8955

(Address, including zip code, and telephone number, including area code, of registrant s principal executive offices)

Mark E. Monroe

President and Chief Operating Officer

302 N. Independence

Enid, Oklahoma 73701

(580) 233-8955

(Address, including zip code, and telephone number, including area code, of agent for service)

With a copy to:

David P. Oelman	**Winthrop B. Conrad, Jr.**
Vinson & Elkins L.L.P.	**Davis Polk & Wardwell**
1001 Fannin, Suite 2300	**450 Lexington Avenue**
Houston, Texas 77002-6760	**New York, New York 10017**
(713) 758-2222	**(212) 450-4000**

Approximate date of commencement of proposed sale to the public: As soon as practicable on or after the effective date of this Registration Statement.

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, check the following box. ¨

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 the earlier effective registration statement for the same offering. ¨

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. ¨

If this Form is a post-effective amendment filed pursuant to Rule 462(d) 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. ¨

The registrant hereby amends this registration statement on such date or dates as may be necessary to delay its effective date until the registrant shall file a further amendment which specifically states that this registration statement shall thereafter become effective in accordance with Section 8(a) of the Securities Act of 1933 or until the registration statement shall become effective on such date as the Securities and Exchange Commission, acting pursuant to said Section 8(a), may determine.

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The information in this prospectus is not complete and may be changed. These securities may not be sold until the registration statement filed with the Securities and Exchange Commission is effective. This prospectus is not an offer to sell these securities nor does it seek an offer to buy these securities in any state where the offer or sale is not permitted.

Subject to completion, dated May 12, 2006

PROSPECTUS

Shares

Continental Resources, Inc.

Common Stock

This is our initial public offering of common stock. The selling shareholder identified in this prospectus is offering shares of our common stock. We will not receive any proceeds from the sale of the shares by the selling shareholder. The estimated initial public offering price is between $ and $ per share.

Prior to this offering, there has been no public market for our common stock. Our common stock has been approved for listing on the New York Stock Exchange, subject to official notice of issuance, under the symbol CXP.

Investing in our common stock involves a high degree of risk. See Risk Factors beginning on page 12.

	Per share	**Total**

Initial public offering price	$	$
Underwriting discount	$	$
Proceeds to selling shareholder(1)	$	$

(1) Expenses, other than underwriting discounts, associated with the offering will be paid by us.

The selling shareholder has granted the underwriters an option for a period of 30 days to purchase up to additional shares of common stock to cover overallotments, if any. If such option is exercised in full, the total underwriting discount will be $ and the total proceeds to the selling shareholder will be $.

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

The underwriters expect to deliver the shares of common stock to investors on , 2006.

JPMorgan **Merrill Lynch & Co.**

Citigroup

UBS Investment Bank

Petrie Parkman & Co.

Raymond James

, 2006

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Cautionary Statement Regarding Forward-Looking Statements

This prospectus contains forward-looking statements that are subject to a number of risks and uncertainties, many of which are beyond our control. All statements, other than statements of historical fact included in this prospectus, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this prospectus, the words could, believe, anticipate, intend, estimate, expect, project and similar expressions are intended to id forward-looking statements, although not all forward-looking statements contain such identifying words.

Forward-looking statements may include statements about our:

- business strategy;
- reserves;
- technology;
- financial strategy;
- oil and natural gas realized prices;
- timing and amount of future production of oil and natural gas;
- the amount, nature and timing of capital expenditures;
- drilling of wells;
- competition and government regulations;
- marketing of oil and natural gas;
- exploitation or property acquisitions;
- costs of exploiting and developing our properties and conducting other operations;

general economic conditions;

uncertainty regarding our future operating results; and

plans, objectives, expectations and intentions contained in this prospectus that are not historical.

All forward-looking statements speak only as of the date of this prospectus. You should not place undue reliance on these forward-looking statements. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this prospectus are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved. We disclose important factors that could cause our actual results to differ materially from our expectations under Risk Factors and Management s Discussion and Analysis of Financial Condition and Results of Operations and elsewhere in this prospectus. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

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Industry and Market Data

The market data and certain other statistical information used throughout this prospectus are based on independent industry publications, government publications or other published independent sources. Some data are also based on our good faith estimates. Although we believe these third-party sources are reliable, we have not independently verified the information and cannot guarantee its accuracy and completeness.

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Prospectus Summary

This summary highlights information contained elsewhere in this prospectus. You should read this entire prospectus carefully, including Risk Factors and our historical consolidated financial statements and the notes to those historical consolidated financial statements included elsewhere in this prospectus. Unless the context otherwise requires, references in this prospectus to Continental Resources, we, us, our, ours or company refer to Continental Resources, Inc. and its subsidiaries.

We have provided definitions for the oil and natural gas terms used in this prospectus in the Glossary of Oil and Natural Gas Terms beginning on page A-1 of this prospectus. Unless otherwise indicated, the information contained in this prospectus assumes that the underwriters do not exercise their overallotment option to purchase additional shares.

Our Business

We are an independent oil and natural gas exploration and production company with operations in the Rocky Mountain, Mid-Continent and Gulf Coast regions of the United States. We focus our exploration activities in large new or developing plays that provide us the opportunity to acquire undeveloped acreage positions for future drilling operations. We have been successful in targeting large repeatable resource plays where horizontal drilling, advanced fracture stimulation and enhanced recovery technologies provide the means to economically develop and produce oil and natural gas reserves from unconventional formations. As a result of these efforts, we have grown substantially through the drillbit, adding 86.2 MMBoe of proved oil and natural gas reserves through extensions and discoveries from January 1, 2001 through December 31, 2005 compared to 4.7 MMBoe added through proved reserve purchases during that same period.

As of December 31, 2005, our estimated proved reserves were 116.7 MMBoe, with estimated proved developed reserves of 80.3 MMBoe, or 69% of our total estimated proved reserves. Crude oil comprised 85% of our total estimated proved reserves. At December 31, 2005, we had 1,233 scheduled drilling locations on the 1,523,000 gross (961,000 net) acres that we held. For the year ended December 31, 2005 and the three months ended March 31, 2006, we generated revenues of $375.8 million and $103.8 million, respectively, and operating cash flows of $265.3 million and $74.9 million, respectively.

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The following table summarizes our total estimated proved reserves, PV-10 and net producing wells as of December 31, 2005, average daily production for the three months ended March 31, 2006 and the reserve-to-production ratio in our principal regions. Our reserve estimates as of December 31, 2005 are based primarily on a reserve report prepared by Ryder Scott Company, L.P., our independent reserve engineers. In preparing its report, Ryder Scott Company, L.P. evaluated properties representing approximately 83% of our PV-10. Our technical staff evaluated properties representing the remaining 17% of our PV-10.

	At December 31, 2005				Average daily production		
	Proved reserves (MBoe)	Percent of total	PV-10(1) (in millions)	Net producing wells	First quarter 2006 (Boe per day)	Percent of total	Annualized reserve/ production index(2)
Rocky Mountain:							
Red River units	67,711	58%	$ 1,215	187	9,677	42%	19.2
Bakken field	24,041	21%	505	34	6,560	29%	10.0
Other	9,065	8%	137	230	1,384	6%	17.9
Mid-Continent	15,472	13%	328	630	3,916	17%	10.8
Gulf Coast	376		19	23	1,323	6%	0.8
Total	116,665	100%	$ 2,204	1,104	22,860	100%	14.0

(1) PV-10 is a non GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. However, our PV-10 and our Standardized Measure are equivalent because we are a subchapter S-corporation. In connection with the closing of this offering, we will convert to a subchapter C-corporation. Our pro-forma Standardized Measure, assuming our conversion to a subchapter C-corporation, was $1.4 billion at December 31, 2005. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and gas properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

(2) The Annualized Reserve/Production Index is the number of years proved reserves would last assuming current production continued at the same rate. This index is calculated by dividing annualized first quarter 2006 production into the proved reserve quantity at December 31, 2005.

The following table provides additional information regarding our key development areas:

	At December 31, 2005					2006 Budget	
	Developed acres		Undeveloped acres				
	Gross	Net	Gross	Net	Scheduled drilling locations(1)	Wells planned for drilling	Capital expenditures (in millions)
Rocky Mountain:							
Red River units	144,176	128,047			135	41	$ 84
Bakken field	52,421	38,971	588,081	356,426	918	54	96
Other	45,720	36,153	358,649	208,612	71	34	40
Mid-Continent	152,734	99,279	115,746	73,582	96	70	64

Gulf Coast	41,842	11,890	23,598	7,873	13	13	17
Total	436,893	314,340	1,086,074	646,493	1,233	212	$ 301

(1) Scheduled drilling locations represent total gross locations specifically identified and scheduled by management as an estimate of our future multi-year drilling activities on existing acreage. Of the total locations shown in the table, 256 are classified as PUDs. As of April 30, 2006, we have commenced drilling of 55 locations shown in the table, including 34 PUD locations. Scheduled drilling locations include 37 potential drilling sites in our New Albany Shale, Lewis Shale, Floyd Shale and Woodford Shale projects. While we owned 168,000 gross (72,000 net) undeveloped acres in these projects as of December 31, 2005, we have not sufficiently evaluated the opportunities on our acreage at this date to schedule further locations. Our actual drilling activities may change depending on oil and natural gas prices, the availability of capital, costs, drilling results, regulatory approvals and other factors. See Risk Factors Risks Relating to the Oil and Natural Gas Industry and Our Business.

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Our Business Strategy

Our goal is to increase shareholder value by finding and developing crude oil and natural gas reserves at costs that provide an attractive rate of return on our investment. The principal elements of our business strategy are:

Growth Through Drilling. Substantially all of our annual capital expenditures are invested in drilling projects and acreage and seismic acquisitions.

Internally Generate Prospects. Our technical staff has internally generated substantially all of the opportunities for the investment of our capital. Because we have been an early entrant in new or emerging plays, our costs to acquire undeveloped acreage have generally been less than those of later entrants into a developing play.

Focus on Unconventional Oil and Natural Gas Resource Plays. Our experience with horizontal drilling, advanced fracture stimulation and enhanced recovery technologies allows us to commercially develop unconventional oil and natural gas resource plays, such as the Red River B dolomite and Bakken Shale formations.

Acquire Significant Acreage Positions in New or Developing Plays. Our technical staff is focused on identifying and testing new unconventional oil and natural gas resource plays where significant reserves could be developed if commercial production rates can be achieved through advanced drilling, fracture stimulation and enhanced recovery techniques.

Our Business Strengths

We have a number of strengths that we believe will help us successfully execute our strategies:

Large Drilling and Acreage Inventory. Our large number of identified drilling locations in all of our areas of operations provide for a multi-year drilling inventory.

Horizontal Drilling and Enhanced Recovery Experience. In 1992, we drilled our initial horizontal well, and we have drilled over 300 horizontal wells since that time. We also have substantial experience with enhanced recovery methods and currently serve as the operator of 39 waterflood units and eight high-pressure air injection units.

Control Operations Over a Substantial Portion of our Assets and Investments. As of December 31, 2005, we operated properties comprising 97% of our PV-10. By controlling operations, we are able to more effectively manage the cost and timing of exploration and development of our properties.

Experienced Management Team. Our senior management team has extensive expertise in the oil and gas industry. Our eight senior officers have an average of 25 years of oil and gas industry experience.

Strong Financial Position. As of May 9, 2006, we had outstanding borrowings under our credit facility of approximately $189.5 million. We believe that our planned exploration and development activities will be funded substantially from our operating cash flows.

Recent Events

Payment of Cash Dividend. On April 13, 2006, we paid a cash dividend of approximately $60.0 million to our shareholders for tax purposes and, subject to forfeiture, to holders of unvested restricted stock. In connection with the completion of this offering, we will convert from a subchapter S-corporation to a subchapter

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C-corporation, and we do not anticipate paying any additional cash dividends on our common stock in the foreseeable future.

NYMEX and Related Oil Price Differential. The difference between the calendar month average of the NYMEX crude oil prices and our realized crude oil prices increased in the Rocky Mountain region during the first quarter 2006. For the year ended December 31, 2005, the average company-wide difference was $5.24 per Bbl. The company-wide difference for January, February and March 2006 was $7.95, $10.70 and $15.00 per Bbl, respectively, and is estimated to be approximately $12.00 per Bbl of oil for April and May 2006. Factors affecting the difference include higher oil imports and production in the region, lower demand by local refineries due to downtime for maintenance and reduced seasonal demand for gasoline and downstream transportation capacity constraints. We are unable to predict when, or if, the difference will revert back to historical levels.

Oil Storage; Production Curtailment. Due to downstream transportation constraints in the Rocky Mountain region, one of our oil purchasers was unable to accept delivery of a portion of our March 2006 sales volumes. As a result, we stored approximately 3,000 net Bbls of oil per day of production in Guernsey, Wyoming. We expect to sell the stored oil in May 2006. As a result of the same market disruption, we shut in wells in the Red River units representing approximately 1,700 net Bbls of oil per day. For the month of April 2006, our wells in the region were on production for the full month except for three to five days of downtime due to loss of electricity in the area as a result of a snowstorm, and we sold all of the production from those wells.

Acquisition of Banner Pipeline Company. For the year ended December 31, 2005, oil sales to Banner Pipeline Company, L.L.C., which was wholly owned by our principal shareholder, accounted for approximately 19% of our total oil and gas sales. In February 2006, we decided to market the majority of our crude oil in the Rocky Mountain region directly or through a wholly owned subsidiary rather than through an affiliate, and, as Banner has existing contacts and relationships with crude oil purchasers, we decided to purchase Banner. On March 30, 2006, we acquired Banner for approximately $8.8 million, the book value of working capital, principally cash, accounts receivable, crude oil inventory and accounts payable.

Acreage Acquisition. In April 2006, we purchased a 50% interest in 135,000 acres in the Marfa Basin in Presidio and Brewster Counties, Texas as well as overriding royalty interests covering a portion of the acreage for approximately $7 million. We plan to re-enter a well on the acreage to test the Woodford and Barnett equivalent shales during the second half of 2006.

Risk Factors

Investing in our common stock involves risks that include the speculative nature of oil and natural gas exploration, competition, volatile oil and natural gas prices and other material factors. You should read carefully the section entitled Risk Factors beginning on page 12 for an explanation of these risks before investing in our common stock. In particular, the following considerations may offset our business strengths or have a negative effect on our business strategy as well as on activities on our properties, which could cause a decrease in the price of our common stock and result in a loss of all or a portion of your investment:

A substantial or extended decline in oil and natural gas prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

Drilling for and producing oil and natural gas are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

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Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The results of enhanced recovery methods are uncertain.

Our development and exploitation projects require substantial capital expenditures. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our oil and natural gas reserves.

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

A substantial portion of our producing properties are located in the Rocky Mountains, making us vulnerable to risks associated with operating in one major geographic area.

Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would adversely affect our cash flows and results of operations.

The unavailability or high cost of additional drilling rigs, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute our exploration and development plans within our budget and on a timely basis.

We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations; we may not be insured for, or our insurance may be inadequate to protect us against, these risks.

The inability of our significant customers to meet their obligations to us may adversely affect our financial results.

Following this offering, our Chairman and Chief Executive Officer will own approximately % of our outstanding common stock, giving him influence and control in corporate transactions and other matters.

For a discussion of other considerations that could negatively affect us, including risks related to this offering and our common stock, see Risk Factors and Cautionary Statement Regarding Forward-Looking Statements.

Corporate History and Information

Continental Resources, Inc. is incorporated under the laws of the State of Oklahoma. We were originally formed in 1967 to explore, develop and produce oil and natural gas properties in Oklahoma. Through 1993, our activities and growth remained focused primarily in Oklahoma. In 1993, we expanded our activity into the Rocky Mountain and Gulf Coast regions. Through drilling success and strategic acquisitions, approximately 87% of our estimated proved reserves as of December 31, 2005 are located in the Rocky Mountain region.

We are currently a subchapter S-corporation under the rules and regulations of the Internal Revenue Service. However, upon the consummation of this offering, we will have more shareholders than the IRS rules and regulations governing S-corporations allow, and, therefore, we will convert automatically from a subchapter S-corporation to a subchapter C-corporation. In connection with this conversion, we will record a charge to earnings estimated to be approximately $127.9 million as of March 31, 2006 to recognize deferred taxes.

In addition, concurrent with the closing of this offering, we will effect an 11 for 1 stock split of our shares in the form of a stock dividend.

Our principal executive offices are located at 302 N. Independence, Enid, Oklahoma 73701, and our telephone number at that address is (580) 233-8955.

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The Offering

Common Stock Offered:

By the selling shareholder: shares

Overallotment option granted by the selling shareholder: shares

Common stock to be owned by the selling shareholder after the offering: shares (or shares if the underwriters overallotment option is exercised in full)

Common stock to be outstanding after the offering: 159,069,801 shares

Use of Proceeds:

We will not receive any proceeds from the sale of the shares of common stock by the selling shareholder. See Use of Proceeds.

Dividend Policy:

We do not anticipate paying any cash dividends on our common stock. See Dividend Policy.

Proposed New York Stock Exchange Symbol:

CXP

Other Information About This Prospectus:

Unless specifically stated otherwise, the information in this prospectus:

- is adjusted to reflect an 11 for 1 stock split of our shares of common stock to be effected in the form of a stock dividend concurrent with the consummation of this offering;
- assumes no exercise of the underwriters overallotment option to purchase additional shares; and
- assumes an initial public offering price of $, which is the midpoint of the range set forth on the front cover of this prospectus.

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Summary Historical and Pro Forma Consolidated Financial Data

This section presents our summary historical and pro forma consolidated financial data. The summary historical consolidated financial data presented below is not intended to replace our historical consolidated financial statements.

The following historical consolidated financial data, as it relates to each of the fiscal years ended December 31, 2003 through 2005, has been derived from our audited historical consolidated financial statements for such periods. The following historical consolidated financial data, as it relates to each of the three month periods ended March 31, 2005 and 2006, has been derived from our unaudited historical consolidated financial statements for such periods. You should read the following summary historical consolidated financial data in connection with Capitalization, Management s Discussion and Analysis of Financial Condition and Results of Operations and our historical consolidated financial statements and related notes included elsewhere in this prospectus. The summary historical consolidated results are not necessarily indicative of results to be expected in future periods.

The summary pro forma financial data reflect the tax effects of our conversion, concurrent with the closing of this offering, from a subchapter S-corporation to a subchapter C-corporation and the earnings per share impact of our 11 for 1 stock split to be effected in the form of a stock dividend concurrent with the closing of this offering.

	Year ended December 31,			Three months ended March 31,	
	2003	2004	2005	2005	2006
	(in thousands, except per share amounts)				
Statement of operations data:					
Revenues:					
Oil and natural gas sales	$ 138,948	$ 181,435	$ 361,833	$ 59,728	$ 99,768
Crude oil marketing and trading(1)	169,547	226,664			
Oil and natural gas service operations	9,114	10,811	13,931	4,360	3,997
Total revenues	317,609	418,910	375,764	64,088	103,765
Operating costs and expenses:					
Production expense	40,821	43,754	52,754	11,159	15,562
Production tax	10,251	12,297	16,031	3,766	4,367
Exploration expense	17,221	12,633	5,231	789	2,082
Crude oil marketing and trading(1)	166,731	227,210			
Oil and gas service operations	5,641	6,466	7,977	2,427	2,118
Depreciation, depletion, amortization and accretion	40,256	38,627	49,802	9,408	13,292
Property impairments	8,975	11,747	6,930	1,907	1,415
General and administrative(2)	9,604	12,400	31,266	7,773	7,936
(Gain) loss on sale of assets	(589)	150	(3,026)	(2,913)	(222)
Total operating costs and expenses	$ 298,911	$ 365,284	$ 166,965	$ 34,316	$ 46,550

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	Year ended December 31,			Three months ended March 31,	
	2003	2004	2005	2005	2006
	(in thousands, except per share amounts)				
Income from operations	$ 18,698	$ 53,626	$ 208,799	$ 29,772	$ 57,215
Other income (expense)					
Interest expense	(19,761)	(23,617)	(14,220)	(3,779)	(2,485)
Loss on redemption on bonds		(4,083)			
Other	295	890	867	85	320
Total other income (expense)	(19,466)	(26,810)	(13,353)	(3,694)	(2,165)
Income (loss) from continuing operations before income taxes	(768)	26,816	195,446	26,078	55,050
Provision for income taxes(3)			1,139	1,139	
Income (loss) from continuing operations	(768)	26,816	194,307	24,939	55,050
Discontinued operations(4)	946	1,680			
Loss on sale of discontinued operations(4)		(632)			
Income before cumulative effect of change in accounting principle	178	27,864	194,307	24,939	55,050
Cumulative effect of change in accounting principle(5)	2,162				
Net income	$ 2,340	$ 27,864	$ 194,307	$ 24,939	$ 55,050
Basic earnings (loss) per share:					
From continuing operations	$ (0.05)	$ 1.87	$ 13.52	$ 1.74	$ 3.83
From discontinued operations(4)	0.06	0.11			
Loss on sale of discontinued operations(4)		(0.04)			
Before cumulative effect of change in accounting principle	0.01	1.94	13.52	1.74	3.83
Cumulative effect of change in accounting principle	0.15				
Net income per share	$ 0.16	$ 1.94	$ 13.52	$ 1.74	$ 3.83
Shares used in basic earnings (loss) per share	14,369	14,369	14,369	14,369	14,369
Diluted earnings (loss) per share:					
From continuing operations	$ (0.05)	$ 1.85	$ 13.42	1.72	3.80
From discontinued operations(4)	0.06	0.12			
Loss on sale of discontinued operations(4)		(0.04)			
Before cumulative effect of change in accounting principle	0.01	1.93	13.42	1.72	3.80
Cumulative effect of change in accounting principle	0.15				
Net income per share	$ 0.16	$ 1.93	$ 13.42	$ 1.72	$ 3.80
Shares used in diluted earnings (loss) per share	14,369	14,476	14,482	14,467	14,489

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	Year ended December 31,			Three months ended March 31,	
	2003	2004	2005	2005	2006
	(in thousands, except per share amounts)				
Pro forma C-corporation and stock split data:					
Income (loss) from continuing operations before income taxes	$ (768)	$ 26,816	$ 195,446	$ 26,078	$ 55,050
Pro forma provision (benefit) for income taxes attributable to operations	(292)	10,190	74,269	9,910	20,919
Pro forma income (loss) from operations after tax	(476)	16,626	121,177	16,168	34,131
Discontinued operations net of tax(4)	587	1,042			
Loss on sale of discontinued operations(4)		(392)			
Cumulative effect of change in accounting principle net of tax	1,340				
Pro forma net income	$ 1,451	$ 17,276	$ 121,177	$ 16,168	$ 34,131
Pro forma basic earnings per share	$ 0.01	$ 0.11	$ 0.77	$ 0.10	$ 0.22
Pro forma diluted earnings per share	0.01	0.11	0.76	0.10	0.21
Other financial data:					
Cash dividends per share	$	$ 1.04	$ 0.14	$	$ 4.15
EBITDAX (6)	88,750	116,498	285,344	45,351	77,617
Net cash provided by operations	65,246	93,854	265,265	21,717	74,889
Net cash used in investing	(108,791)	(72,992)	(133,716)	(15,479)	(58,764)
Net cash provided by (used in) financing	43,302	(7,245)	(141,467)	(14,239)	(11,500)
Capital expenditures	114,145	94,307	144,800	26,332	59,659
Balance sheet data (at period end):					
Cash and cash equivalents	$ 2,277	$ 15,894	$ 6,014	$ 7,886	$ 10,654
Property and equipment, net	439,432	434,339	509,393	436,267	553,360
Total assets	484,988	504,951	600,234	512,799	651,644
Long-term debt, including current maturities	290,920	290,522	143,000	267,000	131,500
Shareholders equity	116,932	130,385	324,730	156,453	319,793

(1) Crude oil marketing and trading captions consist of our marketing activities under which crude oil production was sold at the wellhead and transported to a local hub where we purchased the barrels back to exchange at Cushing, Oklahoma in order to minimize pricing differentials with the NYMEX oil futures contract. We adopted Emerging Issues Task Force (EITF) 04-13 on January 1, 2005, which allowed certain purchase and sales transactions with the same counterparty to be combined and accounted for as a single transaction under the guidance of Accounting Principles Board Opinion No. 29. In 2005, we netted $39.8 million of crude oil marketing and trading revenues and $39.7 million of crude oil marketing and trading expenses under oil and natural gas sales. Prior to the adoption of EITF 04-13, we presented crude oil marketing and trading revenues and expenses gross under the guidance provided by EITF 99-19, Reporting Revenues Gross as a Principal and/or Net as an Agent. Effective March 2005, we ceased marketing our crude oil production under these arrangements. Thereafter, we have sold our crude oil at the wellhead. Certain of these sales have been to our affiliates, as described under Certain Relationships and Related Party Transactions.

(2) We have included stock-based compensation of $0.2 million, $2.0 million, $13.7 million, $3.4 million and $3.3 million in general and administrative expenses for the years ended December 31, 2003, 2004 and 2005 and the three months ended March 31, 2005 and 2006, respectively. Our stock based compensation plan requires us to purchase vested shares at the employee s request based on an internally calculated value of our stock. Amounts noted herein represent the increase in our liability associated with our purchase obligation. The valuation is based on the book value of our shareholders equity adjusted for our PV-10 as of each calendar quarter. Our requirement to purchase vested shares will be eliminated once we begin reporting under Section 12 of the Securities Exchange Act of 1934, as amended (the Exchange Act). As a result of this change, we will recognize a charge of approximately $ upon completion of this offering, assuming an offering price at the midpoint of the range set forth on the cover page of this prospectus. See Capitalization.

(3) Properties owned by us at May 31, 1997, the date we converted into a subchapter S-corporation from a subchapter C-corporation, may be subject to federal taxation if sold for an amount in excess of the then tax basis for the sold assets. During 2005, we incurred federal taxes due to the sale of assets acquired prior to May 31, 1997.

(4) In July 2004, we sold all of the outstanding stock in Continental Gas, Inc., a wholly owned subsidiary, to our shareholders. The Continental Gas, Inc. assets included seven gas gathering systems and three gas-processing plants. These assets represented our entire gas gathering, marketing and processing segment. We have accounted for these operations as discontinued operations.

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(5) We adopted Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations and recorded the cumulative effect of the change in accounting principle on January 1, 2003.

(6) EBITDAX represents earnings before interest expense, income taxes (when applicable), depreciation, depletion, amortization and accretion, property impairments, exploration expense and non-cash compensation expense. EBITDAX is not a measure of net income or cash flow as determined by generally accepted accounting principles (GAAP). EBITDAX should not be considered as an alternative to, or more meaningful than, net income or cash flow as determined in accordance with GAAP or as an indicator of a company s operating performance or liquidity. Certain items excluded from EBITDAX are significant components in understanding and assessing a company s financial performance, such as a company s cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of EBITDAX. Our computations of EBITDAX may not be comparable to other similarly titled measures of other companies. We believe that EBITDAX is a widely followed measure of operating performance and may also be used by investors to measure our ability to meet future debt service requirements, if any. Our credit facility requires that we maintain a total debt to EBITDAX ratio of no greater than 3.75 to 1 on a rolling four-quarter basis. Our credit facility defines EBITDAX consistently with the definition of EBITDAX utilized and presented by us. At December 31, 2005, this ratio was approximately 0.5 to 1, and at March 31, 2006, this ratio was approximately 0.4 to 1. The following table represents a reconciliation of our net income to EBITDAX:

	Year ended December 31,			Three months ended March 31,	
	2003	2004	2005	2005	2006
	(in thousands)				
Net income	$ 2,340	$ 27,864	$ 194,307	$ 24,939	$ 55,050
Interest expense	19,761	23,617	14,220	3,779	2,485
Provision for income taxes			1,139	1,139	
Depreciation, depletion, amortization and accretion	40,256	38,627	49,802	9,408	13,292
Property impairments	8,975	11,747	6,930	1,907	1,415
Exploration expense	17,221	12,633	5,231	789	2,082
Equity compensation	197	2,010	13,715	3,390	3,293
EBITDAX	$ 88,750	$ 116,498	$ 285,344	$ 45,351	$ 77,617

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Summary Reserve, Production and Operating Data

The following table presents summary data with respect to our estimated net proved oil and natural gas reserves as of the dates indicated. Our reserve estimates as of December 31, 2003, 2004 and 2005 are based primarily on reserve reports prepared by Ryder Scott Company, L.P., our independent reserve engineers. In preparing its reports, Ryder Scott Company, L.P. evaluated properties representing approximately 83% of our PV-10 as of the end of each period. Our technical staff evaluated our remaining properties. A copy of Ryder Scott Company, L.P. s summary report as of December 31, 2005 is included in this prospectus beginning on page B-1. All calculations of estimated net proved reserves have been made in accordance with the rules and regulations of the Securities and Exchange Commission, or the SEC. For additional information regarding our reserves, see Business and Properties Proved Reserves.

	As of December 31,		
	2003	2004	2005
Proved reserves:			
Oil (MBbls)	73,000	80,602	98,645
Natural gas (MMcf)	67,096	60,620	108,118
Oil equivalent (MBoe)	84,183	90,705	116,665
Proved developed reserves percentage	55%	83%	69%
PV-10 (in millions)(1)	$ 815	$ 1,114	$ 2,204
Estimated reserve life (in years)	16.0	17.6	16.2
Costs incurred (in thousands):			
Property acquisition costs	$ 8,683	$ 12,456	$ 16,763
Exploration costs	11,981	30,867	9,289
Development costs	75,396	53,036	117,837
Total	$ 96,060	$ 96,359	$ 143,889

(1) PV-10 is a non GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. However, our PV-10 and our Standardized Measure are equivalent because we are a subchapter S-corporation. In connection with the closing of this offering, we will convert to a subchapter C-corporation. Our pro-forma Standardized Measure, assuming our conversion to a subchapter C-corporation, was $1.4 billion at December 31, 2005. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and gas properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

The following table sets forth summary data with respect to our production results, average sales prices and production costs on a historical basis for the periods presented:

	Year ended December 31,			Three months ended March 31,	
	2003	2004	2005	2005	2006
Net production volumes:					

Oil (MBbls)(1)	3,463	3,688	5,708	1,067	1,677
Natural gas (MMcf)	10,751	8,794	9,006	2,100	2,286
Oil equivalents (MBoe)	5,255	5,154	7,209	1,417	2,058
Average prices(1):					
Oil, without hedges ($/Bbl)	$ 28.88	$ 38.85	$ 52.45	$ 45.53	$ 52.81
Oil, with hedges ($/Bbl)	25.98	37.12	52.45	45.53	52.81
Natural gas ($/Mcf)	4.55	5.06	6.93	5.31	7.13
Oil equivalents, without hedges ($/Boe)	28.35	36.45	50.19	42.15	50.86
Oil equivalents, with hedges ($/Boe)	26.44	35.20	50.19	42.15	50.86
Costs and expenses(1):					
Production expense ($/Boe)	$ 7.77	$ 8.49	$ 7.32	$ 7.88	$ 7.93
Production tax ($/Boe)	1.95	2.39	2.22	2.66	2.23
General and administrative ($/Boe)	1.83	2.41	4.34	5.49	4.05
DD&A expense ($/Boe)(2)	7.10	7.02	6.50	6.21	6.37

(1) Oil sales volumes are 96 MBbls less than oil production volumes for the three months ended March 31, 2006. Average prices and per unit costs have been calculated using sales volumes.

(2) Rate is determined based on DD&A expense derived from oil and natural gas assets.

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Risk Factors

You should carefully consider each of the risks described below, together with all of the other information contained in this prospectus, before deciding to invest in shares of our common stock. If any of the following risks develop into actual events, our business, financial condition or results of operations could be materially adversely affected, the trading price of your shares could decline and you may lose all or part of your investment.

Risks Relating to the Oil and Natural Gas Industry and Our Business

A substantial or extended decline in oil and natural gas prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

The price we receive for our oil and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile. These markets will likely continue to be volatile in the future. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include the following:

- changes in global supply and demand for oil and natural gas;
- the actions of the Organization of Petroleum Exporting Countries, or OPEC;
- the price and quantity of imports of foreign oil and natural gas;
- political conditions in or affecting other oil-producing and natural gas-producing countries, including the current conflicts in the Middle East and conditions in South America and Russia;
- the level of global oil and natural gas exploration and production;
- the level of global oil and natural gas inventories;
- localized supply and demand fundamentals and transportation availability;

weather conditions;

technological advances affecting energy consumption; and

the price and availability of alternative fuels.

Lower oil and natural gas prices may also reduce the amount of oil and natural gas that we can produce economically. Substantial decreases in oil and natural gas prices would render uneconomic a significant portion of our exploitation projects. This may result in our having to make significant downward adjustments to our estimated proved reserves. As a result, a substantial or extended decline in oil or natural gas prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

In addition, because our producing properties are geographically concentrated in the Rocky Mountain region, we are vulnerable to fluctuations in pricing in that area. In particular, 77% of our production during the first quarter of 2006 was from the Rocky Mountain region. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, transportation capacity

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constraints, curtailment of production or interruption of transportation of oil produced from the wells in these areas. Such factors can cause significant fluctuation in our realized oil and natural gas prices. For example, the company-wide difference between the average NYMEX oil price and our average realized oil price for the year ended December 31, 2005 was $5.24 per Bbl, whereas the company-wide difference between the NYMEX oil price and our realized oil price for January, February and March 2006 was $7.95, $10.70 and $15.00 per Bbl, respectively. The increase in the difference was caused by higher oil imports and production in the Rocky Mountain region, lower demand by local Rocky Mountain refineries due to downtime for maintenance and reduced seasonal demand for gasoline and downstream transportation capacity constraints. We are unable to predict when, or if, the difference will revert back to historical levels. If such significant price differentials continue, our future business, financial condition and results of operations may be materially adversely affected.

Drilling for and producing oil and natural gas are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our future financial condition and results of operations will depend on the success of our exploitation, exploration, development and production activities. Our oil and natural gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil or natural gas production. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. For a discussion of the uncertainty involved in these processes, see Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves. Our cost of drilling, completing and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Further, many factors may curtail, delay or cancel drilling, including the following:

- delays imposed by or resulting from compliance with regulatory requirements;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel;
- equipment failures or accidents;
- adverse weather conditions, such as hurricanes and tropical storms;
- reductions in oil and natural gas prices;
- title problems; and
- limitations in the market for oil and natural gas.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves shown in this prospectus. See Business and Properties Proved Reserves for information about our oil and natural gas reserves.

In order to prepare our estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and

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reliability of this data can vary. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of reserves shown in this prospectus. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

For example, our initial well in the Bakken Field was completed in August 2003. As of December 31, 2005, we had 10.8 MMBoe of proved producing reserves assigned to 62 producing wells and 13.2 MMBoe of proved undeveloped reserves assigned to 60 undrilled locations. The Bakken Field contained 21% of our total proved reserves and 36% of our total proved undeveloped reserves as of December 31, 2005. Due to the limited production history of our wells in the Bakken Field, the estimates of future production associated with such properties may be subject to greater variance to actual production than would be the case with properties having a longer production history.

You should not assume that the present value of future net revenues from our proved reserves referred to in this prospectus is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, we generally base the estimated discounted future net cash flows from our proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate. If oil prices decline by $1.00 per Bbl, then our PV-10 as of December 31, 2005 would decrease from $2,204 million to $2,156 million. If natural gas prices decline by $0.10 per Mcf, then our PV-10 as of December 31, 2005 would decrease from $2,204 million to $2,199 million.

Our use of enhanced recovery methods creates uncertainties that could adversely affect our results of operations and financial condition.

We inject water and high-pressure air into formations on some of our properties to increase the production of oil and natural gas. The additional production and reserves attributable to the use of these enhanced recovery methods are inherently difficult to predict. If our enhanced recovery programs do not allow for the extraction of oil and natural gas in the manner or to the extent that we anticipate, our future results of operations and financial condition could be materially adversely affected.

Our development and exploitation projects require substantial capital expenditures. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our oil and natural gas reserves.

The oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business for the development, exploitation, production and acquisition of oil and natural gas reserves. To date, these capital expenditures have been financed with cash generated by operations and through borrowings from banks and from our principal shareholder. We intend to finance our future capital expenditures primarily through cash flow from operations and through borrowings under our revolving credit facility; however, our financing needs may require us to alter or increase our capitalization substantially through the issuance of debt or equity securities. The issuance of additional debt will require that a portion of our cash flow from operations be used for the payment of interest and principal on our debt, thereby reducing our ability to use cash flow to fund working capital, capital expenditures and acquisitions. The issuance of additional equity securities could have a dilutive effect on the value of your common stock.

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Our cash flow from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the level of oil and natural gas we are able to produce from existing wells;
- the prices at which our oil and natural gas are sold; and
- our ability to acquire, locate and produce new reserves.

If our revenues or the borrowing base under our credit facility decrease as a result of lower oil or natural gas prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. If additional capital is needed, we may not be able to obtain debt or equity financing. If cash generated by operations or cash available under our revolving credit facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our prospects, which in turn could lead to a decline in our oil and natural gas reserves, and could adversely affect our business, financial condition and results of operations.

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

Accounting rules require that we review periodically the carrying value of our oil and natural gas properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our oil and natural gas properties. A write-down constitutes a non-cash charge to earnings. We may incur impairment charges in the future, which could have a material adverse effect on our results of operations for the periods in which such charges are taken.

Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would adversely affect our cash flows and results of operations.

Unless we conduct successful development, exploitation and exploration activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and natural gas reserves and production, and therefore our cash flow and results of operations, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, exploit, find or acquire sufficient additional reserves to replace our current and future production.

The unavailability or high cost of additional drilling rigs, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute our exploration and development plans within our budget and on a timely basis.

Shortages or the high cost of drilling rigs, equipment, supplies, personnel or oilfield services could delay or adversely affect our development and exploration operations, which could have a material adverse effect on our business, financial condition or results of operations.

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We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations; we may not be insured for, or our insurance may be inadequate to protect us against, these risks.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations. Our oil and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater and shoreline contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- fires, explosions and ruptures of pipelines in connection with our high-pressure air injection operations;
- personal injuries and death; and
- natural disasters.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to our company as a result of:

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- regulatory investigations and penalties;
- suspension of our operations; and
- repair and remediation costs.

We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

Prospects that we decide to drill may not yield oil or natural gas in commercially viable quantities.

Prospects that we decide to drill that do not yield oil or natural gas in commercially viable quantities will adversely affect our result of operations and financial condition. In this prospectus, we describe some of our current prospects and our plans to explore those prospects. Our prospects are in various stages of evaluation, ranging from a prospect which is ready to drill to a prospect that will require substantial additional seismic data processing and interpretation. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. We cannot assure you that the analogies we draw from available data from other wells, more fully explored prospects or producing fields will be applicable to our drilling prospects.

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Our identified drilling locations are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Our management has specifically identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. As of December 31, 2005, we had identified and scheduled 1,233 gross drilling locations. These scheduled drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including oil and natural gas prices, the availability of capital, costs, drilling results, regulatory approvals and other factors. Because of these uncertainties, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce oil or natural gas from these or any other potential drilling locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the locations are identified, the leases for such acreage will expire. As of December 31, 2005, we had 93,922, 123,214 and 160,891 net acres expiring in 2006, 2007 and 2008, respectively. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production.

Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business. We may be required to shut in wells due to lack of a market or inadequacy or unavailability of crude oil or natural gas pipeline or gathering system capacity. If that were to occur, then we would be unable to realize revenue from those wells until production arrangements were made to deliver to market.

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

While our costs to acquire undeveloped acreage in new or emerging plays have generally been less than those of later entrants into a developing play, our drilling results in these areas are more uncertain than drilling results in areas that are developed and producing. Since new or emerging plays have limited or no production history, we are unable to use past drilling results in those areas to help predict our future drilling results. As a result, our cost of drilling, completing and operating wells in these areas may be higher than initially expected, and the value of our undeveloped acreage will decline if drilling results are unsuccessful.

We are subject to complex federal, state, local, provincial and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations.

Our oil and natural gas exploration, production and transportation operations are subject to complex and stringent laws and regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state, local and provincial governmental authorities. We may incur substantial costs in order to maintain compliance with these existing laws and regulations. In addition, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. Such costs could have a material adverse effect on our business, financial condition and results of operations.

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Our business is subject to federal, state, local and provincial laws and regulations as interpreted and enforced by governmental authorities possessing jurisdiction over various aspects of the exploration for, and the production and transportation of, oil and natural gas. Failure to comply with such laws and regulations, as interpreted and enforced, could have a material adverse effect on our business, financial condition and results of operations. See Business and Properties Environmental, Health and Safety Regulation and Business and Properties Regulation of the Oil and Natural Gas Industry for a description of the laws and regulations that affect us.

Our operations expose us to significant costs and liabilities with respect to environmental and operational safety matters.

We may incur significant costs and liabilities as a result of environmental, health and safety requirements applicable to our oil and natural gas exploration, production and transportation activities. These costs and liabilities could arise under a wide range of federal, state, local and provincial laws and regulations relating to protection of the environment, health and safety, including regulations and enforcement policies that have tended to become increasingly strict over time. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, and, to a lesser extent, issuance of injunctions to limit or cease operations. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations.

Strict, joint and several liability may be imposed under certain environmental laws, which could cause us to become liable for the conduct of others or for consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. New laws, regulations or enforcement policies could be more stringent and impose unforeseen liabilities or significantly increase compliance costs. If we were not able to recover the resulting costs through insurance or increased revenues, our business, financial condition or results of operations could be adversely affected. See Business and Properties Environmental, Health and Safety Regulation for more information.

Competition in the oil and natural gas industry is intense, making it more difficult for us to acquire properties, market oil and natural gas and secure trained personnel.

We operate in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. Those companies may be able to pay more for productive oil and natural gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. In addition, those companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. The cost to attract and retain qualified personnel has increased over the past two years due to competition and may increase substantially in the future. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital. Our failure to acquire properties, market oil and natural gas and secure trained personnel and increased compensation for trained personnel could have a material adverse effect on our business.

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The loss of senior management or technical personnel could adversely affect operations.

To a large extent, we depend on the services of our senior management and technical personnel. The loss of the services of our senior management or technical personnel, including Harold G. Hamm, our Chairman and Chief Executive Officer, could have a material adverse effect on our operations. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals.

Terrorist attacks aimed at our energy operations could adversely affect our business.

The continued threat of terrorism and the impact of military and other government action has led and may lead to further increased volatility in prices for oil and natural gas and could affect these commodity markets or financial markets used by us. In addition, the U.S. government has issued warnings that energy assets may be a future target of terrorist organizations. These developments have subjected our oil and natural gas operations to increased risks. Any future terrorist attack on our facilities, those of our customers and, in some cases, those of other energy companies, could have a material adverse effect on our business.

Seasonal weather conditions and lease stipulations adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Oil and natural gas operations in the Rocky Mountains are adversely affected by seasonal weather conditions and lease stipulations designed to protect various wildlife. In certain areas, including parts of Montana, North Dakota, South Dakota, Utah and Wyoming, drilling and other oil and natural gas activities can only be conducted during the spring and summer months. This limits our ability to operate in those areas and can intensify competition during those months for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs.

Our credit facility contains certain covenants that may inhibit our ability to make certain investments, incur additional indebtedness and engage in certain other transactions, which could adversely affect our ability to meet our future goals.

Our credit facility includes certain covenants that, among other things, restrict:

- our investments, loans and advances and the paying of dividends and other restricted payments;
- our incurrence of additional indebtedness;
- the granting of liens, other than liens created pursuant to the credit facility and certain permitted liens;

- mergers, consolidations and sales of all or substantial part of our business or properties;
- the hedging, forward sale or swap of our production of crude oil or natural gas or other commodities;
- the sale of assets; and
- our capital expenditures.

Our credit facility requires us to maintain certain financial ratios, such as leverage ratios. All of these restrictive covenants may restrict our ability to expand or pursue our business strategies. Our ability to comply with these and other provisions of our credit facility may be impacted by changes in economic or business conditions, results of operations or events beyond our control. The breach of any of these covenants could result in a default under our credit facility, in which case, depending on the actions taken by the lenders thereunder or their successors or assignees, such lenders could elect to declare all amounts borrowed under our credit facility, together with accrued interest, to be due and payable. If we were unable to repay such borrowings or interest, our lenders could proceed against their collateral. If the indebtedness under our credit facility were to be accelerated, our assets may not be sufficient to repay in full such indebtedness.

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The inability of our significant customers to meet their obligations to us may adversely affect our financial results.

We are subject to credit risk due to concentration of our crude oil and natural gas receivables with several significant customers. The three largest purchasers of our oil and natural gas in 2005 accounted for 31% , 19% and 10% of our total oil and natural gas sales revenues. We do not require our customers to post collateral. The inability of our significant customers to meet their obligations to us may adversely affect our financial results.

Risks Relating to the Offering and Our Common Stock

The initial public offering price of our common stock may not be indicative of the market price of our common stock after this offering. In addition, our stock price may be volatile.

Prior to this offering, there has been no public market for our common stock. An active market for our common stock may not develop or may not be sustained after this offering. The initial public offering price of our common stock was determined by negotiations between us and representatives of the underwriters, based on numerous factors which we discuss in the Underwriting section of this prospectus. This price may not be indicative of the market price for our common stock after this initial public offering. The market price of our common stock could be subject to significant fluctuations after this offering, and may decline below the initial public offering price. You may not be able to resell your shares at or above the initial public offering price. The following factors could affect our stock price:

- our operating and financial performance and prospects;
- quarterly variations in the rate of growth of our financial indicators, such as net income per share, net income and revenues;
- changes in revenue or earnings estimates or publication of reports by equity research analysts;
- speculation in the press or investment community;
- sales of our common stock by us, Harold G. Hamm or other shareholders, or the perception that such sales may occur;
- general market conditions, including fluctuations in commodity prices; and
- domestic and international economic, legal and regulatory factors unrelated to our performance.

The stock markets in general have experienced extreme volatility that has often been unrelated to the operating performance of particular companies. These broad market fluctuations may adversely affect the trading price of our common stock.

Following this offering, our Chairman and Chief Executive Officer will own approximately % of our outstanding common stock, giving him influence and control in corporate transactions and other matters, including a sale of our company.

As of the closing of this offering, Harold G. Hamm, our Chairman and Chief Executive Officer, will beneficially own shares of our outstanding common stock (assuming no exercise of the underwriters overallotment option), representing approximately % of our outstanding common stock. As a result, Mr. Hamm will continue to be our controlling shareholder and will continue to be able to control the election of our directors, determine our corporate and management policies and determine, without the consent of our other shareholders, the outcome of certain corporate transactions or other matters submitted to our shareholders for approval, including potential mergers or acquisitions, asset sales and other significant corporate transactions. As controlling shareholder, Mr. Hamm could cause, delay or prevent a change of control of our company. The interests of Mr. Hamm may not coincide with the interests of other holders of our common stock.

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Several affiliated companies controlled by Mr. Hamm provide oilfield, gathering and processing, marketing and other services to us. We expect these transactions will continue in the future and may result in conflicts of interest between Mr. Hamm s affiliated companies and us. We can provide no assurance that any such conflicts will be resolved in our favor.

Purchasers of common stock in this offering will experience immediate and substantial dilution of $ per share.

Based on an assumed initial public offering price of $ per share, purchasers of our common stock in this offering will experience an immediate and substantial dilution of $ per share in the pro forma as adjusted net tangible book value per share of common stock from the initial public offering price, and our pro forma as adjusted net tangible book value as of March 31, 2006 after giving effect to this offering would be $2.00 per share. See Dilution for a complete description of the calculation of net tangible book value.

The requirements of being a public company, including compliance with the reporting requirements of the Exchange Act and the requirements of the Sarbanes-Oxley Act, may strain our resources, increase our costs and distract management; and we may be unable to comply with these requirements in a timely or cost-effective manner.

As a public company with listed equity securities, we will need to comply with new laws, regulations and requirements, certain corporate governance provisions of the Sarbanes-Oxley Act of 2002, related regulations of the SEC and the requirements of the New York Stock Exchange (NYSE) with which we are not required to comply as a private company. Complying with these statutes, regulations and requirements will occupy a significant amount of time of our board of directors and management and will increase our costs and expenses. We will need to:

- institute a more comprehensive compliance function;
- design, establish, evaluate and maintain a system of internal controls over financial reporting in compliance with the requirements of Section 404 of the Sarbanes-Oxley Act of 2002 and the related rules and regulations of the SEC and the Public Company Accounting Oversight Board;
- comply with rules promulgated by the NYSE;
- prepare and distribute periodic public reports in compliance with our obligations under the federal securities laws;
- establish new internal policies, such as those relating to disclosure controls and procedures and insider trading;
- involve and retain to a greater degree outside counsel and accountants in the above activities; and
- establish an investor relations function.

In addition, we also expect that being a public company subject to these rules and regulations will require us to accept less director and officer liability insurance coverage than we desire or to incur substantial costs to obtain coverage. These factors could also make it more difficult for us to attract and retain qualified members of our board of directors, particularly to serve on our audit committee, and qualified executive officers. As a result, compliance with the requirements of the Sarbanes-Oxley Act could have a material adverse effect on our business.

Failure by us to achieve and maintain effective internal control over financial reporting in accordance with the rules of the SEC could harm our business and operating results and/or result in a loss of investor confidence in our financial reports, which could have a material adverse effect on our business and stock price.

We are in the process of evaluating our internal controls systems to allow management to report on, and our independent auditors to audit, our internal controls over financial reporting. We will be performing the system

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and process evaluation and testing (and any necessary remediation) required to comply with the management certification and auditor attestation requirements of Section 404 of the Sarbanes-Oxley Act of 2002. We will be required to comply with Section 404 for the year ending December 31, 2007. However, we cannot be certain as to the timing of completion of our evaluation, testing and remediation actions or the impact of the same on our operations. Furthermore, upon completion of this process, we may identify control deficiencies of varying degrees of severity under applicable SEC and Public Company Accounting Oversight Board rules and regulations that remain unremediated. As a public company, we will be required to report, among other things, control deficiencies that constitute a material weakness or changes in internal controls that, or that are reasonably likely to, materially affect internal controls over financial reporting. A material weakness is a significant deficiency or combination of significant deficiencies that results in more than a remote likelihood that a material misstatement of the annual or interim consolidated financial statements will not be prevented or detected. If we fail to implement the requirements of Section 404 in a timely manner, we might be subject to sanctions or investigation by regulatory authorities such as the SEC. In addition, failure to comply with Section 404 or the report by us of a material weakness may cause investors to lose confidence in our consolidated financial statements, and our stock price may be adversely affected as a result. If we fail to remedy any material weakness, our consolidated financial statements may be inaccurate, we may face restricted access to the capital markets and our stock price may be adversely affected.

We have no plans to pay dividends on our common stock, and therefore, you may not receive funds without selling your shares.

While we paid a cash dividend of approximately $60.0 million to our shareholders for tax purposes and, subject to forfeiture, to holders of unvested restricted stock in April 2006, we do not anticipate paying any additional cash dividends on our common stock in the foreseeable future. We currently intend to retain future earnings, if any, to finance the expansion of our business. Our future dividend policy is within the discretion of our board of directors and will depend upon various factors, including our business, financial condition, results of operations, capital requirements and investment opportunities.

We are a controlled company within the meaning of NYSE rules and, as a result, we will qualify for, and may rely on, exemptions from certain corporate governance requirements.

Because Harold G. Hamm will beneficially own in excess of 50% of our outstanding shares of common stock after the completion of this offering, he will be able to control the composition of our board of directors and direct our management and policies. We also will be deemed to be a controlled company under the rules of the NYSE. Under these rules, we are not required to comply with certain corporate governance requirements of the NYSE, including:

- the requirement that a majority of our board of directors consist of independent directors;
- the requirement that we have a nominating/corporate governance committee that is composed entirely of independent directors with a written charter addressing the committee s purpose and responsibilities; and
- the requirement that we have a compensation committee that is composed entirely of independent directors with a written charter addressing the committee s purpose and responsibilities.

Following this offering, we may utilize some or all of these exemptions. Accordingly, you may not have the same protections afforded to shareholders of companies that are subject to all of the corporate governance requirements of the NYSE. Mr. Hamm s significant ownership interest could adversely affect investors perceptions of our corporate governance.

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Provisions in our organizational documents and under Oklahoma law could delay or prevent a change in control of our company, which could adversely affect the price of our common stock.

We are an Oklahoma corporation. The existence of some provisions in our organizational documents, which we will amend and restate prior to the closing of this offering, and under Oklahoma law could delay or prevent a change in control of our company, which could adversely affect the price of our common stock. The provisions in our amended and restated certificate of incorporation and bylaws that could delay or prevent an unsolicited change in control of our company include a staggered board of directors, board authority to issue preferred stock and advance notice provisions for director nominations or business to be considered at a shareholder meeting. See Description of Capital Stock Anti-Takeover Effects of Provisions of Our Certificate of Incorporation and Bylaws and of Oklahoma Law.

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Use of Proceeds

We will not receive any proceeds from the sale of the shares of common stock by the selling shareholder. We estimate that the selling shareholder will receive net proceeds of approximately $ million from the sale of the shares of our common stock in this offering based upon the assumed initial public offering price of $ per share, after deducting underwriting discounts. We will pay all expenses relating to the selling shareholder s sale of common stock in this offering, other than underwriting discounts. If the underwriters overallotment option to purchase additional shares is exercised in full, we estimate that the selling shareholder s net proceeds will be approximately $ million.

Dividend Policy

We paid a cash dividend of approximately $60.0 million to our shareholders for tax purposes and, subject to forfeiture, to holders of unvested restricted stock in April 2006. In connection with the completion of this offering, we will convert from a subchapter S-corporation to a subchapter C-corporation, and we do not anticipate paying any additional cash dividends on our common stock in the foreseeable future. We currently intend to retain future earnings, if any, to finance the expansion of our business. Our future dividend policy is within the discretion of our board of directors and will depend upon various factors, including our results of operations, financial condition, capital requirements and investment opportunities.

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Capitalization

The following table shows our capitalization as of March 31, 2006:

- on a historical basis; and

- on a pro forma basis to reflect our conversion, concurrent with the closing of this offering, from a subchapter S-corporation to a subchapter C-corporation, reclassification of equity compensation accruals, the effect of an 11 for 1 stock split to be effected as a stock dividend prior to the consummation of this offering and other transactions for which pro forma presentation is necessary in conjunction with this offering.

We derived this table from, and it should be read in conjunction with and is qualified in its entirety by reference to, the historical consolidated financial statements and the accompanying notes included elsewhere in this prospectus. You should read this information in conjunction with these consolidated financial statements and Management s Discussion and Analysis of Financial Condition and Results of Operations.

	As of March 31, 2006	
	Historical	Pro forma
	(in thousands)	
Cash and cash equivalents	$ 10,654	$ 10,654
Long-term debt, including current maturities(1)	131,500	131,500
Shareholders equity:		
Common stock, $.01 par value; 20,000,000 shares historical, 500,000,000 shares pro forma authorized, 14,458,291 shares historical, 159,041,201 pro forma issued and outstanding(3)	144	1,590
Additional paid-in capital(3)(4)	27,087	139,239
Retained earnings(2)(4)	292,509	65,140
Accumulated other comprehensive loss, net of taxes	53	53
Total shareholders equity	319,793	206,022
Total capitalization	$ 451,293	$ 337,522

(1) We paid a cash dividend of approximately $60.0 million to our shareholders for tax purposes and, subject to forfeiture, to holders of unvested restricted stock in April 2006. The amount borrowed to fund payment of this dividend has not been included in long-term debt as of March 31, 2006.

(2) Reflects a pro forma adjustment to recognize compensation expense for the increment between the formula-derived value at which compensation expense was recorded and the initial public offering price of $, the midpoint of the range set forth on the cover page of this prospectus.

(3) Reflects reclassification of $1.4 million from additional paid-in capital to common stock in order to adjust for the 11 for 1 stock split to be effected as a stock dividend in connection with the consummation of this offering.

(4) Pro forma adjustments reflect reclassification of the liability for equity compensation to additional paid-in capital, compensation expense as described in (2) above, expensing offering costs, a charge to operations to recognize deferred taxes upon our conversion from a non-taxable subchapter S-corporation to a taxable subchapter C-corporation, the reclassification described in (3) above, and reclassification of undistributed earnings generated during the period of time we were organized as a subchapter S-corporation to additional paid-in capital in connection with our conversion to a subchapter C-corporation.

The following table reconciles historical additional paid-in capital and retained earnings to the pro forma amounts:

	Additional Paid-In Capital	**Retained Earnings**
	(in thousands)	
Historical	$ 27,087	$ 292,509
Reclassification of liability for equity compensation	15,479	
Compensation expense		
Offering costs		(1,350)
Deferred taxes on C-corporation conversion		(127,900)
Reclassification as described in (3) above	(1,446)	
Reclassification of undistributed earnings	98,119	(98,119)
Pro forma	$ 139,239	$ 65,140

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Dilution

Dilution is the amount by which the offering price paid by purchasers of common stock sold in this offering will exceed the net tangible book value per share of common stock after the offering. On a pro forma basis as of March 31, 2006, after giving effect to estimated offering expenses, our net tangible book value was $318.4 million, or $2.01 per share of common stock. Purchasers of common stock in this offering will experience substantial and immediate dilution in net tangible book value per share of common stock for financial accounting purposes, as illustrated in the following table:

Assumed initial public offering price per share		$
Net tangible book value per share as of March 31, 2006	$ 2.01	
Decrease per share attributable to the offering	$ (0.01)	
Pro forma net tangible book value per share after the offering		2.00
Dilution in pro forma as adjusted net tangible book value per share to new investors		$

The average price per share at which our existing shareholders purchased shares of our common stock was $0.17 as compared to the assumed initial public offering price per share of $ paid by new investors.

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Selected Historical and Pro Forma

Consolidated Financial Information

This section presents our selected historical and pro forma consolidated financial data. The selected historical consolidated financial data presented below is not intended to replace our historical consolidated financial statements.

The following historical consolidated financial data, as it relates to each of the fiscal years ended December 31, 2001 through 2005, has been derived from our audited historical consolidated financial statements for such periods. The following historical financial data, as it relates to each of the three month periods ended March 31, 2005 and 2006, has been derived from our unaudited historical consolidated financial statements for such periods. You should read the following selected historical consolidated financial data in connection with Capitalization, Management s Discussion and Analysis of Financial Condition and Results of Operations and our historical consolidated financial statements and related notes included elsewhere in this prospectus. The selected historical consolidated results are not necessarily indicative of results to be expected in future periods.

The selected pro forma financial data reflect the tax effects of our conversion, concurrent with the closing of this offering, from a subchapter S-corporation to a subchapter C-corporation and the earnings per share impact of our 11 for 1 stock split to be effected in the form of a stock dividend concurrent with the closing of this offering.

	Year ended December 31,					Three months ended March 31,	
	2001	2002	2003	2004	2005	2005	2006
	(in thousands, except per share amounts)						
Statement of operations data:							
Revenues:							
Oil and natural gas sales	$ 112,170	$ 108,752	$ 138,948	$ 181,435	$ 361,833	$ 59,728	$ 99,768
Crude oil marketing and trading(1)	245,872	152,092	169,547	226,664			
Oil and natural gas service operations	6,047	5,739	9,114	10,811	13,931	4,360	3,997
Total revenues	364,089	266,583	317,609	418,910	375,764	64,088	103,765
Operating costs and expenses:							
Production expense	31,859	32,299	40,821	43,754	52,754	11,159	15,562
Production tax	8,385	7,729	10,251	12,297	16,031	3,766	4,367
Exploration expense	15,863	10,229	17,221	12,633	5,231	789	2,082
Crude oil marketing and trading(1)	245,003	152,718	166,731	227,210			
Oil and gas service operations	2,820	3,485	5,641	6,466	7,977	2,427	2,118
Depreciation, depletion, amortization and accretion	25,659	29,010	40,256	38,627	49,802	9,408	13,292
Property impairments	10,113	25,686	8,975	11,747	6,930	1,907	1,415
General and administrative(2)	6,199	8,668	9,604	12,400	31,266	7,773	7,936
(Gain) loss on sale	(3,423)	(223)	(589)	150	(3,026)	(2,913)	(222)

Total operating costs and expenses	$ 342,478	$ 269,601	$ 298,911	$ 365,284	$ 166,965	$ 34,316	$ 46,550

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	Year ended December 31,					Three months ended March 31,	
	2001	2002	2003	2004	2005	2005	2006
	(in thousands, except per share amounts)						
Income (loss) from operations	$ 21,611	$ (3,018)	$ 18,698	$ 53,626	$ 208,799	$ 29,772	$ 57,215
Other income (expense)							
Interest expense	(15,324)	(18,216)	(19,761)	(23,617)	(14,220)	(3,779)	(2,485)
Loss on redemption on bonds				(4,083)			
Other	645	912	295	890	867	85	320
Total other income (expense)	(14,679)	(17,304)	(19,466)	(26,810)	(13,353)	(3,694)	(2,165)
Income (loss) from continuing operations before income taxes	6,932	(20,322)	(768)	26,816	195,446	26,078	55,050
Provision for income taxes(3)					1,139	1,139	
Income (loss) from continuing operations	6,932	(20,322)	(768)	26,816	194,307	24,939	55,050
Discontinued operations(4)	4,735	290	946	1,680			
Loss on sale of discontinued operations(4)				(632)			
Income (loss) before cumulative effect of change in accounting principle	11,667	(20,032)	178	27,864	194,307	24,939	55,050
Cumulative effect of change in accounting principle(5)			2,162				
Net income (loss)	$ 11,667	$ (20,032)	$ 2,340	$ 27,864	$ 194,307	$ 24,939	$ 55,050
Basic earnings (loss) per share:							
From continuing operations	$ 0.48	$ (1.41)	$ (0.05)	$ 1.87	$ 13.52	$ 1.74	$ 3.83
From discontinued operations(4)	0.33	0.02	0.06	0.11			
Loss on sale of discontinued operations(4)				(0.04)			
Before cumulative effect of change in accounting principle	0.81	(1.39)	0.01	1.94	13.52	1.74	3.83
Cumulative effect of change in accounting principle			0.15				
Net income (loss) per share	$ 0.81	$ (1.39)	$ 0.16	$ 1.94	$ 13.52	$ 1.74	$ 3.83
Shares used in basic earnings (loss) per share	14,369	14,369	14,369	14,369	14,369	14,369	14,369
Diluted earnings (loss) per share:							
From continuing operations	$ 0.48	$ (1.41)	$ (0.05)	$ 1.85	$ 13.42	1.72	3.80
From discontinued operations(4)	0.33	0.02	0.06	0.12			
Loss on sale of discontinued operations(4)				(0.04)			
Before cumulative effect of change in accounting principle	0.81	(1.39)	0.01	1.93	13.42	1.72	3.80
Cumulative effect of change in accounting principle			0.15				
Net income (loss) per share	$ 0.81	$ (1.39)	$ 0.16	$ 1.93	$ 13.42	$ 1.72	$ 3.80

Shares used in diluted earnings (loss) per share	14,393	14,369	14,369	14,476	14,482	14,467	14,489

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	Year ended December 31,					Three months ended March 31,	
	2001	2002	2003	2004	2005	2005	2006
	(in thousands, except per share amounts)						
Pro forma C-corporation and stock split data:							
Income (loss) from continuing operations before income taxes	$ 6,932	$ (20,322)	$ (768)	$ 26,816	$ 195,446	$ 26,078	$ 55,050
Pro forma provision (benefit) for income taxes attributable to operations	2,634	(7,722)	(292)	10,190	74,269	9,910	20,919
Pro forma income (loss) from operations after tax	4,298	(12,600)	(476)	16,626	121,177	16,168	34,131
Discontinued operations net of tax(4)	2,936	180	587	1,042			
Loss on sale of discontinued operations(4)				(392)			
Cumulative effect of change in accounting principle net of tax			1,340				
Pro forma net income (loss)	$ 7,234	$ (12,420)	$ 1,451	$ 17,276	$ 121,177	$ 16,168	$ 34,131
Pro forma basic earnings (loss) per share	$ 0.05	$ (0.08)	$ 0.01	$ 0.11	$ 0.77	$ 0.10	$ 0.22
Pro forma diluted earnings (loss) per share	0.05	(0.08)	0.01	0.11	0.76	0.10	0.21
Other financial data:							
Cash dividends per share:	$	$	$	$ 1.04	$ 0.14	$	$ 4.15
EBITDAX (6)	78,626	63,288	88,750	116,498	285,344	45,351	77,617
Net cash provided by operations	63,413	46,997	65,246	93,854	265,265	21,717	74,889
Net cash used in investing	(106,384)	(113,295)	(108,791)	(72,992)	(133,716)	(15,479)	(58,764)
Net cash provided by (used in) financing	43,045	61,593	43,302	(7,245)	(141,467)	(14,239)	(11,500)
Capital expenditures	111,023	113,447	114,145	94,307	144,800	26,332	59,659

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	Year ended December 31,					Three months ended March 31,	
	2001	2002	2003	2004	2005	2005	2006
	(in thousands, except per share amounts)						
Balance sheet data (at period end):							
Cash and cash equivalents	$ 7,225	$ 2,520	$ 2,277	$ 15,894	$ 6,014	$ 7,886	$ 10,654
Property and equipment, net	317,331	367,903	439,432	434,339	509,393	436,267	553,360
Total assets	354,485	406,677	484,988	504,951	600,234	512,799	651,644
Long-term debt, including current maturities	183,395	247,105	290,920	290,522	143,000	267,000	131,500
Shareholders equity	135,113	115,081	116,932	130,385	324,730	156,453	319,793

(1) Crude oil marketing and trading captions consist of our marketing activities under which crude oil production was sold at the wellhead and transported to a local hub where we purchased the barrels back to exchange at Cushing, Oklahoma in order to minimize pricing differentials with the NYMEX oil futures contract. We adopted Emerging Issues Task Force (EITF) 04-13 on January 1, 2005, which allowed certain purchase and sales transactions with the same counterparty to be combined and accounted for as a single transaction under the guidance of Accounting Principles Board Opinion No. 29. In 2005, we netted $39.8 million of crude oil marketing and trading revenues and $39.7 million of crude oil marketing and trading expenses under oil and natural gas sales. Prior to the adoption of EITF 04-13, we presented crude oil marketing and trading revenues and expenses gross under the guidance provided by EITF 99-19, Reporting Revenues Gross as a Principal and/or Net as an Agent. Effective March 2005, we ceased marketing our crude oil production under these arrangements. Thereafter, we have sold our crude oil at the wellhead. Certain of these sales have been to our affiliates, as described under Certain Relationships and Related Party Transactions.

(2) We have included stock-based compensation of $0.0 million, $0.2 million, $0.2 million, $2.0 million, $13.7 million, $3.4 million and $3.3 million in general and administrative expenses for the years ended December 31, 2001, 2002, 2003, 2004 and 2005 and for the three months ended March 31, 2005 and 2006, respectively. Our stock based compensation plan requires us to purchase vested shares at the employee s request based on an internally calculated value of our stock. Amounts noted herein represent the increase in our liability associated with our purchase obligation. The valuation is based on the book value of our shareholders equity adjusted for our PV-10 as of each calendar quarter. Our requirement to purchase vested shares will be eliminated once we begin reporting under Section 12 of the Exchange Act. As a result of this change, we will recognize a charge of approximately $ upon completion of this offering, assuming an offering price at the midpoint of the range set forth on the cover page of this prospectus. See Capitalization.

(3) Properties owned by us at May 31, 1997, the date we converted into a subchapter S-corporation from a subchapter C-corporation, may be subject to federal taxation if sold for an amount in excess of the then tax basis for the sold assets. During 2005, we incurred federal taxes due to the sale of assets acquired prior to May 31, 1997.

(4) In July 2004, we sold all of the outstanding stock in Continental Gas, Inc., a wholly owned subsidiary, to our shareholders. The Continental Gas, Inc. assets included seven gas gathering systems and three gas-processing plants. These assets represented our entire gas gathering, marketing and processing segment. We have accounted for these operations as discontinued operations.

(5) We adopted Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations and recorded the cumulative effect of the change in accounting principle on January 1, 2003.

(6) EBITDAX represents earnings before interest expense, income taxes (when applicable), depreciation, depletion, amortization and accretion, property impairments, exploration expense and non-cash compensation expense. EBITDAX is not a measure of net income or cash flow as determined by generally accepted accounting principles (GAAP). EBITDAX should not be considered as an alternative to, or more meaningful than, net income or cash flow as determined in accordance with GAAP or as an indicator of a company s operating performance or liquidity. Certain items excluded from EBITDAX are significant components in understanding and assessing a company s financial performance, such as a company s cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of EBITDAX. Our computations of EBITDAX may not be comparable to other similarly titled measures of other companies. We believe that EBITDAX is a widely followed measure of operating performance and may also be used by investors to measure our ability to meet future debt service requirements, if any. Our credit facility requires that we maintain a total debt to EBITDAX ratio of no greater than 3.75 to 1 on a rolling four-quarter basis. Our credit facility defines EBITDAX consistently with the definition of EBITDAX utilized and presented by us. At December 31, 2005, this ratio was approximately 0.5 to 1, and at March 31, 2006, this ratio was approximately 0.4 to 1. The following table represents a

reconciliation of our net income (loss) to EBITDAX:

	Year ended December 31,					Three months ended March 31,	
	2001	2002	2003	2004	2005	2005	2006
						(unaudited)	
			(in thousands)				
Net income (loss)	$ 11,667	$ (20,032)	$ 2,340	$ 27,864	$ 194,307	$ 24,939	$ 55,050
Interest expense	15,324	18,216	19,761	23,617	14,220	3,779	2,485
Provision for income taxes					1,139	1,139	
Depreciation, depletion, amortization and accretion	25,659	29,010	40,256	38,627	49,802	9,408	13,292
Property impairments	10,113	25,686	8,975	11,747	6,930	1,907	1,415
Exploration expense	15,863	10,229	17,221	12,633	5,231	789	2,082
Equity compensation		179	197	2,010	13,715	3,390	3,293
EBITDAX	$ 78,626	$ 63,288	$ 88,750	$ 116,498	$ 285,344	$ 45,351	$ 77,617

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Management s Discussion and Analysis of

Financial Condition and Results of Operations

The following discussion should be read in conjunction with our historical consolidated financial statements and notes, as well as the selected historical consolidated financial data included elsewhere in this prospectus.

Overview

We are engaged in oil and natural gas exploration and exploitation activities in the Rocky Mountain, Mid-Continent and Gulf Coast regions of the United States. Crude oil comprised 85% of our 116.7 MMBoe of estimated proved reserves as of December 31, 2005 and 79% of our 7,209 MBoe of production for the year then ended. We seek to operate wells in which we own an interest, and we operated wells that accounted for 97% of our PV-10 and 1,213 of our 1,434 gross wells as of December 31, 2005. By controlling operations, we are able to more effectively manage the cost and timing of exploration and development of our properties, including the drilling and fracture stimulation methods used.

Our business strategy has focused on reserve and production growth through exploration and development. For the three-year period ended December 31, 2005, we added 55,385 MBoe of proved reserves through extensions and discoveries, compared to 426 MBoe added through purchases. During this period, our production increased from 5,255 MBoe in 2003 to 7,209 MBoe in 2005. An aspect of our business strategy has been to acquire large undeveloped acreage positions in new or developing locations. As of December 31, 2005, we held approximately 1,086,000 gross (646,000 net) undeveloped acres, including 356,000 net acres in the Bakken field in Montana and North Dakota and 72,000 net acres in the New Albany Shale, Lewis Shale, Floyd Shale and Woodford Shale projects. As an early entrant in new or emerging plays, our costs to acquire undeveloped acreage have generally been less than those of later entrants into a developing play. As an example of the cost advantage of entering a play early, our per acre costs for our lease acquisitions in the North Dakota Bakken field during 2003 and 2004 were approximately 80% lower than the per acre costs paid by third parties and by us in the federal and state lease auctions for acreage near our holdings in that area during 2005. However, as an early entrant, we are exposed to the risk that the value of our undeveloped acreage is diminished by unsuccessful drilling results.

How We Evaluate Our Operations

We use a variety of financial and operational measures to assess our performance. Among these measures are the following:

(1) Volumes of oil and natural gas produced;

(2) Oil and natural gas prices realized;

(3) Volumetric operating and administrative costs; and

(4) EBITDAX.

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Volumes of Oil and Natural Gas Produced

For our operated properties in the Red River units and the Bakken field, we receive daily production estimates that enable us to monitor our production on a current basis. We believe the timeliness of this information and the control we exert as an operator enables us to respond promptly to production difficulties. Over the past three years our equivalent production volumes have increased 37% or 1,954 MBoe due primarily to a 65% increase in oil production. The following table presents our production volumes for each of the three years ended December 31, 2005 and the three months ended March 31, 2005 and 2006:

	Year Ended December 31,			Three-year period		Three months ended March 31,		Three-month period	
	2003	2004	2005	Volume increase (decrease)	Percent increase (decrease)	2005	2006	Volume Increase	Percent Increase
MBbls	3,463	3,688	5,708	2,245	65%	1,067	1,677	610	57%
MMcf	10,751	8,794	9,006	(1,745)	(16%)	2,100	2,286	186	9%
MBoe	5,255	5,154	7,209	1,954	37%	1,417	2,058	641	45%

The increase in our production has been the result of a favorable response to enhanced recovery efforts in our Red River units coupled with exploration and development within our other producing areas, primarily the Montana Bakken field.

Oil and Natural Gas Prices Realized

We market our oil and natural gas production to a variety of purchasers based on regional pricing. A significant portion of our oil and natural gas production has been marketed to affiliates as discussed under Certain Relationships and Related Party Transactions.

The following table presents the NYMEX oil and natural gas prices, our realized oil and natural gas prices, inclusive and exclusive of the effects of hedging, and the differences for each of the three years ended December 31, 2005 and the three months ended March 31, 2005 and 2006. The NYMEX oil price was determined each month as the calendar month average of the prompt NYMEX crude oil futures contract price and, the NYMEX natural gas price, as the average of the last three trading days of the prompt NYMEX natural gas futures contract price. The NYMEX natural gas futures contract price is quoted on an MMBtu basis. For purposes of comparison, in the table below the NYMEX natural gas price was converted to an Mcf basis at a one-to-one conversion:

	Year ended December 31,			Three months ended March 31,	
	2003	2004	2005	2005	2006
NYMEX oil price ($/Bbl)	$ 31.08	$ 41.95	$ 57.69	$ 50.36	$ 63.50
Realized oil price before hedging ($/Bbl)	28.88	38.85	52.45	45.53	52.81
Difference	$ 2.20	$ 3.10	$ 5.24	$ 4.83	$ 10.69
NYMEX natural gas price ($/Mcf)	5.33	6.10	8.54	6.31	9.04
Realized natural gas price ($/Mcf)	4.55	5.06	6.93	5.31	7.13
Difference	$ 0.78	$ 1.04	$ 1.61	$ 1.00	$ 1.91

The differences are subject to variability due to quality and location pricing fluctuations caused by localized supply and demand fundamentals and transportation availability. The increase in the difference between the

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NYMEX oil price and our realized oil price for the three months ended March 31, 2006 was attributable to higher oil imports and production in the Rocky Mountain region, lower demand by local Rocky Mountain refineries due to downtime for maintenance and reduced seasonal demand for gasoline and downstream transportation capacity constraints. We estimate that the company-wide difference for April and May 2006 will be approximately $12.00 per Bbl of oil. We are unable to predict when, or if, the difference will revert back to historical levels.

Our revenues and net income are sensitive to oil and natural gas prices. A $1.00 per Bbl change in realized oil prices would change our reported 2005 revenues and net income by approximately $5.7 million and $5.4 million, respectively. Similarly, a $0.10 per Mcf change in realized natural gas prices would change our reported 2005 revenues and net income by approximately $901,000 and $852,000, respectively.

For the years ended December 31, 2003 and 2004, we realized oil hedging losses of $10.1 million and $6.4 million, respectively. As a result of our limited bank borrowings and strong operational cash flows, we did not enter into any hedges for our 2005 production, and we do not currently have plans to hedge any of our 2006 production.

Volumetric Operating and Administrative Costs

Two other measures that we monitor and analyze are production expense per Boe sold and general and administrative expense per Boe sold. We believe these are important measures because they are indicators of operating cost efficiency.

The following table presents our production expense and general and administrative expense, inclusive of stock-based compensation, per Boe sold for each of the three years ended December 31, 2005 and the three months ended March 31, 2005 and 2006:

	Year ended December 31,			Three months ended March 31,	
	2003	2004	2005	2005	2006
Production expense ($/Boe)	$ 7.77	$ 8.49	$ 7.32	$ 7.88	$ 7.93
General and administrative expense ($/Boe)	1.83	2.41	4.34	5.49	4.05

Our per unit production expense increased during 2004 in connection with our enhanced recovery project in the Red River units which initially lowered volumes and increased production expense. Our per unit production expense declined in 2005 as we are experiencing higher production volumes due to continued drilling and higher production in conjunction with the completion of the enhanced recovery program. Generally as production increases, we will see increased production expense due to additional well costs, such as lifting and workover costs, and additional personnel costs although these costs may be lower on a volumetric basis due to higher production. The increase in our per unit general and administrative expense was primarily due to higher compensation expense. The largest component of the increase was equity compensation, which contributed $0.2 million, $2.0 million and $13.7 million during the years ended December 31, 2003, 2004 and 2005, respectively, and $3.4 million and $3.3 million during the three months ended March 31, 2005 and 2006, respectively. The increases in equity compensation were attributable to additional equity grants and a higher per share valuation resulting from annual increases in our PV-10. We compete with other companies for personnel, particularly in the operational and technical (engineering and geologic) aspects of our business. To remain competitive, we compare the compensation we pay our employees to that of our competitors through surveys, employee feedback and other means. We have experienced higher compensation expense due to competitive pressures, normal merit increases and incentive compensation. Our incentive compensation has increased due to improving operating results. During 2004, we recorded incentive compensation of $413,000 compared to $4.0 million in 2005.

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EBITDAX

We calculate and define EBITDAX as net income before interest expense, income taxes (when applicable), depreciation, depletion, amortization and accretion, property impairments, exploration expense and non-cash compensation expense. EBITDAX is used as a financial measure by our management team and by other users of our consolidated financial statements such as our commercial bank lenders, investors, research analysts and other to assess:

- Our operating performance and return on capital in comparison to other independent exploration and production companies, without regard to financial or capital structure;
- The financial performance of our assets and valuation of the entity without regard to financing methods, capital structure or historical cost basis; and
- Our ability to generate cash sufficient to pay interest costs and support our indebtedness.

The following table presents our EBITDAX for each of the three years ended December 31, 2005 and the three months ended March 31, 2005 and 2006 (in thousands):

	Year ended December 31,			Three months ended March 31,	
	2003	**2004**	**2005**	**2005**	**2006**
EBITDAX	$ 88,750	$ 116,498	$ 285,344	$ 45,351	$ 77,617

EBITDAX is a financial measure that is reported to our lenders each calendar quarter. Our credit facility requires that our total debt to EBITDAX ratio be no greater that 3.75 to 1 on a rolling four quarter basis. This ratio was 0.5 to 1 at December 31, 2005 and 0.4 to 1 at March 31, 2006. Our credit facility defines EBITDAX consistently with the definition of EBITDAX utilized and presented by us. EBITDAX is not and should not be considered as an alternative to net income, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP. For a reconciliation of our consolidated net income (loss) to EBITDAX, see footnote (6) to Summary Historical and Pro Forma Consolidated Financial Data.

Recent Events

Payment of Cash Dividend. On April 13, 2006, we paid a cash dividend of approximately $60.0 million to our shareholders for tax purposes and, subject to forfeiture, to holders of unvested restricted stock. In connection with the completion of this offering, we will convert from a subchapter S-corporation to a subchapter C-corporation, and we do not anticipate paying any additional cash dividends on our common stock in the foreseeable future.

NYMEX and Related Oil Price Differential. The difference between the calendar month average of the NYMEX crude oil prices and our realized crude oil prices increased in the Rocky Mountain region during the first quarter 2006. For the year ended December 31, 2005, the average company-wide difference was $5.24 per Bbl. The company-wide difference for January, February and March 2006 was $7.95, $10.70 and $15.00 per Bbl, respectively, and is estimated to be approximately $12.00 per Bbl of oil for April and May 2006. Factors affecting the difference include higher oil imports and production in the region, lower demand by local refineries due to downtime for maintenance and reduced seasonal demand for gasoline and downstream transportation capacity constraints. We are unable to predict when, or if, the difference will revert back to historical levels.

Oil Storage; Production Curtailment. Due to downstream transportation constraints in the Rocky Mountain region, one of our oil purchasers was unable to accept delivery of a portion of our March 2006 sales volumes. As a result, we stored approximately 3,000 net Bbls of oil per day of production in Guernsey, Wyoming. We expect to sell the stored oil in May 2006. As a result of the same market disruption, we shut in wells in the Red River

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units representing approximately 1,700 net Bbls of oil per day. For the month of April 2006, our wells in the region were on production for the full month, and we sold all of the production from those wells except for three to five days of downtime due to loss of electricity in the area as a result of a snowstorm.

Acquisition of Banner Pipeline Company. For the year ended December 31, 2005, oil sales to Banner Pipeline Company, L.L.C., which was wholly owned by our principal shareholder, accounted for approximately 19% of our total oil and gas sales. In February 2006, we decided to market the majority of our crude oil in the Rocky Mountain region directly or through a wholly owned subsidiary rather than through an affiliate, and, as Banner has existing contacts and relationships with crude oil purchasers, we decided to purchase Banner. On March 30, 2006, we acquired Banner for approximately $8.8 million, the book value of working capital, principally cash, accounts receivable, crude oil inventory and accounts payable.

Acreage Acquisition. In April 2006, we purchased a 50% interest in 135,000 acres in the Marfa Basin in Presidio and Brewster Counties, Texas as well as overriding royalty interests covering a portion of the acreage for approximately $7 million. We plan to re-enter a well on the acreage to test the Woodford and Barnett equivalent shales during the second half of 2006.

Results of Operations

The following tables present selected financial and operating information for each of the three years ended December 31, 2005 and the three months ended March 31, 2005 and 2006:

	Year ended December 31,			Three months ended March 31,	
	2003	**2004**	**2005**	**2005**	**2006**
	(in thousands, except price data)				
Oil and natural gas sales	$ 138,948	$ 181,435	$ 361,833	$ 59,728	$ 99,768
Total revenues(1)	317,609	418,910	375,764	64,088	103,765
Operating costs and expenses(1)	298,911	365,284	166,965	34,316	46,550
Other income (expense)	(19,466)	(26,810)	(13,353)	(3,694)	(2,165)
Income (loss) from continuing operations before income taxes	(768)	26,816	195,446	26,078	55,050
Provision for income taxes			1,139	1,139	
Income (loss) from continuing operations	(768)	26,816	194,307	24,939	55,050
Discontinued operations	946	1,680			
Loss on sale of discontinued operations		(632)			
Cumulative effect of a change in accounting principle	2,162				
Net income	$ 2,340	$ 27,864	$ 194,307	$ 24,939	$ 55,050

Production volumes:					
Oil (MBbl)(2)	3,463	3,688	5,708	1,067	1,677
Natural gas (MMcf)	10,751	8,794	9,006	2,100	2,286
Oil equivalents (MBoe)	5,255	5,154	7,209	1,417	2,058
Average prices(2):					
Oil, without hedges ($/Bbl)	$ 28.88	$ 38.85	$ 52.45	$ 45.53	$ 52.81
Oil, with hedges ($/Bbl)	25.98	37.12	52.45	45.53	52.81
Natural gas ($/Mcf)	4.55	5.06	6.93	5.31	7.13
Oil equivalents, without hedges ($/Boe)	28.35	36.45	50.19	42.15	50.86
Oil equivalents, with hedges ($/Boe)	26.44	35.20	50.19	42.15	50.86

(1) Revenues for 2003 and 2004 include $169,547,000 and $226,664,000, respectively, for crude oil marketing and trading and operating expenses include $166,731,000 and $227,210,000, respectively, for crude oil marketing and trading.

(2) Oil sales volumes are 96 MBbls less than oil production volumes for the three months ended March 31, 2006. Average prices have been calculated using sales volumes.

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Three Months Ended March 31, 2006 Compared to the Three Months Ended March 31, 2005

Revenues

Oil and Natural Gas Sales. Oil and natural gas sales increased $40.0 million or 67% during the three months ended March 31, 2006 as compared to the comparable March 31, 2005 period. The higher level of sales was attributable to an increase in sales volumes from 1,417 MBoe to 1,962 MBoe and a rise in our realized price per Boe from $42.15 to $50.86. During the three months ended March 31, 2006 the difference between NYMEX prices and our realized price for crude oil widened to $10.69 as compared to the average for 2005 of $5.24. Among the factors contributing to the higher difference were higher oil imports and production in the Rocky Mountain region, refinery downtime in the Rocky Mountain region for maintenance which reduced demand, downstream transportation capacity constraints, and reduced seasonal demand for gasoline. We estimate our company-wide crude oil differential for April and May will be $12.00 per Bbl. We are unable to predict when and if the differential will revert back to historical levels. Due to downstream transportation constraints in the Rocky Mountain region, one of our oil purchasers was unable to accept delivery of a portion of our March 2006 sales volumes. As a result, we stored approximately 3,000 net Bbls of oil per day of production in Guernsey, Wyoming. We expect to sell the stored oil in May 2006. As a result of the same market disruption, we shut in wells in the Red River units representing approximately 1,700 net Bbls of oil per day. For the month of April 2006, our wells in the region were on production for the full month and we sold all of the production from those wells.

The following tables reflect our production by product and region for the periods presented:

	Three Months ended March 31,				
	2005		2006		
	Volume	Percent	Volume	Percent	Percent increase
Oil (MBbl)(1)	1,067	75%	1,677	81%	57%
Natural Gas (MMcf)	2,100	25%	2,286	19%	9%
Total (MBoe)	1,417	100%	2,058	100%	45%

	Three Months ended March 31,				
	2005		2006		
	MBoe	Percent	MBoe	Percent	Percent increase
Rocky Mountain(1)	985	69%	1,586	77%	61%
Mid-Continent	322	23%	353	17%	10%
Gulf Coast	110	8%	119	6%	8%
Total MBoe	1,417	100%	2,058	100%	46%

(1) Oil sales volumes are 96 MBbls less than oil production volumes for the three months ended March 31, 2006.

Oil volumes increased 57% or 610 MBbls during the three months ended March 31, 2006 in comparison to the three months ended March 31, 2005. Production increases in the Bakken field contributed incremental volumes in excess of 2005 levels of 285 MBbls, and the Red River units contributed 308 MBbls of incremental production. Initial production commenced in the Bakken field in August 2003 and has increased thereafter as new wells have begun production in excess of 2005 levels. Our well count in the Bakken field increased from 37 gross (19 net) wells at March 31, 2005 to 69 gross (40 net) wells at March 31, 2006. Favorable results from the enhanced recovery program have been the primary contributor to production growth in the Red River units.

Oil and Natural Gas Service Operations. Revenues generated by oil and natural gas service operations declined during 2006 due to a decline in reclaimed oil income of $0.5 million which was offset by a slight increase in saltwater disposal income of $0.1 million. The related oil and natural gas service operations expenses declined in 2006 due to processing approximately 22,000 fewer barrels at the central treating unit, along with a reduction in yard expenses and vehicle expenses in the 2006 period.

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Operating Costs and Expenses

Production expense and tax. Production expenses increased $4.4 million during the three months ended March 31, 2006 in comparison to the three months ended March 31, 2005 primarily due to higher production volumes and rising energy costs. Production expenses generally increase as production rises. During the three months ended March 31, 2006, sales volumes increased 38% from the prior year period. Our Red River units have utilized higher levels of electricity as we have added compressors and increased production. Although production taxes generally increased, due to increased revenue, they declined as a percentage of oil and natural gas sales from 6.3% to 4.4% primarily as a result of tax incentives in Montana which provide for a production tax rate of 0.5% on oil and natural gas sales for the first 18 months of production.

On a unit of sales basis, production expense and production tax were as follows:

	Three Months ended March 31,		Percent increase (decrease)
	2005	2006	
Production expense ($/Boe)	$ 7.88	$ 7.93	1%
Production tax ($/Boe)	2.66	2.23	(16%)
Production expense and tax ($/Boe)	$ 10.54	$ 10.16	(4%)

Exploration expense. Exploration expense increased from $789,000 to $2.1 million due to an increase in dry hole expense being recognized during the first three months of 2006 of approximately $637,000 and an increase in seismic charges of $497,000 in comparison to the prior year period.

Depreciation, depletion, amortization and accretion. Depreciation, depletion, amortization and accretion expense increased $3.9 million to $13.3 million during the three months ended March 31, 2006 compared to the comparable period in 2005. This increase was predominantly attributable to increased sales volumes of 545 MBoe, or 38%. The rate per Boe increased $0.16 per Boe from $6.21 per Boe in the first quarter of 2005 to $6.37 per Boe in the first quarter of 2006. Accretion expense was $260,000 and $442,000 in the first quarter of 2005 and 2006, respectively.

Property impairments. We recognized property impairments of $1.4 million during the first three months of 2006, a decrease from $1.9 million during the same time period in 2005. Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of certain proved undeveloped reserves. Individually significant non-producing properties are periodically assessed for impairment of value and a loss is recognized at the time of impairment by providing an impairment allowance. Other non-producing properties are amortized on a composite method based on our estimated experience of successful drilling and the average holding period. Impairment of non-producing properties was $832,000 and approximately $1.4 million for March 31, 2005 and 2006, respectively.

Impairment provisions for developed oil and gas properties were approximately $1.1 million during the three months ended March 31, 2005 and $42,000 during the three months ended March 31, 2006. The majority of the impairment recognized in these periods relates to fields comprised of a small number of properties or single wells on which we do not expect sufficient future net cash flows to recover our carrying cost.

General and administrative. General and administrative expense rose by $163,000, or 2%, to approximately $7.9 million in the first three months of 2006 compared to the first three months of 2005. The primary contributor to the increase was expenses associated with our contemplated initial public offering, which added approximately $0.5 million to general and administrative expense, partially offset by lower equity compensation expense during the first three months of 2006.

Gain on sale. Gain on sale in the first three months of 2006 decreased $2.7 million compared to the same time period in 2005 mainly due to gains on asset sales and losses on capital lease transactions during 2005, which

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lacked comparable size transactions during the first three months of 2006. In the first quarter of 2005, we recorded a gain of $5.8 million for the sale of 45 properties in the Midfork Lustre area. During the same time period in 2005, we also recorded a loss of $3.1 million on the termination of capital leases on compressors.

Interest expense. Interest expense decreased by $1.3 million or 34% in 2006 due to a lower average outstanding debt balance on our credit facility of $131.5 million compared to $219.0 million for the first three months of 2005. The weighted average interest on our credit facility was 6.5% at March 31, 2006 compared to 4.8% at March 31, 2005. Additionally, in the 2005 period, we had an outstanding balance due to our principal shareholder for $48.0 million which was paid in full during December 2005. Interest on this note was 6%.

Provision for Income Taxes. We recognized income tax expense of $1.1 million during the three months ended March 31, 2005 in connection with the sale of assets acquired prior to our conversion to a subchapter S-corporation from a subchapter C-corporation on May 31, 1997. These assets had Built in gains, as defined by Section 1374 of the Internal Revenue Code, which resulted in a taxable event for us.

Year Ended December 31, 2004 Compared to Year Ended December 31, 2005

Revenues

Oil and Natural Gas Sales. We generally market our production at the wellhead. Oil and natural gas sales increased $180.4 million or 99% to $361.8 million in 2005. The increase was attributable to higher production volumes and higher oil and natural gas prices. During 2004, our average wellhead oil price was $38.85 per Bbl and our wellhead natural gas price was $5.06 per Mcf, compared to $52.45 per Bbl for oil and $6.93 per Mcf for natural gas during 2005. The increases in our wellhead prices were due to general industry price escalations in our producing regions. Our oil sales in 2004 were reduced by a $6.4 million loss in our hedging activities. We did not hedge our production during 2005. The following tables reflect our production by product and region for the periods presented:

	Year ended December 31,				
	2004		2005		
	Volume	Percent	Volume	Percent	Percent increase
Oil (MBbl)	3,688	72%	5,708	79%	55%
Natural Gas (MMcf)	8,794	28%	9,006	21%	2%
Total (MBoe)	5,154	100%	7,209	100%	40%

	Year ended December 31,		
	2004	2005	Percent increase (decrease)

	MBoe	Percent	MBoe	Percent	
Rocky Mountain	3,279	64%	5,410	75%	65%
Mid-Continent	1,461	28%	1,361	19%	(7)%
Gulf Coast	414	8%	438	6%	6%
Total MBoe	5,154	100%	7,209	100%	40%

Production increases in our Bakken field and Red River units in the Rocky Mountain region of 1,226 MBoe and 1,051 MBoe, respectively, accounted for the growth in production for 2005. We commenced drilling our initial well in the Bakken field in May 2003 and completed it as a producing well in August 2003. Our well count in the Bakken field rose from 25 gross (14.5 net) wells at December 31, 2004 to 60 gross (34.2 net) wells at December 31, 2005. Favorable response to the enhanced recovery program was the primary factor in the production growth in the Red River units.

Crude Oil Marketing and Trading. During 2004 and the first three months of 2005, we purchased barrels back from certain of our wellhead purchasers downstream of the initial sales point to exchange at the Cushing, Oklahoma hub in order to minimize pricing differentials with the NYMEX oil futures contract. In 2005, revenues of $39.8 million and expenses of $39.7 million pertaining to these marketing activities were netted as provided by Emerging Issues Task Force (EITF) 04-13, which we adopted as of January 1, 2005. We presented these

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purchase and sale activities gross in the 2004 income statement as crude oil marketing and trading revenues of $226.7 million and crude oil marketing and trading expenses of $227.2 million under the guidance provided by EITF 99-19, Reporting Revenues Gross as a Principal and/or Net as an Agent. We ceased marketing our production in this manner in March 2005 and now generally market our production at the wellhead.

Oil and Natural Gas Service Operations. Our oil and natural gas service operations consist primarily of sales of high-pressure air and the treatment and sale of lower quality crude oil (reclaimed oil). We initiated the sale of high-pressure air from our Red River units to a third party in 2004, and recorded revenues of $2.0 million and $3.0 million during 2004 and 2005, respectively. Higher prices for reclaimed oil sold from our central treating unit in 2005 increased oil and natural gas service operations revenues by $2.2 million to $8.8 million. Associated oil and natural gas service operations expenses increased $2.0 million from 2004 compared to 2005 due principally to an increase in the costs of purchasing and treating oil for resale.

Operating Costs and Expenses

Production Expense and Tax. Our production expense increased $9.0 million or 21%. This increase was primarily due to production expense associated with the 80 gross (45.4 net) productive wells drilled during 2005, industry inflation and higher energy costs in the Red River units. On a unit of production basis, production expense fell from $8.49 per Boe in 2004 to $7.32 per Boe in 2005.

Energy costs in the Red River units increased $3.0 million in 2004 to $9.9 million in 2005. The increased energy costs were mainly due to higher electrical costs, resulting from higher production volumes, to run compressors for the high-pressure air injection and other enhanced recovery operations in the field. Workovers in this field also increased from $0.2 million in 2004 to $1.8 million in 2005.

Production tax increased $3.7 million or 30% in 2005 compared to the 99% increase in oil and gas sales. As a percentage of oil and natural gas revenues, production tax was 4.4% in 2005 compared to 6.8% in 2004. Production taxes are based on the wellhead values of production and vary by state. Additionally, some states offer exemptions or reduced production tax rates for wells that produce less than a certain quantity of oil or gas and to encourage certain activities, such as horizontal drilling and enhanced recovery projects. In the state of Montana, a horizontal well qualifies for a 0.5% production tax rate on oil and natural gas sales for the first 18 months of production. Thereafter, the production tax rate is 9.0%. All of the wells we drilled in the Montana Bakken field qualified for the reduced production tax rate.

Our oil and natural gas revenues from the Montana Bakken field increased to approximately $93.3 million in 2005 from $19.1 million in the prior year. The addition of approximately $74.2 million in oil and gas revenues at a 0.5% production tax rate was the principal reason production tax increased 30% compared to the 99% increase in oil and gas sales.

On a unit of sales basis, production expense and production tax were as follows:

	Year ended December 31,

	2004	2005	Percent decrease
Production expense ($/Boe)	$ 8.49	$ 7.32	(14)%
Production tax ($/Boe)	2.39	2.22	(7)%
Production expense and tax ($/Boe)	$ 10.88	$ 9.54	(12)%

Exploration Expense. Exploration expense decreased from 2004 to 2005 as a result of a reduction primarily in our dry hole expense from $9.5 million in 2004 to $1.4 million in 2005. The higher dry hole expense during 2004 was primarily attributable to dry holes in the Gulf Coast region with a higher per well cost.

Depreciation, Depletion, Amortization and Accretion. The depreciation, depletion and amortization (DD&A) rate per Boe decreased from $7.02 per Boe in 2004 to $6.50 per Boe in 2005. The reduction in the

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DD&A rate per Boe was mainly due to the addition of 32,427 MBoe of proved reserves during 2005. The amount of DD&A attributable to oil and gas properties increased by $10.6 million in 2005 due to increased production volumes. Accretion expense associated with our asset retirement obligations was $1.0 million and $1.6 million in 2004 and 2005, respectively.

Property Impairments. We evaluate our properties on a field-by-field basis, as may be necessary, when facts and circumstances such as downward reserve revisions or lower oil and natural gas prices indicate that their carrying amounts may not be recoverable. We recorded a $6.2 million impairment in 2004 compared to a $2.5 million impairment in 2005 on producing properties. The decrease from 2004 to 2005 was due to higher impairment charges on Gulf Coast region properties during 2004. We also evaluate our undeveloped leasehold cost and adjust the acreage valuation quarterly based on our assessment of the potential for the acreage to be developed and the market value of the acreage. Undeveloped leasehold cost is expensed over the life of the lease or transferred to the associated producing properties. Individually significant non-producing properties are periodically assessed for impairment of value and a loss is recognized if necessary. During 2004 we impaired $5.5 million of undeveloped leasehold cost compared to $4.4 million during 2005.

General and Administrative. The majority of the increase in general and administrative expense for 2005 was the result of higher wages and bonuses paid to our employees. The number of employees increased from 275 at year-end 2004 to 286 at year-end 2005, which, combined with salary adjustments and cash bonus increases, increased payroll and other employee-related expenses by $5.3 million during 2005. On a volumetric basis, our general and administrative expense, including equity compensation of $2.0 million and $13.7 million, respectively, was $2.41 per Boe and $4.34 per Boe for the years ended December 31, 2004 and 2005, respectively.

We have granted stock options and restricted stock to our employees. The terms of the grants require that, while we are a private company, we are required to purchase vested options and restricted stock at each employee s request at a per share amount derived from our shareholders equity value adjusted quarterly for our PV-10. The obligation to purchase the options is eliminated in the event we become a reporting company under Section 12 of the Exchange Act. Equity compensation expense increased from $2.0 million in 2004 to $13.7 million in 2005 primarily due to additional equity grants and a higher per share valuation resulting from the increase in our PV-10.

Interest Expense. Interest expense declined from $23.6 million in 2004 to $14.2 million in 2005. The decline in interest expense was attributable to a lower average bank indebtedness during 2005. At December 31, 2004, we had $230.0 million outstanding on our bank credit facility with an effective interest rate of 4.36% compared to $143.0 million outstanding at December 31, 2005, with an effective interest rate of 6.08%. We incurred $6.8 million and $9.3 million in interest on our credit facility in 2004 and 2005, respectively. On November 22, 2004, we signed a note with our principal shareholder for $50.0 million due March 31, 2008. The annual rate of interest was 6.00% and interest payments were due on the last day of each calendar quarter beginning December 31, 2004. We paid $308,000 and $2.9 million in interest in 2004 and 2005, respectively on this note to our principal shareholder. In December 2005, we paid the note in full to our principal shareholder. During November 2004 we utilized available borrowing capacity under our credit facility to redeem $119.5 million of our outstanding Senior Subordinated 10.25% Notes and paid a premium of $4.1 million due on the early redemption of the Notes. Total interest expense on the Senior Subordinated Notes during 2004 was $11.4 million.

Provision for Income Taxes. We recognized income tax expense of $1.1 million during the three months ended March 31, 2005 in connection with the sale of assets acquired prior to our conversion to a subchapter S-corporation from a subchapter C-corporation on May 31, 1997. These assets had Built in gains, as defined by Section 1374 of the Internal Revenue Code, which resulted in a taxable event for us.

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Discontinued Operations. In July 2004, we completed the sale of all of the outstanding stock in Continental Gas Inc. (CGI) to our shareholders for $22.6 million in cash. The sales price was representative of the fair value of the net assets based on an appraisal by an independent third party who also provided us with an opinion of the fairness from a financial point of view, of the sale of CGI to the shareholders. The CGI assets included seven natural gas gathering systems and three natural gas-processing plants. These assets represented our entire natural gas gathering, marketing and processing segment and have been classified as discontinued operations for all periods presented.

Year Ended December 31, 2003 Compared to Year Ended December 31, 2004

Revenues

Oil and Natural Gas Sales. The increase in oil and natural gas revenues from $138.9 million in 2003 to $181.4 million in 2004 was primarily attributable to higher oil and natural gas prices and reduced oil hedging losses in 2004. Oil and natural gas volumes decreased 101 MBoe from 5,255 MBoe in 2003 to 5,154 in 2004. The decrease in volumes in 2004 was mainly due to the decrease in natural gas volumes of 1,957 MMcf primarily from the Gulf Coast region. Oil and natural gas wellhead prices were $8.10 per Boe higher in 2004 compared to 2003, which offset the lower natural gas sales volumes for 2004.

The following tables present our production by product and region for the years shown:

	Year ended December 31,				
	2003		2004		Percent increase
	Volume	Percent	Volume	Percent	(decrease)
Oil (MBbl)	3,463	66%	3,688	72%	6%
Natural gas (MMcf)	10,751	34%	8,794	28%	(18)%
Total (MBoe)	5,255	100%	5,154	100%	(2)%

	Year ended December 31,				
	2003		2004		Percent increase
	MBoe	Percent	MBoe	Percent	(decrease)
Rocky Mountain	2,918	55%	3,279	64%	12%
Mid-Continent	1,659	32%	1,461	28%	(12)%
Gulf Coast	678	13%	414	8%	(39)%
Total MBoe	5,255	100%	5,154	100%	(2)%

Compared to 2003, the 2004 oil sales were higher due mainly to increased prices and slightly increased volumes. Oil production was 66% of our total produced volume for 2003, compared to 72% in 2004. The increase in oil production in 2004 was the result of response to the enhanced recovery program in the Red River units.

During 2003 and 2004, we utilized fixed-priced contracts and zero-cost collars to reduce exposure to unfavorable changes in oil and natural gas prices that are subject to significant and often volatile fluctuation. Under the fixed price contracts we received the fixed price stated in the contract. Under the zero-cost collars, if the market price of crude oil exceeded the ceiling strike price, we received the ceiling strike price and, if the market price fell below the floor strike price, we received the floor strike price. If the market price was between the floor strike price and the ceiling strike price, we received market price. Oil hedging losses of $10.1 million and $6.4 million were reported as a reduction in oil and gas revenues for the years ended December 31, 2003 and 2004, respectively.

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Crude Oil Marketing and Trading. During 2003 and 2004, we purchased barrels back from certain of our wellhead purchasers downstream of the initial sales point to exchange at the Cushing, Oklahoma hub in order to minimize pricing differentials with the NYMEX oil futures contract. We presented these purchase and sale activities gross in the 2003 and 2004 income statements as crude oil marketing and trading revenues of $169.5 million, including a trading gain of approximately $1.5 million associated with derivatives, and $226.7 million, respectively, and crude oil marketing and trading expenses of $166.7 million and $227.2 million, respectively, under the guidance provided by EITF 99-19, Reporting Revenues Gross as a Principal and/or Net as an Agent. Crude oil marketing and trading amounts increased between 2003 and 2004 due to higher volumes and commodity prices.

Oil and Natural Gas Service Operations. We initiated the sale of high-pressure air to a third party in 2004, which increased our oil and natural gas service operations revenues $2.0 million from 2003 to 2004.

Oil and natural gas service operations expense increased from 2003 to 2004 due to an additional 30 MBbls of oil treated at our central treating unit along with higher oil prices, which increased the costs of purchasing and treating oil for resale.

Operating Costs and Expenses

Production Expense and Tax. Production expense increased from $40.8 million in 2003 to $43.8 million in 2004. The $3.0 million increase was principally the result of increased energy costs in the Red River units of $3.8 million partially offset by a decrease in contract labor and outside operated well expense of $1.4 million. The commencement, during 2003, of High Pressure Air Injection (HPAI) in the Red River units contributed to the increase in energy costs.

Our production tax increased from 2003 compared to 2004 due to the increase in oil and natural gas prices and increased oil volumes in 2004. Production taxes are based on the wellhead values of production and vary across different regions. On a unit of sales basis, production expense and production tax were as follows:

	Year ended December 31,		Percent
	2003	**2004**	**increase**
Production expense ($/Boe)	$ 7.77	$ 8.49	9%
Production tax ($/Boe)	1.95	2.39	23%
Production expense and tax ($/Boe)	$ 9.72	$ 10.88	12%

Exploration Expense. Exploration expenses decreased by $4.6 million from $17.2 million in 2003 to $12.6 million in 2004. This decrease was attributable to lower dry hole expense and seismic costs in 2004.

Depreciation, Depletion, Amortization and Accretion. Depreciation, depletion and amortization (DD&A) of oil and gas properties decreased by $1.1 million to $36.2 million during 2004 as a result of lower production and a lower rate per Boe. The DD&A rate per Boe decreased from $7.10 per Boe in 2003 to $7.02 per Boe in 2004. Accretion expense associated with our asset retirement obligations was $1.2 million and $1.0 million in 2003 and 2004, respectively. Depreciation of other assets decreased by $0.3 million to $1.4 million in 2004.

Property Impairments. We evaluate, as may be necessary due to downward reserve revisions or lower oil and natural gas prices, our properties for impairment. We recorded a $3.8 million impairment in 2003 and a $6.2 million impairment primarily associated with our Gulf Coast properties in 2004.

We also evaluate our undeveloped leasehold cost and adjust the acreage valuation quarterly based on our assessment of the potential for the acreage to be developed and the market value of the acreage. Undeveloped leasehold cost is expensed over the life of the lease or transferred to the associated producing properties. Individually significant non-producing properties are periodically assessed for impairment of value and a loss is

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recognized if necessary. During 2003 we impaired $5.2 million of undeveloped leasehold cost compared to $5.5 million during 2004.

General and Administrative. The majority of the increase in general and administrative expense of $2.8 million to $12.4 million was the result of higher wages and other employee-related expenses of $2.4 million. Our general and administrative expense, including equity compensation of $0.2 million and $2.0 million, respectively, was $1.83 per Boe and $2.41 per Boe for the years ended December 31, 2003 and 2004, respectively.

During 2003 and 2004 we granted stock options to our employees. As permitted by SFAS No. 123, we have elected to follow the intrinsic value method promulgated under APB Opinion 25. The terms of the grants require that, while we are a private company, we are required to purchase vested options at each employee s request at a per share amount derived from our shareholders equity value adjusted quarterly for our PV-10. The obligation to purchase the options is eliminated in the event we become a reporting company under Section 12 of the Exchange Act. Equity compensation expense increased from 2003 compared to 2004 as a result of an increase in the formula-derived value of our shares due to higher shareholders equity and greater PV-10.

Interest Expense. The increase in interest expense from 2003 compared to 2004 was the result of higher average interest rates. At December 31, 2003 and 2004, our long term debt, including the current portion and capital leases, was $290.9 million and $290.5 million, respectively. At December 31, 2003, we had $132.9 million outstanding debt on our bank credit facility with an effective interest rate of 3.75% compared to $230.0 million outstanding debt at December 31, 2004, with an effective interest rate of 4.36%. We incurred $4.9 million and $6.8 million in interest on our bank credit facility in 2003 and 2004, respectively. On November 22, 2004, we signed a note with our principal shareholder for $50.0 million due March 31, 2008. The annual rate of interest was 6.00% and interest payments were due the last day of each calendar quarter beginning December 31, 2004. We paid $308,000 in interest to our principal shareholder in 2004. We redeemed $119.5 million of our outstanding Senior Subordinated 10.25% Notes during November 2004 and paid a premium of $4.1 million due on the early redemption of these notes. Total interest expense on these notes was $13.0 million and $11.4 million during 2003 and 2004, respectively.

Discontinued Operations. In July 2004, we completed the sale of all of the outstanding stock in CGI to our shareholders for $22.6 million in cash. The sales price was representative of the fair value of the net assets based on an appraisal by an independent third party who also provided us with an opinion of the fairness from a financial point of view, of the sale of CGI to the shareholders. The CGI assets included seven natural gas gathering systems and three natural gas-processing plants. These assets represented our entire natural gas gathering, marketing and processing segment and have been classified as discontinued operations for all periods presented.

Liquidity and Capital Resources

Our primary sources of liquidity have been cash flows generated from operating activities and financing provided by our bank credit facility and principal shareholder. In January 2005, our principal shareholder contributed $2.0 million of the previously loaned amount to us. We paid the $48.0 million outstanding balance due on our note with our principal shareholder in December 2005. We believe that funds from operating cash flows and the bank credit facility should be sufficient to meet our cash requirements inclusive of, but not limited to, normal operating needs, debt service obligations, planned capital expenditures, and commitments and contingencies for the next 12 months. We intend to fund our longer term cash requirements beyond 12 months through operating cash flows, commercial bank borrowings and access to equity and debt capital markets. Although our longer term needs may be impacted by factors discussed in the section entitled Risk Factors, such as declines in oil and natural gas prices, drilling results, ability to obtain needed capital on satisfactory terms, and

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other risks which could negatively impact production and our results of operations, we currently anticipate that we will be able to generate or obtain funds sufficient to meet our long-term cash requirements. On April 13, 2006, we paid a cash dividend of approximately $60.0 million to our existing shareholders and, subject to forfeiture, to holders of unvested restricted stock. At December 31, 2005 and March 31, 2006, we had cash and cash equivalents of $6.0 million and $10.7 million, respectively, and available borrowing capacity on our credit facility of $107.0 million and $118.5 million, respectively.

Cash Flow from Operating Activities

Our net cash provided by operating activities was $65.2 million, $93.9 million and $265.3 million for the years ended December 31, 2003, 2004 and 2005 and $21.7 million and $74.9 million for the three months ended March 31, 2005 and 2006, respectively. The increase in operating cash flows in 2005 was principally due to increased production and higher oil and natural gas prices. Additionally, hedging losses were $10.1 million and $6.4 million in 2003 and 2004, respectively. There were no hedges in place during 2005 or during the three months ended March 31, 2006.

Cash Flow from Investing Activities

During the years ended December 31, 2003, 2004 and 2005, we invested $114.1 million, $94.3 million, and $144.8 million, respectively, and during the three months ended March 31, 2005 and 2006, we invested $26.3 million and $59.7 million, respectively, in our capital program, inclusive of dry hole and seismic costs. The increase in our capital program was due to the implementation of enhanced recovery in our Red River units and additional exploration and development drilling.

Cash Flow from Financing Activities

Net cash provided by (used in) financing activities was $43.3 million for 2003, ($7.2) million for 2004, and ($141.5) million for 2005 and ($14.2) million and ($11.5) million for the three months ended March 31, 2005 and 2006, respectively. In 2004, cash used in financing activities was primarily attributable to the repurchase of our Senior Subordinated Notes. In 2005, cash used in financing activities was primarily attributable to the repayment of long-term debt. During each of the three months ended March 31, 2005 and 2006, cash used in financing activities was primarily attributable to the payment of long-term debt. Our long-term debt, including the current portion and capital leases, was $290.9 million, $290.5 million and $143.0 million at December 31, 2003, 2004 and 2005, respectively, and $131.5 million at March 31, 2006.

Credit Facility

We had $143.0 million outstanding under our bank credit facility at December 31, 2005 and $189.5 million outstanding under our bank credit facility at May 9, 2006, which includes borrowings made to pay the $60.0 million cash dividend to our shareholders. The credit facility was amended on April 12, 2006. The amended facility matures on April 12, 2011, and borrowings under our credit facility bear interest, payable quarterly, at (a) a rate per annum equal to the London Interbank Offered Rate for one, two, three or six months as offered by the lead bank plus an applicable margin ranging from 100 to 175 basis points or (b) the lead bank s reference rate. The amended credit facility has a note amount of $750 million, a borrowing base of $500 million, subject to semi-annual redetermination, and a commitment level of $300 million. The terms of the amended facility allow us to determine the commitment level at any level up to the borrowing base.

The amended credit facility contains restrictive covenants that may limit our ability to, among other things, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, change material contracts, incur liens and engage in certain other transactions without the prior consent of the lenders. The facility also requires us to maintain certain ratios as defined and further described in our credit facility: a

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Current Ratio of not less than 1.0 to 1.0, a Total Funded Debt to EBITDAX of no greater than 3.75 to 1.0. These covenants were also included in our previous credit facility. As of December 31, 2005 and March 31, 2006, we were in compliance with all covenants.

Future Capital Expenditures and Commitments

We evaluate opportunities to purchase or sell oil and natural gas properties in the marketplace and could participate as a buyer or seller of properties at various times. We seek acquisitions that utilize our technical expertise or offer opportunities to expand our existing core areas.

Expenditures for exploration and development of oil and natural gas properties are the primary use of our capital resources. We anticipate investing approximately $302 million for capital and exploration expenditures in 2006 as follows (in millions):

	Amount
Exploration and development drilling	$ 237
Capital facilities	27
Workover / recompletion	16
Land costs	16
Seismic	5
Vehicles, computers & other equipment	1
	$ 302

Our budgeted capital expenditures are expected to increase approximately 109% over the $145 million invested during 2005. We plan to invest approximately $150 million in development drilling. In the Red River units, we plan to invest approximately $67 million to drill infill wells and extend horizontal laterals on existing wells to increase production and sweep efficiency of the enhanced recovery projects. Most of the remaining development drilling budget is expected to be invested in the drilling of development wells in the Montana Bakken field. We have budgeted approximately $87 million for exploratory drilling with approximately $28 million allocated to drilling exploratory wells in the North Dakota Bakken field.

Although we cannot provide any assurance, assuming successful implementation of our strategy, including the future development of our proved reserves and realization of our cash flows as anticipated, we believe that our remaining cash balance and cash flows from operations will be sufficient to satisfy our 2006 capital budget. The actual amount and timing of our capital expenditures may differ materially from our estimates as a result of, among other things, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments.

Shareholder Distribution

In 2004, we made a distribution of $14.9 million to our shareholders and in 2005 we made a $2.0 million distribution to our shareholders. On April 13, 2006, we paid a cash dividend of approximately $60.0 million to our shareholders and, subject to forfeiture, to holders of unvested restricted stock. In connection with the completion of this offering, we will convert from a subchapter S-corporation to a subchapter C-corporation, and we do not anticipate paying any additional cash dividends on our common stock in the foreseeable future.

Expenses to be Recognized Following Completion of the Offering

We expect to recognize a charge to earnings of approximately $127.9 million to record deferred taxes as a result of our conversion to a C-corporation upon completion of this offering. This charge represents taxes

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provided on the difference between the book and tax basis of our assets. In addition, we expect to recognize a charge to earnings of approximately $ million representing compensation expense associated with our equity compensation plan upon completion of this offering, assuming an offering price at the midpoint of the range set forth on the cover page of the prospectus.

The terms of our restricted stock grants and stock option grants stipulate that while we are a private company, we are required to purchase the vested restricted stock and stock acquired from stock option exercises at each employee s request based upon the purchase price as determined by a formula specified in each award agreement. Additionally, we have the right to purchase vested restricted stock and stock acquired from stock option exercises at the same price upon termination of employment for any reason and for a period of two years subsequent to employment. We have historically measured compensation cost for the awards based upon the formula purchase price which is determined by calculating a per share value for shareholders equity adjusted for the excess of each period s ending PV-10 oil and gas reserve valuation over the book value of oil and gas properties.

The right to sell and requirement to purchase our restricted stock grants will lapse when we become a reporting company under Section 12 of the Exchange Act. Upon becoming a reporting company under Section 12 of the Exchange Act, we will record the charge to earnings described above to adjust the plan determined share price to the price received in this offering and account for the grants under the fair value provisions of SFAS 123(R) thereafter.

Hedging

We account for derivative instruments in accordance with SFAS No. 133 Accounting for Derivative Instruments and Hedging Activities. The specific accounting treatment for changes in the market value of the derivative instruments used in hedging activities is determined based on the designation of the derivative instruments as a cash flow or fair value hedge and effectiveness of the derivative instruments.

We have utilized fixed-price contracts and zero-cost collars to reduce exposure to unfavorable changes in oil and natural gas prices that are subject to significant and often volatile fluctuation. Under the fixed price physical delivery contracts we received the fixed price stated in the contract. Under the zero-cost collars, if the market price of crude oil was less than the ceiling strike price and greater than the floor strike price, we received market price. If the market price of crude oil exceeded the ceiling strike price or fell below the floor strike price, we received the applicable collar strike price.

We did not hedge any of our oil or natural gas production during 2005 and have not entered into any such hedges from January 1, 2006 through the date of this filing. We do not currently have plans to hedge any of our 2006 production. We recognized hedging losses of $10.1 million and $6.4 million during 2003 and 2004, respectively.

Obligations and Commitments

We have the following contractual obligations and commitments as of December 31, 2005:

	Payments due by period				
	Total	Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years
	(in thousands)				
Bank credit facility(1)	$ 143,000	$	$ 143,000	$	$
Operating lease obligations(2)	15,944	5,239	10,683	22	
Asset retirement obligations(3)	34,353	2,120	2,798	494	28,941
Total contractual cash obligations	$ 193,297	$ 7,359	$ 156,481	$ 516	$ 28,941

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(1) Payments on the bank credit facility listed in the table exclude interest.

(2) Operating leases consist of compressors utilized in field operations, vehicles and office equipment.

(3) Amounts represent expected asset retirements by period.

Critical Accounting Policies and Practices

Our historical consolidated financial statements and notes to our historical consolidated financial statements contain information that is pertinent to our management s discussion and analysis of financial condition and results of operations. Preparation of financial statements in conformity with accounting principles generally accepted in the United States requires that our management make estimates, judgments and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosure of contingent assets and liabilities. However, the accounting principles used by us generally do not change our reported cash flows or liquidity. Interpretation of the existing rules must be done and judgments made on how the specifics of a given rule apply to us.

In management s opinion, the more significant reporting areas impacted by management s judgments and estimates are revenue recognition, the choice of accounting method for oil and natural gas activities, oil and natural gas reserve estimation, asset retirement obligations and impairment of assets. Management s judgments and estimates in these areas are based on information available from both internal and external sources, including engineers, geologists and historical experience in similar matters. Actual results could differ from the estimates, as additional information becomes known.

Revenue Recognition

We derive substantially all of our revenues from the sale of oil and natural gas. Oil and gas revenues are recorded in the month the product is delivered to the purchaser and title transfers. We generally receive payment from one to three months after the sale has occurred. Each month we estimate the volumes sold and the price at which they were sold to record revenue. Variances between estimated revenue and actual amounts are recorded in the month payment is received.

Successful Efforts Method of Accounting

We utilize the successful efforts method of accounting for our oil and natural gas exploration and development activities. Exploration expenses, including geological and geophysical costs, rentals and exploratory dry holes, are charged against income as incurred. Costs of successful wells and related production equipment and developmental dry holes are capitalized and amortized on an individual property basis using the unit-of-production method as oil and natural gas is produced. This accounting method may yield significantly different results than the full cost method of accounting.

Depreciation, depletion and amortization, or DD&A, of capitalized drilling and development costs of oil and natural gas properties are generally computed using the unit of production method on an individual property or unit basis based on total estimated proved developed oil and natural gas reserves. Amortization of producing leasehold is based on the unit-of-production method using total estimated proved reserves. In arriving at rates under the unit-of-production method, the quantities of recoverable oil and natural gas are established based on estimates made by our geologists and engineers and independent engineers. Service properties, equipment and other assets are depreciated using the straight-line method over estimated useful lives of 5 to 40 years. Upon sale or retirement of depreciable or depletable property, the cost and related accumulated DD&A are eliminated from the accounts and the resulting gain or loss is recognized.

Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of certain proved undeveloped reserves. Undeveloped leasehold cost is expensed over the life of the lease or

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transferred to the associated producing properties. Individually significant non-producing properties are periodically assessed for impairment of value.

Oil and Natural Gas Reserves and Standardized Measure of Future Cash Flows

Our independent engineers and technical staff prepare the estimates of our oil and natural gas reserves and associated future net cash flows. Current accounting guidance allows only proved oil and natural gas reserves to be included in our financial statement disclosures. The SEC has defined proved reserves as the estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Even though our independent engineers and technical staff are knowledgeable and follow authoritative guidelines for estimating reserves, they must make a number of subjective assumptions based on professional judgments in developing the reserve estimates. Reserve estimates are updated at least annually and consider recent production levels and other technical information about each field. Periodic revisions to the estimated reserves and future cash flows may be necessary as a result of a number of factors, including reservoir performance, new drilling, oil and natural gas prices, cost changes, technological advances, new geological or geophysical data, or other economic factors. We cannot predict the amounts or timing of future reserve revisions. If such revisions are significant, they could significantly alter future DD&A and result in impairment of assets that may be material.

Asset Retirement Obligations

In June 2001, the FASB issued SFAS No. 143, which applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and the normal operation of a long-lived asset. The primary impact of this standard on us relates to oil and natural gas wells on which we have a legal obligation to plug and abandon. SFAS No. 143 requires us to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. The determination of the fair value of the liability requires us to make numerous judgments and estimates, including judgments and estimates related to the future salvage value of well equipment, future costs to plug and abandon wells, future inflation rates and estimated lives of the related assets.

Impairment of Assets

All of our long-lived assets are monitored for potential impairment when circumstances indicate that the carrying value of an asset may be greater than its future net cash flows, including cash flows from risk adjusted proved reserves. The evaluations involve a significant amount of judgment since the results are based on estimated future events, such as future sales prices for oil and natural gas, future costs to produce these products, estimates of future oil and natural gas reserves to be recovered and the timing thereof, the economic and regulatory climates and other factors. The need to test a field for impairment may result from significant declines in sales prices or downward revisions to oil and natural gas reserves. Any assets held for sale are reviewed for impairment when we approve the plan to sell. Estimates of anticipated sales prices are highly judgmental and subject to material revision in future periods. Because of the uncertainty inherent in these factors, we cannot predict when or if future impairment charges will be recorded.

Off-Balance Sheet Arrangements

Currently, we do not have any off-balance sheet arrangements.

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Recent Accounting Pronouncements

On December 16, 2004, the Financial Accounting Standards Board (FASB) issued SFAS No. 123(R), Share-Based Payment , which is a revision of SFAS No. 123, Accounting for Stock-Based Compensation. SFAS No. 123(R) supersedes APB 25 and amends SFAS No. 95, Statement of Cash Flows. Generally, the approach in SFAS No. 123(R) is similar to the approach described in SFAS No. 123. However, SFAS No. 123(R) requires all share-based payments to employees, including grants of employee stock options, be recognized in the consolidated financial statements based on their estimated fair values. Pro forma disclosures are no longer an alternative.

We have adopted SFAS 123(R) effective January 1, 2006. So long as we are not a reporting company under Section 12 of the Exchange Act, we have an obligation, and accrue a liability for the amount required, to purchase shares acquired through the exercise of stock options and vested restricted shares at a formula price set forth in the award agreements. As a result of this offering, we will no longer have this purchase obligation, and our equity compensation expense will be based on the valuation methodologies contained in SFAS 123(R).

On June 1, 2005, the FASB issued SFAS Statement No. 154, Accounting Changes and Error Corrections (SFAS No. 154), which will require entities that voluntarily make a change in accounting principle to apply that change retrospectively to prior periods financial statements, unless this would be impracticable. SFAS No. 154 supersedes Accounting Principles Board Opinion No. 20, Accounting Changes (APB 20), which previously required that most voluntary changes in accounting principle be recognized by including in the current period s net income the cumulative effect of changing to the new accounting principle. SFAS No. 154 also makes a distinction between retrospective application of an accounting principle and the restatement of financial statements to reflect the correction of an error.

Another significant change in practice under SFAS No. 154 will be that if an entity changes its method of depreciation, amortization, or depletion for long-lived, non-financial assets, the change must be accounted for as a change in accounting estimate. Under APB 20, such a change would have been reported as a change in accounting principle. SFAS No. 154 applies to accounting changes and error corrections that are made in fiscal years beginning after December 15, 2005. Management has not completed its assessment of the impact of SFAS No. 154, but does not anticipate any material impact from implementation of this accounting standard.

In April 2005, the FASB issued Staff Position No. FAS 19-1, Accounting for Suspended Well Costs , or FSP. The FSP amended paragraphs 31-34 of SFAS No. 19, to allow continued capitalization of exploratory well costs beyond one year from the completion of drilling under circumstances where the well has found a sufficient quantity of reserves to justify its completion as a producing well and the enterprise is making sufficient progress assessing the reserves and the economic and operating viability of the project. The guidance in the FSP was effective for the first reporting period beginning after April 4, 2005. We adopted the new requirements accordingly and do not have any capitalized exploratory well costs beyond one year from the completion of drilling.

Inflation

Historically, general inflationary trends have not had a material effect on our operating results. However, we have experienced inflationary pressure on technical staff compensation and the cost of oilfield services and equipment due to the increase in drilling activity and competitive pressures resulting from higher oil and natural gas prices in recent years.

Quantitative and Qualitative Disclosures About Market Risk

We are exposed to a variety of market risks including credit risk, commodity price risk and interest rate risk. We address these risks through a program of risk management including the use of derivative instruments.

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Credit Risk. We monitor our risk of loss due to non-performance by counterparties of their contractual obligations. Our principal exposure to credit risk is through the sale of our oil and natural gas production, which we market to energy marketing companies, refineries and affiliates, as described under Certain relationships and related party transactions. We monitor our exposure to these counterparties primarily by reviewing credit ratings, financial statements and payment history. We extend credit terms based on our evaluation of each counterparty s credit worthiness. Although we have not generally required our counterparties to provide collateral to support trade receivables owed to us, we routinely require prepayment of working interest holders proportionate share of drilling costs. For such prepayments, a liability is recorded and subsequently reduced as the associated work is performed. In this manner, we reduce credit risk.

Commodity Price Risk. We are exposed to market risk as the prices of crude oil and natural gas are subject to fluctuations resulting from changes in supply and demand. To partially reduce price risk caused by these market fluctuations, we have hedged in the past, and may hedge in the future, through the utilization of derivatives, including zero-cost collars and fixed price contracts, a portion of our production. We had no hedging contracts in place at December 31, 2004 or during 2005 and do not currently plan to hedge any of our 2006 production.

Interest Rate Risk. Our exposure to changes in interest rates relates primarily to long-term debt obligations. We manage our interest rate exposure by limiting our variable-rate debt to a certain percentage of total capitalization and by monitoring the effects of market changes in interest rates. We may utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to existing debt issues. Interest rate derivatives are used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio. We are exposed to changes in interest rates as a result of our credit facility. We had total indebtedness of $189.5 million outstanding under our facility at May 9, 2006. The impact of a 1% increase in interest rates on this amount of debt would result in increased interest expense of approximately $1.9 million and a corresponding decrease in net income. The fair value of long-term debt is estimated based on quoted market prices and management s estimate of current rates available for similar issues. The following table itemizes our long-term debt maturities and the weighted-average interest rates by maturity date:

	2006	2007	2008	2009	2010	2011	Total
				(in thousands)			
Variable rate debt:							
Credit facility:							
Principal amount	$	$	$	$	$	$ 189,500	$ 189,500
Weighted-average interest rate						6.00%	6.00%

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Business and Properties

Our Business

We are an independent oil and natural gas exploration and production company with operations in the Rocky Mountain, Mid-Continent and Gulf Coast regions of the United States. We focus our exploration activities in large new or developing plays that provide us the opportunity to acquire undeveloped acreage positions for future drilling operations. We have been successful in targeting large repeatable resource plays where horizontal drilling, advanced fracture stimulation and enhanced recovery technologies provide the means to economically develop and produce oil and natural gas reserves from unconventional formations. As a result of these efforts, we have grown substantially through the drillbit, adding 86.2 MMBoe of proved oil and natural gas reserves through extensions and discoveries from January 1, 2001 through December 31, 2005 compared to 4.7 MMBoe added through proved reserve purchases during that same period.

As of December 31, 2005, our estimated proved reserves were 116.7 MMBoe, with estimated proved developed reserves of 80.3 MMBoe, or 69% of our total estimated proved reserves. Crude oil comprised 85% of our total estimated proved reserves. At December 31, 2005, we had 1,233 scheduled drilling locations on the 1,523,000 gross (961,000 net) acres that we held. For the year ended December 31, 2005 and the three months ended March 31, 2006, we generated revenues of $375.8 million and $103.8 million, respectively, and operating cash flows of $265.3 million and $74.9 million, respectively.

The following table summarizes our total estimated proved reserves, PV-10 and net producing wells as of December 31, 2005, average daily production for the three months ended March 31, 2006 and the reserve-to-production ratio in our principal regions. Our reserve estimates as of December 31, 2005 are based primarily on a reserve report prepared by Ryder Scott Company, L.P., our independent reserve engineers. In preparing its report, Ryder Scott Company, L.P. evaluated properties representing approximately 83% of our PV-10. Our technical staff evaluated properties representing the remaining 17% of our PV-10.

	At December 31, 2005				Average daily production		
	Proved reserves (MBoe)	Percent of total	PV-10(1) (in millions)	Net producing wells	First quarter 2006 (Boe per day)	Percent of total	Annualized reserve/ production index(2)
Rocky Mountain:							
Red River units	67,711	58%	$ 1,215	187	9,677	42%	19.2
Bakken field	24,041	21%	505	34	6,560	29%	10.0
Other	9,065	8%	137	230	1,384	6%	17.9
Mid-Continent	15,472	13%	328	630	3,916	17%	10.8
Gulf Coast	376		19	23	1,323	6%	0.8
Total	116,665	100%	$ 2,204	1,104	22,860	100%	14.0

(1) PV-10 is a non GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. However, our PV-10 and our Standardized Measure are equivalent because we are a subchapter S-corporation. In connection with the closing of this offering, we will convert to a subchapter C-corporation. Our pro-forma Standardized Measure, assuming our conversion to a subchapter C-corporation, was $1.4 billion at December 31, 2005. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and gas properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

(2) The Annualized Reserve/Production Index is the number of years proved reserves would last assuming current production continued at the same rate. This index is calculated by dividing annualized first quarter 2006 production into the proved reserve quantity at December 31, 2005.

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The following table provides additional information regarding our key development areas:

	At December 31, 2005					2006 Budget	
	Developed acres		Undeveloped acres		Scheduled drilling locations(1)	Wells planned for drilling	Capital expenditures (in millions)
	Gross	Net	Gross	Net			
Rocky Mountain:							
Red River units	144,176	128,047			135	41	$ 84
Bakken field	52,421	38,971	588,081	356,426	918	54	96
Other	45,720	36,153	358,649	208,612	71	34	40
Mid-Continent	152,734	99,279	115,746	73,582	96	70	64
Gulf Coast	41,842	11,890	23,598	7,873	13	13	17
Total	436,893	314,340	1,086,074	646,493	1,233	212	$ 301

(1) Scheduled drilling locations represent total gross locations specifically identified and scheduled by management as an estimate of our future multi-year drilling activities on existing acreage. Of the total locations shown in the table, 256 are classified as PUDs. As of April 30, 2006, we have commenced drilling of 55 locations shown in the table, including 34 PUD locations. Scheduled drilling locations include 37 potential drilling sites in our New Albany Shale, Lewis Shale, Floyd Shale and Woodford Shale projects. While we owned 168,000 gross (72,000 net) undeveloped acres in these projects as of December 31, 2005, we have not sufficiently evaluated the opportunities on our acreage at this date to schedule further locations. Our actual drilling activities may change depending on oil and natural gas prices, the availability of capital, costs, drilling results, regulatory approvals and other factors. See Risk Factors Risks Relating to the Oil and Natural Gas Industry and Our Business.

Our Business Strategy

Our goal is to increase shareholder value by finding and developing crude oil and natural gas reserves at costs that provide an attractive rate of return on our investment. The principal elements of our business strategy are:

Growth Through Low-Cost Drilling. Substantially all of our annual capital expenditures are invested in drilling projects and acreage and seismic acquisitions. From January 1, 2001 through December 31, 2005, proved oil and natural gas reserve additions through extensions and discoveries were 86.2 MMBoe compared to 4.7 MMBoe of proved reserve purchases.

Internally Generate Prospects. Our technical staff has internally generated substantially all of the opportunities for the investment of our capital. Because we have been an early entrant in new or emerging plays, our costs to acquire undeveloped acreage have generally been less than those of later entrants into a developing play. As an example of the cost advantage of entering a play early, our per acre costs for our lease acquisitions in the North Dakota Bakken field during 2003 and 2004 were approximately 80% lower than the per acre costs paid by third parties and by us in the federal and state lease auctions for acreage near our holdings in that area during 2005.

Focus on Unconventional Oil and Natural Gas Resource Plays. Our experience with horizontal drilling, advanced fracture stimulation and enhanced recovery technologies allows us to commercially develop unconventional oil and natural gas resource plays, such as the Red River B dolomite and Bakken Shale formations. Production rates in the Red River units also have been increased through the use of enhanced recovery technology. Our production from the Red River units and the Bakken field comprised approximately 71% of our total oil and natural gas production during the three months ended March 31, 2006.

Acquire Significant Acreage Positions in New or Developing Plays. In addition to the 395,000 net acres held in the Montana and North Dakota Bakken field, we held 145,000 net acres in other oil and natural gas shale plays as of December 31, 2005. Our technical staff is focused on identifying and testing new unconventional oil and natural gas resource plays where significant reserves could be developed if commercial production rates can be achieved through advanced drilling, fracture stimulation and enhanced recovery techniques.

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Our Business Strengths

We have a number of strengths that we believe will help us successfully execute our strategies:

Large Drilling and Acreage Inventory. Within the Bakken field, we owned approximately 356,000 net undeveloped acres and had identified over 900 drilling locations as of December 31, 2005. We plan to allocate almost one-third of our current year capital expenditure budget towards developing our Bakken acreage position. Our large number of identified drilling locations provide for a multi-year drilling inventory.

Within other unconventional plays such as the Lewis Shale in Wyoming, the Woodford Shale in Oklahoma, the New Albany Shale in Kentucky and Indiana and the Floyd Shale in Mississippi, we owned approximately 72,000 net undeveloped acres as of December 31, 2005. Within another resource play, the Pierre Shale in North Dakota and Montana, we have 56,000 net acres held by deeper production.

Additionally, at December 31, 2005, we owned approximately 218,000 net undeveloped acres in other projects, including 36,000 net undeveloped acres in Roosevelt County, Montana on which we are planning a 38-square mile 3-D seismic shoot in 2006, 31,000 net undeveloped acres in the Big Horn Basin in Wyoming on which we plan to drill four wells in 2006, 29,000 net undeveloped acres in Bowman County, North Dakota on which we plan to drill a horizontal Red River B well in 2006 and 12,000 net undeveloped acres in Saskatchewan, Canada on which we plan to drill a horizontal Red River C well in 2006.

Within the Red River units, we plan to drill 131 horizontal wells and 51 horizontal extensions of existing wellbores over the next two to three years in order to increase the density of both producing and injection wellbores. We believe these operations will increase production and sweep efficiency. Production in the Red River units, as projected by our proved reserve report for the year ended December 31, 2005, is expected to peak in 2009 at approximately 19,000 net Boe per day. During the three months ended March 31, 2006, production in the Red River units averaged approximately 9,677 net Boe per day.

Horizontal Drilling and Enhanced Recovery Experience. In 1992, we drilled our initial horizontal well, and we have drilled over 300 horizontal wells since that time, which represented more than one-half of our total wells drilled during that period. We also have substantial experience with enhanced recovery methods and currently serve as the operator of 39 waterflood units. Additionally, we operate eight high pressure air injection floods in the United States.

Control Operations Over a Substantial Portion of Our Assets and Investments. As of December 31, 2005, we operated properties comprising 97% of our PV-10. By controlling operations, we are able to more effectively manage the cost and timing of exploration and development of our properties, including the drilling and fracture stimulation methods used.

Experienced Management Team. Our senior management team has extensive expertise in the oil and gas industry. Our Chief Executive Officer, Harold G. Hamm, began his career in the oil and gas industry in 1967. Our eight senior officers have an average of 25 years of oil and gas industry experience. Additionally, our technical staff, which includes 22 petroleum engineers, 16 geoscientists and seven landmen, has an average of more than 19 years experience in the industry.

Strong Financial Position. As of May 9, 2006, we had outstanding borrowings under our credit facility of approximately $189.5 million. We believe that our planned exploration and development activities will be funded substantially from our operating cash flows. As a result of our limited borrowings under our credit facility and strong operational cash flows, we did not enter into any oil or natural gas price hedges for our 2005 production, and we do not currently have plans to hedge any of our 2006 production.

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Conversion to Subchapter C-Corporation

We are currently a subchapter S-corporation under the rules and regulations of the Internal Revenue Service. However, upon the consummation of this offering, we will have more shareholders than the IRS rules and regulations governing S-corporations allow, and therefore, we will convert automatically from a subchapter S-corporation to a subchapter C-corporation. In connection with this conversion, we will record a charge to earnings estimated to be approximately $127.9 million as of March 31, 2006 to recognize deferred taxes.

Proved Reserves

The following table sets forth our estimated proved oil and natural gas reserves, the PV-10 and standardized measure of discounted future net cash flows as of December 31, 2005 by reserve category. Ryder Scott Company, L.P., our independent petroleum engineers, evaluated properties representing approximately 83% of our PV-10, and our technical staff evaluated the remaining properties. Oil and natural gas prices in effect at December 31, 2005, $61.04 per Bbl and $11.23 per MMBtu adjusted for location and quality by field, were used in the computation of future net cash flows.

	Oil (MBbls)	Gas (MMcf)	Total (MBoe)	PV-10(1) (in millions)
Proved developed producing	68,019	54,168	77,047	$ 1,547
Proved developed non-producing	3,240	89	3,255	44
Proved undeveloped	27,386	53,861	36,363	613
Total proved	98,645	108,118	116,665	$ 2,204
Standardized Measure(2)				$ 2,204
Pro Forma Standardized Measure(2)				$ 1,397

(1) PV-10 is a non GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. However, our PV-10 and our Standardized Measure are equivalent because we are a subchapter S-corporation. In connection with the closing of this offering, we will convert to a subchapter C-corporation. Our pro-forma Standardized Measure, assuming our conversion to a subchapter C-corporation, was $1.4 billion at December 31, 2005. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and gas properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

(2) As of December 31, 2005, Continental Resources was structured as a subchapter S-corporation. Accordingly, no provision for federal or state corporate income taxes has been provided because taxable income is passed through to our shareholders. Pro Forma Standardized Measure assumes Continental Resources was restructured as a subchapter C-corporation as of December 31, 2005.

The following table sets forth our estimated proved reserves, percent of total proved reserves that are proved developed and PV-10 as of December 31, 2005 by region:

	Oil (MBbls)	Gas (MMcf)	Total (MBoe)	% Proved developed	PV-10(1) (in millions)

Rocky Mountain:					
Red River units	61,881	34,980	67,711	75%	$ 1,215
Bakken field	22,262	10,671	24,041	45%	505
Other	8,468	3,587	9,065	64%	137
Mid-Continent	5,955	57,098	15,472	82%	328
Gulf Coast	79	1,782	376	100%	19
Total	98,645	108,118	116,665	69%	$ 2,204

(1) PV-10 is a non GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. However, our PV-10 and our Standardized Measure are equivalent because we are a subchapter S-corporation. In connection with the closing of this offering, we will convert to a subchapter C-corporation. Our pro-forma Standardized Measure, assuming our conversion to a subchapter C-corporation, was $1.4 billion at December 31, 2005. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and gas properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

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Production and Price History

The following table sets forth summary information concerning our production results, average sales prices and production costs for the years ended December 31, 2003, 2004 and 2005:

	Year ended December 31,			Three months ended March 31,	
	2003	2004	2005	2005	2006
Net production volumes:					
Oil (MBbls)(1)	3,463	3,688	5,708	1,067	1,677
Natural gas (MMcf)	10,751	8,794	9,006	2,100	2,286
Oil equivalents (MBoe)	5,255	5,154	7,209	1,417	2,058
Average prices(1):					
Oil, without hedges ($/Bbl)	$ 28.88	$ 38.85	$ 52.45	$ 45.53	$ 52.81
Oil, with hedges ($/Bbl)	25.98	37.12	52.45	45.53	52.81
Natural gas ($/Mcf)	4.55	5.06	6.93	5.31	7.13
Oil equivalents, without hedges ($/Boe)	28.35	36.45	50.19	42.15	50.86
Oil equivalents, with hedges ($/Boe)	26.44	35.20	50.19	42.15	50.86
Costs and expenses(1):					
Production expense ($/Boe)	$ 7.77	$ 8.49	$ 7.32	$ 7.88	$ 7.93
Production tax ($/Boe)	1.95	2.39	2.22	2.66	2.23
General and administrative ($/Boe)	1.83	2.41	4.34	5.49	4.05
DD&A expense ($/Boe)(2)	7.10	7.02	6.50	6.21	6.37

(1) Oil sales volumes are 96 MBbls less than oil production volumes for the three months ended March 31, 2006. Average prices and per unit costs have been calculated using sales volumes.

(2) Rate is determined based on DD&A expense derived from oil and natural gas assets.

The following table sets forth information regarding our average daily production during the first quarter of 2006:

	Average daily production First quarter 2006		
	Bbls	Mcf	Boe
Rocky Mountain			
Red River units	9,419	1,549	9,677
Bakken field	5,989	3,426	6,560
Other	1,226	946	1,384
Mid-Continent	1,637	13,676	3,916
Gulf Coast	356	5,804	1,323
Total	18,627	25,401	22,860

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Productive Wells

The following table presents the total gross and net productive wells by region and by oil or gas completion as of December 31, 2005:

	Oil wells		Natural gas wells		Total wells	
	Gross	Net	Gross	Net	Gross	Net
Rocky Mountain:						
Red River units	199	187			199	187
Bakken field	60	34			60	34
Other	262	230			262	230
Mid-Continent	664	514	209	116	873	630
Gulf Coast	7	5	33	18	40	23
Total	1,192	970	242	134	1,434	1,104

Gross wells are the number of wells in which a working interest is owned and net wells are the total of our fractional working interests owned in gross wells. As of December 31, 2005, we owned interests in no wells containing multiple completions.

Developed and Undeveloped Acreage

The following table presents the total gross and net developed and undeveloped acreage by region as of December 31, 2005:

	Developed acres		Undeveloped acres		Total acres	
	Gross	Net	Gross	Net	Gross	Net
Rocky Mountain:						
Red River units	144,176	128,047			144,176	128,047
Bakken field	52,421	38,971	588,081	356,426	640,502	395,397
Other	45,720	36,153	358,649	208,612	404,369	244,765
Mid-Continent	152,734	99,279	115,746	73,582	268,480	172,861
Gulf Coast	41,842					