BERRY PETROLEUM CO
Form 424B5
October 19, 2006

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Filed pursuant to Rule 424(b)5
Registration No. 333-135055

A filing fee of $21,400, calculated in accordance with Rules 457(o) and 457(r), has been paid to the SEC in connection with the offering of notes from the registration statement (File No. 333-135055) by means of this prospectus supplement and the accompanying prospectus. Under Rule 457(o), the registration fee was calculated on the basis of the maximum offering price of all of the notes ($200,000,000) offered hereby.

Prospectus supplement
to prospectus dated June 15, 2006

Berry Petroleum Company

$200,000,000

8 1/4% Senior Subordinated Notes due 2016

Interest payable May 1 and November 1

The notes will mature on November 1, 2016. Interest will accrue from October 24, 2006, and the first interest payment will be due May 1, 2007.

We may redeem the notes, in whole or in part, on and after November 1, 2011 at the redemption prices described in this prospectus supplement. In addition, at any time prior to November 1, 2011, we may redeem some or all of the notes at a price equal to 100% of the principal amount plus accrued and unpaid interest plus a "make-whole" premium. We may also redeem up to 35% of the aggregate principal amount of the notes at a premium using the proceeds of certain equity offerings completed on or before November 1, 2009. If we sell certain of our assets or experience specific kinds of change of control, we must offer to purchase the notes.

The notes will be our senior subordinated obligations. The notes will be unsecured and will be subordinated to all our existing and future senior debt and rank equally in right of payment to any future senior subordinated debt.

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

	Price to public(1)	Underwriting discounts and commissions	Proceeds to Berry Petroleum Co.
Per note	100.00%	2.00%	98.00%
Total	$ 200,000,000	$ 4,000,000	$ 196,000,000

(1) Plus accrued interest, if any, from October 24, 2006.

The notes will not be listed on any securities exchange. Currently, there is no public market for the notes. Delivery of the notes, in book-entry form, will be made on or about October 24, 2006 through The Depository Trust Company, which date is the fourth business day following the date of this prospectus supplement. Purchasers of the notes should consider that trading of the notes may be affected by this settlement date. See "Underwriting."

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

Joint book-running managers

JPMorgan

Citigroup

Wells Fargo Securities

Goldman, Sachs & Co.

Co-managers

SOCIETE GENERALE **BNP PARIBAS**
Wedbush Morgan Securities Inc.
Comerica Securities
Piper Jaffray
First Albany Capital

October 18, 2006

Table of contents

About this prospectus supplement

This document is in two parts. The first part is this prospectus supplement, which describes the specific terms of the $8^{1}/_{4}$% Senior Subordinated Notes due 2016 we are offering and certain other matters. The second part, the base prospectus dated June 15, 2006, provides more general information about the various securities that we may offer from time to time, some of which information may not apply to the notes we are offering hereby. Generally when we refer to this prospectus, we are referring to both this prospectus supplement and the base prospectus combined. If any of the information in this prospectus supplement is inconsistent with any of the information in the base prospectus, you should rely on the information in this prospectus supplement.

You should rely only on the information contained in this prospectus or to which the prospectus refers or that is contained in any free writing prospectus relating to the notes. We have not, and the underwriters have not, authorized anyone to provide you with different information. If anyone provides you with different or inconsistent information, you should not rely on it. We are not making an offer of the notes in any jurisdiction where their offer or sale is not permitted. The information in this prospectus supplement and the base prospectus and incorporated herein by reference may only be accurate as of the date hereof. Our business, financial condition, results of operations and prospects may have changed since those dates.

Incorporation by reference

The SEC allows us to "incorporate by reference" information we file with it. This means that we can disclose important information to you by referring you to those documents. Any information we reference in this manner is considered part of this prospectus. Information we file with the SEC after the date of this prospectus will automatically update and, to the extent inconsistent, supersede the information contained in this prospectus.

We incorporate by reference the documents listed below and future filings we make with the SEC pursuant to Sections 13(a), 13(c), 14 or 15(d) of the Securities Exchange Act of 1934, as amended (Exchange Act) after the date of this prospectus supplement and before the termination of this offering.

- Our Annual Report on Form 10-K for the year ended December 31, 2005;
- Our Quarterly Report on Form 10-Q for the quarter ended March 31, 2006;
- Our Quarterly Report on Form 10-Q for the quarter ended June 30, 2006;
- Our Current Reports on Form 8-K and 8-K/A filed on February 2, 2006 (other than information furnished pursuant to Item 7.01), February 8, 2006 (other than information furnished pursuant to Item 7.01), March 23, 2006, June 8, 2006, June 19, 2006, June 26, 2006 (other than information furnished pursuant to Item 7.01), July 27, 2006, August 7, 2006 (other than information furnished to pursuant Item 7.01) and August 24, 2006; and
- The description of our Class A Common Stock contained in our Registration Statement on Form 8-A which was declared effective by the Securities and Exchange Commission on or about October 20, 1987, and the description of our Rights to Purchase Series B Junior Participating Preferred Stock contained in our Registration Statement on Form 8-A filed with the Securities and Exchange Commission on December 7, 1999.

All share amounts and per share information in this prospectus supplement have been adjusted to reflect a two-for-one stock split of our Class A Common Stock and Class B Stock that was effected on June 2, 2006. The historical financial statements included in our Form 10-K for the year ended December 31, 2005 and our Form 10-Q for the quarter ended March 31, 2006 do not reflect this stock split.

Prospectus supplement summary

This summary highlights selected information contained elsewhere in this prospectus and in the documents we incorporate by reference. This summary is not complete and does not contain all of the information that you should consider before deciding whether or not to invest in the notes. For a more complete understanding of our company and this offering, we encourage you to read this entire document, including "Risk factors," the financial and other information incorporated by reference in this prospectus and the other documents to which we have referred. Unless otherwise indicated or required by the context, as used in this prospectus, the terms "we," "our" and "us" refer to Berry Petroleum Company. Some of the oil and gas terms we use are defined under "Glossary of oil and gas terms."

Berry Petroleum Company

We are an independent energy company engaged in the production, development, acquisition, exploitation of, and exploration for, crude oil and natural gas. While we were incorporated in Delaware in 1985 and have been a publicly traded company since 1987, we can trace our roots in California oil production back to 1909. Since 2002, we have expanded our portfolio of assets to include properties in the Rocky Mountain and Mid-Continent region. Our corporate headquarters are in Bakersfield, California, and we have a regional office in Denver, Colorado.

We have a geographically diverse asset base with 74% of our reserves located in California and 26% in the Rocky Mountain and Mid-Continent region. As of December 31, 2005, our estimated proved reserves were 126.3 MMBOE of which 74% were heavy crude oil, 8% light crude oil and 18% natural gas. 72% of our proved reserves were proved developed. For the twelve months ended June 30, 2006, we generated revenues and EBITDA of $467 million and $248 million, respectively. See " Summary historical financial data" for a reconciliation of EBITDA to net income.

For the year ended December 31, 2005 and for the quarter ended June 30, 2006, we had average daily production of 23.0 MBOE and 24.8 MBOE, respectively. Our properties generally have long reserve lives and reasonably stable and predictable well production characteristics with a ratio of proved reserves to production (based on the year ended December 31, 2005) of approximately 15.0 years. The following table sets forth the estimated quantities of proved reserves and production attributable to our principal operating areas.

		Proved reserves as of December 31, 2005			Average daily production	
Field	**Type**	**Proved reserves (MMBOE)**	**Proved developed reserves as a % of total proved reserves**	**% Average working interest**	**Year ended December 31, 2005 (MBOE/D)**	**Quarter ended June 30, 2006 (MBOE/D)**
Midway-Sunset, CA	Heavy oil	68.1	48%	99%	12.2	11.7
Brundage Canyon, UT	Light oil / Natural gas	15.1	7%	100%	5.1	6.1
Placerita, CA	Heavy oil	16.6	6%	100%	2.7	2.4
Tri-State, CO/KS/NE	Natural gas	17.4	7%	50%	1.6	2.3
Montalvo, CA	Heavy oil	6.9	2%	100%	.7	.6
Poso Creek, CA	Heavy oil	2.0	2%	100%	.5	.8
Various	Various	.2	%	15%	.2	.9
Total		126.3	72%		23.0	24.8

In 2006, we acquired properties in the Piceance basin for approximately $310 million (approximately $210 million funded through August 31, 2006), further adding to our acreage position and undeveloped drilling opportunities in the Rocky Mountain and the Mid-Continent region. We also plan to invest in 2006 approximately $275 million directed toward developing reserves, increasing oil and gas production, appraising our exploration opportunities and other capital items. We expect to allocate approximately 69% of this capital to our properties in the Rocky Mountain and Mid-Continent region and 31% to our existing core assets in California.

We have identified over 2,000 drilling locations on our properties which represent several years of drilling opportunities at our current drilling rate. We plan to continue our record activity levels by drilling over 500 gross wells and performing approximately 200 well workovers in 2006, as compared to drilling 234 wells and 140 well workovers in 2005. With the capital expenditure budget and our Piceance basin acquisitions, we are targeting an increase in our 2006 year-end proved reserves of 20 to 25 MMBOE after our annual production, resulting in proved reserves in excess of 146 MMBOE. We anticipate funding our drilling capital program primarily from internally generated cash flow.

Business strengths

Balanced high quality asset portfolio with a long reserve life. Since 2002, we have grown and diversified our California heavy oil asset base through three key acquisitions in the Rocky Mountain and Mid-Continent region that have significant growth potential. Our base of legacy California assets provides us with a steady stream of cash flow to re-invest into our significant drilling inventory and the appraisal of our prospects. Our wells are generally characterized by long production lives and predictable performance. At December 31, 2005 our implied proved reserve life was 15.0 years and our implied proved developed reserve life was 10.7 years.

Track record of efficient proved reserve and production growth. For the three years ended December 31, 2005, our average annual reserve replacement rate was 210% at an attractive average cost of $8.29 per BOE. During the same period our proved reserves and production increased at an annualized compounded rate of 7.5% and 17.0%, respectively. We were able to deliver that growth predominantly through low-risk drilling and achieved an average drilling success rate of 98%. We believe we can continue to deliver strong growth through the drill bit by exploiting our large undeveloped leasehold position. We also plan to complement this drill bit growth through selective and focused acquisitions.

Experienced management and operational teams. Our key executives have an average of 26 years of industry experience. Our president and chief executive officer, Robert Heinemann, has a Ph.D in chemical engineering and 18 years experience with a major integrated energy company. Under Mr. Heinemann's leadership, we have significantly expanded and deepened our core team of technical staff and operating managers, who have broad industry experience, including experience in California heavy oil thermal recovery operations and Rocky Mountain tight gas sands development and completion. We continue to utilize technologies and steam practices that we believe will allow us to improve the ultimate recoveries of crude oil on our mature California properties. We also utilize 3-D seismic technology for evaluation of sub-surface geologic trends of our many prospects. For example, at our Tri-State prospect area, the use of seismic data combined with appropriate drilling configurations has allowed us to drill wells with a 98% success rate with improved efficiency which has resulted in lower costs.

Operational control and financial flexibility. We exercise operating control over approximately 95% of our proved reserve base. We generally prefer to retain operating control over our properties, allowing us to more effectively control operating costs, timing of development activities and technological enhancements, marketing of production, and allocation of our capital budget. In addition, the timing of most of our capital expenditures is discretionary which allows us a significant degree of flexibility to adjust the size of our capital budget. We finance our drilling budget primarily through our internally generated operating cash flows and we also have a $750 million senior unsecured revolving credit facility with a current borrowing base of $500 million.

Established risk management policies. We actively manage our exposure to commodity price fluctuations by hedging a material portion of our forecasted production. We use hedges to help us mitigate the effects of price declines and secure operating cash flows to fund our capital expenditures program. Our California long-term crude oil contract with a refiner and our long-term firm natural gas pipeline transportation agreements help us mitigate price differential volatility and assure product delivery to markets. The operation of our cogeneration facilities provides a partial hedge against increases in natural gas prices because of the high correlation between electricity and natural gas prices under our electricity sale contracts.

Corporate strategy

Our objective is to increase the value of our business through consistent growth in our production and reserves, both through the drill-bit and acquisitions. We strive to operate our properties in an efficient manner to maximize the cash flow and earnings of our assets. The strategies to accomplish these goals include:

Developing our existing resource base. We intend to increase both production and reserves annually. We are focused on the timely and prudent development of our large resource base through developmental and step-out drilling, down-spacing, well completions, remedial work and by application of enhanced oil recovery (EOR) methods, and optimization technologies, as applicable. In the first half of 2006, we invested in a large undeveloped probable reserve position in the Piceance basin in Colorado, and are planning for significant drilling there over the next several years. We also have large potential hydrocarbon resources in place in the Uinta basin, Utah (Lake Canyon) and the San Joaquin Valley basin, California (diatomite). We have a proven track record of developing reserves and increasing production in both of our operating regions, California and the Rocky Mountain/Mid-Continent.

Acquiring additional assets with significant growth potential. We will continue to evaluate oil and gas properties with proved reserves, probable reserves and/or sizeable acreage positions that we believe contain substantial hydrocarbons which can be developed at reasonable costs. We have identified the Rocky Mountain and Mid-Continent region as our primary area of interest for growth. Significant recent acquisitions in the region include: $105 million acquisition in 2005 of mostly proved reserves in the Niobrara gas play in the Denver-Julesburg basin and two transactions in 2006 pursuant to which we have committed over $310 million to acquire or earn natural gas acreage in the Piceance basin. We will continue to review asset acquisitions that meet our economic criteria with a primary focus on large repeatable development potential in these regions. Additionally, we seek to increase our net revenue interest in assets that we already operate. In California, we continue to evaluate available properties for acquisition to take advantage of our significant operational and technical expertise in the development and production of heavy oil.

Utilizing joint ventures with respected partners to enter new basins. We believe that early entry into some basins offers the best potential for establishing low cost acreage positions in those basins. In areas where we do not have existing operations, we seek to utilize the skills and knowledge of other industry participants upon entering these new basins so that we can reduce our risk and improve our ultimate success in the area. Our joint development with an industry partner at Lake Canyon in the Uinta basin reflects this strategy.

Accumulating significant acreage positions near our producing operations. We have been successful in adding significant acreage positions in less than three years with the intent of appraising the potential of the acreage for the economic production of hydrocarbons. These positions include 503,000 and 255,000 gross acres in the Denver-Julesburg and Uinta basins, respectively, which are adjacent to, or in the proximity of, our producing assets within those basins. This strategy allows us to leverage our operating and technical expertise within the area and build on established core operations. We also have 186,000 gross acres in the Williston basin. We are appraising these acreage blocks by shooting and utilizing 3-D seismic data, participating in drilling programs in areas of mutual interest with partners and utilizing current geological, geophysical and drilling technologies. We intend to also pursue acreage in large resource plays that may result in repeatable-type development.

Investing our capital in a disciplined manner and maintaining a strong financial position. The oil and gas business is capital intensive so we focus on utilizing our available capital on projects where we are likely to have success in increasing production and/or reserves at attractive returns. We believe that maintaining a strong financial position will allow us to capitalize on investment opportunities and be better prepared for a lower commodity price environment. We expect to continue to hedge oil and gas prices and utilize long-term sales contracts with the objective of achieving cash flow necessary for the development of our assets.

We were incorporated in Delaware in 1985. Our corporate headquarters and principal executive offices are located at 5201 Truxtun Avenue, Suite 300, Bakersfield, California 93309, and our telephone number is (661) 616-3900. We maintain a web site at http://www.bry.com. The information on our website is not part of this prospectus, and you should rely only on the information contained in this prospectus and in the documents incorporated by reference when making a decision as to whether to invest in the notes.

The offering

The following summary contains basic information about the notes and is not intended to be complete. For a more complete understanding of the notes, please refer to the section entitled "Description of notes" in this prospectus supplement.

Issuer	Berry Petroleum Company
Securities offered	$200,000,000 aggregate principal amount of 8 1/4% Senior Subordinated Notes due 2016.
Maturity	November 1, 2016
Interest payment dates	May 1 and November 1, commencing May 1, 2007
Optional redemption	The notes will be redeemable at our option, in whole or in part, at any time on and after November 1, 2011 at the redemption prices described in this prospectus supplement, together with accrued and unpaid interest, if any, to the date of redemption. At any time prior to November 1, 2009, we may redeem up to 35% of the original principal amount of the notes with the proceeds of certain equity offerings at a redemption price of 108.25% of the principal amount of the notes, together with accrued and unpaid interest, if any, to the date of redemption. At any time prior to November 1, 2011, we may also redeem some or all of the notes at a price equal to 100% of the principal amount of the notes plus accrued and unpaid interest plus a "make-whole" premium.
Mandatory offers to purchase	If a specified change of control event occurs, subject to certain conditions, we must make an offer to purchase the notes at a purchase price of 101% of the principal amount of the notes, plus accrued and unpaid interest to the date of the purchase. See "Description of notes Change of control." Certain asset dispositions will be triggering events that may require us to use the net proceeds from those asset dispositions to make an offer to purchase the notes at 100% of their principal amount, together with accrued and unpaid interest, if any, to the date of purchase if such proceeds are not otherwise used within 365 days to repay indebtedness (with a corresponding permanent reduction in commitment, if applicable) or to invest in capital assets or capital expenditures related to our business or capital stock of a restricted subsidiary. See "Description of notes Covenants Limitation on sales of assets and subsidiary stock."

Ranking	The notes will be our unsecured senior subordinated obligations. The notes will rank: junior in right of payment to all of our existing and future senior indebtedness including our senior unsecured revolving credit facility and our senior unsecured money market line of credit; equally in right of payment with any future senior subordinated indebtedness; and senior in right of payment to any future subordinated obligations. As of August 31, 2006, after giving pro forma effect to this offering and the application of the net proceeds from this offering, the notes would have ranked junior to approximately $178 million of senior indebtedness (excluding hedging obligations). See "Description of notes Ranking and subordination."
Covenants	We will issue the notes under an indenture with Wells Fargo Bank, National Association, as trustee. The indenture will, among other things, limit our ability and the ability of our future restricted subsidiaries to: incur, assume or guarantee additional indebtedness; issue redeemable stock and preferred stock; pay dividends or distributions or redeem or repurchase capital stock; prepay, redeem or repurchase debt that is junior in right of payment to the notes; make loans and other types of investments; incur liens; restrict dividends, loans or asset transfers from our subsidiaries; sell or otherwise dispose of assets, including capital stock of subsidiaries; consolidate or merge with or into, or sell substantially all of our assets to, another person; enter into transactions with affiliates; and enter into new lines of business. These covenants are subject to important exceptions and qualifications, which are described under the caption "Description of notes Certain covenants." In addition, if and for as long as the notes have an investment grade rating from both Standard & Poor's Ratings Group, Inc. and Moody's Investors Service, Inc., and no default exists under the indenture, we will not be subject to certain of the covenants listed above.

Use of proceeds	We intend to use approximately $195 million of the net proceeds from this offering as follows: approximately $144 million to repay current borrowings under our senior unsecured revolving credit facility; and $51 million to finance the November 1, 2006 installment under our joint venture agreement to develop properties in the Piceance basin. See "Use of proceeds."

Risk factors

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

Summary historical financial data

The following table shows our summary historical financial data as of and for the periods indicated. Our summary historical financial data as of and for the fiscal years ended December 31, 2003, 2004 and 2005 have been derived from our audited financial statements. Our summary historical financial data as of and for the six months ended June 30, 2005 and 2006, as well as the summary historical financial data as of and for the 12 months ended June 30, 2006, are derived from our unaudited financial statements and, in our opinion, have been prepared on the same basis as the audited financial statements and include all adjustments, consisting of normal recurring adjustments, necessary for a fair presentation of this information. Certain historical amounts have been reclassified to conform to the current presentation. On May 17, 2006 a two-for-one stock split was approved. All per share amounts have been adjusted for the split.

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

($ in thousands, except ratios and earnings per share)	Years ended December 31, 2003(1)	2004(1)	2005	Six months ended June 30, 2005	2006	Twelve months ended June 30, 2006
				(unaudited)	(unaudited)	(unaudited)
Statement of operations data:						
Revenues:						
Sales of oil and gas	$ 135,848	$ 226,876	$ 349,691	$ 156,196	$ 212,575	$ 406,070
Sales of electricity	44,200	47,644	55,230	23,970	26,884	58,144
Interest and other income, net	816	426	1,804	518	1,296	2,582
Total revenues	$ 180,864	$ 274,946	$ 406,725	$ 180,684	$ 240,755	$ 466,796
Expenses:						
Operating costs oil and gas production	$ 57,830	$ 73,838	$ 99,066	$ 45,086	$ 52,813	$ 106,793
Operating costs electricity generation	42,351	46,191	55,086	24,281	24,958	55,763
Production taxes	3,097	6,431	11,506	4,695	6,606	13,417
Exploration costs			3,649	786	3,761	6,624
Depreciation, depletion and amortization oil and gas production	17,258	29,752	38,150	17,988	29,359	49,521
Depreciation and amortization electricity generation	3,256	3,490	3,260	1,611	1,701	3,350
General and administrative expenses	14,495	22,504	21,396	10,023	16,192	27,565
Commodity derivatives					(736)	(736)
Dry hole, abandonment and impairment	4,195	745	5,705	2,622	6,782	9,865
Loss on disposal of assets		410				
Total expenses	$ 142,482	$ 183,361	$ 237,818	$ 107,092	$ 141,436	$ 272,162
Income from operations	$ 38,382	$ 91,585	$ 168,907	$ 73,592	$ 99,319	194,634
Interest expense	1,414	2,067	6,048	2,902	4,038	7,184
Income before provision for income taxes	$ 36,968	$ 89,518	$ 162,859	$ 70,690	$ 95,281	$ 187,450
Provision for income taxes	4,605	20,331	50,503	22,925	37,827	65,405
Net income	$ 32,363	$ 69,187	$ 112,356	$ 47,765	$ 57,454	$ 122,045
Earnings per share (basic)(2)	$ .74	$ 1.58	$ 2.55	$ 1.08	$ 1.31	$ 2.78
Earnings per share (diluted)(2)	$ .73	$ 1.54	$ 2.50	$ 1.06	$ 1.28	$ 2.72

Balance sheet data (as of period end):						
Cash and cash equivalents	$ 10,658	$ 16,690	$ 1,990	$ 9,561	$ 626	$ 626
Working capital	(3,540)	(3,840)	(54,757)	(9,209)	(61,195)	(61,195)
Oil and gas properties, buildings and equipment, net	295,151	338,706	552,984	487,220	784,216	784,216
Total assets	340,377	412,104	635,051	575,309	899,995	899,995
Total debt	50,000	28,000	86,500	125,000	272,500	272,500
Shareholders' equity	197,338	263,086	334,210	286,190	335,922	335,922
Cash flows data:						
Net cash flow provided by (used in):						
Operating activities	$ 64,825	$ 124,613	$ 187,780	$ 66,191	$ 84,096	$ 205,685
Investing activities	(87,723)	(85,187)	(242,599)	(164,221)	(271,431)	(349,809)
Financing activities	23,690	(33,394)	40,119	90,901	185,971	135,189
Other financial data:						
EBITDA(3)	$ 58,896	$ 124,827	$ 210,317	$ 93,191	$ 130,379	$ 247,505
Exploration and development of oil and gas properties	41,061	71,556	118,718	57,134	103,939	165,523
Property acquisitions	48,579	2,845	112,249	103,712	161,600	170,137
Ratio of total debt to EBITDA	.84x	.22x	.41x	n/a	n/a	1.10x
Ratio of EBITDA to interest expense(4)	41.65x	60.39x	34.77x	32.11x	32.29x	34.45x
Ratio of earnings to fixed charges(5)	24.55x	40.72x	27.03x	24.52x	14.36x	19.15x

(1) Information has been revised to reflect our change in allocation of technical labor and production taxes. See Note 2 following our audited financial statements for the year ended December 31, 2005, which are incorporated by reference into this prospectus.

(2) All earnings per share amounts have been restated to give retroactive effect to the two-for-one stock split that became effective on May 17, 2006.

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

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

	Years ended December 31,			Six months ended June 30,		Twelve months ended June 30,
($ in thousands)	**2003**	**2004**	**2005**	**2005**	**2006**	**2006**

				(unaudited)	**(unaudited)**	**(unaudited)**
Net income	$ 32,363	$ 69,187	$ 112,356	$ 47,765	$ 57,454	$ 122,045
Provision for income taxes	4,605	20,331	50,503	22,925	37,827	65,405
Interest expense	1,414	2,067	6,048	2,902	4,038	7,184
Depreciation, depletion and amortization	20,514	33,242	41,410	19,599	31,060	52,871
EBITDA	$ 58,896	$ 124,827	$ 210,317	$ 93,191	$ 130,379	$ 247,505

(4) Represents EBITDA divided by interest expense. The ratio of net income to interest expense for the years ended December 31, 2003, 2004 and 2005 were 22.9x, 33.5x and 18.6x, respectively.

(5) For purposes of this table, "earnings" consists of income before provision for income taxes plus fixed charges. "Fixed charges" consists of interest expense, the interest component of rent expense (estimated to be one-third of rent expense) and capitalized interest.

Summary reserve, production and operating data

Estimates of our oil and natural gas reserves and present values as of and for our fiscal years ended December 31, 2003, 2004 and 2005 are derived from reserve reports prepared by DeGolyer and MacNaughton (D&M). Guidelines established by the SEC regarding the present value of future net cash flows were utilized to prepare these estimates. Estimates of reserves and their value are inherently imprecise and are subject to constant revision and change, and they should not be construed as representing the actual quantities of future production or cash flows to be realized from oil and natural gas properties or the fair market value of such properties.

The following table sets forth summary data with respect to estimated proved reserves and future net cash flows on a historical basis as of and for the periods presented:

	As of December 31,		
($ in thousands)	**2003**	**2004**	**2005**
Proved reserves:			
Crude oil (MBbl)	106,640	105,549	103,733
Natural gas (MMcf)	19,680	25,724	135,311
Total (MBOE)	109,920	109,836	126,285
% oil	97%	96%	82%
% proved developed	73%	74%	72%
Reserve life (years)(1)	18.2	14.6	15.0
Undiscounted future net cash flows	$ 1,077,051	$ 1,303,100	$ 2,341,294
Standardized measure of discounted future net cash flows(2)	$ 528,220	$ 686,748	$ 1,251,380

(1) Calculated by dividing year-end reserves by annual production rates. This methodology implies that reserves are produced ratably over the reserve life indicated. Actual production rates for new wells tend initially to increase to peak production and thereafter to decline at an initially accelerated rate before moderating to decrease much more gradually over the majority of the well's productive life.

(2) The following table shows the average sales prices (without regard to hedging) used to derive our standardized measure of discounted future net cash flows.

	As of December 31,		
Average sales prices	**2003**	**2004**	**2005**
Oil ($/Bbl)	$25.77	$29.49	$48.38
Gas ($/Mcf)	4.94	6.61	7.91
BOE Price	$25.89	$29.87	$48.21

The following table sets forth summary data with respect to production data and effective unit prices on a historical basis for the periods presented:

	As of December 31,			Six months ended June 30,		Twelve months ended June 30,
	2003	2004	2005	2005	2006	2006
Production data:						
Crude oil (MBbl)	5,827	7,044	7,081	3,433	3,448	7,096
Natural gas (MMcf)	1,277	2,839	7,919	3,552	5,361	9,739
Total production (MBOE)	6,040	7,517	8,401	4,025	4,341	8,717
Effective unit prices before the impact of hedges:						
Crude oil (Bbl)	$ 26.40	$ 31.50	$ 47.06	$ 42.75	$ 54.12	$ 52.63
Natural gas (Mcf)	5.13	6.12	7.94	6.51	7.27	7.58
Average sales price before hedging (BOE)	$ 24.48	$ 33.64	$ 47.01	$ 42.34	$ 51.08	$ 51.31
Effective unit prices including impact of hedges:						
Crude oil (Bbl)	$ 24.37	$ 28.57	$ 40.85	$ 38.34	$ 51.40	$ 47.23
Natural gas (Mcf)	4.32	5.49	6.49	5.65	6.13	7.43
Average sales price after hedging (BOE)	$ 22.52	$ 30.32	$ 41.62	$ 38.62	$ 48.92	$ 46.75
Operating expenses per BOE:						
Operating costs oil and gas production	$ 9.57	$ 10.09	$ 11.79	$ 11.14	$ 12.10	$ 10.93
Production taxes	.51	.86	1.37	1.16	1.51	1.54
DD&A oil and gas production	2.86	3.96	4.54	4.40	6.73	5.70
G&A	2.40	2.99	2.55	2.48	3.71	3.16
Interest expense	.23	.27	.72	.72	.92	.82
Total	$ 15.57	$ 18.17	$ 20.97	$ 19.90	$ 24.97	$ 22.15

Risk factors

You should carefully consider the risks described below, as well as other information included or incorporated by reference in this prospectus supplement, before making an investment decision. The risks and uncertainties described below are not the only ones we face. Additional risks and uncertainties not presently known to us or that we currently deem immaterial may also impair our business operations. If any of the following risks actually occurs, our business, financial condition or results of operations could be materially adversely affected, which in turn could adversely affect our ability to pay interest and/or principal on the notes.

Risks related to our business

Oil and gas prices fluctuate widely, and low prices for an extended period of time are likely to have a material adverse impact on our business, results of operations and financial condition.

Our revenues, profitability and future growth and reserve calculations depend substantially on reasonable prices for oil and gas. These prices also affect the amount of our cash flow available for capital expenditures, working capital and payments on the notes and our ability to borrow and raise additional capital. The amount we can borrow under our senior unsecured revolving credit facility is subject to periodic asset redeterminations based in part on changing expectations of future crude oil and natural gas prices. Lower prices may also reduce the amount of oil and gas that we can produce economically.

Among the factors that can cause fluctuations are:

- domestic and foreign supply of oil and natural gas;
- level of consumer demand;
- political conditions in oil and gas producing regions;
- weather conditions;
- world-wide economic conditions;
- domestic and foreign governmental regulations; and
- price and availability of alternative fuels.

Our heavy crude oil in California is less economic than lighter crude oil and natural gas.

As of December 31, 2005, approximately 74% of our proved reserves, or 93 million barrels, consisted of heavy oil. Light crude oil represented 8% and natural gas represented 18% of our oil and gas reserves. Heavy crude oil sells for a discount to light crude oil, as more complex refining equipment is required to convert heavy oil into high value products. We currently sell our heavy crude oil in California under a long term contract for approximately $8.15 below WTI pricing. Additionally, most of our crude oil in California is produced using the enhanced oil recovery process of steam injection. This process is more costly than primary and secondary recovery methods.

A widening of commodity differentials may adversely impact our revenues and per barrel economics.

Both our produced crude oil and natural gas are subject to pricing in the local markets where the production occurs. It is customary that such products are priced based on local or regional supply and demand factors. California heavy crude oil sells at a discount to WTI, the U.S. benchmark crude oil, primarily due to the additional cost to refine gasoline or light product out of a barrel of heavy crude. In addition, our Utah light crude is currently priced at $10.50 to $17.00 per barrel below WTI with certain volumes tied to field posting, and, in some cases, our realized price is further reduced by transportation charges. Natural gas field prices are normally priced off of Henry Hub NYMEX price, the benchmark for U.S. natural gas. While we attempt to contract for the best possible price in each of our producing locations, there is no assurance that past price differentials will continue into the future. Numerous factors may influence local pricing, such as refinery capacity, particularly for paraffinic crude, pipeline capacity and specifications, upsets in the mid-stream or downstream sectors of the industry, trade restrictions and governmental regulations. We may be adversely impacted by a widening differential on the products we sell. Our oil and natural gas hedges are based on WTI or natural gas index prices, so we may be subject to basis risk if the differential on the products we sell widens from those benchmarks if we do not have a contract tied to those benchmarks. Additionally, insufficient pipeline capacity and the lack of demand in any given operating area may cause the differential to widen in that area compared to other oil and gas producing areas.

Market conditions or operational impediments may hinder our access to crude 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, processing facilities and refineries 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 for a lack of a market or because of inadequacy or unavailability of natural gas pipelines, gathering system capacity, processing facilities or refineries. If that were to occur, then we would be unable to realize revenue from those wells until arrangements were made to deliver the production to market.

Factors that can cause price volatility for crude oil and natural gas include:

- availability and capacity of refineries;
- availability of gathering systems with sufficient capacity to handle local production;
- seasonal fluctuations in local demand for production;
- local and national gas storage capacity;
- interstate pipeline capacity; and
- availability and cost of gas transportation facilities.

Our Utah crude oil is a paraffinic crude and can be processed efficiently by only a limited number of refineries. Increased production of crude oil in the region, the ability of refiners to process other higher sulfur crudes as a result of capital upgrades, as well as the increasing availability of Canadian crude oil, is putting downward pressure on the sales price of our crude oil.

Contracts for our Utah crude oil are currently priced at approximately $10.50 to $17.00 per barrel below WTI, with certain volumes tied to field posting. In some cases, our realized price is further reduced by transportation charges. From October 1, 2003 through April 30, 2006, we sold our Utah crude oil at approximately $2.00 per barrel below WTI; and from May 1, 2006 through September 30, 2006, we sold the majority of our Utah crude oil at approximately $9.00 per barrel below WTI. Due to this lower pricing and based on sales of 4,600 Bbl/D gross, we estimate our revenues will be lower by approximately $8 million in the last six months of 2006, as compared to the first six months of 2006. If this pricing continues throughout 2007 and on the same volumes, we estimate our 2007 revenues will be lower by approximately $15 million versus our expected 2006 revenues.

Passing of a California proposition may impact the additional taxes placed on hydrocarbon production.

Our California production may be burdened with a severance tax in addition to the current ad valorem tax structure if Proposition 87 is passed by California voters in November 2006. This initiative can add up to a 6% severance tax on our California production after December 31, 2006. If this initiative is passed, we may redetermine our allocation of capital to our inventory of projects to optimize the return on our capital investments.

We may be subject to the risk of adding additional steam generation equipment if the electricity market deteriorates significantly.

We are dependent on several cogeneration facilities that provide over half of our steam requirement. These facilities are dependent on reasonable power contracts for the sale of electricity. If, for any reason, including if utilities that purchase electricity from us are no longer required by regulation to enter into power contracts with us, we were unable to enter into new or replacement contracts or were to lose any existing contract, we may not be able to supply 100% of the steam requirements necessary to maximize production from our heavy oil assets. An additional investment in various steam sources may be necessary to replace such steam, and there may be risks and delays in being able to install conventional steam equipment due to permitting requirements. The financial cost and timing of such new investment may adversely affect our production, capital outlays and cash provided by operating activities. We have power contracts covering our electricity generation which contracts expire in 2009.

The future of the electricity market in California is uncertain.

We utilize cogeneration plants in California to generate lower cost steam compared to conventional steam generation methods. Electricity produced by our cogeneration plants is sold to utilities and the steam costs are allocated to our oil and gas operations. While we have electricity sales contracts in place with the utilities that are currently scheduled to terminate in 2009, legal and regulatory decisions, especially related to the pricing of electricity under the contracts, can adversely affect the economics of our cogeneration facilities and thereby, the cost of steam for use in our oil and gas operations.

A shortage of natural gas in California could adversely affect our business.

We may be subject to the risks associated with a shortage of natural gas and/or the transportation of natural gas into and within California. We are highly dependent on sufficient volumes of natural gas that we use for fuel in generating steam in our heavy oil operations in California. If the required volume of natural gas for use in our operations were to be unavailable or too highly priced to produce heavy oil economically, our production could be adversely impacted. We have firm transportation to move 12,000 MMBtu/D on the Kern River Pipeline from the Rocky Mountains to Kern County, CA, which accounts for only one-third of our current requirement.

Our use of oil and gas price and interest rate hedging contracts involves credit risk and may limit future revenues from price increases or reduced expenses from lower interest rates, as well as result in significant fluctuations in net income and shareholders' equity.

We use hedging transactions with respect to a portion of our oil and gas production with the objective of achieving a more predictable cash flow, and to reduce our exposure to a significant decline in the price of crude oil. We also utilize interest rate hedges to fix the rate on a portion of our variable rate indebtedness, as only a portion of our total indebtedness has a fixed rate and we are therefore exposed to fluctuations in interest rates. While the use of hedging transactions limits the downside risk of price declines or rising interest rates, as applicable, their use may also limit future revenues from price increases or reduced expenses from lower interest rates, as applicable. Hedging transactions also involve the risk that the counterparty may be unable to satisfy its obligations.

Our future success depends on our ability to find, develop and acquire oil and gas reserves.

To maintain production levels, we must locate and develop or acquire new oil and gas reserves to replace those depleted by production. Without successful exploration, exploitation or acquisition activities, our reserves, production and revenues will decline. We may not be able to find and develop or acquire additional reserves at an acceptable cost. In addition, substantial capital is required to replace and grow reserves. If lower oil and gas prices or operating difficulties result in our cash flow from operations being less than expected or limit our ability to borrow under credit arrangements, we may be unable to expend the capital necessary to locate and develop or acquire new oil and gas reserves.

Actual quantities of recoverable oil and gas reserves and future cash flows from those reserves, future production, oil and gas prices, revenues, taxes, development expenditures and operating expenses most likely will vary from estimates.

Estimating accumulations of oil and gas is complex. The process relies on interpretations of available geologic, geophysical, engineering and production data. The extent, quality and reliability of this data can vary. The process also requires certain economic assumptions, such as oil and gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds, some of which are mandated by the SEC. The accuracy of a reserve estimate is a function of:

- quality and quantity of available data;

- interpretation of that data; and

- accuracy of various mandated economic assumptions.

Any significant variance could materially affect the quantities and present value of our reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of development and exploration and prevailing oil and gas prices.

In accordance with SEC requirements, we base the estimated discounted future net cash flows from proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate.

If oil or gas prices decrease or if our exploration and development activities are unsuccessful, we may be required to take writedowns.

We may be required to writedown the carrying value of our oil and gas properties when oil or gas prices are low, including basis differentials, or there are substantial downward adjustments to our estimated proved reserves, increases in estimates of development costs or deterioration in exploration or production results.

We capitalize costs to acquire, find and develop our oil and gas properties under the successful efforts accounting method. If net capitalized costs of our oil and gas properties exceed fair value, we must charge the amount of the excess to earnings. We review the carrying value of our properties annually and at any time when events or circumstances indicate a review is necessary, based on prices in effect as of the end of the reporting period. The carrying value of oil and gas properties is computed on a field-by-field basis. Once incurred, a writedown of oil and gas properties is not reversible at a later date even if oil or gas prices increase.

Competitive industry conditions may negatively affect our ability to conduct operations.

Competition in the oil and gas industry is intense, particularly with respect to the acquisition of producing properties and proved undeveloped acreage. Major and independent oil and gas companies actively bid for desirable oil and gas properties, as well as for the equipment, supplies, labor and services required to operate and develop their properties. Some of these resources may be limited and have higher prices due to current strong demand. Many of our competitors have financial resources that are substantially greater, which may adversely affect our ability to compete within the industry.

Drilling is a high-risk activity.

Our future success will partly depend on the success of our drilling program. In addition to the numerous operating risks described in more detail below, these drilling activities involve the risk that no commercially productive oil or gas reservoirs will be discovered. In addition, we are often uncertain as to the future cost or timing of drilling, completing and producing wells. Furthermore, drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- obtaining government and tribal required permits;

- unexpected drilling conditions;

- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions;
- compliance with governmental or landowner requirements; and
- shortages or delays in the availability of drilling rigs and the delivery of equipment and/or services, including experienced labor.

The oil and gas business involves many operating risks that can cause substantial losses; insurance may not protect us against all of these risks. These risks include:

- fires;
- explosions;
- blow-outs;
- uncontrollable flows of oil, gas, formation water or drilling fluids;
- natural disasters;
- pipe or cement failures;
- casing collapses;
- embedded oilfield drilling and service tools;
- abnormally pressured formations;
- major equipment failures, including cogeneration facilities; and
- environmental hazards such as oil spills, natural gas leaks, pipeline ruptures and discharges of toxic gases.

If any of these events occur, we could incur substantial losses as a result of:

- injury or loss of life;
- severe damage or destruction of property, natural resources and equipment;

- pollution and other environmental damage;
- investigatory and clean-up responsibilities;
- regulatory investigation and penalties;
- suspension of operations; and
- repairs to resume operations.

If we experience any of these problems, our ability to conduct operations could be adversely affected. If a significant accident or other event occurs and is not fully covered by insurance, it could adversely affect us. In accordance with customary industry practices, we maintain insurance coverage against some, but not all, potential losses in order to protect against the risks we face. We do not carry business interruption insurance. We may elect not to carry insurance if our management believes that the cost of available insurance is excessive relative to the risks presented. In addition, we cannot insure fully against pollution and environmental risks. The occurrence of an event not fully covered by insurance could have a material adverse effect on our financial condition and results of operations. While we intend to obtain and maintain appropriate insurance coverage for these risks, there can be no assurance that our operations will not expose us to liabilities exceeding such insurance coverage or to liabilities not covered by insurance.

We are subject to complex federal, state, regional, local and other laws and regulations that could give rise to substantial liabilities from environmental contamination or otherwise adversely affect our cost, manner or feasibility of doing business.

All facets of our operations are regulated extensively at the federal, state, regional and local levels. In addition, a portion of our leases in the Uinta basin are, and some of our future leases may be, regulated by Native American tribes. Environmental laws and regulations impose limitations on our discharge of pollutants into the environment, establish standards for our management, treatment, storage, transportation and disposal of hazardous materials and of solid and hazardous wastes, and impose on us obligations to investigate and remediate contamination in certain circumstances. We also must satisfy, in some cases, federal and state requirements for providing environmental assessments, environmental impact studies and/or plans of development before we commence exploration and production activities. Environmental and other requirements applicable to our operations generally have become more stringent in recent years, and compliance with those requirements more expensive. Frequently changing environmental and other governmental laws and regulations have increased our costs to plan, design, drill, install, operate and abandon oil and natural gas wells and other facilities, and may impose substantial liabilities if we fail to comply with such regulations or for any contamination resulting from our operations. Failure to comply with these laws and regulations may also result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Furthermore, our business, results from operations and financial condition may be adversely affected by any failure to comply with, or future changes to, these laws and regulations.

In addition, we could also be liable for the investigation or remediation of contamination, as well as other liabilities concerning hazardous materials or contamination such as claims for personal injury or property damage. Such liabilities may arise at many locations, including properties in which we have an ownership interest but no operational control, properties we formerly owned or operated and sites where our wastes have been treated or disposed of, as well as at properties that we currently own or operate, and may arise even where the contamination does not result from any noncompliance with applicable environmental laws. Under a number of environmental laws, such liabilities may also be joint and several, meaning that we could be held responsible for more than our share of the liability involved, or even the entire share. We have incurred expenses and penalties in connection with remediation of contamination in the past, and we may do so in the future. From time to time we have experienced accidental spills, leaks and other discharges of contaminants at some of our properties, as have other similarly situated oil and gas companies, and some of the properties that we have acquired, or in which we may hold an interest but not operational control, may have past or ongoing contamination for which we may be held responsible.

Some of our operations are in environmentally sensitive areas, including coastal areas, wetlands, areas that may provide habitat for endangered or threatened species, and other protected areas, and our operations in such areas must satisfy additional regulatory requirements. Moreover, public interest in environmental protection has increased in recent years, and environmental organizations have opposed certain drilling projects and/or access to prospective lands and have filed litigation to attempt to stop such projects, including decisions by the Bureau of Land Management regarding several leases in Utah that we have been awarded.

Our activities are also subject to the regulation by oil and natural gas-producing states and one Native American tribe of conservation practices and protection of correlative rights. These regulations affect our operations and limit the quantity of oil and natural gas we may produce and sell. A major risk inherent in our drilling plans is the need to obtain drilling permits from federal, state, local and Native American tribal authorities. Delays in obtaining regulatory approvals or drilling permits, the failure to obtain a drilling permit for a well or the receipt of a permit with unreasonable conditions that are more expensive than we have anticipated could have a negative effect on our ability to explore on or develop our properties. Additionally, the oil and natural gas regulatory environment could change in ways that might substantially increase the financial and managerial costs to comply with the requirements of these laws and regulations and, consequently, adversely affect our profitability.

Future environmental regulations, including potential state and federal restrictions on greenhouse gasses that may be passed in response to climate change concerns, could increase our costs to operate and produce our properties and also reduce the demand for the oil we produce. While we continue to diversify our asset base by acquiring additional natural gas assets, our business, results from operations and financial condition may be adversely affected by future restrictions.

Furthermore, we benefit from federal energy laws and regulations that relieve our cogeneration plants, all of which are QFs, from compliance with extensive federal and state regulations that control the financial structure of electricity generating plants, as well as the prices and terms on which electricity may be sold by those plants. These federal energy regulations also require that electric utilities purchase electricity generated by our cogeneration plants at a price based on the purchasing utility's avoided cost, and that the utility sell back-up power to us on a non-discriminatory basis. The term "avoided cost" is defined as the incremental cost to an electric utility of electric energy or capacity, or both, which, but for the purchase from QFs, such utility would generate for itself or purchase from another source. These regulations have recently been amended; and a utility may now petition FERC to be relieved of its obligation to enter into any new contracts with us, if the FERC determines that a competitive electricity market is available to us in our service territory.

Property acquisitions are a component of our growth strategy, and our failure to complete future acquisitions successfully could reduce our earnings and slow our growth.

Our business strategy has emphasized growth through strategic acquisitions, but we may not be able to continue to identify properties for acquisition or we may not be able to make acquisitions on terms that we consider economically acceptable. There is intense competition for acquisition opportunities in our industry. Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. Our strategy of completing acquisitions is dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. If we are unable to achieve strategic acquisitions, our growth may be impaired, thus impacting earnings, cash from operations and reserves.

Acquisitions are subject to the uncertainties of evaluating recoverable reserves and potential liabilities. Our recent growth is due in part to acquisitions of producing properties, and we expect acquisitions will continue to contribute to our future growth. Successful acquisitions require an assessment of a number of factors, many of which are beyond our control. These factors include recoverable reserves, exploration potential, future oil and natural gas prices, operating costs, production taxes and potential environmental and other liabilities. Such assessments are inexact and their accuracy is inherently uncertain. In connection with our assessments, we perform a review of the acquired properties, which we believe is generally consistent with industry practices. However, such a review will not reveal all existing or potential problems. In addition, our review may not allow us to become sufficiently familiar with the properties, and we do not always discover structural, subsurface and environmental problems that may exist or arise. Our review prior to signing a definitive purchase agreement may be even more limited.

We generally are not entitled to contractual indemnification for preclosing liabilities, including environmental liabilities, on acquisitions. Often, we acquire interests in properties on an "as is" basis with limited remedies for breaches of representations and warranties. If material breaches are discovered by us prior to closing, we could require adjustments to the purchase price or if the claims are significant, we or the seller may have a right to terminate the agreement. We could also fail to discover breaches or defects prior to closing and incur significant unknown liabilities, including environmental liabilities, or experience losses due to title defects, for which we would have limited or no contractual remedies or insurance coverage.

There are risks in acquiring producing properties, including difficulties in integrating acquired properties into our business, additional liabilities and expenses associated with acquired properties, diversion of management attention, and costs of increased scope, geographic diversity and complexity of our operations.

Increasing our reserve base through acquisitions is an important part of our business strategy. Our failure to integrate acquired businesses successfully into our existing business, or the expense incurred in consummating future acquisitions, could result in our incurring unanticipated expenses and losses. In addition, we may have to assume cleanup or reclamation obligations or other unanticipated liabilities in connection with these acquisitions. The scope and cost of these obligations may ultimately be materially greater than estimated at the time of the acquisition.

In connection with future acquisitions, the process of integrating acquired operations into our existing operations may result in unforeseen operating difficulties and may require significant management attention and financial resources that would otherwise be available for the ongoing development or expansion of existing operations

Possible future acquisitions could result in our incurring additional debt, contingent liabilities and expenses, all of which could have a material adverse effect on our financial condition and operating results.

The loss of key personnel could adversely affect our business.

We depend to a large extent on the efforts and continued employment of our executive management team and other key personnel. The loss of the services of these or other key personnel could adversely affect our business, and we do not maintain key man insurance on the lives of any of these persons. Our drilling success and the success of other activities integral to our operations will depend, in part, on our ability to attract and retain experienced geologists, engineers, landmen and other professionals. Competition for many of these professionals is intense. If we cannot retain our technical personnel or attract additional experienced technical personnel, our ability to compete could be harmed.

We have limited control over the activities on properties that we do not operate.

Although we operate most of the properties in which we have an interest, other companies operate some of the properties. We have limited ability to influence or control the operation or future development of these nonoperated properties or the amount of capital expenditures that we are required to fund their operation. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence or control the operation and future development of these properties could have a material adverse effect on the realization of our targeted returns or lead to unexpected future costs.

We may not adhere to our proposed drilling schedule.

Our final determination of whether to drill any scheduled or budgeted wells will depend on a number of factors, including:

- results of our exploration efforts and the acquisition, review and analysis of our seismic data, if any;
- availability of sufficient capital resources to us and any other participants for the drilling of the prospects;
- approval of the prospects by other participants after additional data has been compiled;
- economic and industry conditions at the time of drilling, including prevailing and anticipated prices for oil and natural gas and the availability and prices of drilling rigs and crews; and
- availability of leases, license options, farm-outs, other rights to explore and permits on reasonable terms for the prospects.

Although we have identified or budgeted for numerous drilling prospects, we may not be able to lease or drill those prospects within our expected time frame, or at all. In addition, our drilling schedule may vary from our expectations because of future uncertainties and rig availability and access to our drilling locations utilizing available roads.

We may incur losses as a result of title deficiencies.

We acquire from third parties or directly from the mineral fee owners working and revenue interests in the oil and natural gas leaseholds and estates upon which we will perform our exploration activities. The existence of a material title deficiency can reduce the value or render a property worthless thus adversely affecting the results of our operations and financial condition. Title insurance covering mineral leaseholds is not always available and when available is not always obtained. As is customary in our industry, we rely upon the judgment of staff and independent landmen who perform the field work of examining records in the appropriate governmental offices and abstract facilities before attempting to acquire or place under lease a specific mineral interest and/or undertake drilling activities. We, in some cases, perform curative work to correct deficiencies in the marketability of the title to us. In cases involving title problems, the amount paid for affected oil and natural gas leases or estates can be generally lost, and a prospect can become undrillable.

Risks related to our indebtedness and the notes

We have a substantial amount of debt and the cost of servicing that debt could adversely affect our business and hinder our ability to make payments on the notes, and such risk could increase if we incur more debt.

We have a substantial amount of indebtedness. At June 30, 2006 and August 31, 2006, we had total long-term debt of $249 million and $309 million, respectively, and short-term debt under our senior unsecured money market line of credit of $24 million and $13 million, respectively. After giving effect to this offering and the application of net proceeds from this offering, as of August 31, 2006, we would have had approximately $165 million outstanding under our senior unsecured revolving credit facility, with additional borrowing availability of $322 million. The amount outstanding under our senior unsecured revolving credit facility fluctuates throughout the year depending on our working capital and other needs. In addition, on May 1, 2007, we expect to borrow funds under our senior unsecured revolving credit facility to finance the final $51 million payment under our joint venture agreement with an industry partner to develop properties in the Piceance basin.

We have demands on our cash resources in addition to interest expense on the notes, including, among others, operating expenses and interest and principal payments under our senior unsecured revolving credit facility and our senior unsecured money market line of credit. Our level of indebtedness relative to our proved reserves and these significant demands on our cash resources could have important effects on our business and on your investment in the notes. For example, they could:

- make it more difficult for us to satisfy our obligations with respect to the notes and our other debt;

- require us to dedicate a substantial portion of our cash flow from operations to payments on our debt, thereby reducing the amount of our cash flow available for working capital, capital expenditures, acquisitions and other general corporate purposes;

- require us to make principal payments under our senior unsecured revolving credit facility if the quantity of proved reserves attributable to our natural gas and crude oil properties are insufficient to support our level of borrowings under that credit facility;
- limit our flexibility in planning for, or reacting to, changes in the oil and gas industry;
- place us at a competitive disadvantage compared to our competitors that have lower debt service obligations and significantly greater operating and financing flexibility than we do;
- limit our financial flexibility, including our ability to borrow additional funds or issue equity;
- increase our interest expense if interest rates increase, because borrowings under our senior unsecured revolving credit facility are at a variable rate of interest, and borrowings under our senior unsecured money market line of credit are generally at a variable rate of interest;
- increase our vulnerability to general adverse economic and industry conditions; and
- result in an event of default upon a failure to comply with financial covenants contained in our senior unsecured revolving credit facility or senior unsecured money market line of credit which, if not cured or waived, could have a material adverse effect on our business, financial condition or results of operations.

Our ability to pay the principal and interest on our long-term debt, including the notes, and to satisfy our other liabilities will depend upon our future performance and our ability to refinance our debt as it becomes due. Our future operating performance and ability to refinance will be affected by economic and capital markets conditions, our financial condition, results of operations and prospects and other factors, many of which are beyond our control.

If we are unable to service our indebtedness and fund our operating costs, we will be forced to adopt alternative strategies that may include:

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

There can be no assurance that any such strategies could be implemented on satisfactory terms, if at all.

Despite current indebtedness levels, we may still be able to incur substantially more debt. This could further exacerbate the risks described above.

We will be able to incur substantial additional indebtedness under our senior unsecured revolving credit facility, and we may be able to incur other substantial indebtedness in the future. The terms of the indenture do not fully prohibit us from doing so. If we incur any additional indebtedness that ranks equally with the notes, the holders of that debt will be entitled to share ratably with you in any proceeds distributed in connection with any insolvency, liquidation, reorganization, dissolution or other winding-up of our business. This may have the effect of reducing the amount of proceeds paid to you. If new debt is added to our current debt levels, the related risks that we now face could intensify. See "Description of notes" and "Description of other indebtedness."

Covenants in our senior unsecured revolving credit facility and the indenture governing the notes restrict our ability to engage in certain activities.

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

- incur, assume or guarantee additional indebtedness;
- issue redeemable stock and preferred stock;
- pay dividends or distributions or redeem or repurchase capital stock;
- prepay, redeem or repurchase debt that is junior in right of payment to the notes;
- make loans and other types of investments;
- incur liens;
- restrict dividends, loans or asset transfers from our subsidiaries;
- sell or otherwise dispose of assets, including capital stock of subsidiaries;
- consolidate or merge with or into, or sell substantially all of our assets to, another person;
- make capital expenditures or acquire assets or businesses;
- enter into transactions with affiliates; and
- enter into new lines of business.

In addition, our senior unsecured revolving credit facility contains certain covenants, which, among other things, require the maintenance of a minimum current ratio and a minimum earnings (before interest, taxes, depreciation, depletion and amortization, non-cash income and expense) to debt ratio. Our ability to borrow under our senior unsecured revolving credit facility is dependent upon the quantity of proved reserves attributable to our natural gas and crude oil properties and the respective projected commodity prices as determined by the lenders under that credit facility. Our ability to meet these covenants or requirements may be affected by events beyond our control, and we cannot assure you that we will satisfy such covenants and requirements.

If we default on our obligations to pay our indebtedness we may not be able to make payments on the notes.

Any default under the agreements governing our indebtedness, including a default under our senior unsecured revolving credit facility or our senior unsecured money market line of credit that is not waived by the required lenders, and the remedies sought by the holders of such indebtedness, could make us unable to pay principal, premium, if any, and interest on the notes and substantially decrease the market value of the notes. If we are unable to generate

sufficient cash flow and are otherwise unable to obtain funds necessary to meet required payments of principal, premium (if any) and interest on our indebtedness, or if we otherwise fail to comply with the various covenants, including financial and operating covenants, in the instruments governing our indebtedness (including covenants in our indenture, our senior unsecured revolving credit facility and our senior unsecured money market line of credit), we could be in default under the terms of the agreements governing such indebtedness. In the event of such default, the holders of such indebtedness could elect to declare all the funds borrowed thereunder to be due and payable, together with accrued and unpaid interest, the lenders could elect to terminate their commitments thereunder and cease making further loans and we could be forced into bankruptcy or liquidation. Moreover, our senior unsecured revolving line of credit, our senior unsecured money market line of credit and the indenture governing the notes each contain cross-default or cross-acceleration provisions that would be triggered by the occurrence of a default or acceleration under other instruments governing our indebtedness. If the payment of our indebtedness is accelerated, there can be no assurance that our assets would be sufficient to repay in full that indebtedness and our other indebtedness that would become due as a result of any acceleration.

If our operating performance declines, we may in the future need to obtain waivers from the required lenders under our senior unsecured revolving credit facility to avoid being in default. If we breach our covenants under our senior unsecured revolving credit facility and seek a waiver, we may not be able to obtain a waiver from the required lenders. If this occurs, we would be in default under our senior unsecured revolving credit facility, the lenders could exercise their rights and the lenders under our senior unsecured money market line of credit and the indenture governing the note could exercise their cross-default or cross-acceleration rights, as described above, and we could be forced into bankruptcy or liquidation. See "Description of other indebtedness" and "Description of notes."

Your right to receive payments on the notes is junior to our senior indebtedness.

The indebtedness evidenced by the notes will be our senior subordinated obligations. The payment of the principal of, premium on, if any, and interest on the notes is subordinate in right of payment, as set forth in the indenture, to the prior payment in full of all of our senior indebtedness, including our obligations under our senior unsecured revolving credit facility and our senior unsecured money market line of credit. Any future subsidiary guarantee will be similarly subordinated to senior indebtedness of such subsidiary guarantor.

As of August 31, 2006, we had approximately $13 million outstanding on our senior unsecured money market line and $309 million outstanding on our senior unsecured revolving credit facility. After giving effect to this offering and the application of net proceeds from this offering, we would have had approximately $165 million outstanding under our senior unsecured revolving credit facility, with additional borrowing availability of $322 million, which would be senior indebtedness if incurred. Although the indenture governing the notes contains limitations on the amount of additional indebtedness that we may incur, under certain circumstances the amount of such indebtedness could be substantial and, in any case, such indebtedness may be senior indebtedness. See "Description of notes Certain covenants Limitation on indebtedness."

Because of the subordination provisions of the notes, in the event of our bankruptcy, liquidation or dissolution, our assets would be available to pay obligations under the notes only after all payments had been made on our senior indebtedness, including under our senior unsecured revolving credit facility and our senior unsecured money market line of credit. In the event of a bankruptcy, liquidation or dissolution, holders of the notes will participate with the trade creditors and all holders of our senior subordinated indebtedness in the assets remaining after we have paid all of our senior indebtedness. We cannot assure you that sufficient assets will remain after all these payments have been made to make any payments on the notes, including payments of interest when due. Also, because the indenture requires that amounts otherwise payable to holders of the notes in a bankruptcy or similar proceeding be paid to holders of senior indebtedness instead, holders of the notes may receive less, ratably, than holders of trade payables or other unsecured, unsubordinated creditors in any such proceeding. In addition, all payments on the notes will be prohibited in the event of a payment default on senior indebtedness, including borrowings under our senior unsecured revolving credit facility and our senior unsecured money market line of credit, and may be prohibited for up to 179 days in the event of non-payment defaults on certain of our senior indebtedness. See "Description of notes Ranking and subordination."

The notes are not secured by our assets.

The notes will be our general unsecured obligations and will be effectively subordinated in right of payment to all of our secured indebtedness, if any, to the extent of the value of the assets securing such indebtedness. If we become insolvent or are liquidated, our assets which serve as collateral under our secured indebtedness, if any, would be made available to satisfy our obligations under any secured debt before any payments are made on the notes.

Variable rate indebtedness subjects us to interest rate risk, which could cause our debt service obligations to increase significantly.

Our borrowings under our senior unsecured revolving credit facility (and generally under our senior unsecured money market line of credit) are, and are expected to continue to be, at variable rates of interest and expose us to interest rate risk. If interest rates increase, our debt service obligations on the variable rate indebtedness would increase even though the amount borrowed remained the same, and our net income would decrease. Borrowings under our senior unsecured revolving credit facility can either be base rate loans or LIBOR loans. On all base rate loans we pay a varying rate per annum equal to the sum of (i) the higher of (a) the prime rate announced from time to time by Wells Fargo Bank, National Association, and (b) the sum of the Federal Funds Rate most recently determined by the Federal Reserve Bank of New York plus one-half of one percent, plus (ii) a base rate margin of between .0% and .5% depending on the amount of utilization by us. On all LIBOR loans, we pay a rate per interest period equal to the sum of (x) the quotient of (a) LIBOR rate for deposits in U.S. dollars as of 11:00 a.m. London time two business days prior to the first day of the interest period, divided by (b) one minus the reserve requirement applicable to such interest period, plus (y) a LIBOR margin of between 1.0% and 1.75% per annum depending on the total outstanding under that credit facility. Borrowings under our senior unsecured money market line of credit bear interest at a mutually agreed interest per annum (and are generally at a variable rate). As of June 30, 2006, a one percent change in interest rates would result in a $2 million change our in annual interest expense. We currently have $100 million of our borrowings hedged using interest rate swaps at a fixed rate of approximately 5.5% plus the senior unsecured revolving credit facility's margin. We may liquidate some or all of these hedges immediately following this offering. In the future we may enter into additional interest rate swaps, involving the exchange of floating for fixed rate interest payments, to reduce interest rate volatility.

The notes will be structurally subordinated to all indebtedness and other liabilities of our future subsidiaries that are not guarantors of the notes.

You will not have any claim as a creditor against any of our future subsidiaries that do not become guarantors of the notes. Indebtedness and other liabilities, including trade payables, whether secured or unsecured, of those subsidiaries will be effectively senior to your claims against those subsidiaries. As of June 30, 2006, we had no subsidiaries.

In addition, the indenture governing the notes will, subject to some limitations, permit our future non-guarantor subsidiaries, if any, to incur additional indebtedness and will not contain any limitation on the amount of other liabilities, such as trade payables, that these subsidiaries may incur.

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

Upon the occurrence of specific kinds of change of control events, we will be required to offer to repurchase all outstanding notes at 101% of their principal amount, plus accrued and unpaid interest. We may not be able to repurchase the notes upon a change of control because we may not have sufficient funds. Our failure to repurchase the notes upon a change of control would cause a default under the indenture and a cross-default under the senior unsecured revolving credit facility and our senior unsecured money market line of credit. Our senior unsecured revolving credit facility also provides that a change of control, as defined in such agreement, will be a default that permits lenders to terminate their commitment to lend and to accelerate the maturity of borrowings thereunder, thereby limiting our ability to raise cash to purchase the notes, and reducing the practical benefit of the offer-to-purchase provisions to the holders of the notes. Any of our future debt agreements may contain similar provisions.

In addition, the change of control provisions in the indenture may not protect you from certain important corporate events, such as a leveraged recapitalization (which would increase the level of our indebtedness), reorganization, restructuring, merger, sale or other disposition of all or substantially all of our assets or other similar transaction. Such a transaction may not involve a change in voting power or beneficial ownership or, even if it does, may not involve a change that constitutes a "Change of Control" as defined in the indenture that would trigger our obligation to repurchase the notes. If an event occurs that does not constitute a "Change of Control" as defined in the indenture, we will not be required to make an offer to repurchase the notes and you may be required to continue to hold your notes despite the event. See "Description of other indebtedness" and "Description of notes Change of Control."

You cannot be sure that an active trading market will develop for the notes.

The notes will constitute a new issue of securities for which there is no established trading market. We do not intend to list the notes on any national securities exchange or seek the admission of the notes for quotation through the National Association of Securities Dealers Automated Quotation System. We have been informed by the underwriters that they intend to make a market in the notes after this offering is completed. However, the underwriters are not obligated to do so and may cease their market-making activities at any time. In addition, the liquidity of the trading market in the notes, and the market price quoted for the notes, will depend on a number of factors, including:

- the number of holders of notes;
- our operating performance, financial condition or prospects;
- the operating performance, financial condition or prospects of other companies in our industry;
- the overall market for high yield securities;
- the interest of securities dealers in making a market in the notes; and
- prevailing interest rates.

Historically, the market for non-investment grade debt has been subject to disruptions that have caused substantial volatility in the prices of securities similar to the notes. We cannot assure you that an active trading market for the notes will develop or that the market will be free from similar disruptions or that any such disruptions may not adversely affect the prices at which you may sell your notes. Therefore, we cannot assure you that you will be able to sell your notes at a particular time or the price that you receive when you sell will be favorable.

Special note regarding forward-looking statements

This prospectus contains statements that are, or may be deemed to be, "forward-looking statements" within the meaning of Section 27A of the Securities Act and Section 21E of the Securities Exchange Act of 1934, as amended. These statements relate to future events or our future financial performance. We have attempted to identify forward-looking statements by terminology such as "anticipate," "believe," "can," "continue," "could," "estimate," "expect," "intend," "may," "plan," "potential," "predict," "should," "would" or "will" or the negative of these terms or other comparable terminology. These statements are only predictions and involve known and unknown risks, uncertainties and other factors, including those discussed under "Risk factors," which could cause our actual results to differ from those projected in any forward-looking statements we make.

We believe that it is important to communicate our future expectations to our investors. However, there may be events in the future that we are unable to accurately predict or control and that may cause our actual results to differ materially from the expectations we describe in our forward-looking statements. Forward-looking statements speak only as of the date of such statement. We do not plan to publicly update or revise any forward-looking statements after we distribute this prospectus, whether as a result of any new information, future events or otherwise. Potential investors should not place undue reliance on our forward-looking statements. Before you invest in the notes, you should be aware that the occurrence of any of the events described in the "Risk factors" section and elsewhere in this prospectus could harm our business, prospects, operations and financial condition. Although we believe that the expectations reflected in the forward-looking statements are reasonable, we cannot guarantee future results, levels of activity, performance or achievements.

Use of proceeds

We estimate that the net proceeds from this offering will be approximately $195 million after deducting underwriting discounts and commissions and estimated expenses of the offering. We intend to allocate the net proceeds as follows:

- approximately $144 million to repay current borrowings under our senior unsecured revolving credit facility, which borrowings were used in 2006 primarily in connection with an acquisition and a joint venture in the Piceance basin; and

- $51 million to finance the November 1, 2006 installment under our joint venture agreement to develop properties in the Piceance basin.

See "Management's discussion and analysis of financial condition and results of operation" for more information about our acquisition and our joint venture in the Piceance basin.

As of June 30, 2006, the weighted average interest rate with respect to our senior unsecured revolving credit facility was 6.6%. The indebtedness under our senior unsecured revolving credit facility matures on July 1, 2011. Affiliates of certain of the underwriters are lenders under our senior unsecured revolving credit facility, a portion of which we intend to repay with the net proceeds of the offering.

Capitalization

The following table sets forth our capitalization as of June 30, 2006:

- on a historical basis; and

- on an as adjusted basis to reflect this offering and the application of net proceeds from this offering of approximately $144 million to repay current borrowings under our senior unsecured revolving credit facility and $51 million to finance the November 1, 2006 installment under our joint venture agreement to develop properties in the Piceance basin, as if this offering occurred on June 30, 2006.

This table is unaudited and should be read together with our financial statements and accompanying notes incorporated by reference into this prospectus.

	As of June 30, 2006	
($ in thousands)	**Actual**	**As adjusted**
	(unaudited)	**(unaudited)**
Cash and cash equivalents	$ 626	$ 626
Short-term debt:		
Senior unsecured money market line of credit(1)	$ 23,500	$ 23,500
Long-term debt:		
Senior unsecured revolving credit facility(1)	249,000	105,000
Notes offered hereby(2)		200,000
Total long-term debt	$ 249,000	$ 305,000
Total debt	$ 272,500	$ 328,500
Total shareholders' equity	335,922	335,922
Total capitalization	$ 608,422	$ 664,422

(1) As of August 31, 2006, we had approximately $13 million outstanding on our senior unsecured money market line and $309 million outstanding on our senior unsecured revolving credit facility. After giving effect to this offering and the application of net proceeds from this offering, we would have had approximately $165 million outstanding under our senior unsecured revolving credit facility, with additional borrowing availability of $322 million. The amount outstanding under our senior unsecured revolving credit facility fluctuates throughout the year depending on our working capital and other needs.

(2) Includes approximately $5 million of underwriters' discount and expenses relating to the issuance of $200 million aggregate principal amount of new senior subordinated notes, which amount will be amortized over the ten year life of the notes.

Ratio of earnings to fixed charges

Our ratio of earnings to combined fixed charges is as follows:

($ in thousands)	2001	2002	2003	2004	2005	Six months ended June 30, 2006
	Years ended December 31,					
						(unaudited)
Earnings:						
Income before provision for income taxes	$ 25,694	$ 36,327	$ 36,968	$ 89,518	$ 162,859	$ 95,281
Capitalized interest						(2,764)
Fixed charges	3,719	1,171	1,570	2,254	6,256	6,923
Total earnings	$ 29,413	$ 37,498	$ 38,538	$ 91,772	$ 169,115	$ 99,440
Fixed charges:						
Interest expense	$ 3,719	$ 1,042	$ 1,414	$ 2,067	$ 6,048	$ 4,038
Interest component of rent expense(1)		129	156	187	208	121
Capitalized interest						2,764
Total fixed charges	$ 3,719	$ 1,171	$ 1,570	$ 2,254	$ 6,256	$ 6,923
Ratio of earnings to fixed charges	7.91x	32.02x	24.55x	40.72x	27.03x	14.36x

(1) Estimated to be one-third of rent expense.

For purposes of calculating the ratio of earnings to fixed charges, "earnings" represents income from operations before provision for income taxes plus fixed charges. "Fixed charges" consist of interest expense, interest component of rent expense (estimated to be one-third of rent expense) and capitalized interest.

The calculation of ratio of earnings to fixed charges is different from the calculation of the Consolidated Coverage Ratio contemplated by the Indenture. See "Description of notes" for more information about the Consolidated Coverage Ratio.

Because the proceeds of this offering will be used to repay indebtedness under our senior unsecured revolving credit facility and our ratio of our earnings to fixed charges would change by ten percent or more, we are presenting our pro forma ratio below.

In computing the pro forma ratio, the historical ratio is adjusted by the pro forma interest expense (net) amount calculated as follows:

(1) Add to historical fixed charges the increase in interest costs resulting from the proposed issuance of new debt; and

(2) Deduct from historical fixed charges the decrease in interest costs resulting from the retirement of any debt presently outstanding (but only for the period of time outstanding if less than one year) which will be retired with the proceeds from the proposed offering.

($ in thousands)	Pro forma year ended December 31, 2005	Pro forma six months ended June 30, 2006
Total earnings	$169,115	$99,440
Fixed charges, as above	6,256	6,923
Adjustments:		
Estimated net increase in interest expense from refinancing	5,313	1,188
Total pro forma fixed charges	11,569	8,111
Pro forma ratio of earnings to fixed charges	14.62x	12.26x

Selected historical financial information

The following table shows our selected historical financial data as of and for the periods indicated. Our selected historical financial data as of and for the fiscal years ended December 31, 2003, 2004 and 2005 have been derived from our audited financial statements. Our selected historical financial data as of and for the six months ended June 30, 2005 and 2006 are derived from our unaudited financial statements and, in our opinion, have been prepared on the same basis as the audited financial statements and include all adjustments consisting of normal recurring adjustments, necessary for a fair presentation of this information. Certain historical amounts have been reclassified to conform to the current presentation. On May 17, 2006 a two-for-one stock split was approved. All per share amounts have been adjusted for the split. The following information is not necessarily indicative of our future results.

You should read the selected historical financial data below in conjunction with our financial statements and the accompanying notes which are incorporated by reference into this prospectus. You should also read the section entitled "Management's discussion and analysis of financial condition and results of operations."

($ in thousands, except per BOE data)				Years ended December 31,		Six months ended June 30,	
	2001(1)(2)	**2002(1)(2)**	**2003(2)**	**2004(2)**	**2005**	**2005**	**2006**
						(unaudited)	**(unaudited)**
Statement of operations data:							
Revenues:							
Sales of oil and gas	$100,146	$102,026	$ 135,848	$ 226,876	$ 349,691	$156,196	$212,575
Sales of electricity	35,133	27,691	44,200	47,644	55,230	23,970	26,884
Interest and other income, net	2,478	1,652	816	426	1,804	518	1,296
Total revenues	$137,757	$131,369	$ 180,864	$ 274,946	$ 406,725	$180,684	$240,755
Expenses:							
Operating costs oil and gas production	$ 34,605	$ 41,108	$ 57,830	$ 73,838	$ 99,066	$ 45,086	$ 52,813
Operating costs electricity generation	36,890	26,747	42,351	46,191	55,086	24,281	24,958
Production taxes	2,479	2,907	3,097	6,431	11,506	4,695	6,606
Exploration costs					3,649	786	3,761
Depreciation, depletion and amortization oil and gas production	13,225	13,388	17,258	29,752	38,150	17,988	29,359
Depreciation and amortization electricity generation	3,295	3,064	3,256	3,490	3,260	1,611	1,701
General and administrative expenses	9,747	10,417	14,495	22,504	21,396	10,023	16,192
Commodity derivatives	1,458						(736)
Dry hole, abandonment and impairment			4,195	745	5,705	2,622	6,782
(Recovery) write-off of electricity receivable	6,645	(3,631)					
Loss on disposal of assets				410			
Total expenses	$108,344	$ 94,000	$ 142,482	$ 183,361	$ 237,818	$107,092	$141,436

($ in thousands, except per BOE data and earnings per share)	Years ended December 31,					Six months ended June 30,	
	2001(1)(2)	2002(1)(2)	2003(2)	2004(2)	2005	2005	2006
						(unaudited)	(unaudited)
Income from operations	$ 29,413	$ 37,369	$ 38,382	$ 91,585	$ 168,907	$ 73,592	$ 99,319
Interest expense	3,719	1,042	1,414	2,067	6,048	2,902	4,038
Income before provision for income taxes	$ 25,694	$ 36,327	$ 36,968	$ 89,518	$ 162,859	$ 70,690	$ 95,281
Provision for income taxes	4,709	7,117	4,605	20,331	50,503	22,925	37,827
Net income	$ 20,985	$ 29,210	$ 32,363	$ 69,187	$ 112,356	$ 47,765	$ 57,454
Earnings per share (basic)(3)	$ .48	$ .67	$ .74	$ 1.58	$ 2.55	$ 1.08	$ 1.31
Earnings per share (diluted)(3)	$ .47	$ .67	$ .73	$ 1.54	$ 2.50	$ 1.06	$ 1.28
Balance sheet data (as of period end):							
Cash and cash equivalents	$ 7,238	$ 9,866	$ 10,658	$ 16,690	$ 1,990	$ 9,561	$ 626
Working capital	6,314	(2,892)	(3,540)	(3,840)	(54,757)	(9,209)	(61,195)
Oil and gas properties, buildings and equipment, net	208,860	228,475	295,151	338,706	552,984	487,220	784,216
Total assets	238,779	259,325	340,377	412,104	635,051	575,309	899,995
Total debt	25,000	15,000	50,000	28,000	86,500	125,000	272,500
Shareholders' equity	153,590	172,774	197,338	263,086	334,210	286,190	335,922
Cash flows data:							
Net cash flow provided by (used in):							
Operating activities	$ 35,433	$ 57,895	$ 64,825	$ 124,613	$ 187,780	$ 66,191	$ 84,096
Investing activities	(17,029)	(36,526)	(87,723)	(85,187)	(242,599)	(164,221)	(271,431)
Financing activities	(13,897)	(18,741)	23,690	(33,394)	40,119	90,901	185,971
Exploration and development of oil and gas properties	14,776	30,163	41,061	71,556	118,718	57,134	103,939
Property acquisitions	2,273	5,880	48,579	2,845	112,249	103,712	161,600
Additions to vehicles, drilling rigs and other fixed assets	119	469	494	669	11,762	3,375	5,892
Unaudited operating data:							
Oil and gas producing operations (per BOE):							
Average sales price before hedging	$ 19.63	$ 20.11	$ 24.48	$ 33.64	$ 47.01	$ 42.34	$ 51.08
Average sales price after hedging	19.79	19.39	22.52	30.32	41.62	38.62	48.92
Average operating costs oil and gas production	6.86	7.83	9.57	10.09	11.79	11.14	12.10
Production taxes	.49	.55	.51	.86	1.37	1.16	1.51
G&A	1.93	1.98	2.40	2.99	2.55	2.48	3.71

DD&A oil and gas production	2.62	2.55	2.86	3.96	4.54	4.40	6.73
Production (MBOE)	5,044	5,251	6,040	7,517	8,401	4,025	4,341
Electricity generation (MMWh)	483	748	767	776	741	363	371

Proved reserves information (as of period end):							
Total BOE	102,855	101,719	109,920	109,836	126,285	n/a	n/a
Standardized measure of discounted cash flows(4)	278,453	449,857	528,220	686,748	1,251,380	n/a	n/a
Year-end average BOE price	$ 14.13	$ 24.91	$ 25.89	$ 29.87	$ 48.21	n/a	n/a

(1) Information has been revised to reflect our change in allocation of cogeneration costs to oil and gas operations. See "Management's Discussion and Analysis."

(2) Information has been revised to reflect our change in allocation of technical labor and production taxes. See Note 2 following our audited financial statements for the year ended December 31, 2005, which are incorporated by reference into this prospectus.

(3) All earnings per share amounts have been restated to give retroactive effect to the two-for-one stock split that became effective on May 17, 2006.

(4) See Supplemental Information About Oil & Gas Producing Activities (unaudited) following our audited financial statements for the year ended December 31, 2005, which are incorporated by reference into this prospectus.

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

The following discussion should be read in conjunction with our financial statements and the related notes incorporated by reference into this prospectus. In addition to historical information, this discussion includes forward-looking information that involves risks and uncertainties which could cause actual results to differ materially from management's expectations. Please read "Risk factors" in this prospectus for a discussion of some of these risks and uncertainties.

Overview

Our mission is to increase the value of our business through consistent growth in our production and reserves, both through the drill bit and acquisitions. We strive to operate our properties in an efficient manner to maximize the cash flow and earnings of our assets. The strategies to accomplish these goals include:

- Developing our existing resource base
- Acquiring additional assets with significant growth potential
- Utilizing joint ventures with respected partners to enter new basins
- Accumulating significant acreage positions near our producing operations
- Investing our capital in a disciplined manner and maintaining a strong financial position

Notable items in 2005

- Achieved record production which averaged 23,015 BOE/D, up 12% from 2004
- Achieved record cash from operating activities of $188 million, up 50% from 2004
- Achieved record net income of $112 million, up 62% from 2004
- 2005 developmental capital expenditures were $131 million, up 82% from 2004
- Acquired and integrated the eastern Colorado Niobrara natural gas producing assets acquisition cost of $105 million
- Added 24.9 million BOE of reserves before production ending 2005 at 126.3 million BOE
- Achieved reserve replacement rate of 296%
- Negotiated new four-year crude oil sales contract for California heavy oil production
- Observed positive results on diatomite play and expanded pilot

Placed price collars on 10,000 BOE/D of future production from 2006 through 2009

Added approximately 186,000 gross (46,000 net) acres in the North Dakota Bakken play

Added approximately 624,000 gross (315,000 net) acres to Tri-State area inventory

Increased quarterly dividend to $.065 per share and paid special dividend of $.05 per share for total payout of $.30 per share

Began drilling to assess several prospects including Lake Canyon, Coyote Flats and Tri-State area

Increased financial capacity by establishing a $500 million senior unsecured revolving credit facility with an initial borrowing base of $350 million

Initiated a $50 million share buyback program

Notable items in the first six months of 2006

Achieved production which averaged 24,118 BOE/D, up 8% from the second half of 2005

Announced discovery in Green River formation at Lake Canyon, Utah

Acquired operatorship and significant working interest in natural gas assets in the Garden Gulch property in the Grand Valley field in the Piceance basin, Colorado, at an acquisition cost of $159 million

Entered into an agreement to jointly develop natural gas properties in the North Parachute Ranch property in the Grand Valley field in the Piceance basin, Colorado, to earn a 95% working interest in 4,300 gross acres near our Grand Gulch assets

Began $25 million, 50 well expansion of our diatomite project in California

Participated in a light oil discovery in the Wasatch formation at Lake Canyon and wrote off the well cost for the Mesaverde formation

Added financial capacity by increasing our senior unsecured revolving credit facility to $750 million with an initial borrowing base of $500 million

Completed two-for-one split of Class A Common Stock and Class B Stock

Notable items and expectations for the remainder of 2006

Increasing production from the diatomite expansion and further evaluation of the pilot performance

Began drilling the next six wells to expand the appraisal of our Lake Canyon acreage

Begin drilling in the Ashley Forest located in the southern portion of our Brundage Canyon property upon receiving approval of environmental review

Increased our 2006 capital budget to $275 million to accelerate growth

Increased our regular quarterly dividend by 15% to $.075 per share ($.30 annually) and declared a special dividend of $.02 per share

Targeting 2006 year-end reserves of at least 146 million BOE.

New joint venture. In June 2006, we entered into an agreement with a party to jointly develop the North Parachute Ranch property in the Grand Valley field of the Piceance basin of western Colorado for approximately $153 million payable by us in three installments by May 2007, which will fund the drilling of 90 natural gas wells on the party's acreage. We will hold a 5% working interest in those wells. Drilling the 90 wells will take place through December 1, 2008.

In July 2006, we paid $51 million, which was the first installment of the total $153 million, which earned us 4,300 gross acres elsewhere in the property with a working interest to us of 95% and a net revenue interest of approximately 79%. We are required to drill 120 wells on this acreage which drilling will take place through 2011. The 2006 budgeted capital expenditure to begin drilling wells on this acreage is approximately $48 million. At the date of the agreement there were no operating activities from these oil and gas assets.

Key acquisitions. In January 2005, we acquired certain interests in the Niobrara fields in northeastern Colorado for approximately $105 million. At December 31, 2005 the properties consisted of approximately 127,000 gross (100,000 net) acres. Production at acquisition was approximately 9 MMcf/D of natural gas, with estimated proved reserves of 87 Bcf. For the month of December 2005, production averaged approximately 13.8 MMcf/D and year-end proved reserves were 105 Bcf. The acquisition included approximately 200 miles of a pipeline gathering system and gas compression facilities for delivery into interstate gas lines.

In January 2005, we acquired a working interest in eastern Colorado, western Kansas and southwestern Nebraska, from an industry partner. We and our partner will jointly explore and develop shallow Niobrara natural gas, Sharon Springs shale gas and deeper Pennsylvanian formation oil assets on the acreage. We paid approximately $5 million for our working interest in the acreage and believe the potential of the Tri-State area can be exploited by using new drilling techniques, with 3D seismic technology, to assess structural complexity, estimate potentially recoverable oil and gas and determine drilling locations.

In 2005, we completed several transactions whereby we now have working interests in 186,000 gross acres (46,000 net) located in the Williston basin in North Dakota. These lease acquisitions, totaling approximately $11 million, provide us an entry into the emerging Bakken oil play in the Williston basin. The acreage covers several contiguous blocks located primarily on the eastern flank of the Nesson Anticline. Development activity in the Middle Bakken play is generally expanding to the area surrounding the Nesson Anticline.

In October 2005, we purchased a 50% working interest in approximately 69,000 gross undeveloped acres (24,000 net) in Colorado's Phillips and Sedgwick Counties. This additional Niobrara leasehold position is adjacent to and immediately north of our producing natural gas assets in Yuma County.

In February 2006, we acquired a 50% working interest in natural gas assets in the Garden Gulch property in the Piceance basin of western Colorado for approximately $159 million in cash. We internally estimate there are 26 Bcf of proved reserves and have identified over 600 drilling locations based on 10-acre development. We are the operator in the 6,314 gross acres targeting gas in the Williams Fork section of the Mesaverde formation.

Asset dispositions. We have significantly increased and strengthened our portfolio of assets since 2002 and expect to continue to make acquisitions. We anticipate that we will dispose of certain properties or assets over time. The assets most likely for disposition will be those that do not fit or complement our strategic growth plan, are not contributing satisfactory economic returns given the profile of the assets, or we believe the development potential will not be meaningful to our company as a whole.

Capital expenditures. Excluding the acquisition price of new properties, in 2006 we plan to spend approximately $275 million on capital expenditures. These expenditures will be directed toward developing reserves, increasing oil and gas production and exploration opportunities. For 2006, we plan to invest approximately $190 million, or 69%, in our Rocky Mountain and Mid-Continent region assets, and $85 million, or 31%, in our California assets. Approximately half the capital budget is focused on converting probable and possible reserves into proved reserves and on our appraisal and exploratory projects, while the other half is for the development of our proved reserves and facility costs.

This capital program allows us to continue record activity levels by drilling over 500 gross wells and performing approximately 200 well workover activities in 2006 versus approximately 234 gross wells and 140 well workovers in 2005. As a result, we are targeting 2006 production growth of 10% to average between 25,300 BOE/D to 25,800 BOE/D, which includes the Piceance basin acquisitions and we plan to continue to actively appraise significant acreage positions held for hydrocarbon potential. In 2006, we expect production to be approximately 62% heavy oil, 16% light oil and 22% natural gas and anticipate funding our capital program generally from internally generated cash flow. Successes may also encourage the initiation of additional discretionary projects. We have currently secured the necessary equipment and are meeting permit requirements to achieve the 2006 program.

Development, exploitation and exploration activity

Rocky Mountain and Mid-Continent

We have interests in over one million gross acres, including both productive and prospective, in the Rocky Mountain and Mid-Continent region and have the following development and/or appraisal activities in progress.

Uinta basin projects

Brundage Canyon: We continue the development of the Green River formation at Brundage Canyon in 2006 to assist full development and will include a 20-acre spacing pilot. In the second quarter we drilled 37 wells with a 100% success rate. We continue to develop this field with a three rig drilling program. For the second quarter, daily net production averaged 6,059 BOE/D. Minor infield gas gathering infrastructure has been upgraded and an additional compressor was set to handle increasing volumes of natural gas. The environmental review process is proceeding to initiate drilling in the Ashley National Forest where we anticipate drilling several wells in 2006.

Lake Canyon: On January 13, 2006, we announced commercial success from our first two wells on this acreage. The Nielsen Marsing and Taylor Herrick wells have tested production rates of 98 and 163 BOE/D, respectively, from the same Green River formation that is productive immediately east (approximately three miles) in our Brundage Canyon field. Initial performance from these discovery wells suggests that expected reserves per well are on par with the Brundage Canyon field (approximately 80,000 BOE gross) that is currently being developed on 40-acre spacing. Production from these two shallow Green River wells continues to be favorable. We have a 56.25% working interest in these two wells which contributed 70 net

BOE/D in the second quarter. The next six Green River locations are permitted to confirm the previously announced discoveries and drilling is expected to commence in the third quarter of 2006. We are in the permitting process for an additional 26 wells which are intended to continue exploratory and development drilling on the eastern portion of our Lake Canyon acreage. The timing of drilling these wells is uncertain, but we are preparing to begin drilling these wells this year. The focus will be to begin the methodical appraisal of a sizeable portion of this acreage block. Our working interest in these wells will be either 75% or 56.25% depending on the participation of the land owner. The shallow zones are those above the Wasatch which is at approximately 6,000 feet. Our industry partner has finished testing the productivity of the deep Mesaverde sands and has reported this interval non-commercial. The well was plugged back and completed in the Wasatch formation at a depth of 6,600 feet. We have a 25% working interest in this well. Second quarter 2006 production contribution from this well, net to us, has been 44 BOE/D of approximately 40 degree API crude oil from Wasatch formation sands. Due to the success of the #1 DLB Wasatch discovery well, our partner plans to drill four Wasatch wells in the fourth quarter of 2006.

Coyote Flats: We have three successful appraisal Ferron gas wells on the east side of the Scofield reservoir which have each tested flow rates exceeding 900 Mcf/D. We are proceeding with plans to construct a 13 mile gas pipeline to transport gas from three wells and project sales to begin in early 2007. We have negotiated an amendment to the participating agreement with our industry partner to earn our 50% interest in the project without drilling the remaining Emery coalbed methane wells. We determined in the first quarter of 2006 that the Emery coalbed methane well we drilled was a dry hole due to low gas saturation, and its costs were expensed.

Piceance basin

In the second quarter of 2006, we drilled five wells on the Garden Gulch properties in the Grand Valley field of the Piceance basin and had 14 wells producing. Our net production in the second quarter 2006 averaged 3,356 Mcf/D (559 BOE/D). We now have a total of four rigs working on the project. We have made significant progress in gearing up for extensive development of this asset, including additional outlets for gas sales. Our production from Garden Gulch is now gathered and processed under an agreement which prorates the pipeline system capacity among our partners and us. This gathering system will be expanded as we progress with our drilling program. We previously processed our gas under a different, interruptible contract that could curtail our production. We estimate that our second quarter production was negatively impacted by approximately 1,000 Mcf/D by these curtailments.

In June 2006, we announced an agreement for an additional 4,300 gross acres in the Piceance basin, immediately east of the Garden Gulch property. This agreement for the North Parachute Ranch property expands upon our reserves and drilling opportunities with an additional 400 locations. We will invest over $20 million in this project in the third and fourth quarters of 2006. Production from these wells is expected to be similar to Garden Gulch wells, with initial production rates ranging from 1.3 to 2.0 MMcf/D.

Denver-Julesburg basin

In our Tri-State area, we drilled 71 wells in the second quarter of 2006 with no dry holes. In the second quarter 2006, net production averaged 13.8 MMcf/D or 2,307 BOE/D. Gas gathering facility upgrades have been completed, including the setting of additional compression by one of our gas gatherers. On our Paoli prospect (Colorado) and our Kansas acreage we have permitted 24 locations (12 at each) based on the results of the 3D seismic we shot or acquired in the first quarter of 2006. We will begin drilling the vertical wells on these prospects in the third quarter and several horizontal wells will be drilled in 2006 by our industry partner in Kansas.

Williston basin projects

Bakken Play: In North Dakota, we intend to participate with up to a 15% working interest in at least four horizontal oil wells to appraise the prospective oil formation.

California

San Joaquin Valley basin

Diatomite: In 2005, oil production from the initial 14 well pilot (6 producers) averaged approximately 135 Bbl/D. Based on promising results from the pilot project, we began an expansion of the pilot with a 25 well program (15 producers) in the third quarter of 2005, and completed it in the fourth quarter. Based on the initial reservoir response to our first 39 wells (21 producers, 15 steam injectors and 3 service wells) we began a 50 well expansion (38 producers, 11 steam injectors and 1 service well) of the commercial test of the diatomite resource during the second quarter of 2006. We anticipate that all of these wells will be completed and ready for production in the second half of 2006. We continue to assess the long-term economic and operating viability of the project as these wells are an indication of future large-scale development. We are monitoring the steam to oil ratio (SOR) because we believe achieving an SOR of 6 or less is necessary for such development. SOR measures how much steam is required for injection into the reservoir to produce one barrel of oil. Estimated original oil in place is approximately 200 million barrels and we are targeting a minimum 25% recovery of this oil. In 2005, we booked 2.5 million BOE of reserves based on asset performance. The project's current performance is meeting our expectations and our goal of determining to move forward with full-scale development in 2006 is on track. Production has increased consistently, and in August averaged approximately 350 BOE/D.

Midway-Sunset: Production, excluding diatomite, remained basically flat at approximately 11,400 Bbl/D in the second quarter versus the first quarter of 2006. The new horizontal producers drilled in the first quarter have been steamed and are responding as expected. We have steamed a significant number of our horizontal producers during the second quarter using our traditional approach and are expecting to see the response from this concentrated program in the second half of 2006. We are focused on improving our production by optimizing our steam distribution and reservoir temperatures and project that production will average approximately 11,800 Bbl/D in the second half of 2006.

We are accelerating the development of new steam floods on our Ethel D and Pan properties (which are both included in Midway-Sunset production) and Poso Creek properties. We are drilling approximately 60 producing wells on these properties in 2006 and installing the appropriate steam generators and water processing facilities. As of August 31, 2006, production from these properties was over 2,000 Bbl/D.

Reserve replacement rate. The reserve replacement rate is calculated by dividing total new proved reserves added for the year by total production for the year. This measure is important because it is an indication of growth in our proved reserves and, thus may impact our value. We believe our calculation of this measure is substantially similar to how other companies compute reserve replacement rate.

Development, exploitation and exploration activity. We drilled 251 gross (163 net) wells during the first six months of 2006, realizing a gross success rate of 98 percent. Our approved capital budget in 2006 is $275 million.

Drilling activity. The following table sets forth certain information regarding drilling activities for the six months ended June 30, 2006:

	Six months ended June 30, 2006		
	Gross wells	**Net wells**	**Net workovers**
Midway-Sunset(1)	44	43.5	14.9
Poso Creek	18	18.0	2.0
Placerita			6.0
Brundage Canyon	57	57.0	14.0
Lake Canyon	1	.3	1.0
Coyote Flats(2)	2	2.0	.5
Tri-State(3)	115	36.8	27.7
Piceance	10	5.0	
Bakken(4)	4	.3	
Totals	251	162.9	66.1

(1) Includes 1 gross well (1 net well) that was a dry hole in the second quarter of 2006.

(2) Includes 2 gross wells that were dry holes in first quarter of 2006. Acreage ownership is earned upon fulfilling certain drilling obligations.

(3) Includes 1 gross well (.3 net well) that was a dry hole in the first quarter of 2006.

(4) Includes 1 gross well (.06 net well) that was a dry hole in the first quarter of 2006.

Rocky Mountain and Mid-Continent region drilling rigs. During 2005 and 2006, we purchased three drilling rigs, two of which began drilling in the third quarter of 2006. These rigs are leased to a drilling company under three year contracts and carry purchase options available to the drilling company. Owning these rigs allows us to successfully meet a portion of our drilling needs in both the Uinta and Piceance basins over the next several years. We have several more rigs we do not own that are drilling or are contracted to begin drilling in 2006.

Results of operations

The following is a more detailed discussion of our financial condition and results of operation for the periods presented.

Six months ended June 30, 2006 compared to six months ended June 30, 2005

Revenue. The following companywide results for the six months ended June 30, 2006 and 2005:

($ in thousands, except per share data)	Six months ended June 30, 2005	Six months ended June 30, 2006	% Change
	(unaudited)	(unaudited)	
Sales of oil	$ 132,922	$ 178,247	34%
Sales of gas	23,274	34,328	47%
Total sales of oil and gas	$ 156,196	$ 212,575	36%
Sales of electricity	23,970	26,884	12%
Interest and other income, net	518	1,296	150%
Total revenues and other income	$ 180,684	$ 240,755	33%
Net income	$ 47,765	$ 57,454	20%
Earnings per share (diluted)	$ 1.06	$ 1.28	21%

Our production for the six months ended June 30, 2006 was 24,118 BOE/D, which was up 8% from the same period last year. Our Rockies and Mid-Continent production is meeting our expectations and averaged just under 9,200 BOE/D in the second quarter of 2006. We are accelerating the development of three new steam floods in California to partially offset the delay in the production response to our steam optimization efforts in our core assets. Due to the uncertainty in the timing of the production increases from our projects, we are forecasting average production of between 25,300 BOE/D and 25,800 BOE/D for 2006.

In the first six months of 2006, we incurred charges of $3.8 million in exploration costs which consists of our geological and geophysical costs, primarily 3D surveys and data accumulation, associated with our Tri-State and Uinta basin acreage. We project our total exploration expense for 2006 to be between $4 million and $6 million. We also incurred charges of $5.2 million for two dry holes drilled at the Coyote Flats, Utah prospect. In addition to the two dry holes at Coyote Flats, we also had one non-commercial well in the North Dakota Bakken play and one dry hole on our Tri-State acreage in the first quarter of 2006. The combined dry hole expense for these two wells was less than $.3 million. During the second quarter of 2006, we incurred charges for our 25% share of a deep well drilled at Lake Canyon in the Uinta basin. This well, which was completed in late April was tested and determined, in the second quarter of 2006, to be commercial in the Wasatch formation and non-commercial in the zones below the Wasatch, thus, approximately $1.6 million net to our interest of the well cost was written off.

In the first quarter ended March 31, 2006, we took a charge for the change in fair market value of our natural gas derivatives put in place to protect our Piceance basin acquisition future cash flows. These gas derivatives did not qualify for hedge accounting under SFAS 133 because the price index in the derivative instrument did not correlate closely with the item being hedged. The pre-tax charge in the first quarter was $4.8 million which represented the change in fair market value over the life of the contract, which resulted from an increase in natural gas prices from the date of the derivative to March 31, 2006. On May 31, 2006, we entered into basis swaps with natural gas volumes to match the volumes on our NYMEX Henry Hub collars that were placed on March 1, 2006. The combination of the derivative instruments entered into on March 1, 2006 (described above) and the basis swaps were designated as cash flow hedges in accordance with SFAS 133. Thus, the unrealized net gain of $5.6 million on the income statement in the second quarter of 2006 under the caption "Commodity derivatives" is primarily the change in fair value of the derivative instrument caused by changes in forward price curves prior to designating these instruments as cash flow hedges. Post May 31, 2006 changes in the marked-to-market fair values are reflected in Other Comprehensive Income.

***Operating data*.**

The following table is for the six months ended June 30, 2006 and 2005:

	Six months ended			
	June 30, 2005	%	June 30, 2006	%
	(unaudited)		(unaudited)	
Oil and Gas				
Heavy oil production (Bbl/D)	15,773	71	15,470	64
Light oil production (Bbl/D)	3,298	15	3,684	15
Total oil production (Bbl/D)	19,071	86	19,154	79
Natural gas production (Mcf/D)	19,734	14	29,784	21
Total (BOE/D)	22,359	100	24,118	100
Per BOE:				
Average sales price before hedging	$42.34		$51.08	
Average sales price after hedging	38.62		48.92	
Oil, per Bbl:				
Average WTI price	$51.53		$67.13	
Price sensitive royalties	(3.44)		(5.52)	
Quality differential	(5.34)		(7.49)	
Crude oil hedges	(4.41)		(2.72)	
Average oil sales price after hedging	$38.34		$51.40	
Gas, per MMBtu:				
Average HH price	$ 6.57		$ 7.28	
Natural gas hedges	(.06)		(.01)	
Location and quality differentials	(.86)		(1.14)	
Average gas sales price after hedging	$ 5.65		$ 6.13	

Oil Contracts. See discussion in "Business Crude oil and natural gas marketing."

Hedging. See Note 5 to our unaudited condensed financial statements for the six months ended June 30, 2006, which are incorporated by reference herein.

Electricity. We consume natural gas as fuel to operate our three cogeneration facilities which are intended to provide an efficient and secure long-term supply of steam necessary for the economic production of heavy oil. Revenue and operating costs in the six months ended June 30, 2006 were up from the six months ended June 30, 2005 due to 8% higher electricity prices and 7% higher natural gas prices, respectively. The following table is for the six months ended June 30, 2006 and 2005:

	Six months ended	
	June 30, 2005	**June 30, 2006**
	(unaudited)	**(unaudited)**
Electricity		
Revenues (in millions)	$ 24.0	$ 26.9
Operating costs (in millions)	$ 24.3	$ 25.0
Electric power produced MWh/D	2,006	2,051
Electric power sold MWh/D	1,810	1,855
Average sales price/MWh after hedging	$ 71.55	$ 76.99
Fuel gas cost/MMBtu (excluding transportation)	$ 5.94	$ 6.36

Oil and gas operating, production taxes, G&A and interest expenses. We believe that the most informative way to analyze changes in recurring operating expenses from one period to another is on a per unit-of-production, or per BOE, basis. The following table presents information about our operating expenses for each of the six month periods ended:

	Amount per BOE			Amount ($ in thousands)	
	June 30, 2005	**June 30, 2006**	**Change**	**June 30, 2005**	**June 30, 2006**
	(unaudited)	**(unaudited)**		**(unaudited)**	**(unaudited)**
Operating costs oil and gas production	$11.14	$12.10	9%	$ 45,086	$ 52,813
Production taxes	1.16	1.51	30%	4,695	6,606
DD&A oil and gas production	4.40	6.73	53%	17,988	29,359
G&A	2.48	3.71	50%	10,023	16,192
Interest expense	.72	.92	28%	2,902	4,038
Total	$19.90	$24.97	25%	$ 80,694	$ 109,008

Our total operating costs, production taxes, G&A and interest expenses for the six months ended June 30, 2006, stated on a unit-of-production basis, increased 25% over the six months ended June 30, 2005. The changes were primarily related to the following items:

Operating costs. Operating costs in the first six months of 2006 were 9% higher than the first six months of 2005 due to the net effect of a 11% higher volume of steam used at 7% higher costs of fuel gas. The first half of 2006 also had increased well servicing activities and higher cost of goods and services in general. The cost of our steaming operations on our heavy oil properties in California vary depending on the cost of natural gas used as fuel and the volume of steam injected. The following table presents steam information:

	Six months ended		
	June 30, 2005	**June 30, 2006**	**% Change**
Average volume of steam injected (Bbl/D)	69,631	77,165	11%
Fuel gas cost/MMBtu	5.94	6.36	7%

As commodity prices remain robust, we anticipate that cost pressures within our industry may continue. Natural gas prices impact our cost structure in California by approximately $1.75 per California BOE for each $1.00 change in natural gas price.

Production taxes. Our production taxes have increased over the last year as the value of our oil and natural gas has increased. Severance taxes, which are prevalent in Utah and Colorado, are directly related to the cost of the field sales price of the commodity and in California, our production is burdened with ad valorem taxes on our total proved reserves. We expect production taxes to track the commodity price generally. If California Proposition 87, "The Clean Energy Initiative" is passed by California voters in November 2006, this initiative can add up to a 6% severance tax on our California production. At $70 WTI, this could add over $3.00 per barrel of new taxes on each of our California barrels produced after December 31, 2006. If this initiative is passed, we may redetermine our allocation of capital to our inventory of projects to optimize the return on our capital investments.

Depreciation, depletion and amortization. DD&A increased per BOE in the six months ended June 30, 2006 due to several sizable acquisitions, more extensive development in higher cost fields and cost pressures in our labor and capital investments. As these costs increase, our DD&A rates per BOE will also increase.

General and administrative. Approximately two-thirds of our G&A is compensation or compensation related costs. To remain competitive in workforce compensation and achieve our growth goals, our compensation costs increased significantly in 2006 due to additional staffing, higher compensation levels, bonuses, stock compensation and benefit costs.

Interest expense. Our outstanding borrowings, including our senior unsecured money market line of credit, was $273 million at June 30, 2006 and $125 million at June 30, 2005. Average borrowings in 2006 increased as a result of a $159 million acquisition during February 2006. A certain portion of our interest cost related to our Piceance basin acquisition and joint venture has been capitalized into the basis of the assets, and we anticipate a portion will continue to be capitalized during 2006 and 2007 until our probable reserves have been recategorized to proved reserves.

Income taxes. See Note 9 to our unaudited condensed financial statements for the six months ended June 30, 2006, which are incorporated by reference herein. Our effective tax rate will be higher in 2006 as compared to 2005 due to the phase-out of the EOR tax credit in 2006. We experienced an effective tax rate in the second quarter of 40%, which is in line with our projections.

Fiscal year ended December 31, 2005 compared to fiscal years ended December 31, 2004 and 2003

Revenues. Sales of oil and gas were up 54% in 2005 compared to 2004 and up 157% from 2003. This significant improvement was due to increases in both oil and gas prices and production levels.

Improvements in production volume are due to acquisitions and sizable capital investments. Improvement in prices during 2005 are due to a tighter supply and demand balance and the nervousness of the market about possible supply disruptions. The increase in oil prices contributed roughly two-thirds of the revenue increase and the increase in production volumes contributed the other third. Approximately 84% of our oil and gas sales volumes in 2005 were crude oil, with 78% of the crude oil being heavy oil produced in California which was sold under a contract based on the higher of WTI minus a fixed differential or the average posted price plus a premium. This contract ended on January 31, 2006. The contract allowed us to improve our California revenues over the posted price by approximately $41 million and $13 million in 2005 and 2004, respectively. In November, 2005, we entered into a new crude oil sales contract for our California production for deliveries beginning February 1, 2006, as discussed above.

The following companywide results are for the years ended December 31:

	Years ended December 31,		
($ in millions, except per share data)	**2003**	**2004**	**2005**
Sales of oil	$ 130	$ 210	$ 289
Sales of gas	6	17	61
Total sales of oil and gas	$ 136	$ 227	$ 350
Sales of electricity	44	48	55
Interest and other income, net	1		2
Total revenues and other income	$ 181	$ 275	$ 407
Net income	$ 32	$ 69	$ 112
Earnings per share (diluted)	$ .73	$ 1.54	$ 2.50

Hedging. See Note 15 to our audited financial statements for the fiscal year ended December 31, 2005, which are incorporated by reference herein.

Operating data. The following table is for the years ended December 31:

	Years ended December 31,					
	2003	**% Of production**	**2004**	**% Of production**	**2005**	**% Of production**
Production						
Heavy Oil Production (Bbl/D)	15,477	94	15,901	77	16,063	70
Light Oil Production (Bbl/D)	489	3	3,345	16	3,336	14
Total Oil Production (Bbl/D)	15,966	97	19,246	93	19,399	84
Natural Gas Production (Mcf/D)	3,499	3	7,752	7	21,696	16
Total (BOE/D)	16,549	100	20,537	100	23,015	100
Percentage increase from prior year	15%		24%		12%	
Per BOE:						
Average sales price before hedging	$24.48		$33.64		$47.01	
Average sales price after hedging	22.52		30.32		41.62	
Oil, per Bbl:						
Average WTI price	$31.16		$39.21		$56.70	
Price sensitive royalties	(1.79)		(2.78)		(4.42)	
Gravity differential	(2.97)		(4.93)		(5.22)	
Crude oil hedges	(2.03)		(2.93)		(6.21)	
Average oil sales price after hedging	$24.37		$28.57		$40.85	
Gas, per MMBtu:						
Average HH price	$5.11		$6.13		$8.05	
Natural gas hedges	.02		(.01)		(.11)	
Location and quality differentials	(.81)		(.63)		(1.45)	
Average gas sales price after hedging	$4.32		$5.49		$6.49	

Electricity. We consume natural gas as fuel to operate our three cogeneration facilities which are intended to provide an efficient and secure long-term supply of steam necessary for the cost-effective production of heavy oil. We sell our electricity to utilities under standard offer contracts, which are based on "avoided cost" or SRAC pricing approved by the CPUC and under which our revenues are currently linked to the cost of natural gas. Natural gas index prices are the primary determinant of our electricity sales price based on the current pricing formula under these contracts. The correlation between electricity sales and natural gas prices allows us to more effectively manage our cost of producing steam. Revenue and operating costs in the year ended 2005 were up from the year ended 2004 due to 18% higher electricity prices and

34% higher natural gas prices, respectively. We purchased approximately 38 MMBtu/D as fuel for use in our cogeneration facilities in the year ended December 31, 2005.

	Years ended December 31,		
($ in millions, unless otherwise noted)	2003	2004	2005
Revenues	$ 44.2	$ 47.6	$ 55.2
Operating costs	42.4	46.2	55.1
Decrease to total oil and gas operating expenses-per barrel	.32	.19	.02
Electric power produced MWh/D	2,100	2,121	2,030
Electric power sold MWh/D	1,925	1,915	1,834
Average sales price/MWh before hedging	$ 62.91	$ 70.24	$ 82.73
Average sales price/MWh after hedging	61.95	70.24	82.73
Fuel gas cost/MMBtu (after hedging and excluding transportation)	4.88	5.46	7.30

Royalties. A price-sensitive royalty burdens a portion of our Midway-Sunset California property which produces approximately 3,800 BOE/D. This royalty is 75% of the amount of the heavy oil posted price above a base price which was $15.18 in 2005. This base price escalates at 2% annually, thus the threshold price is $15.48 per barrel in 2006. Amounts paid were $29 million, $19.3 million and $10.2 million in the years ended December 31, 2005, 2004 and 2003, respectively. Accounts payable associated with this royalty at year end 2005 was $29 million. Because our interest in the revenue varies according to crude prices, the continuing development on this property will depend on its future profitability.

A second price sensitive royalty burdened approximately 700 BOE/D at our Placerita field in California. This royalty is calculated when the sales price exceeds $26 per barrel up to a maximum. The royalty was $2.8 million, $1.4 million and $.3 million in the years ended December 31, 2005, 2004 and 2003, respectively. The maximum amount of the royalty over its life is $5 million, thus, this royalty was fully accrued in the first quarter of 2006.

In 2005, the Bureau of Land Management revoked their royalty exemption for certain heavy oil properties. This resulted in a reduction to us of .9 million barrels of reserves and approximately 100 BOE/D in the fourth quarter of 2005. In addition, in December 2004, certain royalty owners exercised their right to convert their royalty interest into a working interest on our Formax property in the Midway-Sunset field. This resulted in a reduction of 1.8 million barrels of reserves and represented approximately 450 BOE/D as of December 31, 2004.

Oil and gas operating, production taxes, G&A and interest expenses. The following table presents information about our operating expenses for each of the years in the two-year period ended December 31, 2005:

	Amount			Amount ($ per BOE)		
($ in thousands, unless otherwise noted)	**2004**	**2005**	**% Change**	**2004**	**2005**	**% Change**
Operating costs oil and gas production	$ 73,838	$ 99,066	34%	$ 10.09	$ 11.79	17%
Production taxes	6,431	11,506	79%	.86	1.37	59%
DD&A oil and gas production	29,752	38,150	28%	3.96	4.54	15%
G&A	22,504	21,396	(5)%	2.99	2.55	(15)%
Interest expense	2,067	6,048	193%	.27	.72	167%
Total	$ 134,592	$ 176,166	31%	$ 18.17	$ 20.97	15%

Our total operating costs, production taxes, G&A and interest expenses for 2005, stated on a unit-of-production basis, increased 15% over 2004. The changes were primarily related to the following items:

Operating costs: Higher crude oil and natural gas prices have created an incentive for the U.S. domestic oil and gas industry to significantly increase exploration and development activities, which is straining the capacity for goods and services that support our industry. Thus, higher costs are prominent throughout the industry and resulted in higher operating costs per BOE for the year ended 2005 as compared to 2004. Costs in California were also higher due to increased well servicing activities and increases in steam costs. The cost of our steaming operations on our heavy oil properties represents a significant portion of our operating costs and will vary depending on the cost of natural gas used as fuel and the volume of steam injected. The following table presents steam information:

	2004	**2005**	**% Change**
Average volume of steam injected (Bbl/D)	69,200	70,032	1%
Fuel gas cost/MMBtu	$ 5.46	$ 7.30	34%

Natural gas prices impact our cost structure in California by approximately $1.75 per California BOE for each $1.00 move in natural gas price.

Production taxes. Higher prices, such as those exhibited in 2005, create increased production taxes.

Depreciation, depletion and amortization. DD&A increased per BOE in the year ended 2005 from the year ended 2004 due to higher acquisition costs of our Rocky Mountain and Mid-Continent region assets as compared to our legacy heavy oil assets in California and higher finding and development costs. As these costs increase, our DD&A rates per BOE will also increase.

General and administrative. Approximately two-thirds of our G&A is compensation or compensation related costs. We intend to remain competitive in workforce compensation to achieve our growth plans. Stock-based compensation expense was $.35 per BOE and $.56 per

BOE for the years ended December 31, 2005 and 2004, respectively. Compensation expenses increased due to increased staffing resulting from our growth, and increases in compensation levels and bonuses. Additionally, we incurred increased legal and accounting fees, primarily due to compliance with the Sarbanes-Oxley Act of 2002, and growth through acquisitions and other financial reporting related matters. Legal and accounting expenses were $.28 per BOE in 2005 as compared to $.23 per BOE in 2004.

Interest expense. We increased our outstanding borrowings to $75 million at December 31, 2005 as compared to $28 million at December 31, 2004. Average borrowings increased as a result of acquisitions of $112 million during 2005. Additionally, interest rates have increased by approximately 1.75% since December 31, 2004.

The following table presents information about our operating expenses for each of the years in the two-year period ended December 31, 2004:

	Amount			Amount ($ per BOE)		
($ in thousands, unless otherwise noted)	**2003**	**2004**	**% Change**	**2003**	**2004**	**% Change**
Operating costs oil and gas production	$ 57,830	$ 73,838	28%	$ 9.57	$ 10.09	5%
Production taxes	3,097	6,431	108%	.51	.86	69%
DD&A oil and gas production	17,258	29,752	72%	2.86	3.96	38%
G&A	14,495	22,504	55%	2.40	2.99	25%
Interest expense	1,414	2,067	46%	.23	.27	17%
Total	$ 94,094	$ 134,592	43%	$ 15.57	$ 18.17	17%

Our total operating, production taxes, G&A and interest expenses for 2004, stated on a unit-of-production basis, increased 17% over 2003. The changes were primarily related to the following items:

Operating costs. 2004, on a per barrel basis, increased over 2003 due primarily to higher steam costs. The cost of our steaming operations for its heavy oil properties represents a significant portion of our operating costs and will vary depending on both the cost of natural gas used as fuel and the volume of steam injected during the year. The following table presents steam information:

	2003	**2004**	**% Change**
Average volume of steam injected (Bbl/D)	63,300	69,200	9%
Fuel gas cost/MMBtu	$ 4.88	$ 5.46	12%

Depreciation, depletion and amortization. 2004 was higher due to higher finding and development costs, the shorter reserve life of our Brundage Canyon properties in Utah and the cumulative effect of increased development activities in recent years. We expect DD&A to trend higher over the next few years due to the shorter reserve life of the Rocky Mountain assets compared to our California properties and continued development of our California and Rocky Mountain properties.

General and administrative. 2004 was up from 2003 due to stock-based compensation costs increasing by $2 million in 2004, which are primarily non-cash charges resulting from marked-to-market adjustments under the variable method of accounting prior to the change of certain exercise provisions of our stock option plan on July 29, 2004 and non-cash compensation expense under the fair value method of accounting. Compensation expenses increased due to increased staffing resulting from our growth, an increase in compensation levels and bonuses and costs related to a change in chief executive officers. Additionally, we incurred increased legal and accounting fees during 2004, primarily due to compliance with Sarbanes-Oxley and other financial reporting related matters.

Interest expense. 2004 was up from 2003. Although our borrowings at year-end 2004 were $28 million, down from $50 million in 2003, we borrowed $40 million in August 2003 to fund the acquisition of our Brundage Canyon property. We reduced our debt from 2003 levels during the latter half of 2004.

Dry hole, abandonment and impairment. The $5.7 million reflected on our income statement under dry hole, abandonment and impairment is made up of the following three items:

- At December 31, 2004, we were in the process of drilling one exploratory well on our Midway-Sunset property and one exploratory well on our Coyote Flats prospect. These two wells were determined non-commercial in February 2005 and $2.2 million was incurred and expensed in 2005.

- Two exploratory wells at northern Brundage Canyon were expensed for $.6 million.

- Finally, we impaired the remaining carrying value of our Illinois and eastern Kansas prospective CBM acreage acquired in 2002 by $2.9 million.

Costs of $.7 million which were incurred on the Midway-Sunset property and the exploratory well on the Coyote Flats prospect as of December 31, 2004 were charged to expense. During 2003, we recorded a pre-tax write down of $4.2 million related to two CBM pilot projects.

Exploration costs. We incurred exploration costs of $3.6 million in 2005 compared to zero costs in 2004 and 2003. These costs consist primarily of geological and geophysical costs. We participated in 3-D seismic surveys at Lake Canyon, Utah and in the Tri-State area. We are projecting exploration costs in 2006 of between $4 million and $6 million.

Income taxes. The Revenue Reconciliation Act of 1990 included a tax credit for certain costs associated with extracting high-cost, capital-intensive marginal oil or gas and which utilizes at least one of nine designated "enhanced" or tertiary recovery methods (EOR). Cyclic steam and steam flood recovery methods for heavy oil, which we utilize extensively, are qualifying EOR methods. In 1996, California conformed to the federal law, thus, on a combined basis, we are able to achieve credits approximating 12% of our qualifying costs. The credit is earned only for qualified EOR projects by investing in one of three types of expenditures: 1) drilling development wells, 2) adding facilities that are integrally related to qualified EOR production, or 3) utilizing a tertiary injectant, such as steam, to produce oil. The credit may be utilized to reduce our tax liability down to, but not below, our alternative minimum tax liability. This credit has been significant through 2005 in reducing our income tax liabilities and effective tax rate. However, with higher crude oil prices and the increasing investment in our light crude oil and natural gas properties, our effective income tax rate trended higher in 2005 compared to prior years. The average U.S. wellhead price for crude oil exceeded $43 in 2005, thus triggering a full phase-out of the EOR credit for 2006. If the U.S. wellhead price of crude oil declines below the triggering point in future years, we will be able to claim the EOR credit on qualifying expenditures and our effective tax rate should decline. As of December 31, 2005 we have approximately $23 million of federal and $17 million of state (California) EOR tax credit carryforwards available to reduce future income taxes. The EOR credits will begin to expire, if unused, in 2024 and 2015 for federal and California, respectively.

We experienced an effective tax rate of 31%, 23% and 12% reported in 2005, 2004 and 2003, respectively. The increase in effective tax rate during 2005 is primarily due to a much higher (over 80%) pre-tax income in relation to consistent EOR credits in 2005 over 2004. Our expansion outside of California and investment in non-thermal projects are also key factors in the increase. We have been able to achieve an effective tax rate below the statutory tax rate of approximately 40% through 2005 primarily as a result of significant EOR tax credits earned by our continued investment in the development of thermal EOR projects, both through capital expenditures and continued steam injection. We expect our effective tax rate will be higher as the EOR credit will be non-existent for 2006 and possibly later years, and we expect to have an effective tax rate in the 38% to 40% range in 2006, based on WTI prices averaging between $50 and $70. See Note 9 to our audited financial statements for the fiscal year ended December 31, 2005, which are incorporated by reference herein, for further information.

Financial condition, liquidity and capital resources

Substantial capital is required to replace and grow reserves. We achieve reserve replacement and growth primarily through successful development and exploration drilling and the acquisition of properties. Fluctuations in commodity prices have been the primary reason for short-term changes in our cash flow from operating activities. The net long-term growth in our cash flow from operating activities is the result of growth in production as affected by period to period fluctuations in commodity prices. In the second quarter of 2006, we revised our senior unsecured revolving credit facility to increase our maximum credit amount under the facility to $750 million and increased our current borrowing base to $500 million. As of June 30, 2006, we had total borrowings under the senior unsecured revolving credit facility and senior unsecured money market line of credit of $273 million.

Capital Expenditures. We establish a capital budget for each calendar year based on our development opportunities and the expected cash flow from operations for that year. We may revise our capital budget during the year as a result of acquisitions and/or drilling outcomes.

Excluding the acquisition price of new properties, in 2006 our approved budget is $275 million for capital expenditures. For 2006, we plan to invest approximately $190 million, or 69% of the approved capital budget, in our Rocky Mountain and Mid-Continent region assets, and $85 million, or 31%, in our California assets. Approximately half of the capital budget is focused on converting probable and possible reserves into proved reserves and on our appraisal and exploratory projects, while the other half is for the development of our proved reserves and facility costs. Our capital expenditures, excluding acquisitions, are funded primarily out of internally generated cash flow. See "Business Capital expenditures summary."

Acquisitions. In July 2006, the title of 4,300 gross acres from North Parachute Ranch of the Piceance basin was transferred to us, and we made the first of three installment payments of $51 million. The second and third installment payments of $51 million are due in November 2006 and May 2007. We plan to fund these payments using the net proceeds from this offering and our senior unsecured revolving credit facility.

Dividends. In the third quarter of 2005, we increased the quarterly dividend to $.065 per share and paid a special dividend of $.05 per share. In August 2006, we increased the quarterly dividend to $.075 per share and paid a special dividend of $.02 per share effective for the September 2006 payment.

Working capital and cash flows. Cash flow from operations is dependent upon the price of crude oil and natural gas and our ability to increase production and manage costs.

Our working capital balance fluctuates as a result of the amount of borrowings and the timing of repayments under our credit arrangements. We use our long-term borrowings under our senior unsecured revolving credit facility primarily to fund property acquisitions. Generally, we use excess cash to pay down borrowings under our credit arrangement. As a result, we often have a working capital deficit or a relatively small amount of positive working capital.

The table below compares financial condition, liquidity and capital resources changes for the six month periods ended:

	Six months ended		
(in millions, except for production and average prices)	**June 30, 2005**	**June 30, 2006**	**% Change**
	(unaudited)	**(unaudited)**	
Production (BOE/D)	22,359	24,118	8%
Average oil and gas sales prices, per BOE after hedging	$ 38.62	$ 48.92	27%
Net cash provided by operating activities	$ 66,191	$ 84,096	27%
Working capital, excluding senior unsecured money market line of credit	$ (9)	$ (38)	(322)%
Sales of oil and gas	$ 156	$ 213	37%
Debt, including senior unsecured money market line of credit	$ 125	$ 273	118%
Capital expenditures, including acquisitions and deposits on acquisitions(1)	$ 161	$ 265	65%
Dividends paid	$ 5.3	$ 5.7	8%

(1) Does not include our commitment to drill wells on our Lake Canyon prospect pursuant to our joint venture or the remaining payments under our Piceance basin joint venture.

Financial policy. We use various credit statistics to measure the Company's financial leverage and focus on the four measures below. Our goal is to maintain a sound capital structure to accommodate our growth goals. We believe that the following range of financial leverage is appropriate for the Company and intend to manage our business to not exceed the upper limits of this range.

Debt to EBITDA	1.5 to 3.0
EBITDA Interest Coverage	10.0 to 5.0
Debt to Capitalization	30% to 55%
Debt per Proved BOE	$2.50 to $5.00

Contractual obligations. Our contractual obligations as of June 30, 2006 are due in the years ended December 31, as follows:

					Years ended December 31,		
($ in thousands)	**Total**	**2006**	**2007**	**2008**	**2009**	**2010**	**Thereafter**
Long-term debt and interest	$ 339,387	$ 16,434	$ 16,434	$ 16,434	$ 16,434	$ 16,434	$257,217
Abandonment obligations	10,812	315	360	539	556	556	8,486
Operating lease obligations	11,060	584	1,400	1,370	1,178	955	5,573
Drilling and rig obligations	116,462	25,661	29,246	24,535	37,020		
Firm natural gas transportation contracts	73,490	2,039	4,574	7,304	8,217	8,379	42,977
Total(1)	$ 551,211	$ 45,033	$ 52,014	$ 50,182	$ 63,405	$ 26,324	$314,253

(1) Does not include two payments of $51 million each under our Piceance basin joint venture agreement due on November 1, 2006 and May 1, 2007.

Long-term debt and interest Long-term debt and related quarterly interest on the long-term debt borrowings can be paid before its maturity date without significant penalty.

Operating leases We lease corporate and field offices in California and Colorado.

Drilling obligation We intend to participate in the drilling of over 16 gross wells on our Lake Canyon prospect over the next four years, and our minimum obligation under our exploration and development agreement is $9.6 million. Also included above, our June 2006 joint venture agreement states that we must have 120 wells drilled by December 31, 2009 to avoid penalties of $24 million.

Drilling rig obligation We are obligated in operating lease agreements for the use of multiple drilling rigs.

Firm natural gas transportation We have one firm transportation contract which provides us additional flexibility in securing our natural gas supply and allows us to potentially benefit from lower natural gas prices in the Rocky Mountains compared to natural gas prices in California. We also have several long-term gas transportation contracts which provide us with physical access to interstate pipelines to move gas from our producing areas to markets.

Application of critical accounting policies

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions for the reporting period and as of the financial statement date. These estimates and assumptions affect the reported amounts of assets and liabilities, the disclosure of contingent liabilities and the reported amounts of revenues and expenses. Actual results could differ from those amounts.

A critical accounting policy is one that is important to the portrayal of our financial condition and results, and requires management to make difficult subjective and/or complex judgments. Critical accounting policies cover accounting matters that are inherently uncertain because the future resolution of such matters is unknown. We believe the following accounting policies are critical policies.

Successful efforts method of accounting. We account for our oil and gas exploration and development costs using the successful efforts method. Geological and geophysical costs and the costs of carrying and retaining undeveloped properties are expensed as incurred. Exploratory well costs are capitalized pending further evaluation of whether economically recoverable reserves have been found. If economically recoverable reserves are not found, exploratory well costs are expensed as dry holes. All exploratory wells are evaluated for economic viability within one year of well completion. Exploratory wells that discover potentially economic reserves that are in areas where a major capital expenditure would be required before production could begin, and where the economic viability of that major capital expenditure depends upon the successful completion of further exploratory work in the area, remain capitalized as long as the additional exploratory work is under way or firmly planned.

Oil and gas reserves. Oil and gas reserves include proved reserves that represent estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Our oil and gas reserves are based on estimates prepared by independent engineering consultants. Reserve engineering is a subjective process that requires judgment in the evaluation of all available geological, geophysical, engineering and economic data. Projected future production rates, the timing of future capital expenditures as well as changes in commodity prices may significantly impact estimated reserve quantities. Depreciation, depletion and amortization (DD&A) expense and impairment of proved properties are impacted by our estimation of proved reserves. These estimates are subject to change as additional information and technologies become available. Accordingly, oil and natural gas quantities ultimately recovered and the timing of production may be substantially different than projected. Reduction in reserve estimates may result in increased DD&A expense, increased impairment of proved properties and a lower standardized measure of discounted future net cash flows.

Carrying value of long-lived assets. Downward revisions in our estimated reserve quantities, increases in future cost estimates or depressed crude oil or natural gas prices could cause us to reduce the carrying amounts of our properties. We perform an impairment analysis of our proved properties annually by comparing the future undiscounted net revenue per the annual reserve valuation prepared by our independent reserve engineers to the net book carrying value of the assets. An analysis of the proved properties will also be performed whenever events or changes in circumstances indicate an asset's carrying value may not be recoverable from future net revenue. Assets are grouped at the field level and if it is determined that the net book carrying value cannot be recovered by the estimated future undiscounted cash flow, they are written down to fair value. Cash flows used in the impairment analysis are determined based on our estimates of crude oil and natural gas reserves, future crude oil and natural gas prices in effect at the end of the period and costs to extract these reserves. For our unproved properties, we perform an impairment analysis annually or whenever events or changes in circumstances indicate an asset's net book carrying value may not be recoverable.

Derivatives and hedging. We follow the provisions of Statement of Financial Accounting Standards (SFAS) No. 133, *Accounting for Derivative Instruments and Hedging Activities*. SFAS 133 requires the accounting recognition of all derivative instruments as either assets or liabilities at fair value. Derivative instruments that are not hedges must be adjusted to fair value through net income. Under the provisions of SFAS 133, we may designate a derivative instrument as hedging the exposure to change in fair value of an asset or liability that is attributable to a particular risk (a fair value hedge) or as hedging the exposure to variability in expected future cash flows that are attributable to a particular risk (a cash flow hedge). Both at the inception of a hedge and on an ongoing basis, a fair value hedge must be expected to be highly effective in achieving offsetting changes in fair value attributable to the hedged risk during the periods that a hedge is designated. Similarly, a cash flow hedge must be expected to be highly effective in achieving offsetting cash flows attributable to the hedged risk during the term of the hedge. The expectation of hedge effectiveness must be supported by matching the essential terms of the hedged asset, liability or forecasted transaction to the derivative contract or by effectiveness assessments using statistical measurements. Our policy is to assess hedge effectiveness at the end of each calendar quarter.

Income taxes. We compute income taxes in accordance with SFAS No. 109, *Accounting for Income Taxes*. SFAS No. 109 requires an asset and liability approach which results in the recognition of deferred income taxes on the difference between the tax basis of an asset or liability and its carrying amount in our financial statements. This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is recovered or settled, respectively. Considerable judgment is required in determining when these events may occur and whether recovery of an asset is more likely than not. Additionally, our federal and state income tax returns are generally not filed before the financial statements are prepared, therefore we estimate the tax basis of our assets and liabilities at the end of each calendar year as well as the effects of tax rate changes, tax credits, and tax credit carryforwards. A valuation allowance is recognized if it is determined that deferred tax assets may not be fully utilized in future periods. Adjustments related to differences between the estimates used and actual amounts reported are recorded in the period in which income tax returns are filed. These adjustments and changes in estimates of asset recovery could have an impact on results of operations. We may generate EOR tax credits from the production of our heavy crude oil in California which results in a deferred tax asset and believe that these credits will be fully utilized in future years and consequently have not recorded any valuation allowance related to these credits. Due to uncertainties involved with tax matters, the future effective tax rate may vary significantly from the estimated current year effective tax rate.

Asset retirement obligations. We have significant obligations to plug and abandon oil and natural gas wells and related equipment at the end of oil and gas production operations. The computation of our asset retirement obligations (ARO) was prepared in accordance with SFAS No. 143, *Accounting for Asset Retirement Obligations*, which requires us to record the fair value of liabilities for retirement obligations of long-lived assets. The adoption of SFAS No. 143 in 2002 resulted in an immaterial difference in the liability that had been previously recorded by us. Estimating the future ARO requires management to make estimates and judgments regarding timing, current estimates of plugging and abandonment costs, as well as what constitutes adequate remediation. We obtained estimates from third parties and used the present value of estimated cash flows related to our ARO to determine the fair value. Inherent in the present value calculation are numerous assumptions and judgments including the ultimate costs, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. Changes in any of these assumptions can result in significant revisions to the estimated ARO. To the extent future revisions to these assumptions impact the present value of the existing ARO liability, a corresponding adjustment will be made to the related asset. Due to the subjectivity of assumptions and the relatively long life of our assets, the costs to ultimately retire our wells may vary significantly from previous estimates.

Environmental remediation liability. We review, on a quarterly basis, our estimates of costs of the cleanup of various sites including sites in which governmental agencies have designated us as a potentially responsible party. In accordance with SFAS No. 5, *Accounting for Contingencies,* when it is probable that obligations have been incurred and where a minimum cost or a reasonable estimate of the cost of remediation can be determined, the applicable amount is accrued. Determining when expenses should be recorded for these contingencies and the appropriate amounts for accrual is an estimation process that includes the subjective judgment of management. In many cases, management's judgment is based on the advice and opinions of legal counsel and other advisers, the interpretation of laws and regulations, which can be interpreted differently by regulators or courts of law, our experience and the experience of other companies in dealing with similar matters and the decision of management on how it intends to respond to a particular matter. A change in estimate could impact our oil and gas operating costs and the liability, if applicable, recorded on our balance sheet.

Accounting for business combinations. We have grown substantially through acquisitions and our business strategy is to continue to pursue acquisitions as opportunities arise. We have accounted for all of our business combinations using the purchase method, which is the only method permitted under SFAS 141. The accounting for business combinations is complicated and involves the use of significant judgment. Under the purchase method of accounting, a business combination is accounted for at a purchase price based upon the fair value of the consideration given, whether in the form of cash, assets, stock or the assumption of liabilities. The assets and liabilities acquired are measured at their fair values, and the purchase price is allocated to the assets and liabilities based upon these fair values. The excess of the fair value of assets acquired and liabilities assumed over the cost of an acquired entity, if any, is allocated as a pro rata reduction of the amounts that otherwise would have been assigned to certain acquired assets.

Determining the fair values of the assets and liabilities acquired involves the use of judgment, since some of the assets and liabilities acquired do not have fair values that are readily determinable. Different techniques may be used to determine fair values, including market prices, where available, appraisals, comparisons to transactions for similar assets and liabilities and present value of estimated future cash flows, among others. Since these estimates involve the use of significant judgment, they can change as new information becomes available.

Each of the business combinations completed were of interests in oil and gas assets. We believe the consideration we paid to acquire these assets represents the fair value of the assets and liabilities acquired at the time of acquisition. Consequently, we have not recognized any goodwill from any of our business combinations, nor do we expect to recognize any goodwill from similar business combinations that we may complete in the future.

Stock-based compensation. Effective January 1, 2004, we voluntarily adopted the fair value method of accounting for our stock option plan as prescribed by SFAS 123, Accounting for Stock-Based Compensation. The modified prospective method was selected as described in SFAS 148, *Accounting for Stock-Based Compensation Transition and Disclosure*. Under this method, we recognize stock option compensation expense as if we had applied the fair value method to account for unvested stock options from the original effective date. Stock option compensation expense is recognized from the date of grant to the vesting date. The fair value of each option award is estimated on the date of grant using the Black-Scholes option pricing model that uses the following assumptions. Expected volatilities are based on the historical volatility of our stock. We use historical data to estimate option exercises and employee terminations within the valuation model; separate groups of employees that have similar historical exercise behavior are considered separately for valuation purposes. The expected term of options granted is based on historical exercise behavior and represents the period of time that options granted are expected to be outstanding; the range results from certain groups of employees exhibiting different exercise behavior. The risk free rate for periods within the contractual life of the option is based on U.S. Treasury rates in effect at the time of grant.

Electricity cost allocation. Our investment in our cogeneration facilities has been for the express purpose of lowering steam costs in our California heavy oil operations and securing operating control of the respective steam generation. Such cogeneration operations produce electricity and steam and use natural gas as fuel. We allocate steam costs to our oil and gas operating costs based on the conversion efficiency (of fuel to electricity and steam) of the cogeneration facilities plus certain direct costs in producing steam. Electricity revenue represents sales to the utilities. Electricity used in oil and gas operations is allocated at cost. A portion of the DD&A expenses associated with capital is allocated to DD&A oil and gas production.

Recent accounting pronouncements

In December 2004, SFAS No. 123(R), *Share-Based Payment*, was issued which establishes standards for transactions in which an entity exchanges its equity instruments for goods or services. This standard requires an issuer to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award. In April 2005, the SEC issued a rule that SFAS No. 123(R) will be effective for annual reporting periods beginning on or after June 15, 2005. As a result, the Company adopted this statement beginning January 1, 2006. The Company previously adopted the fair value recognition provisions of SFAS No. 123, *Accounting for Stock-Based Compensation*. Accordingly, the adoption of SFAS No. 123(R) using the modified prospective method, did not have a material impact on the Company's condensed financial statements for the three or six months ended June 30, 2006.

In March 2005, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations* ("FIN 47"). FIN 47 clarifies the definition and treatment of conditional asset retirement obligations as discussed in FASB Statement No. 143, *Accounting for Asset Retirement Obligations*. A conditional asset retirement obligation is defined as an asset retirement activity in which the timing and/or method of settlement are dependent on future events that may be outside our control. FIN 47 states that a company must record a liability when incurred for conditional asset retirement obligations if the fair value of the obligation is reasonably estimable. FIN 47 is intended to provide more information about long-lived assets and future cash outflows for these obligations and more consistent recognition of these liabilities and is effective for the fiscal year end December 31, 2005. Our adoption of FIN 47 did not have an immediate effect on our financial statements.

On April 4, 2005 the FASB adopted FASB Staff Position (FSP) FSP 19-1 *Accounting for Suspended Well Costs* that amends SFAS 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies*, to permit the continued capitalization of exploratory well costs beyond one year if the well found a sufficient quantity of reserves to justify its completion as a producing well and the entity is making sufficient progress assessing the reserves and the economic and operating viability of the project. In accordance with the guidance in the FSP, we applied the requirements prospectively in our second quarter of 2005. Our adoption of FSP 19-1 did not have an immediate effect on our financial statements. However, it could impact the timing of the recognition of expenses for exploratory well costs in future periods.

In May 2005, SFAS No. 154, *Accounting Changes and Error Corrections, a replacement of APB Opinion No. 20 and FASB Statement No. 3* was issued. SFAS No. 154 requires retrospective application to prior period financial statements for changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. SFAS No. 154 also requires that retrospective application of a change in accounting principle be limited to the direct effects of the change. Indirect effects of a change in accounting principle should be recognized in the period of the accounting change. SFAS No. 154 became effective for our fiscal year beginning January 1, 2006. The impact of SFAS No. 154 will depend on the nature and extent of any voluntary accounting changes and correction of errors after the effective date.

In February 2006, SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments an amendment of FASB Statements No. 133 and 140* was issued. This statement resolves issues addressed in Statement 133 Implementation Issue No. D1, *Application of Statement 133 to Beneficial Interests in Securitized Financial Assets*. SFAS No. 155 will become effective for our fiscal year beginning after September 15, 2006 and while we anticipate no impact on our financial statements based on our existing derivatives, we may experience a financial impact depending on the nature and extent of any new derivative instruments entered into after the effective date of SFAS No. 155.

In June 2006, the Financial Accounting Standards Board (FASB) issued Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109*. FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return, and provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. This Interpretation is effective for fiscal years beginning after December 15, 2006. We are currently assessing the potential impact of this Interpretation on our financial statements.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*, which defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. SFAS No. 157 will become effective for our fiscal year beginning after November 15, 2007. We are currently assessing the potential impact of this Statement on our financial statements.

Quantitative and qualitative disclosures about market risk

As discussed in Note 5 to our unaudited condensed financial statements for the six months ended June 30, 2006, which are incorporated by reference herein, to minimize the effect of a downturn in oil and gas prices and protect our profitability and the economics of our development plans, from time to time we enter into crude oil and natural gas hedge contracts. The terms of contracts depend on various factors, including management's view of future crude oil and natural gas prices, acquisition economics on purchased assets and our future financial commitments. This price hedging program is designed to moderate the effects of a severe crude oil and natural gas price downturn while allowing us to participate in the upside. In California, we benefit from lower natural gas pricing and elsewhere, we benefit from higher natural gas pricing. We have hedged, and may hedge in the future both natural gas purchases and sales as determined appropriate by management. Management regularly monitors the crude oil and natural gas markets and our financial commitments to determine if, when, and at what level some form of crude oil and/or natural gas hedging or other price protection is appropriate in accordance with policy established by our board of directors.

Currently, our hedges are in the form of swaps and collars. However, we may use a variety of hedge instruments in the future to hedge WTI or the index gas price. We have crude oil sales contracts in place which are priced based on a correlation to WTI. Natural gas (for cogeneration and conventional steaming operations) is purchased at the SoCal border price and we sell our produced gas in Colorado and Utah at the Colorado Interstate Gas (CIG) and Questar index prices, respectively.

The following table summarizes our hedge position as of June 30, 2006:

Term	**Average barrels per day**	**Average price**	**Term**	**Average MMBtu per day**	**Average price**
Crude Oil Sales (NYMEX WTI) Swaps			**Natural Gas Sales (NYMEX HH TO CIG) Basis Swaps**		
3rd Quarter 2006	3,000	$49.56	2006 Average	8,000	$1.45
			2007 Average	13,500	$1.65
			2008 Average	18,250	$1.50
			Natural Gas Sales (NYMEX HH)		
Collars		**Floor/ceiling prices**	**Swaps**		
1st through 3rd Quarter 2006	7,000	$47.50/$70	3rd Quarter 2006	6,000	$7.35
4th Quarter 2006	10,000	$47.50/$70			
Full year 2007	10,000	$47.50/$70	**Collars**		**Floor/ceiling prices**
Full year 2008	10,000	$47.50/$70	4th Quarter 2006	8,000	$8.00/$9.72
Full year 2009	10,000	$47.50/$70	1st Quarter 2007	12,000	$8.00/$16.70
			2nd Quarter 2007	13,000	$8.00/$8.82
			3rd Quarter 2007	14,000	$8.00/$9.10
			4th Quarter 2007	15,000	$8.00/$11.39
			1st Quarter 2008	16,000	$8.00/$15.65
			2nd Quarter 2008	17,000	$7.50/$8.40
			3rd Quarter 2008	19,000	$7.50/$8.50
			4th Quarter 2008	21,000	$8.00/$9.50

The collar strike prices will allow us to protect a significant portion of our future cash flow if 1) oil prices decline below $47.50 per barrel while still participating in any oil price increase up to $70 per barrel on these volumes and 2) if gas prices decline below approximately $8 per MMBtu. These hedges improve our financial flexibility by locking in significant revenues and cash flow upon a substantial decline in crude oil or natural gas prices. It also allows us to develop our long-lived assets and pursue exploitation opportunities with greater confidence in the projected economic outcomes and allows us to borrow a higher amount under our senior unsecured revolving credit facility.

While we have designated our hedges as cash flow hedges in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, it is possible that a portion of the hedge related to the movement in the WTI to California heavy crude oil price differential may be determined to be ineffective. Likewise, we may have some ineffectiveness in our natural gas hedges due to the movement of HH pricing as compared to actual sales points. If this occurs, the ineffective portion will directly impact net income rather than being reported as Other Comprehensive Income. While we believe that the differential will narrow and move closer toward its historical level over time, there are no assurances as to the movement in the differential. If the differential were to change significantly, it is possible that our hedges, when marked-to-market, could have a material impact on earnings in any given quarter and, thus, add increased volatility to our net income. The marked-to-market values reflect the liquidation values of such hedges and not necessarily the values of the hedges if they are held to maturity.

Irrespective of the unrealized gains reflected in Other Comprehensive Income, the ultimate impact to net income over the life of the hedges will reflect the actual settlement values. All of these hedges have historically been deemed to be cash flow hedges with the marked-to-market valuations provided by external sources, based on prices that are actually quoted.

At June 30, 2006, Accumulated Other Comprehensive Loss, net of income taxes, consisted of $68.4 million of unrealized losses from our crude oil and natural gas hedges. Deferred net losses recorded in Accumulated Other Comprehensive Loss at June 30, 2006, are expected to be reclassified to earnings over the life of the contracts. The use of hedging transactions also involves the risk that the counterparties will be unable to meet the financial terms of such transactions. With respect to our hedging activities, we utilize multiple counterparties on our hedges and monitor each counterparty's credit rating.

Based on NYMEX futures prices as of June 30, 2006 (WTI $74.20; HH $8.82) and due to the backwardated nature of the futures prices as of that date, we would expect to make pre-tax future cash payments or to receive payments over the remaining term of our crude oil and natural gas hedges in place as follows:

	June 30, 2006 NYMEX Futures	Impact of percent change in futures prices on earnings			
		-20%	**-10%**	**+10%**	**+20%**
Average WTI Price	$ 74.20	$ 59.36	$ 66.78	$ 81.62	$ 89.04
Crude Oil gain/(loss) (in millions)	(59.3)	(2.7)	(4.8)	(154.2)	(249.1)
Average HH Price	8.82	7.05	7.94	9.70	10.58
Natural Gas gain/(loss) (in millions)	(.5)	10.3	3.5	(5.2)	(13.6)
Net pre-tax future cash (payments) and receipts by year (in millions):					
2006	$ (14.5)	$ (1.0)	$ (3.7)	$ (29.1)	$ (43.8)
2007	(22.3)	3.8	1.2	(51.2)	(82.0)
2008	(15.8)	4.8	1.2	(45.5)	(77.1)
2009	(7.2)			(33.6)	(59.8)
Total	$ (59.8)	$ 7.6	$ (1.3)	$ (159.4)	$ (262.7)

Interest rates. Our exposure to changes in interest rates results primarily from long-term debt. Total long-term debt outstanding at August 31, 2006 was $309 million. Interest on amounts borrowed is charged at LIBOR plus 1.0% to 1.75%, with the exception of the $100 million of principal for which we have a hedge in place to fix the interest rate at approximately 5.5% plus the senior unsecured revolving credit facility's margin through June 30, 2011. Based on these borrowings, a 1% change in interest rates would have a $2 million impact on our financial statements.

Business

Overview

We are an independent energy company engaged in the production, development, acquisition, exploitation of, and exploration for, crude oil and natural gas. While we were incorporated in Delaware in 1985 and have been a publicly traded company since 1987, we can trace our roots in California oil production back to 1909. Since 2002, we have expanded our portfolio of assets to include properties in the Rocky Mountain and Mid-Continent region. Our corporate headquarters are in Bakersfield, California, and we have a regional office in Denver, Colorado.

We have a geographically diverse asset base with 74% of our reserves located in California and 26% in the Rocky Mountain and Mid-Continent region. As of December 31, 2005, our estimated proved reserves were 126.3 MMBOE of which 74% were heavy crude oil, 8% light crude oil and 18% natural gas. 72% of our proved reserves were proved developed. For the twelve months ended June 30, 2006, we generated revenues and EBITDA of $467 million and $248 million, respectively. See "Prospectus supplement summary Summary historical financial data" for a reconciliation of EBITDA to net income.

For the year ended December 31, 2005 and for the quarter ended June 30, 2006, we had average daily production of 23.0 MBOE and 24.8 MBOE, respectively. Our properties generally have long reserve lives and reasonably stable and predictable well production characteristics with a ratio of proved reserves to production (based on the year ended December 31, 2005) of approximately 15.0 years. The following table sets forth the estimated quantities of proved reserves and production attributable to our principal operating areas.

		Proved reserves as of December 31, 2005			Average daily production	
Field	**Type**	**Proved reserves (MMBOE)**	**Proved developed reserves as a % of total proved reserves**	**% Average working interest**	**Year ended December 31, 2005 (MBOE/D)**	**Quarter ended June 30, 2006 (MBOE/D)**
Midway-Sunset, CA	Heavy oil	68.1	48%	99%	12.2	11.7
Brundage Canyon, UT	Light oil/Natural gas	15.1	7%	100%	5.1	6.1
Placerita, CA	Heavy oil	16.6	6%	100%	2.7	2.4
Tri-State, CO/KS/NE	Natural gas	17.4	7%	50%	1.6	2.3
Montalvo, CA	Heavy oil	6.9	2%	100%	.7	.6
Poso Creek, CA	Heavy oil	2.0	2%	100%	.5	.8
Various	Various	.2	%	15%	.2	.9
Total		126.3	72%		23.0	24.8

In 2006, we acquired properties in the Piceance basin for approximately $310 million (approximately $210 million funded through August 31, 2006), further adding to our acreage position and undeveloped drilling opportunities in the Rocky Mountain and the Mid-Continent region. We also plan to invest in 2006 approximately $275 million directed toward developing reserves, increasing oil and gas production, appraising our exploration opportunities and other capital items. We expect to allocate approximately 69% of this capital to our properties in the Rocky Mountain and Mid-Continent region and 31% to our existing core assets in California.

We have identified over 2,000 drilling locations on our properties which represent several years of drilling opportunities at our current drilling rate. We plan to continue our record activity levels by drilling over 500 gross wells and performing approximately 200 well workovers in 2006, as compared to drilling 234 wells and 140 well workovers in 2005. With the capital expenditure budget and our Piceance basin acquisitions, we are targeting an increase in our 2006 year-end proved reserves of 20 to 25 MMBOE after our annual production, resulting in proved reserves in excess of 146 MMBOE. We anticipate funding our drilling capital program primarily from internally generated cash flow.

Business strengths

Balanced high quality asset portfolio with a long reserve life. Since 2002, we have grown and diversified our California heavy oil asset base through three key acquisitions in the Rocky Mountain and Mid-Continent region that have significant growth potential. Our base of legacy California assets provides us with a steady stream of cash flow to re-invest into our significant drilling inventory and the appraisal of our prospects. Our wells are generally characterized by long production lives and predictable performance. At December 31, 2005 our implied reserve life was 15.0 years and our implied proved developed reserve life was 10.7 years.

Track record of efficient proved reserve and production growth. For the three years ended December 31, 2005, our average annual reserve replacement rate was 210% at an attractive average cost of $8.29 per BOE. During the same period our proved reserves and production increased at an annualized compounded rate of 7.5% and 17.0%, respectively. We were able to deliver that growth predominantly through low-risk drilling and achieved an average drilling success rate of 98%. We believe we can continue to deliver strong growth through the drill bit by exploiting our large undeveloped leasehold position. We also plan to complement this drill bit growth through selective and focused acquisitions.

Experienced management and operational teams. Our key executives have an average of 26 years of industry experience. Our president and chief executive officer, Robert Heinemann, has a Ph.D in chemical engineering and 18 years experience with a major integrated energy company. Under Mr. Heinemann's leadership, we have significantly expanded and deepened our core team of technical staff and operating managers, who have broad industry experience, including experience in California heavy oil thermal recovery operations and Rocky Mountain tight gas sands development and completion. We continue to utilize technologies and steam practices that we believe will allow us to improve the ultimate recoveries of crude oil on our mature California properties. We also utilize 3-D seismic technology for evaluation of sub-surface geologic trends of our many prospects. For example, at our Tri-State prospect area, the use of seismic data combined with appropriate drilling configurations has allowed us to drill wells with a 98% success rate with improved efficiency which has resulted in lower costs.

Operational control and financial flexibility. We exercise operating control over approximately 95% of our proved reserve base. We generally prefer to retain operating control over our properties, allowing us to more effectively control operating costs, timing of development activities and technological enhancements, marketing of production, and allocation of our capital budget. In addition, the timing of most of our capital expenditures is discretionary which allows us a significant degree of flexibility to adjust the size of our capital budget. We finance our drilling budget primarily through our internally generated operating cash flows and we also have a $750 million senior unsecured revolving credit facility with a current borrowing base of $500 million.

Established risk management policies. We actively manage our exposure to commodity price fluctuations by hedging a material portion of our forecasted production. We use hedges to help us mitigate the effects of price declines and secure operating cash flows to fund our capital expenditures program. Our California long-term crude oil contract with a refiner and our long-term firm natural gas pipeline transportation agreements help us mitigate price differential volatility and assure product delivery to markets. The operation of our cogeneration facilities provides a partial hedge against increases in natural gas prices because of the high correlation between electricity and natural gas prices under our electricity sale contracts.

Corporate strategy

Our objective is to increase the value of our business through consistent growth in our production and reserves, both through the drill bit and acquisitions. We strive to operate our properties in an efficient manner to maximize the cash flow and earnings of our assets. The strategies to accomplish these goals include:

Developing our existing resource base. We intend to increase both production and reserves annually. We are focused on the timely and prudent development of our large resource base through developmental and step-out drilling, down-spacing, well completions, remedial work and by application of enhanced oil recovery (EOR) methods, and optimization technologies, as applicable. In the first half of 2006, we invested in a large undeveloped probable reserve position in the Piceance basin in Colorado, and are planning for significant drilling there over the next several years. We also have large potential hydrocarbon resources in place in the Uinta basin, Utah (Lake Canyon) and the San Joaquin Valley basin, California (diatomite). We have a proven track record of developing reserves and increasing production in both of our operating regions, California and the Rocky Mountain/Mid-Continent.

Acquiring additional assets with significant growth potential. We will continue to evaluate oil and gas properties with proved reserves, probable reserves and/or sizeable acreage positions that we believe contain substantial hydrocarbons which can be developed at reasonable costs. We have identified the Rocky Mountain and Mid-Continent region as our primary area of interest for growth. Significant recent acquisitions in the region include: $105 million acquisition in 2005 of mostly proved reserves in the Niobrara gas play in the Denver-Julesburg basin and two transactions in 2006 pursuant to which we have committed over $310 million to acquire or earn natural gas acreage in the Piceance basin. We will continue to review asset acquisitions that meet our economic criteria with a primary focus on large repeatable development potential in these regions. Additionally, we seek to increase our net revenue interest in assets that we already operate. In California, we continue to evaluate available properties for acquisition to take advantage of our significant operational and technical expertise in the development and production of heavy oil.

Utilizing joint ventures with respected partners to enter new basins. We believe that early entry into some basins offers the best potential for establishing low cost acreage positions in those basins. In areas where we do not have existing operations, we seek to utilize the skills and knowledge of other industry participants upon entering these new basins so that we can reduce our risk and improve our ultimate success in the area. Our joint development with an industry partner at Lake Canyon in the Uinta basin reflects this strategy.

Accumulating significant acreage positions near our producing operations. We have been successful in adding significant acreage positions in less than three years with the intent of appraising the potential of the acreage for the economic production of hydrocarbons. These positions include 503,000 and 255,000 gross acres in the Denver-Julesburg and Uinta basins, respectively, which are adjacent to, or in the proximity of, our producing assets within those basins. This strategy allows us to leverage our operating and technical expertise within the area and build on established core operations. We also have 186,000 gross acres in the Williston basin. We are appraising these acreage blocks by shooting and utilizing 3-D seismic data, participating in drilling programs in areas of mutual interest with partners and utilizing current geological, geophysical and drilling technologies. We intend to also pursue acreage in large resource plays that may result in repeatable-type development.

Investing our capital in a disciplined manner and maintaining a strong financial position. The oil and gas business is capital intensive so we focus on utilizing our available capital on projects where we are likely to have success in increasing production and/or reserves at attractive returns. We believe that maintaining a strong financial position will allow us to capitalize on investment opportunities and be better prepared for a lower commodity price environment. We expect to continue to hedge oil and gas prices and utilize long-term sales contracts with the objective of achieving cash flow necessary for the development of our assets.

Proved reserves and revenues

As of December 31, 2005, our estimated proved reserves were 126 MMBOE,of which 74% were heavy crude oil, 8% light crude oil and 18% natural gas, and nearly 40% are owned in fee. As of December 31, 2005, 74% of our reserves are located in California and 26% in the Rocky Mountain and Mid-Continent region. Proved undeveloped reserves make up 28% of our proved total. The projected capital to develop these proved undeveloped reserves is $201 million, at an estimated cost of approximately $5.54 per BOE. Approximately 77% of the capital to develop these reserves is expected to be expended in the next five years. Average daily production in 2005 was 8.4 MMBOE, up 12% from production of 7.5 MMBOE in 2004. Our reserves-to-production ratio was approximately 15.0 years at year-end 2005, and 2004.

The following table depicts all of our producing assets as of December 31, 2005. We operate all of the assets, except Wyoming:

State	Name	Type	Daily production (BOE/D)	% Of daily production	Proved reserves (BOE) in thousands	% Of proved reserves	Oil & gas revenues before hedging (in millions)	% of Oil & gas revenues
CA	Midway-Sunset	Heavy oil	12,214	53%	68,071	54%	$ 199	50%
UT	Brundage Canyon	Light oil/Natural gas	5,079	22%	15,116	12%	98	25%
CA	Placerita	Heavy oil	2,654	12%	16,592	13%	48	12%
CO	Tri-State	Natural gas	1,600	7%	17,442	14%	26	7%
CA	Montalvo	Heavy oil	728	3%	6,869	5%	12	3%
CA	Poso Creek	Heavy oil	544	2%	2,046	2%	10	3%
WY/CA	Various	Various	196	1%	149		2	
Totals			23,015	100%	126,285	100%	$ 395	100%

We continued to engage D&M to appraise the extent and value of our proved oil and gas reserves and the future net revenues to be derived from our properties for the year ended December 31, 2005. D&M is an independent oil and gas consulting firm located in Dallas, Texas. In preparing their reports, D&M reviewed and examined geologic, economic, engineering and other data considered applicable to properly determine our reserves. They also examined the reasonableness of certain economic assumptions regarding forecasted operating and development costs and recovery rates in light of the economic environment on December 31, 2005.

Acquisitions

See "Management's discussion and analysis of financial condition and results of operations."

Operations

In California, we operate all of our principal oil and gas producing properties. The Midway-Sunset, Placerita and Poso Creek fields contain predominantly heavy crude oil which requires heat, supplied in the form of steam, injected into the oil producing formations to reduce the oil viscosity which allows the oil to flow to the wellbore for production. We utilize cyclic steam and/or steam flood recovery methods in all of these fields in addition to primary recovery methods at our Montalvo field. We are able to produce our heavy oil at our Montalvo field without steam because the majority of the producing reservoir is at a depth in excess of 11,000 feet and the reservoir temperature is high enough to produce the oil without the assistance of additional heat from steam. Field operations related to oil production include the initial recovery of the crude oil and its transport through treating facilities into storage tanks. After the treating process is completed, which includes removal of water and solids by mechanical, thermal and chemical processes, the crude oil is metered through automatic custody transfer units or gauged before sale and subsequently transferred into crude oil pipelines owned by other companies or transported via truck.

In the Rocky Mountain and Mid-Continent region, crude oil produced from the Brundage Canyon field is transported by truck, while its gas production, net of field usage, is transported by gathering or distribution systems to the Questar Pipeline. Natural gas produced from the eastern Colorado Niobrara gas assets is transported to one of two main pipelines. We have a pipeline gathering system and gas compression facilities for delivery into these two interstate gas lines in this region. Our Piceance basin natural gas is gathered and sold by our industry partner.

Crude oil and natural gas marketing

Economy. The global and California crude oil markets continue to remain strong. Product prices continued to exhibit an overall-strengthening trend through 2005. The range of WTI crude prices for 2005, based upon NYMEX settlements, was a low of $42.12 and a high of $69.81. We expect that crude prices will continue to be volatile in 2006.

	2003	2004	2005
Average NYMEX settlement price for WTI	$ 30.99	$ 41.47	$ 56.70
Average posted price for our:			
Utah light crude oil	27.63	38.60	53.03
California 13 degree API heavy crude oil	25.33	32.84	44.36
Average crude price differential between WTI and our:			
Utah light crude oil	3.36	2.87	3.67
California 13 degree API heavy crude oil	5.66	8.63	12.34

Oil contracts. We market our crude oil production to competing buyers including independent and major oil refining companies. Because of our ability to deliver significant volumes of crude oil over a multi-year period, we secured a three-year sales agreement, beginning in late 2002, with a major oil company whereby we sold over 90% of our California production under a negotiated pricing mechanism. This contract ended on January 31, 2006. Pricing in this agreement was based upon the higher of the average of the local field posted prices plus a fixed premium, or WTI minus a fixed differential near $6.00 per barrel. This contract allowed us to improve our California revenues over the posted price by approximately $41 million and $13 million in 2005 and 2004, respectively.

On November 21, 2005, we entered into a new crude oil sales contract for our California production for deliveries beginning February 1, 2006 and ending January 31, 2010. The per barrel price, calculated on a monthly basis and blended across the various producing locations, is the higher of (1) the WTI NYMEX crude oil price less a fixed differential approximating $8.15, or (2) heavy oil field postings plus a premium of approximately $1.35. The initial term of the contract is for four years with a one-year renewal at our option. The agreement effectively eliminates our exposure to the risk of a widening WTI to California heavy crude price differential over the next four years and allows us to effectively hedge our production based on WTI pricing similar to the previous contract. If this contract had been in place during 2005, it would have allowed us to improve our California revenues over the posted prices by approximately $25 million in 2005, but $16 million below what was actually received by us under the contract in place in 2005.

Our Utah light crude oil is sold under multiple contracts with different purchasers for varying term lengths and pricing. As of October 1, 2006 we have firm contracts for 3,500 Bbl/D and one refiner has indicated they expect to take additional volumes. Our current gross production is approximately 4,600 Bbl/D. We anticipate that we will be able to sell all of our crude oil production from this region. Our Utah crude oil is a paraffinic crude and can be processed efficiently by only a limited number of refineries. Increased production of crude oil in the region, the ability of refiners to process other higher sulfur crudes as a result of capital upgrades, as well as the increasing availability of Canadian crude oil, is pressuring the sales price of our crude oil. Our contracts are currently priced at approximately $10.50 to $17.00 per barrel below WTI with certain volumes tied to field posting, and in some cases our realized price is further reduced by transportation charges.

Our contracts have terms ranging from eight months to one year as of October 1, 2006 and we are actively pursuing additional contracts beyond the existing terms. We are able to deliver a sizable volume of crude oil over a five to ten year term and are evaluating various arrangements with refiners to handle increased volumes of paraffinic crude oil. From October 1, 2003 through April 30, 2006 we were able to sell our Utah crude oil at approximately $2.00 per barrel below WTI and from May 1, 2006 through September 30, 2006, we were selling the majority of our Utah crude at approximately $9.00 per barrel below WTI. Due to this lower pricing and based on sales of 4,600 Bbl/D gross, we estimate our revenues will be lower by approximately $8 million in the last six months of 2006 as compared to the first six months of 2006. If this pricing continues throughout 2007 and on the same volumes, we estimate our revenues will be lower by approximately $15 million versus our 2006 revenues.

Natural gas marketing. We market produced natural gas from Colorado, Utah, Wyoming and California. Generally, natural gas is sold at monthly index related prices plus an adjustment for transportation. Certain volumes are sold at a daily spot related price.

	2003	2004	2005
Annual average closing price per MMBtu for:			
NYMEX HH prompt month natural gas contract	$ 5.84	$ 6.18	$ 9.01
Rocky Mountain Questar first-of-month indices (Brundage Canyon sales)	4.00	5.05	6.73
Rocky Mountain CIG first-of-month indices (Tri-State sales)	4.04	5.17	6.95
Average natural gas price per MMBtu differential between NYMEX HH and:			
Questar	1.84	1.13	2.28
CIG	1.80	1.01	2.06

We have physical access to interstate gas pipelines to move gas to or from market. To assure delivery of gas, we have entered into several long-term gas transportation contracts as follows:

Long-term transportation summary

Name	From	To	Quantity (Avg. MMBtu/D)	Term	2005 base costs ($ per MMBtu)	Remaining contractual obligation ($ in thousands)
Kern River Pipeline	Opal, WY	Kern County, CA	12,000	5/2003 to 4/2013	$ .6425	$ 20,640
Questar Pipeline	Brundage Canyon	Salt Lake City, UT	2,500	9/2003 to 4/2007	.1739	211
Questar Pipeline	Brundage Canyon	Salt Lake City, UT	2,800	9/2003 to 9/2007	.1739	317
KMIGT	Yuma County, CO	Grant, KS	2,500	1/2005 to 10/2013	.2270	1,624
Cheyenne Plains Gas Pipeline	Tri-State, CO	Panhandle Eastern Pipeline	11,000	(Est.) Q4 2006 to Q4 2016	.3400	13,662
Total(1)			30,800			$ 36,454

(1) Does not include Rockies Express Pipeline where we have 10,000 MMBtu/D of transportation, which services our Piceance basin properties, beginning in 2008.

Steaming operations

Cogeneration steam supply. As of December 31, 2005, approximately 69% of our proved reserves, or 87 million barrels, consisted of heavy crude oil produced from depths of less than 2,000 feet. In pursuing our goal of being a cost-efficient heavy oil producer in California, we have remained focused on minimizing our steam cost. We believe one of the main methods of keeping steam costs low is through the ownership and efficient operation of our three cogeneration facilities. Two of these cogeneration facilities, a 38 MW facility and an 18 MW facility are located in our Midway-Sunset field. We also own a 42 MW cogeneration facility located in the Placerita field. Steam generation from these cogeneration facilities is more efficient than conventional steam generation as both steam and electricity are concurrently produced from a common fuel stream. By maintaining a correlation between electricity and natural gas prices, we are able to better control the cost of producing steam.

Conventional Steam Generation. In addition to these cogeneration plants, we own 16 conventional boilers. The quantity of boilers operated at any point in time is dependent on (1) the steam volume required for us to achieve our targeted production and (2) the price of natural gas compared to the price of crude oil sold.

Total BSPD capacity as of December 31, 2005 is as follows:

(BSPD)	**Year ended December 31, 2005**
Total steam generation capacity of cogeneration plants	38,000
Additional steam purchased under contract with third party	2,000
Total steam generation capacity of conventional boilers	43,000
Total steam capacity	83,000

The average volume of steam injected for the years ended December 31, 2005 and 2004 was 70,032 and 69,200 BSPD, respectively.

Ownership of these varied steam generation facilities and sources allows for maximum operational control over the steam supply, location, and to some extent aggregated cost of steam generation. Our steam supply and flexibility are crucial for the maximization of California thermally enhanced heavy oil production, cost control and ultimate reserve recovery.

We believe that it may become necessary to add additional steam capacity for our future development projects at Midway-Sunset and Poso Creek to allow for full development of our properties. We regularly review our most economical source for obtaining additional steam to achieve our growth objectives.

Our conventional steam generators operated in 2005 to achieve our goal of increasing heavy oil production to record levels. Approximately 70% of the volume of natural gas purchased to generate steam and electricity is based upon SoCal Border indices. We pay distribution/transportation charges for the delivery of gas to our various locations where we consume gas for steam generation purposes, however, in some cases this transportation cost is embedded in the price of the gas. The remaining 30% of supply volume is purchased in Wyoming and moved to the Midway-Sunset field using our firm transport on the Kern River Pipeline. This gas is purchased based upon the Rocky Mountain Northwest Pipeline (NWPL) index.

($ per MMBtu)	2003	2004	2005
Average SoCal Border Monthly Index Price	$ 5.00	$ 5.60	$ 7.37
Average Rocky Mountain NWPL Monthly Index Price	4.34(1)	5.24	6.96

(1) Contract began May 2003

We historically were a net purchaser of natural gas and thus our net income was negatively impacted when natural gas prices rose higher than its oil equivalent. In 2005, on a gas balance basis, we achieved parity due to our eastern Colorado Niobrara gas acquisition. Thus, going forward, we are a net seller of gas and operationally should benefit when gas prices are higher. The balance between natural gas (MMBtu/D) consumed and produced during the month of December 2005 was approximately as follows:

(MMBtu/D)	Year ended December 31, 2005
Natural gas consumed in:	
Cogeneration operations	27,000
Conventional boilers	11,000
Total natural gas consumed	38,000
Less: Company's estimate of approximate natural gas consumed to produce electricity(1)	(20,000)
Total approximate natural gas volumes consumed to produce steam	18,000
Natural gas produced:	
Tri-State (Niobrara)	11,900
Brundage Canyon (associated gas)	11,400
Other	1,700
Total natural gas volumes produced in operations	25,000

(1) We estimate this volume based on electricity revenues divided by the purchase price, including transportation, per MMBtu for the respective period.

Electricity

Generation. The total annual average electrical generation of our three cogeneration facilities is approximately 93 MW, of which we consume approximately 8 MW for use in our operations. Each facility is centrally located on an oil producing property such that the steam generated by the facility is capable of being delivered to the wells that require steam for the EOR process. Our investment in our cogeneration facilities has been for the express purpose of lowering the steam costs in our heavy oil operations and securing operating control of the respective steam generation. Expenses of operating the cogeneration plants are analyzed regularly to determine whether they are advantageous versus conventional steam boilers. Cogeneration costs are allocated between electricity generation and oil and gas operations based on the conversion efficiency (of fuel to electricity and steam) of each cogeneration facility and certain direct costs to produce steam. Cogeneration costs allocated to electricity will vary based on, among other factors, the thermal efficiency of our cogeneration plants, the price of natural gas used for fuel in generating electricity and steam, and the terms of our power contracts. We view any profit or loss from the generation of electricity as a decrease or increase, respectively, to our total cost of producing our heavy oil in California. DD&A related to our cogeneration facilities is allocated between electricity operations and oil and gas operations using a similar allocation method.

Sales Contracts. Historically, we have sold electricity produced by our cogeneration facilities, each of which is a QF under PURPA, to two California public utilities, Southern California Edison Company (Edison) and PG&E, under long-term contracts approved by the CPUC. These contracts are referred to as standard offer (SO) contracts under which we are paid an energy payment that reflects the utility's SRAC plus a capacity payment that reflects a recovery of capital expenditures that would otherwise have been made by the utility. An SO2 contract is more beneficial as it requires the utility to pay a higher capacity payment than an SO1 contract. The SRAC energy price is currently determined by a formula approved by the CPUC that reflects the utility's marginal fuel cost and a conversion efficiency that represents a hypothetical resource to generate electricity in the absence of the cogenerator. During most periods natural gas is the marginal fuel for California utilities so this formula provides a hedge against our cost of gas to produce electricity and steam in our cogeneration facilities. A proceeding is now underway at the CPUC to review and revise the methodology used to determine SRAC energy prices and to determine to what extent the utilities would be required to enter into future contracts with QFs. This proceeding is currently anticipated to be completed by the end of 2006. There is no assurance that any new methodology will continue to provide a hedge against our fuel cost or that a revised pricing mechanism or terms will be as beneficial as the current contract pricing and terms.

The original SO2 contract for Placerita Unit 1 continues in effect through March 2009. This unit makes up approximately 17% of total approximate BSPD. The modified SRAC pricing terms of this contract reflected a fixed energy price of 5.37 cents/KWh through June 2006, at which time the energy price reverted to the SRAC pricing methodology. We are paid a capacity payment that is fixed through the term of the contract.

In December 2004, we executed a five-year SO1 contract with Edison for the Placerita Unit 2 facility, and five-year SO1 contracts with PG&E for the Cogen 18 and Cogen 38 facilities, each effective January 1, 2005. Pursuant to these contracts, we are paid the purchasing utility's SRAC energy price and a capacity payment that is subject to adjustment from time to time by the CPUC. Edison and PG&E challenged, in the California Court of Appeals, the legality of the CPUC decision that ordered the utilities to enter into these five-year SO1 contracts, and similar one-year SO1 contracts that were ordered for 2004. The Court ruled that the CPUC had the right to order the utilities to execute these contracts. The Court also ruled that the CPUC was obligated to review the prices paid under the contracts and to retroactively adjust the prices to the extent it was later determined that such prices did not comply with the requirements of PURPA. To date, the CPUC has taken no final action based on this court ruling.

We believe that QFs, such as our facilities, provide an important source of distributive power generation into California's electricity grid, and as such, that our facilities will be economic to operate for at least the current five-year contract term. Based on the current pricing mechanism for our electricity under the contracts (which includes electricity purchased for internal use), we expect that our electricity revenues will be in the $50 million to $60 million range for 2006.

Facility and contract summary

Location and facility	Type of contract	Purchaser	Contract expiration	Approximate megawatts available for sale	Approximate megawatts consumed in operations	Approximate BSPD
Placerita						
Placerita Unit 1	SO2	Edison	Mar-09(1)	20		6,600
Placerita Unit 2	SO1	Edison	Dec-09	16	4	6,700
Midway-Sunset						
Cogen 18	SO1	PG&E	Dec-09	12	4	6,600
Cogen 38	SO1	PG&E	Dec-09	37		18,000

(1) On July 1, 2006, the contract pricing converted to the SRAC pricing of the original contract.

Competition

The oil and gas industry is highly competitive. As an independent producer, we do not own any refining or retail outlets and, therefore, we have little control over the price we receive for our crude oil. As such, higher costs, fees and taxes assessed at the producer level cannot necessarily be passed on to our customers. In acquisition activities, significant competition exists as integrated and independent companies and individual producers are active bidders for desirable oil and gas properties and prospective acreage. Although many of these competitors have greater financial and other resources than we have, we believe we are in a position to compete effectively due to our efficient operating cost structure, transaction flexibility, strong financial position, experience and determination.

Employees

On June 30, 2006, we had 233 full-time employees, up from 209 and 156 full-time employees on December 31, 2005 and December 31, 2004, respectively.

Net oil and gas producing properties at December 31, 2005 (MBOE unless otherwise noted)

Name	Average working interest (%)	Total net acres	Proved reserves	Proved developed reserves	% Of total proved reserves	Proved undeveloped reserves	% Of total proved reserves	Average depth of producing reservoir (feet)
Midway-Sunset, CA	99%	4,836	68,071	60,627	48%	7,443	6%	1,200
Brundage Canyon, UT	100%	45,420	15,116	8,554	7%	6,561	5%	6,000
Placerita, CA	100%	965	16,592	7,462	6%	9,130	7%	1,800
Tri-State, CO/KS/NE	50%	315,473	17,442	8,411	7%	9,031	7%	2,600
Montalvo, CA	100%	8,563	6,869	2,811	2%	4,059	3%	11,500
Poso Creek, CA	100%	680	2,046	2,046	2%			1,200
Various	15%	815	149	150				various
Totals		376,752	126,285	90,061	72%	36,224	28%	

Capital expenditures summary

The following is a summary of the capital expenditures for 2004 and 2005 and the budgeted capital expenditures for 2006 as of August 31, 2006.

	Years ended December 31,		
($ in millions)	**2004**	**2005**	**2006(1)**
Total California	$ 25.4	$ 48.1	$ 80.0
Total Rocky Mountains and Mid-Continent	$ 46.1	$ 59.4	$ 177.0
Other Fixed Assets	.7	11.8	18.0
Total	$ 72.2	$ 119.3	$ 275.0

(1) Budgeted capital expenditures may be adjusted for numerous reasons including, but not limited to, oil, and natural gas price levels and equipment availability, permitting and regulatory issues. See "Management's discussion and analysis of financial condition and results of operations."

Production. The following table sets forth certain information regarding production for the years ended December 31, as indicated:

	Years ended December 31,		
	2003	**2004**	**2005**
Net annual production:(1)			
Oil (Mbbl)	5,827	7,044	7,081
Gas (MMcf)	1,277	2,839	7,919
Total equivalent barrels (MBOE)(2)	6,040	7,517	8,401
Average sales price:			
Oil (per Bbl) before hedging	$ 24.41	$ 33.43	$ 47.04
Oil (per Bbl) after hedging	22.37	29.89	40.83
Gas (per Mcf) before hedging	4.40	6.13	7.88
Gas (per Mcf) after hedging	4.43	6.12	7.73
Per BOE before hedging	24.48	33.64	47.01
Per BOE after hedging	22.52	30.32	41.62
Average operating cost oil and gas production (per BOE)	9.57	10.09	11.79

(1) Net production represents that owned by us and produced to our interests.

(2) Equivalent oil and gas information is at a ratio of 6 Mcf of natural gas to 1 barrel (Bbl) of oil.

Acreage and wells. As of December 31, 2005, our properties accounted for the following developed and undeveloped acres:

	Developed acres		Undeveloped acres		Total	
	Gross	Net	Gross	Net	Gross	Net
California	8,007	8,007	7,038	7,038	15,045	15,045
Colorado	79,910	67,302	162,966	77,029	242,876	144,331
Illinois			35,481	33,249	35,481	33,249
Kansas			424,885	275,494	424,885	275,494
Nebraska			124,025	57,756	124,025	57,756
North Dakota			185,976	46,252	185,976	46,252
Utah(1)(2)	9,520	9,360	99,033	66,686	108,553	76,046
Wyoming	3,800	750	3,146	1,130	6,946	1,880
Other	80	19			80	19
Total(3)	101,317	85,438	1,042,550	564,634	1,143,867	650,072

(1) Includes 44,583 gross undeveloped acres (22,292 net) where we have an interest in 75% of the deep rights and 25% of the shallow rights.

(2) Does not include 125,000 gross (70,000 net) acres, 125,000 gross (23,000 net) acres and 69,000 gross (34,000 net) acres at Lake Canyon (shallow), Lake Canyon (deep) and Coyote Flats, respectively, which we can earn upon fulfilling specific drilling obligations.

(3) Does not include acres acquired in 2006, including 10,600 gross acres in the Piceance basin.

Gross acres represent acres in which we have a working interest; net acres represent our aggregate working interests in the gross acres.

As of December 31, 2005, we have 2,035 gross oil wells (1,951 net) and 976 gross gas wells (419 net). Gross wells represent the total number of wells in which we have a working interest. Net wells represent the number of gross wells multiplied by the percentages of the working interests owned by us. One or more completions in the same bore hole are counted as one well. Any well in which one of the multiple completions is an oil completion is classified as an oil well.

Drilling activity. The following table sets forth certain information regarding our drilling activities for the periods indicated:

	2003		2004		2005	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells drilled(1):						
Productive			5	5	13	6
Dry(2)					1	1
Development wells drilled:						
Productive	121	119	123	111	213	176
Dry(2)	1	1			7	5
Total wells drilled:						
Productive	121	119	128	116	226	182
Dry(2)	1	1			8	6

(1) Does not include one gross well drilled by our industry partner that was being evaluated at December 31, 2005.

(2) A dry well is a well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

	2005	
	Gross	Net
Total productive wells drilled:		
Oil	113	111
Gas	113	71

Dry hole, abandonment and impairment. See "Management's discussion and analysis of financial condition and results of operations."

Rocky Mountain and Mid-Continent region drilling rigs. During 2005 and 2006, we purchased three drilling rigs, two of which began drilling in the third quarter of 2006. These rigs are leased to a drilling company under three year contracts and carry purchase options available to the drilling company. Owning these rigs allows us to successfully meet a portion of our drilling needs in both the Uinta and Piceance basins over the next several years. We have several more rigs we do not own drilling or scheduled to begin drilling in 2006.

Environmental and other regulations

We are committed to responsible management of the environment, health and safety, as these areas relate to our operations. We strive to achieve the long-term goal of sustainable development within the framework of sound environmental, health and safety practices and standards. We strive to make environmental, health and safety protection an integral part of all business activities, from the acquisition and management of our resources through the decommissioning and reclamation of our wells and facilities.

We have programs in place to identify and manage known risks, to train employees in the proper performance of their duties and to incorporate viable new technologies into our operations. The costs incurred to ensure compliance with environmental, health and safety laws and other regulations are normal operating expenses and are not material to our operating cost. There can be no assurances, however, that changes in, or additions to, laws and regulations regarding the protection of the environment will not have an impact in the future. We maintain insurance coverage that we believe is customary in the industry although we are not fully insured against all environmental or other risks.

Environmental regulation. Our oil and gas exploration, production and related operations are subject to numerous and frequently changing federal, state, tribal and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Environmental laws and regulations may require the acquisition of certain permits prior to or in connection with drilling activities or other operations, restrict or prohibit the types, quantities and concentration of substances that can be released into the environment including releases in connection with drilling and production, restrict or prohibit drilling activities or other operations that could impact wetlands, endangered or threatened species or other protected areas or natural resources, require remedial action to mitigate pollution from ongoing or former operations, such as cleanup of environmental contamination, pit cleanups and plugging of abandoned wells, and impose substantial liabilities for pollution resulting from our operations. See Risk Factors "We are subject to complex federal, state, regional, local and other laws and regulations that could give rise to substantial liabilities from environmental contamination or otherwise adversely affect our cost, manner or feasibility of doing business."

Regulation of oil and gas. The oil and gas industry, including our operations, is extensively regulated by numerous federal, state and local authorities, and with respect to tribal lands, Native American tribes.

These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. Regulations may also govern the location of wells, the method of drilling and casing wells, the rates of production or "allowables," the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells, and notice to surface owners and other third parties. Certain laws and regulations may limit the amount of oil and natural gas we can produce from our wells or limit the number of wells or the locations at which we can drill. We are also subject to various laws and regulations pertaining to Native American tribal surface ownership, Native American oil and gas leases and other exploration agreements, fees, taxes, and other burdens, obligations and issues unique to oil and gas ownership and operations within Native American reservations.

Federal energy regulation. The enactment of PURPA, as amended, and the adoption of regulations thereunder by FERC provided incentives for the development of cogeneration facilities such as those owned by us. A domestic electricity generating project must be a QF under FERC regulations in order to take advantage of certain rate and regulatory incentives provided by PURPA.

PURPA provides two primary benefits to QFs. First, QFs generally are relieved of compliance with extensive federal and state regulations that control the financial structure of an electricity generating plant and the prices and terms on which electricity may be sold by the plant. Second, FERC's regulations promulgated under PURPA require that electric utilities purchase electricity generated by QFs at a price based on the purchasing utility's avoided cost, and that the utility sell back-up power to the QF on a non-discriminatory basis. The term "avoided cost" is defined as the incremental cost to an electric utility of electric energy or capacity, or both, which, but for the purchase from QFs, such utility would generate for itself or purchase from another source. The Energy Policy Act of 2005 amends PURPA to allow a utility to petition FERC to be relieved of its obligation to enter into any new contracts with QFs if the FERC determines that a competitive wholesale electricity market is available to QFs in its service territory. This amendment does not affect any of our current SO contracts. FERC regulations also permit QFs and utilities to negotiate agreements for utility purchases of power at rates lower than the utilities' avoided costs.

In order to be a QF, a cogeneration facility must produce not only electricity, but also useful thermal energy for use in an industrial or commercial process for heating or cooling applications in certain proportions to the facility's total energy output, and must meet certain energy efficiency standards. Each of our cogeneration facilities is a QF, pursuant to PURPA.

State energy regulation. The CPUC has broad authority to regulate both the rates charged by, and the financial activities of, electric utilities operating in California and to promulgate regulation for implementation of PURPA. Since a power sales agreement becomes a part of a utility's cost structure (generally reflected in its retail rates), power sales agreements with independent electricity producers, such as we, are potentially under the regulatory purview of the CPUC and in particular the process by which the utility has entered into the power sales agreements. While we are not subject to regulation by the CPUC, the CPUC's implementation of PURPA is important to us.

Management

Directors

Our directors and their ages and positions as of August 31, 2006 are as follows:

Nominee	Age	Position	Director since
Martin H. Young, Jr.	53	Chairman of the Board and Director	1999
Robert F. Heinemann	53	President, Chief Executive Officer and Director	2002
Joseph H. Bryant	51	Director	2005
Ralph B. Busch, III	46	Director	1996
William E. Bush, Jr.	59	Director	1986
Stephen L. Cropper	56	Director	2002
J. Herbert Gaul, Jr.	62	Director	1999
Thomas J. Jamieson	63	Director	1993
J. Frank Keller	62	Director	2006
Ronald J. Robinson	60	Director	2006

Mr. Young was named Chairman of the Board of Directors on June 16, 2004 and is a member of the Audit Committee. Mr. Young has been the Senior Vice President and Chief Financial Officer of Falcon Seaboard Diversified, Inc. (Falcon) and its predecessor companies, Falcon Seaboard Holdings, L.P. and Falcon Seaboard Resources, Inc. since 1992. Falcon is a private energy company involved in natural gas exploration and production, real estate and private investments. Mr. Young is also the Chairman of the Board of the Texas Mutual Insurance Company, the largest provider of workers' compensation insurance in the State of Texas. Prior to his employment with Falcon, Mr. Young had 13 years of banking experience, the last 10 working for a major California bank as the Vice President/Area Manager for the corporate banking group.

Mr. Heinemann was named the President and Chief Executive Officer on June 16, 2004 and was previously named the interim President and interim Chief Executive Officer on April 26, 2004 and the Chairman of the Board from April 1, 2004 until June 16, 2004. From December 5, 2003, to March 31, 2004, Mr. Heinemann was the Director designated to serve as the presiding Director at executive sessions of the Board in the absences of the Chairman and to act as liaison between the independent Directors and the Chief Executive Officer. From 2000 until 2002, Mr. Heinemann served as the Senior Vice President and Chief Technology Officer of Halliburton Company and as the Chairman of the Halliburton Technology Advisory Committee. He was previously with Mobil Oil Corporation (Mobil) where he served in a variety of positions for Mobil and its various affiliate companies in the energy and technical fields from 1981 to 1999, most recently as the Vice President of Mobil Technology Company and the General Manager of the Mobil Exploration and Producing Technical Center.

Mr. Bryant is a member of the Compensation Committee. Mr. Bryant is the Chairman and Chief Executive Officer of Cobalt International Energy, L.P. Mr. Bryant was the President and Chief Operating Officer for Unocal Corp. from September 2004 until September 2005 and was President of BP Angola from March 2000 until August 2004.

Mr. Busch is a member of the Compensation Committee and of the Corporate Governance and Nominating Committee. Prior to August 29, 2005, Mr. Busch also served on the Audit Committee. Mr. Busch is currently Executive Vice President and Chief Operating Officer for Aon Risk Services of Central California. Prior to his position with Aon Risk Services, Mr. Busch was President of Central Coast Financial from 1986 to 1993. Mr. Busch is a cousin to William E. Bush, Jr.

Mr. Bush is the Chairman of the Corporate Governance and Nominating Committee. Mr. Bush is a marketing consultant and private investor. Mr. Bush was formerly the Plant Manager of California Planting Cotton Seed Distributors from 1987 to 2000 and served for over 27 years in various management positions with other companies. Mr. Bush became a director of Eagle Creek Mining & Drilling (Eagle Creek) in 2003 and was previously a director of Eagle Creek from 1985 to 1998. Mr. Bush is a cousin to Ralph B. Busch, III.

Mr. Cropper is a member of the Audit Committee and served as its Chairman until May 18, 2006. Mr. Cropper is a consultant and private investor. Mr. Cropper retired in 1998 after 25 years with The Williams Companies, most recently serving as the President and Chief Executive Officer of Williams Energy Services, which was involved in various energy related businesses. Mr. Cropper is also a director of three public entities, Sunoco Logistics Partners LP, Rental Car Finance Corp. and NRG Energy, Inc. Mr. Cropper also serves as a Trustee for Oklahoma State University in Tulsa and is on the board of several community and industry associations.

Mr. Gaul is the Chairman of the Audit Committee and prior to May 18, 2006 was a member of the Corporate Governance and Nominating Committee. Mr. Gaul is a private investor. Mr. Gaul was the Chief Financial Officer for Gentek Building Products from 1995 to 1997 and served for over 25 years in senior treasury or finance positions with various other companies.

Mr. Jamieson is the Chairman of the Compensation Committee and a member of the Audit Committee. Mr. Jamieson is the Chief Executive Officer, President, owner and founder of Jaco Oil Company since 1970. Jaco Oil Company, based in Bakersfield, California, is one of the largest independent gasoline marketers in the western United States. Mr. Jamieson is also the owner of several private businesses involved in the petroleum, real estate and water utility industries.

Mr. Keller is a member of the Corporate Governance and Nominating Committee. Mr. Keller is a private investor. Mr. Keller retired in 2006 from Bill Barrett Corporation where he most recently served as the Vice Chairman of the Board and Chief Operating Officer. Mr. Keller was previously a co-founder of Barrett Resources Corporation in 1981 and served as Barrett Resources' Executive Vice President from 1983 until Barrett Resources was acquired in 2001. He has more than 25 years of experience in the oil and gas industry.

Mr. Robinson is a member of the Corporate Governance and Nominating Committee. Since 2003, Mr. Robinson has been the chairman and CEO of Knowledge Deployment, Inc. and has worked for over 30 years in the oil and gas industry. From 1998 to 2001, Mr. Robinson served as the President of Texaco's Technology Division. From 2001 until 2003 Mr. Robinson served as the department head and the Albert B. Stevens Endowed Chair professor at the Harold Vance Department of Petroleum Engineering at Texas A&M University.

Executive officers

Our executive officers are appointed by, and serve at the discretion of, our board of directors. There are no family relationships between our directors and our officers. Our executive officers (other than our Chief Executive Officer) and their ages and positions as of August 31, 2006 are as follows:

Ralph J. Goehring, 50, has been Executive Vice President and Chief Financial Officer since June 2004. Mr. Goehring was Senior Vice President from April 1997 to June 2004, and has been Chief Financial Officer since March 1992 and was Manager of Taxation from September 1987 until March 1992. Mr. Goehring is also one of our Assistant Secretaries.

Michael Duginski, 40, has been Executive Vice President of Corporate Development and California since October 2005. Mr. Duginski was Senior Vice President of Corporate Development from June 2004 through October 2005 and was Vice President of Corporate Development from February 2002 through June 2004. Mr. Duginski, a mechanical engineer, was previously with Texaco, Inc. from 1988 to 2002 where his positions included Director of New Business Development, Production Manager and Gas and Power Operations Manager. Mr. Duginski is also one of our Assistant Secretaries.

Dan Anderson, 43, has been Vice President of Rocky Mountain and Mid-Continent Production since October 2005. Mr. Anderson was Rocky Mountain and Mid-Continent Manager of Engineering from August 2003 through October 2005. Mr. Anderson, a petroleum engineer, was previously a Senior Staff Petroleum Engineer with Williams Production RMT from August 2001 through August 2003. He previously was a Senior Staff Engineer with Barrett Resources from October 2000 through August 2001.

Walter B. Ayers, 63, has been Vice President of Human Resources since May 2006. Mr. Ayers was previously a private consultant to the energy industry from January 2002 until his employment with Berry Petroleum Company. Prior to that, Mr. Ayers was Manager, Human Resources for Mobil Oil Corporation from June 1965 until December 2000 where his positions included Manager of Compensation and various other human resource management positions primarily in the upstream sector of Mobil.

George T. Crawford, 46, has been Vice President of California Production since October 2005. Mr. Crawford was Vice President of Production from December 2000 through October 2005 and was Manager of Production from January 1999 to December 2000. Mr. Crawford, a petroleum engineer, was previously the Production Engineering Supervisor for Atlantic Richfield Corp. from 1989 to 1998 in numerous engineering and operational assignments including Production Engineering Supervisor, Planning and Evaluation Consultant and Operations Superintendent.

Bruce S. Kelso, 51, has been Vice President of Rocky Mountain and Mid-Continent Exploration since October 2005. Mr. Kelso was Rocky Mountain and Mid-Continent Exploration Manager from August 2003 through October 2005. Mr. Kelso, a petroleum geologist, was previously a Senior Staff Geologist assigned to Rocky Mountain assets with Williams Production RMT, from January 2002 through August 2003. He previously was the Vice President of Exploration and Development at Redstone Resources, Inc. from 2000 to 2001.

Shawn M. Canaday, 30, has been Treasurer since December 2004 and was Senior Financial Analyst from November 2003 until December 2004. Mr. Canaday has worked in the oil and gas industry since 1998 in various finance functions at Chevron and in public accounting. Mr. Canaday is also one of our Assistant Secretaries.

Donald A. Dale, 60, has been Controller since December 1985.

Kenneth A. Olson, 51, has been Corporate Secretary since December 1985 and was Treasurer from August 1988 until December 2004.

Security ownership of management and certain beneficial owners

Management

The following table sets forth certain information regarding the beneficial ownership of our capital stock as of August 31, 2006 by (i) each of our directors who own our capital stock, (ii) all named officers, and (iii) all directors and officers as a group.

Name and address of beneficial owner*	Position	Beneficial ownership(1)(2)(17) Shares	Percent
Martin H. Young, Jr.	Chairman of the Board and Director	90,000(3)	**
Robert F. Heinemann	President, Chief Executive Officer and Director	158,010(4)	**
Joseph H. Bryant	Director	10,000(5)	**
Ralph B. Busch, III	Director	446,168(6)	1.0%
William E. Bush, Jr.	Director	366,646(7)	**
Stephen L. Cropper	Director	45,000(8)	**
J. Herbert Gaul, Jr.	Director	74,000(9)	**
Thomas J. Jamieson	Director	166,800(10)	**
J. Frank Keller	Director	10,000(11)	**
Ronald J. Robinson	Director	0	**
Ralph J. Goehring	Executive Vice President and Chief Financial Officer	153,966(12)	**
Michael Duginski	Executive Vice President of Corporate Development and California	106,132(13)	**
Logan Magruder	Executive Vice President of Rocky Mountain and Mid-Continent region (Resigned 3-23-06)	2,849(14)	**
George T. Crawford	Vice President of California Production	162,142(15)	**
All Directors and Officers as a group (19 persons)		1,831,536(16)	4.10%

* All Directors and beneficial owners listed above can be contacted at Berry Petroleum Company, 5201 Truxtun Avenue, Suite 300, Bakersfield, CA 93309.

** Represents beneficial ownership of less than 1% of our outstanding Capital Stock.

(1) Unless otherwise indicated, shares shown as beneficially owned are those as to which the named person possesses sole voting and investment power. All holdings have been adjusted for the Company's two-for-one stock split of May 17, 2006.

(2) All shares indicated are Common Stock and percent calculations are based on total shares of Capital Stock outstanding, including the 1,797,784 shares of Class B Stock outstanding which can be converted, at the request of the shareholder, to Class A Common Stock.

(3) Includes 20,000 shares held directly and 70,000 shares which Mr. Young has the right to acquire under our Equity Plans.

(4) Includes 2,000 shares held directly, 152,500 shares which Mr. Heinemann has the right to acquire under our Equity Plans and 3,510 shares which Mr. Heinemann holds in the 401(k) Plan.

(5) Includes 10,000 shares which Mr. Bryant has the right to acquire under our Equity Plans.

(6) Includes 152,378 shares held directly, 128,040 shares held in the B Group Trust at Union Bank of California which Mr. Busch votes, 97,750 shares held in a family trust for which Mr. Busch shares voting and investment power as co-trustee and 8,000 shares held in a family foundation for which Mr. Busch shares voting and investment power with his parents and siblings. Also includes 60,000 shares which Mr. Busch has the right to acquire under our Equity Plans.

(7) Includes 346,446 shares held directly, 200 shares held in Trust for his grandchildren and 20,000 shares which Mr. Bush has the right to acquire under our Equity Plans.

(8) Includes 5,000 shares held directly and 40,000 shares which Mr. Cropper has the right to acquire under our Equity Plans.

(9) Includes 4,000 shares held directly and 70,000 shares which Mr. Gaul has the right to acquire under our Equity Plans.

(10) Includes 18,000 shares held directly, 33,800 shares held indirectly by Mr. Jamieson through Jaco Oil Company, a corporation, 25,000 shares held indirectly by Mr. Jamieson through a partnership which he controls and 90,000 shares which Mr. Jamieson has the right to acquire under our Equity Plans.

(11) Includes 10,000 shares which Mr. Keller has the right to acquire under our Equity Plans.

(12) Includes 49,012 shares held directly, 4,954 shares which Mr. Goehring holds in the 401(k) plan, and 100,000 shares which Mr. Goehring has the right to acquire under our Equity Plans.

(13) Includes 8,304 shares held directly, 7,828 shares which Mr. Duginski holds in the 401(k) plan, and 90,000 shares which Mr. Duginski has the right to acquire under our Equity Plans.

(14) Includes 1,000 shares held directly, 1,849 shares which Mr. Magruder holds in the 401(k) plan. Mr. Magruder resigned as an Officer and employee of our company on March 23, 2006.

(15) Includes 7,644 shares held directly, 1,998 shares which Mr. Crawford holds in the 401(k) plan, and 152,500 shares which Mr. Crawford has the right to acquire under our Equity Plans.

(16) Includes 7,854 shares held directly by Officers not included above, an additional 1,609 shares held indirectly by Officers not included above in our 401(k) Plan and 30,360 shares which our Officers not included above have the right to acquire under our Equity Plans.

(17) Does not include 97,989 units in a stock account owned by the Directors which represent the economic equivalent of shares of Common Stock which have been earned by six of the Directors through the Non-Employee Directors Deferred Compensation Plan. These share equivalents are subject to Common Stock market price fluctuations and are non-voting. Stock account units owned as of August 31, 2006 were 30,369 for Mr. Young, 3,007 by Mr. Heinemann, 1,229 by Mr. Bryant, 12,778 by Mr. Busch, 25,044 by Mr. Gaul, and 28,569 by Mr. Jamieson.

Other beneficial owners

The following table sets forth, as of August 31, 2006, information regarding our voting securities owned beneficially, within the meaning of the rules of the Securities and Exchange Commission, by persons, other than directors or officers, known by us to own beneficially more than 5% of the indicated class:

Title of class	Name and address of beneficial owner	Amount and nature of beneficial ownership	Percent of class
Class A Common Stock	UnionBanCal Corporation 445 South Figueroa St., Third Floor Los Angeles, CA 90017	2,468,648(1)	5.8%
Class A Common Stock	William F. Berry c/o Berry Petroleum Company 5201 Truxtun Avenue, Suite 300 Bakersfield, CA 93309	2,993,648(2)	6.8%
Class A Common Stock	Winberta Holdings, Ltd. c/o Berry Petroleum Company 5201 Truxtun Avenue, Suite 300 Bakersfield, CA 93309	1,974,116(3)	4.7%
Class B Stock	Winberta Holdings, Ltd. c/o Berry Petroleum Company 5201 Truxtun Avenue, Suite 300 Bakersfield, CA 93309	1,797,784(3)	100%

(1) As reflected in Schedule 13G/A, dated January 27, 2006, and filed with the Securities and Exchange Commission by UnionBanCal Corporation (Union Bank). According to the Schedule 13G/A, Union Bank is the trustee of certain trusts to which the trustors retain voting and investment power and Union Bank has shared dispositive power on the shares indicated. In addition, Union Bank has shared power to vote 6,937 shares and the sole power to vote and control the investment power on another 8,000 shares.

(2) Mr. Berry retired from the Board of Directors on May 17, 2006. The above shares reflect his ownership of our stock as reflected in his latest Form 4 filing, which we believe to be accurate. The above shares also reflect 10,000 shares which Mr. Berry has the right to acquire under our equity plans.

(3) As reflected in Schedule 13G/A, dated February 3, 2006, and filed with the Securities and Exchange Commission by Winberta Holdings Ltd. (Winberta). According to the Schedule 13G/A, Winberta has sole voting and dispositive power on all of the shares indicated. The Class B Stock shares are convertible into Class A Common Stock at the request of Winberta. The Class A Common Stock and Class B Stock are voted as a single class. Winberta's combined shares comprise 8.6% of our total capital stock outstanding.

To our knowledge, the above information remains accurate as of the date of this prospectus supplement

Certain relationships and related party transactions

Eagle Creek Mining & Drilling, Inc.

Eagle Creek Mining & Drilling, Inc. (Eagle Creek), a California corporation, was a wholly-owned subsidiary of our predecessor, Berry Holding Company, until it was spun off to the majority shareholders of the predecessor in 1984. On November 30, 1989, Eagle Creek purchased the assets of S&D Supply Company (S&D), a California partnership. S&D, a retail distributor of oilfield parts and supplies, is now a division of Eagle Creek. The five-year contract whereby we purchased oilfield parts and supplies from S&D at competitive prices expired November 30, 1999 and was not renewed. Even though the contract expired, based on competitive pricing, we continue to purchase oilfield parts and supplies from S&D. The amounts paid to S&D in 2005, 2004 and 2003 were $890,919, $635,552 and $352,873, respectively. Mr. Bush is a director of Eagle Creek and collectively Mr. Bush and his immediate family and Mr. Busch and his immediate family own more than 10% but less than 20% of the stock of Eagle Creek.

Victory Settlement Trust

In connection with our reorganization in 1985, a shareholder of Berry Holding Company (BHC), Victory Oil Company (Victory), a California partnership, brought suit against Berry Holding Company (one of our predecessor companies prior to the reorganization in 1985) and all of its directors and officers and certain significant shareholders seeking to enjoin the reorganization. As a result of the reorganization, Victory's shares of BHC stock were converted into shares of our Common Stock representing approximately 9.7% of the shares of our Common Stock outstanding immediately subsequent to the reorganization. In 1986, we and Victory, together with certain of its affiliates, entered into the Instrument for Settlement of Claims and Mutual Release (the Settlement Agreement).

The Settlement Agreement provided for the exchange (and retirement) of all shares of our Common Stock held by Victory and certain of its affiliates for certain assets (the Settlement Assets) conveyed by us to Victory. The Settlement Assets consisted of (i) a 5% overriding royalty interest in the production removed or sold from certain real property situated in the Midway-Sunset field which is referred to as the Maxwell property (Maxwell Royalty) and (ii) a parcel of real property in Napa, California.

The shares of BHC originally acquired by Victory and the shares of our Common Stock issued to Victory in exchange for the BHC Stock in the reorganization (the Victory Shares) were acquired subject to a legend provision designed to carry out certain provisions of the Will of Clarence J. Berry, the founder of our predecessor companies. The legend enforces an Equitable Charge (the Equitable Charge) which requires that 37.5% of the dividends declared and paid on such shares from time to time be distributed to a group of lifetime income beneficiaries (the B Group).

As a result of the Settlement Agreement, the B Group was deprived of the distributions related to the stock that they would have received on the Victory Shares under the Equitable Charge. In order to adequately protect the interests of the B Group, we executed a Declaration of Trust (the Victory Settlement Trust). In recognition of our obligations and those of Victory with respect to the Equitable Charge, Victory agreed in the Settlement Agreement to pay to us in our capacity as trustee under the Victory Settlement Trust, 20% of the 5% Maxwell Royalty (Maxwell B Group Payments). The Maxwell B Group Payments will continue until the death of the last surviving member of the B Group, at which time the payments will cease and the Victory Settlement Trust will terminate. There is one surviving member of the B Group.

Under the Settlement Agreement, we agreed to guarantee that the B Group will receive the same distributions under the Equitable Charge that they would have received had the Victory shares remained as issued and outstanding shares. Accordingly, when we declare and pay dividends on our capital stock, we are obligated to calculate separately the applicable distribution (the Trust Payment). We will make payment from the Victory Settlement Trust to the surviving member of the B Group, which payments may constitute all or a part of the Trust Payment in March and September of each year. Such payments will be made to the surviving member of the B Group for the remainder of his life. Typically, the Maxwell B Group Payments have contributed to a portion or all of the Trust Payment. Pursuant to the Settlement Agreement, we paid $186,325 to the Victory Settlement Trust in 2005.

Description of other indebtedness

We have two credit facilities: a $750 million senior unsecured revolving credit facility, and a $30 million senior unsecured money market line of credit.

$750 million senior unsecured revolving credit facility

On April 28, 2006, we entered into an updated credit facility with the lenders named therein, Wells Fargo Bank, National Association as the Administrative Agent, Lead Arranger and Sole Book Runner, Societe Generale and BNP Paribas, as Co-Syndication Agents, JPMorgan Chase Bank, N.A. and Citibank (West), FSB, as Co-Documentation Agents and Comerica Bank, Union Bank of California, N.A., Bank of Scotland, MidFirst Bank and U.S. Bank National Association, as lenders. This credit facility replaced a previous credit facility with all of the previously named lenders, except for JPMorgan Chase Bank, N.A. and U.S. Bank National Association.

This credit facility is a five year $750 million senior unsecured revolving credit facility with an initial borrowing base of $500 million.

The maturity of the senior unsecured revolving credit facility is July 1, 2011. Borrowings under this facility can either be base rate loans or LIBOR loans. On all base rate loans we pay a varying rate per annum equal to the sum of (i) the higher of (a) the prime rate announced from time to time by Wells Fargo Bank, National Association, and (b) the sum of the Federal Funds Rate most recently determined by the Federal Reserve Bank of New York plus one-half of one percent, plus (ii) a base rate margin of between .0% and .5% depending on the amount of utilization by us. Interest on base rate loans is payable on the last day of each fiscal quarter. On all LIBOR loans, we pay a rate per interest period equal to the sum of (x) the quotient of (a) the LIBOR rate for deposits in U.S. dollars as of 11:00 a.m. London time two business days prior to the first day of the interest period, divided by (b) one minus the reserve requirement applicable to such interest period plus (y) a LIBOR margin of between 1.0% and 1.75% per annum depending on the total outstanding under the credit facility. Interest periods on Eurodollar rate loans may be one, two, three or six months, and if available, nine or twelve months. We may elect from time to time to convert LIBOR loans to base rate loans or to convert base rate loans to LIBOR loans. A commitment fee is paid on the undrawn balance each fiscal quarter on an annual rate of .25% to .375% based on the percentage of borrowing base usage. As of June 30, 2006, the rate for amounts outstanding was 6.6%.

The borrowing base of the senior unsecured revolving credit facility is subject to an annual redetermination and pursuant to unscheduled redeterminations at our request or at the request of the lenders, respectively once in each calendar year. If, as a result of any reduction in the amount of borrowing base, the total amount of our outstanding debt were to exceed the amount of the borrowing base in effect, then, within 90 days after we are notified of the borrowing base deficiency, we would be required to pay to the lenders one half of the deficiency and within 180 days pay the other half of the deficiency. If for any reason we are unable to eliminate the deficiency in the required period, we would be in a default of our obligations under this credit facility.

The senior unsecured revolving credit facility includes terms and covenants that place limitations on certain types of activities, including restrictions or requirements with respect to use of proceeds, additional debt, liens, asset sales, hedging activities, investments, mergers and acquisitions, dividends (which are limited to the greater of $20 million or 75% of net income over any four quarter period) and stock repurchases (which may not exceed $35 million over any four quarter period). The facility also includes certain financial maintenance covenants, which require the maintenance of a minimum current ratio and a maximum ratio of total funded debt to earnings (before interest, taxes, depreciation, depletion and amortization).

Under certain conditions, amounts outstanding under the senior unsecured revolving credit facility may be accelerated. Bankruptcy and insolvency events with respect to our company or certain of our subsidiaries, if any, will result in an automatic acceleration of the indebtedness. Subject to notice and cure periods in certain cases, other events of default under the senior credit facility will result in acceleration of the indebtedness at the option of the lenders. Such other events of default include non-payment, breach of warranty, non-performance of obligations under the senior credit facility (including financial covenants, defaults on other indebtedness, certain pension plan events, certain adverse judgments and change of control, as defined).

We have received consent from the lenders under the senior unsecured revolving credit facility to the offering of the notes contemplated by this prospectus supplement.

$30 million senior unsecured money market line of credit

On November 3, 2005, we entered into an unsecured senior uncommitted money market line of credit with Societe Generale in the amount of $30 million. This line of credit is terminable by either party. The maximum interest period is up to 30 days and the loans bear interest at a rate per annum as mutually agreed from time to time. As of June 30, 2006, the rate for amounts outstanding was 6.2%. This line of credit operates as a cash management program for us. Events of default under this line of credit may result in acceleration of the indebtedness at the option of the lender. We have received consent from the lender under this line of credit to the offering of notes contemplated by this prospectus supplement.

Description of notes

The Company will issue the Notes under the Indenture (as such may be amended, supplemented or otherwise modified from time to time, the "*Indenture*") between itself and Wells Fargo Bank, National Association, as trustee (the "*Trustee*"). The terms of the Notes include those expressly set forth in the Indenture and those made part of the Indenture by reference to the Trust Indenture Act of 1939, as amended (the "*Trust Indenture Act*"). The Indenture is unlimited in aggregate principal amount, although the issuance of notes in this offering will be limited to $200.0 million. We may from time to time issue an unlimited principal amount of additional notes under the Indenture having identical terms and conditions as the Notes other than issue date, issue price and the first interest payment date (the "*Additional Notes*"). We will only be permitted to issue such Additional Notes if at the time of such issuance, we are in compliance with the covenants contained in the Indenture. Any Additional Notes will be part of the same issue as the Notes that we are currently offering and will vote on all matters with the holders of the Notes.

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

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

General

The notes.   The Notes:

- are general unsecured, senior subordinated obligations of the Company;
- are limited to an aggregate principal amount of $200.0 million, subject to our ability to issue Additional Notes;
- will mature on November 1, 2016;
- will be issued in denominations of $2,000 and larger integral multiples of $1,000;
- will be represented by one or more registered Notes in global form, but in certain circumstances may be represented by Notes in definitive form. See "Book-entry, delivery and form;"
- are subordinated in right of payment to all existing and future Senior Indebtedness of the Company, including under the Senior Credit Facility; and
- rank equally in right of payment to any future Senior Subordinated Indebtedness of the Company, without giving effect to collateral arrangements.

Interest. Interest on the Notes will:

- accrue at the rate of $8^{1}/_{4}$% per annum;
- accrue from the date of original issuance or, if interest has already been paid, from the most recent interest payment date;
- be payable in cash semi-annually in arrears on May 1 and November 1, commencing on May 1, 2007;
- be payable to the holders of record on the April 15 and October 15 immediately preceding the related interest payment dates; and
- be computed on the basis of a 360-day year comprised of twelve 30-day months.

Payments on the notes; paying agent and registrar

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

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

Transfer and exchange

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

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

Optional redemption

Except as described below, the Notes are not redeemable until November 1, 2011. On and after November 1, 2011, the Company may redeem all or, from time to time, a part of the Notes upon not less than 30 nor more than 60 days' notice, at the following redemption prices (expressed as a percentage of principal amount) plus accrued and unpaid interest on the Notes, if any, to the applicable redemption date (subject to the right of holders of record on the relevant record date to receive interest due on the relevant interest payment date), if redeemed during the twelve-month period beginning on November 1 of the years indicated below:

Year	Percentage
2011	104.125%
2012	102.750%
2013	101.375%
2014 and thereafter	100.000%

Prior to November 1, 2009, the Company may on any one or more occasions redeem up to 35% of the original principal amount of the Notes (calculated after giving effect to any issuance of Additional Notes) with the Net Cash Proceeds of one or more Equity Offerings at a redemption price of 108.25% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date (subject to the right of holders of record on the relevant record date to receive interest due on the relevant interest payment date); *provided* that

(1) at least 65% of the original principal amount of the Notes (calculated after giving effect to any issuance of Additional Notes) remains outstanding after each such redemption; and

(2) the redemption occurs within 90 days after the closing of such Equity Offering.

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

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

In addition, the Notes may be redeemed, in whole or in part, at any time prior to November 1, 2011 at the option of the Company upon not less than 30 nor more than 60 days' prior notice mailed by first-class mail to each holder of Notes at its registered address, at a redemption price equal to 100% of the principal amount of the Notes redeemed plus the Applicable Premium plus accrued and unpaid interest, if any, to the redemption date (subject to the right of holders of record on the relevant record date to receive interest due on the relevant interest payment date).

"*Applicable Premium*" means, with respect to a Note on any date of redemption, the greater of (1) 1.0% of the principal amount of such Note and (2) the excess of (a) the present value at such time of (i) the redemption price of such Note on November 1, 2011 (such redemption price being described under the first paragraph under "Optional redemption") plus (ii) all required interest payments due on such Note through November 1, 2011 (but excluding accrued and unpaid interest to the redemption date), computed using a discount rate equal to the Treasury Rate plus 50 basis points, over (b) the then-outstanding principal amount of such Note.

"*Treasury Rate*" means the yield to maturity at the time of computation of United States Treasury securities with a constant maturity (as compiled and published in the most recent Federal Reserve Statistical Release H.15 (519) which has become publicly available at least two Business Days prior to the redemption date (or, if such Statistical Release is no longer published, any publicly available source of similar market data)) most nearly equal to the period from the redemption date to November 1, 2011; *provided, however*, that if the period from the redemption date to November 1, 2011 is not equal to the constant maturity of a United States Treasury security for which a weekly average yield is given, the Treasury Rate shall be obtained by linear interpolation (calculated to the nearest one-twelfth of a year) from the weekly average yields of United States Treasury securities for which such yields are given, except that if the period from the redemption date to November 1, 2011 is less than one year, the weekly average yield on actually traded United States Treasury securities adjusted to a constant maturity of one year shall be used.

The Company is not required to make mandatory redemption payments or sinking fund payments with respect to the Notes. However, under certain circumstances, the Company may be required to offer to purchase Notes as described below under the captions "Change of control" and "Certain covenants Limitation on sales of assets and subsidiary stock."

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

Ranking and subordination

The Notes will be unsecured Senior Subordinated Indebtedness of the Company, will be subordinated in right of payment to all existing and future Senior Indebtedness of the Company, will rank equally in right of payment with all future Senior Subordinated Indebtedness of the Company and will be senior in right of payment to all future Subordinated Obligations of the Company. The Notes will be effectively subordinated to all secured Indebtedness of the Company to the extent of the value of the assets securing such Indebtedness. As a result of the subordination provisions described below, holders of the Notes may recover less than creditors of the Company who are holders of Senior Indebtedness in the event of an insolvency, bankruptcy, reorganization, receivership or similar proceedings relating to the Company. However, payment from the money or the proceeds of U.S. Government Obligations held in any defeasance trust (as described under "Defeasance" below) will not be subordinated to any Senior Indebtedness or subject to the subordination provisions of the Indenture.

Although the Company does not currently have any Subsidiaries, the Notes will be structurally subordinated to the liabilities of any future Subsidiaries of the Company that do not provide Subsidiary Guarantees.

Assuming that we had issued the Notes and applied the net proceeds we expect to receive from the offering in the manner described under "Use of proceeds," as of August 31, 2006:

- our outstanding Senior Indebtedness (excluding Hedging Obligations) would have been approximately $178 million, none of which would have been secured; and

- the Company would have had no Senior Subordinated Indebtedness other than the Notes.

Although the Indenture will limit the amount of indebtedness that the Company and any Restricted Subsidiaries may Incur, such indebtedness may be substantial and all of it may be Senior Indebtedness or Guarantor Senior Indebtedness, as the case may be.

Only Indebtedness of the Company that is Senior Indebtedness will rank senior in right of payment to the Notes in accordance with the provisions of the Indenture. The Notes will rank equally in right of payment with all other Senior Subordinated Indebtedness of the Company. As described in " Certain covenants Limitation on layering," the Company may not Incur any indebtedness that is senior in right of payment to the Notes, but junior in right of payment to Senior Indebtedness. Indebtedness is not deemed to be subordinate in right of payment to any other Indebtedness solely by virtue of being unsecured, being secured by junior liens or having a later maturity date.

The Company may not pay principal of, premium, if any, or interest on, or other payment obligations in respect of, the Notes or make any deposit pursuant to the provisions described under " Defeasance" below and may not otherwise repurchase, redeem or retire any Notes (collectively, "*pay the Notes*") if:

(1) any payment in respect of Senior Indebtedness is not paid when due in cash or Cash Equivalents; or

(2) any other default on Senior Indebtedness occurs and the maturity of such Senior Indebtedness is accelerated in accordance with its terms,

unless, in either case, the default has been cured or waived and any such acceleration has been rescinded or such Senior Indebtedness has been paid in full in cash or Cash Equivalents. However, the Company may pay the Notes if the Company and the Trustee receive written notice approving such payment from the Representative of the Senior Indebtedness with respect to which either of the events set forth in clause (1) or (2) of the immediately preceding sentence has occurred and is continuing.

The Company also will not be permitted to pay the Notes for a Payment Blockage Period (as defined below) during the continuance of any default, other than a default described in clause (1) or (2) of the preceding paragraph which are treated in the manner set forth in that paragraph, on any Designated Senior Indebtedness that permits the holders of the Designated Senior Indebtedness to accelerate its maturity immediately without either further notice (except such notice as may be required to effect such acceleration) or the expiration of any applicable grace periods.

A "*Payment Blockage Period*" commences on the receipt by the Trustee (with a copy to the Company) of written notice (a "*Blockage Notice*") of a default of the kind described in the immediately preceding paragraph from the Representative of the holders of such Designated

Senior Indebtedness specifying an election to effect a Payment Blockage Period and ends 179 days after receipt of such notice. The Payment Blockage Period will end earlier if such Payment Blockage Period is terminated:

(1) by written notice to the Trustee and the Company from the Person or Persons who gave such Blockage Notice;

(2) because the default giving rise to such Blockage Notice is no longer continuing; or

(3) because such Designated Senior Indebtedness has been repaid in full.

The Company may resume payments on the Notes after the end of the Payment Blockage Period (including any missed payments), unless the holders of such Designated Senior Indebtedness or the Representative of such holders have accelerated the maturity of such Designated Senior Indebtedness. Not more than one Blockage Notice may be given in any consecutive 360-day period, irrespective of the number of defaults with respect to Designated Senior Indebtedness during such period. However, if any Blockage Notice within such 360-day period is given by or on behalf of any holders of Designated Senior Indebtedness other than the Bank Indebtedness, the Representatives of the Bank Indebtedness may give another Blockage Notice within such period. In no event, however, may the total number of days during which any Payment Blockage Period or Periods is in effect exceed 179 days in the aggregate during any 360 consecutive day period. For purposes of this paragraph, no default or event of default that existed or was continuing on the date of the commencement of any Payment Blockage Period with respect to the Designated Senior Indebtedness initiating such Payment Blockage Period shall be, or be made, the basis of the commencement of a subsequent Payment Blockage Period by the Representative of such Designated Senior Indebtedness, whether or not within a period of 360 consecutive days, unless such default or event of default shall have been cured or waived for a period of not less than 90 consecutive days.

In the event of:

(1) a total or partial liquidation or dissolution of the Company;

(2) a reorganization, bankruptcy, insolvency, receivership of or similar proceeding relating to the Company or its property; or

(3) an assignment for the benefit of creditors or marshaling of the Company's assets and liabilities, then

the holders of Senior Indebtedness will be entitled to receive payment in full in cash or Cash Equivalents in respect of Senior Indebtedness (including interest accruing after, or which would accrue but for, the commencement of any proceeding at the rate specified in the applicable Senior Indebtedness, whether or not a claim for such interest would be allowed) before the holders of the Notes will be entitled to receive any payment or distribution other than Junior Securities, in the event of any payment or distribution of the assets or securities of the Company. In addition, until the Senior Indebtedness is paid in full in cash or Cash Equivalents, any payment or distribution to which holders of the Notes would be entitled but for the subordination provisions of the Indenture will be made to holders of the Senior Indebtedness as their interests may appear, except that the holders of the Notes may receive (a) Capital Stock and (b) debt securities, in each case that are subordinated in right of payment to such Senior

Indebtedness (or any securities or debt instruments distributed in lieu thereof) to at least the same extent as the Notes ("*Junior Securities*"). If a payment or distribution is made to holders of the Notes that, due to the subordination provisions, should not have been made to them, such holders are required to hold it in trust for the holders of Senior Indebtedness and pay the payment or distribution over to holders of Senior Indebtedness, as their interests may appear.

If payment of the Notes is accelerated because of an Event of Default, the Company or the Trustee will promptly notify the holders of the Designated Senior Indebtedness or the Representative of such holders of the acceleration. The Company may not pay the Notes until five Business Days after such holders or the Representative of the Designated Senior Indebtedness receives notice of such acceleration and, after that five Business Day