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

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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

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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)	Years ended December 31, 2001	2002	2003	2004	2005	Six months ended June 30, 2006
						(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, 2001(1)(2)	2002(1)(2)	2003(2)	2004(2)	2005	Six months ended June 30, 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 period, may pay the Notes only if the subordination provisions of the Indenture otherwise permit payment at that time.

Change of control

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

Within 30 days following any Change of Control, unless the Company has given irrevocable notice that it will exercise its right to redeem all of the Notes as described under " Optional redemption," the Company will mail a notice (the "*Change of Control Offer*") to each holder, with a copy to the Trustee, stating:

(1) that a Change of Control has occurred and that such holder has the right to require the Company to purchase such holder's Notes at a purchase price in cash equal to 101% of the principal amount of such Notes plus accrued and unpaid interest, if any, to the date of purchase (subject to the right of holders of record on a record date to receive interest on the relevant interest payment date) (the "*Change of Control Payment*");

(2) the repurchase date (which shall be no earlier than 30 days nor later than 60 days from the date such notice is mailed) (the "*Change of Control Payment Date*"); and

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

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

(1) accept for payment all Notes or portions of Notes (of $2,000 or larger integral multiples of $1,000) properly tendered pursuant to the Change of Control Offer;

(2) deposit with the paying agent an amount equal to the Change of Control Payment in respect of all Notes or portions of Notes so tendered; and

(3) deliver or cause to be delivered to the Trustee any definitive Notes so accepted together with an Officers' Certificate stating the aggregate principal amount of Notes or portions of Notes being purchased by the Company.

The paying agent will promptly mail to each holder of Notes so tendered the Change of Control Payment for such Notes, and the Trustee will promptly authenticate and mail (or cause to be transferred by book entry) to each holder a new Note equal in principal amount to any unpurchased portion of the Notes surrendered, if any; *provided* that each such new Note will be in a principal amount of $2,000 or larger integral multiples of $1,000.

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

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

Prior to making a Change of Control Payment, and as a condition to such payment (a) all Senior Indebtedness must be repaid in full, or the Company must offer to repay all Senior Indebtedness and make payment to the holders of such Senior Indebtedness that accept such offer and obtain waivers of any event of default from the remaining holders of such Senior Indebtedness or (b) the requisite holders of each issue of Senior Indebtedness shall have consented to such Change of Control Payment being made. The Company covenants to effect such repayment or obtain such consent prior to making a Change of Control Payment, it being a default of the Change of Control provisions if the Company fails to comply with such covenant.

The Company will not be required to make a Change of Control Offer following a Change of Control if a third party makes the Change of Control Offer in the manner, at the times and otherwise in compliance with the requirements set forth in the Indenture applicable to a Change of Control Offer made by the Company and purchases all Notes validly tendered and not withdrawn under such Change of Control Offer.

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

The Company's ability to repurchase Notes pursuant to a Change of Control Offer may be limited by a number of factors. The occurrence of certain of the events that constitute a Change of Control would constitute a default under the Senior Credit Facility. In addition, certain events that may constitute a change of control under the Senior Credit Facility and cause a default under that agreement may not constitute a Change of Control under the

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

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

The Change of Control provisions described above may deter certain mergers, tender offers and other takeover attempts involving the Company by increasing the capital required to effectuate such transactions, but may have no impact on certain other proposed takeover transactions. The definition of "Change of Control" includes a disposition of all or substantially all of the assets of the Company and its Restricted Subsidiaries taken as a whole to any Person other than a Permitted Holder. Although there is a limited body of case law interpreting the phrase "substantially all," there is no precise established definition of the phrase under applicable law. Accordingly, in certain circumstances there may be a degree of uncertainty as to whether a particular transaction would involve a disposition of "all or substantially all" of the property or assets of a Person. As a result, it may be unclear as to whether a Change of Control has occurred and whether a holder of Notes may require the Company to make an offer to repurchase the Notes as described above.

Certain provisions under the Indenture relative to the Company's obligation to make an offer to repurchase the Notes as a result of a Change of Control may be waived or modified with the written consent of the holders of a majority in principal amount of the Notes.

Certain covenants

Effectiveness of covenants

Following the first day:

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

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

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

" Limitation on indebtedness,"

" Limitation on layering,"

" Limitation on restricted payments,"

" Limitation on restrictions on distributions from restricted subsidiaries,"

" Limitation on sales of assets and subsidiary stock,"

" Limitation on affiliate transactions,"

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

" Limitation on lines of business," and

Clause (3) of " Merger and consolidation"

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

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

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

Limitation on indebtedness

The Company will not, and will not permit any of its Restricted Subsidiaries to, Incur any Indebtedness (including Acquired Indebtedness); *provided, however,* that the Company and any Subsidiary Guarantors may Incur Indebtedness if on the date thereof:

(1) the Consolidated Coverage Ratio for the Company and its Restricted Subsidiaries is at least 2.50 to 1.00; and

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

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

(1) Indebtedness of the Company or any Subsidiary Guarantor Incurred pursuant to Credit Facilities in an aggregate amount up to the greater of (a) $750.0 million and (b) 40% of Adjusted Consolidated Net Tangible Assets determined as of the date of the Incurrence of such Indebtedness;

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

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

    (a) if the Company is the obligor on such Indebtedness, such Indebtedness is expressly subordinated to the prior payment in full in cash of all obligations with respect to the Notes;

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

(c)

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

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

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

(4) Indebtedness represented by (a) the Notes issued on the Issue Date and the Subsidiary Guarantees, (b) any Indebtedness (other than the Indebtedness described in clauses (1), (2), (3), (6), (8), (9) and (10) of this paragraph) outstanding on the Issue Date and (c) any Refinancing Indebtedness Incurred in respect of any Indebtedness described in this clause (4) or clause (5) of this paragraph or Incurred pursuant to the first paragraph of this covenant;

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

(6) Indebtedness under Hedging Obligations that are Incurred in the ordinary course of business (and not for speculative purposes) (a) for the purpose of fixing or hedging interest rate risk with respect to any Indebtedness permitted under the Indenture; (b) for the purpose of fixing or hedging currency exchange rate risk with respect to any currency exchanges; or (c) for the purpose of fixing or hedging commodity price risk with respect to any commodities;

(7) the Incurrence by the Company or any of its Restricted Subsidiaries of Indebtedness represented by Capitalized Lease Obligations, mortgage financings, purchase money obligations or other payments, in each case Incurred to finance all or any part of the purchase price or cost of construction or improvement of assets or property (other than Capital Stock or other Investments) acquired, constructed or improved by the Company or such Restricted Subsidiary and related financing costs, and Attributable Indebtedness, and all Refinancing Indebtedness Incurred to refund, defease, renew, extend, refinance or replace any Indebtedness Incurred pursuant to this clause (7), in an aggregate principal amount not to exceed $25.0 million at any time outstanding;

(8) Indebtedness Incurred in respect of workers' compensation claims, self-insurance obligations, performance, surety and similar bonds and completion guarantees provided by the Company or a Restricted Subsidiary in the ordinary course of business;

(9) Indebtedness arising from agreements of the Company or a Restricted Subsidiary providing for indemnification, adjustment of purchase price or similar obligations, in each case, Incurred or assumed in connection with the acquisition or disposition of any business, assets or Capital Stock of a Restricted Subsidiary or any business or assets of the Company and Refinancing Indebtedness Incurred with the same counterparty in respect thereof, *provided* that the maximum aggregate liability in respect of all such Indebtedness shall at no time exceed the gross proceeds actually paid or received by the Company and its Restricted Subsidiaries in connection with such acquisition or disposition;

(10) Indebtedness arising from the honoring by a bank or other financial institution of a check, draft or similar instrument (except in the case of daylight overdrafts) drawn against insufficient funds or in respect of cash management services provided by a bank or other financial institution, each in the ordinary course of business, *provided*, *however*, that such Indebtedness is extinguished within five Business Days of Incurrence;

(11) Indebtedness in respect of the financing of insurance premiums with the providers of such insurance or their Affiliates in the ordinary course of business;

(12) for the avoidance of doubt, in-kind obligations relating to net oil or natural gas balancing positions arising in the ordinary course of business; and

(13) in addition to the items referred to in clauses (1) through (12) above, Indebtedness of the Company and its Restricted Subsidiaries in an aggregate outstanding principal amount which, when taken together with the principal amount of all other Indebtedness Incurred pursuant to this clause (13) and then outstanding, will not exceed $20.0 million at any time outstanding.

The Company will not Incur any Indebtedness under the preceding paragraph if the proceeds thereof are used, directly or indirectly, to refinance any Subordinated Obligations of the Company unless such Indebtedness will be subordinated to the Notes to at least the same extent as such Subordinated Obligations. No Subsidiary Guarantor will Incur any Indebtedness under the preceding paragraph if the proceeds thereof are used, directly or indirectly, to refinance any Guarantor Subordinated Obligations of such Subsidiary Guarantor unless such Indebtedness will be subordinated to the obligations of such Subsidiary Guarantor under its Subsidiary Guarantee to at least the same extent as such Guarantor Subordinated Obligations. No Subsidiary Guarantor will Incur any Indebtedness under the preceding paragraph if the proceeds thereof are used, directly or indirectly, to refinance any Guarantor Senior Subordinated Indebtedness unless such refinancing Indebtedness is either Guarantor Senior Subordinated Indebtedness or Guarantor Subordinated Obligations. No Restricted Subsidiary (other than a Subsidiary Guarantor) may Incur any Indebtedness if the proceeds are used to refinance Indebtedness of the Company or a Subsidiary Guarantor.

For purposes of determining compliance with, and the outstanding principal amount of any particular Indebtedness Incurred pursuant to and in compliance with, this covenant:

(1) in the event that Indebtedness meets the criteria of more than one of the types of Indebtedness described in the first and second paragraphs of this covenant, the Company, in its sole discretion, will classify such item of Indebtedness on the date of Incurrence and may from time to time re-classify such item of Indebtedness in any

manner that complies with this covenant and only be required to include the amount and type of such Indebtedness in one of such clauses; *provided* that all Indebtedness outstanding on the Issue Date under the Senior Credit Facility shall be deemed Incurred under clause (1) of the second paragraph of this covenant and not the first paragraph or clause (4) of the second paragraph of this covenant;

(2) Guarantees of, or obligations in respect of letters of credit relating to, Indebtedness which is otherwise included in the determination of a particular amount of Indebtedness shall not be included;

(3) if obligations in respect of letters of credit are Incurred pursuant to a Credit Facility and are being treated as Incurred pursuant to clause (1) of the second paragraph above and the letters of credit relate to other Indebtedness, then such other Indebtedness shall not be included;

(4) the principal amount of any Disqualified Stock of the Company or a Restricted Subsidiary, or Preferred Stock of a Restricted Subsidiary that is not a Subsidiary Guarantor, will be equal to the greater of the maximum mandatory redemption or repurchase price (not including, in either case, any redemption or repurchase premium) or the liquidation preference thereof;

(5) Indebtedness permitted by this covenant need not be permitted solely by reference to one provision permitting such Indebtedness but may be permitted in part by one such provision and in part by one or more other provisions of this covenant permitting such Indebtedness;

(6) the principal amount of any Indebtedness outstanding in connection with a securitization transaction or series of securitization transactions is the amount of obligations outstanding under the legal documents entered into as part of such transaction that would be characterized as principal if such transaction were structured as a secured lending transaction rather than as a purchase relating to such transaction; and

(7) the amount of Indebtedness issued at a price that is less than the principal amount thereof will be equal to the amount of the liability in respect thereof determined in accordance with GAAP.

Accrual of interest, accrual of dividends, the accretion of accreted value, the payment of interest in the form of additional Indebtedness, the payment of dividends in the form of additional shares of Preferred Stock or Disqualified Stock and the incurrence of unrealized losses or charges in respect of Hedging Obligations (including those resulting from the application of FAS 133 and similar provisions), in each case will be deemed not to be Incurrences of Indebtedness for purposes of this covenant. The amount of any Indebtedness outstanding as of any date shall be (i) the accreted value thereof in the case of any Indebtedness issued with original issue discount and (ii) the principal amount or liquidation preference thereof, together with any interest thereon that is more than 30 days past due, in the case of any other Indebtedness.

In addition, the Company will not permit any of its Unrestricted Subsidiaries to Incur any Indebtedness or issue any shares of Disqualified Stock, other than Non-Recourse Debt. If at any time an Unrestricted Subsidiary becomes a Restricted Subsidiary, any Indebtedness of such

Subsidiary shall be deemed to be Incurred by a Restricted Subsidiary as of such date (and, if such Indebtedness is not permitted to be Incurred as of such date under this " Limitation on indebtedness" covenant, the Company shall be in Default of this covenant).

For purposes of determining compliance with any U.S. dollar-denominated restriction on the Incurrence of Indebtedness, the U.S. dollar-equivalent principal amount of Indebtedness denominated in a foreign currency shall be calculated based on the relevant currency exchange rate in effect on the date such Indebtedness was Incurred, in the case of term Indebtedness, or first committed, in the case of revolving credit Indebtedness; *provided* that if such Indebtedness is Incurred to refinance other Indebtedness denominated in a foreign currency, and such refinancing would cause the applicable U.S. dollar-denominated restriction to be exceeded if calculated at the relevant currency exchange rate in effect on the date of such refinancing, such U.S. dollar-denominated restriction shall be deemed not to have been exceeded so long as the principal amount of such refinancing Indebtedness does not exceed the principal amount of such Indebtedness being refinanced. Notwithstanding any other provision of this covenant, the maximum amount of Indebtedness that the Company may Incur pursuant to this covenant shall not be deemed to be exceeded solely as a result of fluctuations in the exchange rate of currencies. The principal amount of any Indebtedness Incurred to refinance other Indebtedness, if Incurred in a different currency from the Indebtedness being refinanced, shall be calculated based on the currency exchange rate applicable to the currencies in which such Refinancing Indebtedness is denominated that is in effect on the date of such refinancing.

Limitation on layering

The Company will not Incur any Indebtedness if such Indebtedness is contractually subordinate in right of payment to any Senior Indebtedness unless such Indebtedness is Senior Subordinated Indebtedness or is a Subordinated Obligation. No Subsidiary Guarantor will Incur any Indebtedness if such Indebtedness is contractually subordinate in right of payment to any Guarantor Senior Indebtedness of such Subsidiary Guarantor unless such Indebtedness is Guarantor Senior Subordinated Indebtedness of such Subsidiary Guarantor or is a Guarantor Subordinated Obligation.

For purposes of the foregoing, no Indebtedness will be 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.

Limitation on restricted payments

The Company will not, and will not permit any of its Restricted Subsidiaries, directly or indirectly, to:

(1) declare or pay any dividend or make any distribution (whether made in cash, securities or other property) on or in respect of its Capital Stock (including any payment in connection with any merger or consolidation involving the Company or any of its Restricted Subsidiaries) except:

(a) dividends or distributions payable in Capital Stock of the Company (other than Disqualified Stock); and

(b) dividends or distributions payable to the Company or another Restricted Subsidiary (and if such Restricted Subsidiary is not a Wholly Owned Subsidiary, to its other holders of common Capital Stock on a pro rata basis);

(2) purchase, redeem, retire or otherwise acquire for value any Capital Stock of the Company or any direct or indirect parent of the Company held by Persons other than the Company or a Restricted Subsidiary (other than in exchange for Capital Stock of the Company (other than Disqualified Stock));

(3) purchase, repurchase, redeem, defease or otherwise acquire or retire for value, prior to scheduled maturity, scheduled repayment or scheduled sinking fund payment, any Subordinated Obligations or Guarantor Subordinated Obligations (other than (a) Indebtedness of the Company owing to and held by any Subsidiary Guarantor or Indebtedness of a Subsidiary Guarantor owing to and held by the Company or any other Subsidiary Guarantor permitted under clause (3) of the second paragraph of the covenant "Limitation on indebtedness" or (b) the purchase, repurchase, redemption, defeasance or other acquisition or retirement of Subordinated Obligations or Guarantor Subordinated Obligations in anticipation of satisfying a sinking fund obligation, principal installment or final maturity, in each case due within one year of the date of purchase, repurchase, redemption, defeasance or other acquisition or retirement); or

(4) make any Restricted Investment in any Person;

(any such dividend, distribution, purchase, redemption, repurchase, defeasance, other acquisition, retirement or Restricted Investment referred to in clauses (1) through (4) shall be referred to herein as a "*Restricted Payment*"), if at the time the Company or such Restricted Subsidiary makes such Restricted Payment:

(a) a Default shall have occurred and be continuing (or would result therefrom); or

(b) the Company is not able to Incur $1.00 of additional Indebtedness pursuant to the first paragraph under the "Limitation on indebtedness" covenant after giving effect, on a pro forma basis, to such Restricted Payment as if such Restricted Payment and the use of proceeds thereof had been made at the beginning of the applicable four-quarter period; or

(c) the aggregate amount of such Restricted Payment and all other Restricted Payments declared or made subsequent to the Issue Date (except as excluded by other provisions of this covenant) would exceed the sum of:

(i) 50% of Consolidated Net Income for the period (treated as one accounting period) from the beginning of the fiscal quarter prior to the quarter in which the Issue Date occurs to the end of the most recent fiscal quarter ending prior to the date of such Restricted Payment for which financial statements are in existence (or, in case such Consolidated Net Income is a deficit, minus 100% of such deficit); plus

(ii) 100% of the aggregate fair market value of Qualified Proceeds received by the Company or any Subsidiary Guarantor from the issue or sale of its Capital Stock (other than Disqualified Stock) or other capital contributions subsequent to the Issue Date (other than Qualified Proceeds received from an issuance or sale of such Capital Stock to a Subsidiary of the Company or an employee stock ownership plan, option plan or similar trust to the extent such sale to an employee stock ownership plan or similar trust is financed by loans from or

Guaranteed by the Company or any Restricted Subsidiary unless such loans have been repaid with cash on or prior to the date of determination) excluding in any event (A) Net Cash Proceeds received by the Company from the issue and sale of its Capital Stock or capital contributions to the extent applied to redeem Notes in compliance with the provisions set forth under the second paragraph of the caption " Optional redemption" and (B) Qualified Proceeds to the extent used as consideration for Permitted Investments pursuant to clause (17) of the definition of "Permitted Investments"; plus

(iii) the amount by which Indebtedness of the Company or its Restricted Subsidiaries is reduced on the Company's balance sheet upon the conversion or exchange (other than by a Subsidiary of the Company) subsequent to the Issue Date of any Indebtedness of the Company or its Restricted Subsidiaries convertible or exchangeable for Capital Stock (other than Disqualified Stock) of the Company (less the amount of any cash, or the fair market value of any other property, distributed by the Company upon such conversion or exchange); plus

(iv) the amount equal to the net reduction in Restricted Investments made by the Company or any of its Restricted Subsidiaries in any Person resulting from:

(A) repurchases or redemptions of such Restricted Investments by such Person, proceeds realized upon the sale of such Restricted Investment to an unaffiliated purchaser, repayments of loans or advances or other transfers of assets (including by way of dividend or distribution) by such Person to the Company or any Restricted Subsidiary (other than for reimbursement of tax payments) and to the extent not otherwise already included releases or reductions of Guarantees; or

(B) the redesignation of Unrestricted Subsidiaries as Restricted Subsidiaries or the merger or consolidation of an Unrestricted Subsidiary with and into the Company or any of its Restricted Subsidiaries (valued in each case as provided in the definition of "Investment") not to exceed the amount of Investments previously made by the Company or any Restricted Subsidiary in such Unrestricted Subsidiary,

which amount in each case under this clause (iv) was included in the calculation of the amount of Restricted Payments; *provided, however*, that no amount will be included under this clause (iv) to the extent it is already included in Consolidated Net Income.

The provisions of the preceding paragraph will not prohibit:

(1) any purchase, repurchase, redemption, defeasance or other acquisition or retirement of Capital Stock, Disqualified Stock or Subordinated Obligations of the Company or Guarantor Subordinated Obligations of any Subsidiary Guarantor made by conversion into or exchange for, or out of the proceeds of the substantially concurrent sale of, Capital Stock of the Company (other than Disqualified Stock and other than Capital Stock issued or sold to a Subsidiary or an employee stock ownership plan or similar trust to the extent such sale to an employee stock ownership plan or similar trust is financed by loans from or Guaranteed by the Company or any Restricted Subsidiary

unless such loans have been repaid with cash on or prior to the date of determination); *provided, however*, that the amount of such Restricted Payments will be excluded in subsequent calculations of the amount of Restricted Payments; *provided, further,* that the Qualified Proceeds from such sale of Capital Stock (to the extent so used) will be excluded from clause (c)(ii) of the preceding paragraph;

(2) any purchase, repurchase, redemption, defeasance or other acquisition or retirement of Subordinated Obligations of the Company or Guarantor Subordinated Obligations of any Subsidiary Guarantor made by exchange for, or out of the proceeds of the substantially concurrent sale or Incurrence of, Subordinated Obligations of the Company or any purchase, repurchase, redemption, defeasance or other acquisition or retirement of Guarantor Subordinated Obligations made by exchange for or out of the proceeds of the substantially concurrent sale or Incurrence of Guarantor Subordinated Obligations that, in each case, is permitted to be Incurred pursuant to the covenant described under " Limitation on indebtedness" and that, if Incurred under the second paragraph thereof, in each case constitutes Refinancing Indebtedness; *provided, however*, that the amount of such Restricted Payments will be excluded in subsequent calculations of the amount of Restricted Payments;

(3) any purchase, repurchase, redemption, defeasance or other acquisition or retirement of Disqualified Stock of the Company or a Restricted Subsidiary made by exchange for or out of the proceeds of the substantially concurrent sale of Disqualified Stock of the Company or such Restricted Subsidiary, as the case may be, that, in each case, is permitted to be Incurred pursuant to the covenant described under " Limitation on indebtedness" and that in each case constitutes Refinancing Indebtedness; *provided, however*, that the amount of such Restricted Payments will be excluded in subsequent calculations of the amount of Restricted Payments;

(4) dividends paid within 60 days after the date of declaration if at such date of declaration such dividend would have complied with this provision; *provided, however*, that from and after the date of payment thereof the amount of such Restricted Payments will be included in subsequent calculations of the amount of Restricted Payments;

(5) so long as no Default or Event of Default has occurred and is continuing,

(a) the repurchase, redemption or other acquisition or retirement for value of Capital Stock of the Company or any direct or indirect parent of the Company held by any existing or former employees or directors of the Company or any Subsidiary of the Company or their assigns, estates or heirs, in each case in connection with the repurchase provisions under employee stock option or stock purchase agreements or other compensation-related agreements; *provided* that such Capital Stock was received for services related to, or for the benefit of, the Company and its Subsidiaries; and *provided further* that such repurchases, redemptions, acquisitions and retirements pursuant to this clause will not exceed $2.0 million in the aggregate during any calendar year and $5.0 million in the aggregate for all such redemptions and repurchases, plus in each case, to the extent not previously applied, the amount of any capital contributions to the Company as a result of sales of Capital Stock of the Company or any direct or indirect parent of the Company to such Persons (*provided, however,* that the Qualified Proceeds from such sale of Capital Stock (to the extent so used) will be excluded from clause (c)(ii) of the preceding paragraph), plus the amount of any "key man" insurance proceeds received by the Company or any Restricted Subsidiary to the extent not previously applied; and

(b)

loans or advances to, and Guarantees of obligations of, employees, officers or directors of the Company or any Subsidiary of the Company the proceeds of which are used to purchase Capital Stock of the Company or any direct or indirect parent of the Company, in an aggregate amount not in excess of $2.0 million with respect to all loans or advances made since the Issue Date (without giving effect to the forgiveness of any such loan); *provided, however,* that the Company and its Subsidiaries shall comply in all material respects with the provisions of the Sarbanes Oxley Act of 2002 and the rules and regulations promulgated in connection therewith relating to the provision of any such loans and advances as if the Company had filed a registration statement with the SEC;

provided, however, that the amount of such Restricted Payments will be excluded in subsequent calculations of the amount of Restricted Payments;

(6)

so long as no Default or Event of Default has occurred and is continuing, the declaration and payment of dividends to holders of any class or series of Disqualified Stock of the Company issued in accordance with the terms of the Indenture to the extent such dividends are included in the definition of "Consolidated Interest Expense;" *provided, however*, that the amount of such Restricted Payments will be excluded in subsequent calculations of the amount of Restricted Payments;

(7)

repurchases of Capital Stock deemed to occur upon the exercise of stock options, warrants or other convertible securities if such Capital Stock represents a portion of the exercise price thereof; *provided, however*, that the amount of such Restricted Payments will be excluded in subsequent calculations of the amount of Restricted Payments;

(8)

the purchase, repurchase, redemption, defeasance or other acquisition or retirement for value of any Subordinated Obligation or Guarantor Subordinated Obligation (a) at a purchase price not greater than 101% of the principal amount of such Subordinated Obligation or Guarantor Subordinated Obligation in the event of a Change of Control in accordance with provisions similar to the " Change of control" covenant or (b) at a purchase price not greater than 100% of the principal amount thereof in accordance with provisions similar to the " Limitation on sales of assets and subsidiary stock" covenant; *provided* that, prior to or simultaneously with such purchase, repurchase, redemption, defeasance or other acquisition or retirement, the Company (or a third party, in the case of a Change of Control Offer) has made the Change of Control Offer or Asset Disposition Offer, as applicable, as provided in such covenant with respect to the Notes and has completed the repurchase of all Notes validly tendered for payment in connection with such Change of Control Offer or Asset Disposition Offer; *provided, however*, that the amount of such Restricted Payments will be included in subsequent calculations of the amount of Restricted Payments;

(9)

(a) so long as no Event of Default described under clauses (1) or (2) thereof has occurred and is continuing, the declaration of dividends to holders of Common Stock of the Company of up to $10.0 million in the aggregate for all such dividends and the subsequent payment of such dividends and (b) so long as no Default or Event of Default has occurred and is continuing, the declaration of dividends to holders of Common Stock of the Company of up to $0.36 per share per calendar year (but in no event in excess of $20.0 million in the aggregate during any calendar year pursuant to this clause (9)) and the subsequent payment of such dividends; *provided, however*, that in each case the amount of such Restricted Payments will be included in subsequent calculations of the amount of Restricted Payments;

(10) so long as no Default or Event of Default has occurred and is continuing, repurchases of Common Stock pursuant to a previously announced share repurchase program for up to an aggregate purchase price after the Issue Date of $25.0 million; *provided, however*, that the amount of such Restricted Payments will be included in subsequent calculations of the amount of Restricted Payments;

(11) for avoidance of doubt, payments pursuant to any customary tax sharing or tax indemnification arrangement; *provided, however*, that the amount of such payments will be excluded in subsequent calculations of the amount of Restricted Payments;

(12) the payment of cash in lieu of issuance of fractional shares of Capital Stock in connection with any transaction otherwise permitted under this covenant; *provided, however*, that the amount of such Restricted Payments will be included in subsequent calculations of the amount of Restricted Payments;

(13) payments to dissenting stockholders not to exceed $5.0 million (A) pursuant to applicable law or (B) in connection with the settlement or other satisfaction of legal claims made pursuant to or in connection with a consolidation, merger or transfer of assets in connection with a transaction that is not prohibited by the Indenture; *provided, however*, that such payments will be included in subsequent calculations of the amount of Restricted Payments; and

(14) so long as no Default or Event of Default has occurred and is continuing, Restricted Payments in an aggregate amount not to exceed $30.0 million; *provided, however*, that the amount of such Restricted Payments will be included in subsequent calculations of the amount of Restricted Payments.

The amount of all Restricted Payments (other than cash) shall be the fair market value on the date of such Restricted Payment of the asset(s) or securities proposed to be paid, transferred or issued by the Company or such Restricted Subsidiary, as the case may be, pursuant to such Restricted Payment. The fair market value of any cash Restricted Payment shall be its face amount and any non-cash Restricted Payment (i) of less than $5.0 million shall be determined conclusively by an executive officer of the Company acting in good faith whose certification with respect thereto shall be delivered to the Trustee or (ii) of $5.0 million or more shall be determined conclusively by the Board of Directors of the Company acting in good faith whose resolution with respect thereto shall be delivered to the Trustee, such determination to be based upon an opinion or appraisal issued by an accounting, appraisal or investment banking firm of national standing if such fair market value is estimated in good faith by the Board of Directors of the Company to exceed $25.0 million. Not later than the date of making any Restricted Payment, the Company shall deliver to the Trustee an Officers' Certificate stating that such Restricted Payment is permitted and setting forth the basis upon which the calculations required by the covenant " Restricted Payments" were computed, together with a copy of any fairness opinion or appraisal required by the Indenture.

Limitation on liens

The Company will not, and will not permit any of its Restricted Subsidiaries to, directly or indirectly, create, Incur or suffer to exist any Lien (other than Permitted Liens) upon any of its property or assets (including Capital Stock of Subsidiaries), whether owned on the Issue Date or acquired after that date, which Lien is securing any Senior Subordinated Indebtedness, Subordinated Obligations, Guarantor Senior Subordinated Indebtedness or Guarantor Subordinated Obligations, unless contemporaneously with the Incurrence of such Liens effective provision is made to secure the Indebtedness due under the Indenture and the Notes or, in respect of Liens on any Restricted Subsidiary's property or assets, any Subsidiary Guarantee of such Restricted Subsidiary, with Liens in such property or assets (1) in the case of Senior Subordinated Indebtedness or Guarantor Senior Subordinated Indebtedness, that rank equally and ratably with, or senior in priority to, the Liens securing such other Indebtedness, and (2) in the case of Subordinated Obligations or Guarantor Subordinated Obligations, that rank senior in priority to the Liens securing such other Indebtedness, in each case for so long as such other Indebtedness is so secured.

Limitation on restrictions on distributions from restricted subsidiaries

The Company will not, and will not permit any Restricted Subsidiary to, create or otherwise cause or permit to exist or become effective any consensual encumbrance or consensual restriction on the ability of any Restricted Subsidiary to:

(1) pay dividends or make any other distributions on its Capital Stock or pay any Indebtedness or other obligations owed to the Company or any Restricted Subsidiary (it being understood that the priority of any Preferred Stock in receiving dividends or liquidating distributions prior to dividends or liquidating distributions being paid on Common Stock shall not be deemed a restriction on the ability to make distributions on Capital Stock);

(2) make any loans or advances to the Company or any Restricted Subsidiary (it being understood that the subordination of loans or advances made to the Company or any Restricted Subsidiary to other Indebtedness Incurred by the Company or any Restricted Subsidiary shall not be deemed a restriction on the ability to make loans or advances); or

(3) transfer any of its property or assets to the Company or any Restricted Subsidiary (it being understood that such transfers shall not include any type of transfer described in clause (1) or (2) above).

The preceding provisions will not prohibit:

(a) any encumbrance or restriction pursuant to an agreement in effect at or entered into on the Issue Date, including, without limitation, the Indenture, the Notes, the Subsidiary Guarantees, and the Senior Credit Facility (and related documentation) in effect on such date;

(b) any encumbrance or restriction with respect to a Restricted Subsidiary pursuant to any Capital Stock or agreement (including an agreement relating to any Capital Stock or Indebtedness) Incurred by a Restricted Subsidiary on or before the date on which such Restricted Subsidiary became a Restricted Subsidiary or was merged with or into or consolidated with or was acquired by the Company or a Restricted Subsidiary (other than Capital Stock or Indebtedness Incurred as consideration in, or to provide all or any portion of the funds utilized to consummate, the transaction or series of related transactions pursuant to which such Restricted Subsidiary became a Restricted Subsidiary or was acquired by the Company or in contemplation of the transaction) and outstanding on such date *provided*, that any such encumbrance or restriction shall not extend to any assets or property of the Company or any other Restricted Subsidiary other than the assets and property so acquired and all improvements, additions and accessions thereto and products and proceeds thereof, and that, in the case of Indebtedness, was permitted to be Incurred pursuant to the Indenture;

(c) any encumbrance or restriction with respect to a Restricted Subsidiary pursuant to an agreement effecting a refunding, replacement or refinancing, in whole or in part, of Indebtedness Incurred pursuant to an agreement referred to in clause (a) or (b) of this paragraph or this clause (c) or contained in any amendment, restatement, modification, renewal, supplement, refunding, replacement or refinancing of an agreement referred to in clause (a) or (b) of this paragraph or this clause (c); *provided, however,* that the encumbrances and restrictions with respect to such Restricted Subsidiary contained in any such agreement are not materially less favorable, taken as a whole, to the holders of the Notes than the encumbrances and restrictions contained in such agreements referred to in clauses (a) or (b) of this paragraph on the Issue Date or the date such Restricted Subsidiary became a Restricted Subsidiary or was merged into a Restricted Subsidiary, whichever is applicable;

(d) in the case of clause (3) of the first paragraph of this covenant, encumbrances and restrictions in agreements governing Liens permitted to be incurred under the provisions of the covenant described under " Limitation on liens;"

(e) (i) purchase money obligations for property acquired in the ordinary course of business and (ii) Capitalized Lease Obligations permitted under the Indenture, in each case, that impose encumbrances or restrictions of the nature described in clause (3) of the first paragraph of this covenant on the property so acquired;

(f) any restriction with respect to a Restricted Subsidiary (or any of its property or assets) imposed pursuant to an agreement entered into for the direct or indirect sale or disposition of the Capital Stock or assets of such Restricted Subsidiary (or the property or assets that are subject to such restriction) pending the closing of such sale or disposition;

(g) any customary encumbrances or restrictions imposed pursuant to any agreement constituting a Permitted Business Investment;

(h) restrictions on cash or other deposits and net worth provisions in leases and other agreements entered into by the Company or any Restricted Subsidiary in the ordinary course of business;

(i) encumbrances or restrictions arising or existing by reason of applicable law or any applicable rule, regulation or order;

(j) encumbrances or restrictions contained in Credit Facilities, indentures, other debt agreements and Hedging Obligations Incurred by the Company or any Restricted Subsidiary or Preferred Stock issued by Restricted Subsidiaries subsequent to the Issue Date and permitted pursuant to the covenant described under " Limitations on indebtedness;" *provided* that such encumbrances and restrictions contained in any such agreement or instrument will not materially affect the Company's ability to make anticipated principal or interest payments on the Notes (as determined by the Board of Directors of the Company);

(k) customary supermajority voting provisions and other similar provisions contained in corporate charters, bylaws, stockholders' agreements, limited liability company agreements, partnership agreements, joint venture agreements and other similar agreements;

(l) encumbrances and restrictions contained in contracts entered into in the ordinary course of business, not relating to any Indebtedness, and that do not, individually or in the aggregate, detract from the value of property or assets of the Company or any Restricted Subsidiary or the ability of the Company or such Restricted Subsidiary to realize such value, or to make any distributions relating to such property or assets in each case in any material respect; and

(m) restrictions on the transfer of property or assets required by any regulatory authority having jurisdiction over the Company or any Restricted Subsidiary or any of their businesses.

Limitation on sales of assets and subsidiary stock

The Company will not, and will not permit any of its Restricted Subsidiaries to, make any Asset Disposition *unless*:

(1) the Company or such Restricted Subsidiary, as the case may be, receives consideration at least equal to the fair market value (such fair market value to be determined on the date of contractually agreeing to such Asset Disposition), as determined in good faith by the Board of Directors (including as to the value of all non-cash consideration), of the shares and assets subject to such Asset Disposition;

(2) at least 75% of the consideration from such Asset Disposition received by the Company or such Restricted Subsidiary, as the case may be, is in the form of cash or Cash Equivalents; and

(3) an amount equal to 100% of the Net Available Cash from such Asset Disposition is applied by the Company or such Restricted Subsidiary, as the case may be:

(a) to the extent the Company or any Restricted Subsidiary, as the case may be, elects (or is required by the terms of any Senior Indebtedness or Guarantor Senior Indebtedness), to prepay, repay, redeem, defease or purchase Senior Indebtedness of the Company or Indebtedness of a Restricted Subsidiary (other than any Disqualified Stock, Guarantor Senior Subordinated Indebtedness or Guarantor Subordinated Obligations of a Subsidiary Guarantor) (in each case other than Indebtedness owed to the Company or an Affiliate of the Company) within 365 days from the later of the date of such Asset Disposition or the receipt of such Net Available Cash; *provided, however,* that, in connection with any prepayment, repayment, redemption, defeasance or purchase of Indebtedness pursuant to this clause (a), the Company or such Restricted Subsidiary will retire such Indebtedness and will cause the related commitment (if any) to be permanently reduced in an amount equal to the principal amount so prepaid, repaid, redeemed, defeased or purchased; and

(b)

to the extent the Company or such Restricted Subsidiary elects, to invest in Additional Assets within 365 days from the later of the date of such Asset Disposition or the receipt of such Net Available Cash;

provided that pending the final application of any such Net Available Cash in accordance with clause (a) or clause (b) above, the Company and its Restricted Subsidiaries may temporarily reduce Indebtedness or otherwise invest such Net Available Cash in any manner not prohibited by the Indenture.

Any Net Available Cash from Asset Dispositions that is not applied or invested as provided in the preceding paragraph will be deemed to constitute "Excess Proceeds." On the 366th day after an Asset Disposition, if the aggregate amount of Excess Proceeds exceeds $20.0 million, the Company will be required to make an offer (an "*Asset Disposition Offer*") to all holders of Notes and to the extent required by the terms of other Pari Passu Indebtedness, to all holders of other Pari Passu Indebtedness outstanding with similar provisions requiring the Company to make an offer to purchase such Pari Passu Indebtedness with the proceeds from any Asset Disposition ("*Pari Passu Notes*"), to purchase the maximum principal amount of Notes and any such Pari Passu Notes to which the Asset Disposition Offer applies that may be purchased out of the Excess Proceeds, at an offer price in cash in an amount equal to 100% of the principal amount of the Notes and Pari Passu Notes plus accrued and unpaid interest to the date of purchase, in accordance with the procedures set forth in the Indenture or the agreements governing the Pari Passu Notes, as applicable, in each case in denominations of $2,000 and larger integral multiples of $1,000. To the extent that the aggregate amount of Notes and Pari Passu Notes so validly tendered and not properly withdrawn pursuant to an Asset Disposition Offer is less than the Excess Proceeds, the Company may use any remaining Excess Proceeds for general corporate purposes, subject to other covenants contained in the Indenture. If the aggregate principal amount of Notes surrendered by holders thereof and other Pari Passu Notes surrendered by holders or lenders, collectively, exceeds the amount of Excess Proceeds, the Trustee shall select the Notes and Pari Passu Notes to be purchased on a pro rata basis on the basis of the aggregate principal amount of tendered Notes and Pari Passu Notes. Upon completion of such Asset Disposition Offer, the amount of Excess Proceeds shall be reset at zero.

The Asset Disposition Offer will remain open for a period of 20 Business Days following its commencement, except to the extent that a longer period is required by applicable law (the "*Asset Disposition Offer Period*"). No later than five Business Days after the termination of the Asset Disposition Offer Period (the "*Asset Disposition Purchase Date*"), the Company will purchase the principal amount of Notes and Pari Passu Notes required to be purchased pursuant to this covenant (the "*Asset Disposition Offer Amount*") or, if less than the Asset Disposition Offer Amount has been so validly tendered, all Notes and Pari Passu Notes validly tendered in response to the Asset Disposition Offer.

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

For the purposes of clause (2) of the first paragraph of this covenant only, the following will be deemed to be cash:

(1) the release of the Company and its Restricted Subsidiaries from all liability on Indebtedness (other than Senior Subordinated Indebtedness, Subordinated Obligations or Disqualified Stock) of the Company or Indebtedness of a Restricted Subsidiary (other than Guarantor Senior Subordinated Indebtedness, Guarantor Subordinated Obligations or Disqualified Stock of any Subsidiary Guarantor) in connection with such Asset Disposition, whether by assumption and release, satisfaction and discharge, or otherwise (in which case the Company will, without further action, be deemed to have applied such deemed cash to Indebtedness in accordance with clause (3)(a) above); and

(2) securities, notes or other obligations received by the Company or any Restricted Subsidiary from the transferee that are promptly converted by the Company or such Restricted Subsidiary into cash or Cash Equivalents.

The Company will not, and will not permit any Restricted Subsidiary to, engage in any Asset Swaps, *unless*:

(1) at the time of entering into such Asset Swap and immediately after giving effect to such Asset Swap, no Default or Event of Default shall have occurred and be continuing or would occur as a consequence thereof;

(2) in the event such Asset Swap involves the transfer by the Company or any Restricted Subsidiary of assets having an aggregate fair market value, as determined by the Board of Directors of the Company in good faith, in excess of $10.0 million, the terms of such Asset Swap have been approved by a majority of the members of the Board of Directors of the Company; and

(3) in the event such Asset Swap involves the transfer by the Company or any Restricted Subsidiary of assets having an aggregate fair market value, as determined by the Board of Directors of the Company in good faith, in excess of $25.0 million, the terms of such Asset Swap have been approved by a majority of the independent members of the Board of Directors of the Company.

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

Limitation on affiliate transactions

The Company will not, and will not permit any of its Restricted Subsidiaries to, directly or indirectly, enter into or conduct any transaction (including the purchase, sale, lease or exchange of any property or the rendering of any service) with any Affiliate of the Company (an "*Affiliate Transaction*") *unless*:

(1) the terms of such Affiliate Transaction are no less favorable to the Company or such Restricted Subsidiary, as the case may be, than those that could be obtained in a comparable transaction at the time of such transaction in arm's-length dealings with a Person who is not such an Affiliate;

(2) in the event such Affiliate Transaction involves an aggregate consideration in excess of $10.0 million, the terms of such transaction have been approved by a majority of the members of the Board of Directors of the Company and by a majority of the members of such Board having no personal stake in such transaction, if any (and such majority or majorities, as the case may be, determines that such Affiliate Transaction satisfies the criteria in clause (1) above); and

(3) in the event such Affiliate Transaction involves an aggregate consideration in excess of $25.0 million, the Company has received a written opinion from an independent investment banking, accounting or appraisal firm of nationally recognized standing that such Affiliate Transaction is fair to the Company or not materially less favorable than those that might reasonably have been obtained in a comparable transaction at such time on an arm's-length basis from a Person that is not an Affiliate.

The preceding paragraph will not apply to:

(1) any Restricted Payment (other than a Restricted Investment) and Permitted Investments (other than pursuant to clauses (1), (2), (11), (13) and (14)) permitted to be made pursuant to the Indenture;

(2) any issuance of securities, or other payments, awards or grants in cash, securities or otherwise pursuant to, or the funding of, employment agreements and other compensation arrangements, options to purchase Capital Stock of the Company, restricted stock plans, long-term incentive plans, stock appreciation rights plans, participation plans or similar employee benefits plans and/or indemnity provided on behalf of officers, directors and employees approved by the Board of Directors of the Company;

(3) the payment of customary fees paid to, and indemnity provided on behalf of, directors of the Company or any Restricted Subsidiary;

(4) loans or advances to employees, officers or directors of the Company or any Restricted Subsidiary in the ordinary course of business in an aggregate amount not in excess of $2.0 million with respect to all loans or advances made since the Issue Date (without giving effect to the forgiveness of any such loan); *provided, however,* that the Company and its Subsidiaries shall comply in all material respects with the provisions of the Sarbanes Oxley Act of 2002 and the rules and regulations promulgated in

connection therewith relating to the provision of any such loans and advances as if the Company had filed a registration statement with the SEC;

(5) any transaction between the Company and a Restricted Subsidiary or between Restricted Subsidiaries and Guarantees issued by the Company or a Restricted Subsidiary for the benefit of the Company or a Restricted Subsidiary, as the case may be, in accordance with " Limitations on indebtedness;"

(6) the existence of, and the performance of obligations of the Company or any of its Restricted Subsidiaries under the terms of any agreement to which the Company or any of its Restricted Subsidiaries is a party as of or on the Issue Date and identified on a schedule to the Indenture on the Issue Date, as these agreements may be amended, modified, supplemented, extended or renewed from time to time; *provided, however,* that any future amendment, modification, supplement, extension or renewal entered into after the Issue Date will be permitted to the extent that its terms, taken as a whole, are not materially more disadvantageous to the holders of the Notes than the terms of the agreements in effect on the Issue Date;

(7) transactions with customers, clients, suppliers or purchasers or sellers of goods or services, including Eagle Creek Mining & Drilling, Inc., in each case in the ordinary course of the business of the Company and its Restricted Subsidiaries and otherwise in compliance with the terms of the Indenture; *provided* that in the reasonable determination of the members of the Board of Directors or senior management of the Company, such transactions are on terms that are no less favorable to the Company or the relevant Restricted Subsidiary than those that would have been obtained in a comparable transaction by the Company or such Restricted Subsidiary with an unrelated Person; and

(8) any issuance or sale of Capital Stock (other than Disqualified Stock) to Affiliates of the Company and the granting of registration and other customary rights in connection therewith.

Limitation on sale of capital stock of restricted subsidiaries

The Company will not, and will not permit any Restricted Subsidiary to, transfer, convey, sell, lease or otherwise dispose of any Voting Stock of any Restricted Subsidiary or, with respect to a Restricted Subsidiary, to issue any of the Voting Stock of a Restricted Subsidiary (other than, if necessary, shares of its Voting Stock constituting Foreign Required Minority Shares) to any Person except:

(1) to the Company or a Wholly Owned Subsidiary;

(2) the granting of Liens permitted under " Limitation on liens"; and

(3) in compliance with the covenant described under " Limitation on sales of assets and subsidiary stock" and immediately after giving effect to such issuance or sale, such Restricted Subsidiary would continue to be a Restricted Subsidiary.

Notwithstanding the preceding paragraph, the Company and its Restricted Subsidiaries may sell all the Voting Stock of a Restricted Subsidiary as long as the Company or its Restricted Subsidiaries comply with the terms of the covenant described under " Limitation on sales of assets and subsidiary stock."

SEC reports

Notwithstanding that the Company may not be subject to the reporting requirements of Section 13 or 15(d) of the Exchange Act, to the extent permitted by the Exchange Act, the Company will file with the SEC, and make available to the Trustee and the registered holders of the Notes, the annual reports and the information, documents and other reports (or copies of such portions of any of the foregoing as the SEC may by rules and regulations prescribe) that are specified in Sections 13 and 15(d) of the Exchange Act with respect to U.S. issuers, in each case not later than 60 days after the final due dates therefor specified therein or in the relevant forms (after giving effect to any cure period specified therein). For the avoidance of doubt, no Default shall be deemed to occur under the Indenture until the expiration of such 60-day period.

In the event that the Company is not permitted to file such reports, documents and information with the SEC pursuant to the Exchange Act, the Company will nevertheless make available such Exchange Act information to the Trustee and the holders of the Notes as if the Company were subject to the reporting requirements of Section 13 or 15(d) of the Exchange Act, in each case not later than 60 days after the final due dates therefor specified therein or in the relevant forms (after giving effect to any cure period specified therein). For the avoidance of doubt, no Default shall be deemed to occur under the Indenture until the expiration of such 60-day period.

If the Company has designated any of its Subsidiaries as Unrestricted Subsidiaries, then the quarterly and annual financial information required by the preceding paragraph shall include a reasonably detailed presentation, either on the face of the financial statements or in the footnotes to the financial statements and in Management's Discussion and Analysis of Results of Operations and Financial Condition, of the financial condition and results of operations of the Company and its Restricted Subsidiaries.

In the event that any direct or indirect parent company of the Company becomes a guarantor of the Notes, the Company may satisfy its obligations under this covenant by furnishing financial information relating to such parent; *provided* that (a) such financial statements are accompanied by consolidating financial information for such parent, the Company, the Subsidiary Guarantors and the Subsidiaries of the Company that are not Subsidiary Guarantors in the manner prescribed by the SEC and (b) such parent is not engaged in any business in any material respect other than incidental to its ownership, directly or indirectly, of the Capital Stock of the Company.

A Default under this covenant is subject to a 180-day cure period. During such cure period, the interest rate on the Notes shall increase by 0.50% per annum.

Merger and consolidation

The Company will not consolidate with or merge with or into, or convey, transfer or lease all or substantially all its assets to, any Person, *unless*:

(1) the resulting, surviving or transferee Person (the "*Successor Company*") will be a corporation organized and existing under the laws of the United States of America, any State of the United States or the District of Columbia and the Successor Company (if not the Company) will expressly assume, by supplemental indenture, executed and

delivered to the Trustee, in form satisfactory to the Trustee, all the obligations of the Company under the Notes and the Indenture;

(2) immediately after giving effect to such transaction (and treating any Indebtedness that becomes an obligation of the Successor Company or any Subsidiary of the Successor Company as a result of such transaction as having been Incurred by the Successor Company or such Subsidiary at the time of such transaction), no Default or Event of Default shall have occurred and be continuing;

(3) immediately after giving effect to such transaction, the Successor Company would be able to Incur at least $1.00 of additional Indebtedness pursuant to the first paragraph of the " Limitation on indebtedness" covenant or the Consolidated Coverage Ratio for the Successor Company and its Restricted Subsidiaries would be greater than such ratio for the Company and its Restricted Subsidiaries immediately prior to such transaction;

(4) each Subsidiary Guarantor (unless it is the other party to the transactions above, in which case clause (1) shall apply or unless the Company is the Successor Company and such Subsidiary Guarantor was a Subsidiary Guarantor immediately prior to such transaction) shall have by supplemental indenture confirmed that its Subsidiary Guarantee shall apply to such Person's obligations in respect of the Indenture and the Notes; and

(5) the Company shall have delivered to the Trustee an Officers' Certificate and an Opinion of Counsel, together stating that such consolidation, merger or transfer and such supplemental indenture (if any) comply with the Indenture.

For purposes of this covenant, the sale, lease, conveyance, assignment, transfer, or other disposition of all or substantially all of the properties and assets of one or more Subsidiaries of the Company, which properties and assets, if held by the Company instead of such Subsidiaries, would constitute all or substantially all of the properties and assets of the Company on a consolidated basis, shall be deemed to be the transfer of all or substantially all of the properties and assets of the Company.

The predecessor Company will be released from its obligations under the Indenture and the Successor Company will succeed to, and be substituted for, and may exercise every right and power of, the Company under the Indenture, but, in the case of a lease of all or substantially all its assets, the predecessor Company will not be released from the obligation to pay the principal of and interest on the Notes.

Although there is a limited body of case law interpreting the phrase "substantially all," there is no precise established definition of the phrase under applicable law. Accordingly, in certain circumstances there may be a degree of uncertainty as to whether a particular transaction would involve "all or substantially all" of the property or assets of a Person.

Notwithstanding the preceding clause (3), (a) any Restricted Subsidiary may consolidate with, merge into or transfer all or part of its properties and assets to the Company or any Subsidiary Guarantor and (b) the Company may merge with an Affiliate incorporated solely for the purpose of reincorporating the Company in another jurisdiction to realize tax benefits; *provided* that, in the case of a Restricted Subsidiary that merges into the Company or any Subsidiary Guarantor, the Company will not be required to comply with the preceding clause (5).

In addition, the Company will not permit any Subsidiary Guarantor to consolidate with, merge with or into any Person (other than the Company or another Subsidiary Guarantor) and will not permit the conveyance, transfer or lease of all or substantially all of the assets of any Subsidiary Guarantor (other than to the Company or another Subsidiary Guarantor) *unless*:

(1) (a) if such entity remains a Subsidiary Guarantor, the resulting, surviving or transferee Person will be a corporation, partnership, trust or limited liability company organized and existing under the laws of the United States of America, any State of the United States or the District of Columbia and shall have by supplemental indenture confirmed that its Subsidiary Guarantee shall apply to such Person's obligations in respect of the Indenture and the Notes; (b) immediately after giving effect to such transaction (and treating any Indebtedness that becomes an obligation of the resulting, surviving or transferee Person or any Restricted Subsidiary as a result of such transaction as having been Incurred by such Person or such Restricted Subsidiary at the time of such transaction), no Default of Event of Default shall have occurred and be continuing; and (c) the Company will have delivered to the Trustee an Officers' Certificate and an Opinion of Counsel, together stating that such consolidation, merger or transfer and such supplemental indenture (if any) comply with the Indenture; and

(2) the transaction is made in compliance with the covenant described under " Limitation on sales of assets and subsidiary stock," (it being understood that only such portion of the Net Available Cash as is required to be applied on the date of such transaction in accordance with the terms of the Indenture needs to be applied in accordance therewith at such time) " Limitation on sale of capital stock of restricted subsidiaries" and this " Merger and consolidation" covenant.

Future subsidiary guarantors

After the Issue Date, the Company will cause each Restricted Subsidiary (other than a Foreign Subsidiary) that Guarantees any Indebtedness of the Company or any Subsidiary Guarantor to execute and deliver to the Trustee a Subsidiary Guarantee pursuant to which such Subsidiary Guarantor will unconditionally Guarantee, on a joint and several basis, the full and prompt payment of the principal of, premium, if any and interest on the Notes on a senior subordinated basis.

Each Subsidiary Guarantee will be subordinated to the prior payment in full of all Guarantor Senior Indebtedness in the same manner and to the same extent that the Notes are subordinated to Senior Indebtedness. Each Subsidiary Guarantee will rank equally in right of payment with all other Guarantor Senior Subordinated Indebtedness of that Subsidiary Guarantor and will be senior in right of payment to all future Guarantor Subordinated Obligations of that Subsidiary Guarantor. The Subsidiary Guarantees will be effectively subordinated to any secured Indebtedness of the applicable Subsidiary Guarantor to the extent of the value of the assets securing such Indebtedness.

The obligations of each Subsidiary Guarantor will be limited to the maximum amount as will, after giving effect to all other contingent and fixed liabilities of such Subsidiary Guarantor (including, without limitation, any guarantees under the Senior Credit Facility) and after giving effect to any collections from or payments made by or on behalf of any other Subsidiary Guarantor in respect of the obligations of such other Subsidiary Guarantor under its Subsidiary

Guarantee or pursuant to its contribution obligations under the Indenture, result in the obligations of such Subsidiary Guarantor under its Subsidiary Guarantee not constituting a fraudulent conveyance or fraudulent transfer under federal or state law.

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

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

(2) all the obligations of such Subsidiary Guarantor under all Indebtedness of the Company and all Subsidiary Guarantors terminate upon consummation of such transaction.

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

Limitation on lines of business

The Company will not, and will not permit any Restricted Subsidiary to, engage in any business as a primary line of business other than a Related Business.

Payments for consent

Neither the Company nor any of its Restricted Subsidiaries will, directly or indirectly, pay or cause to be paid any consideration, whether by way of interest, fees or otherwise, to any holder of any Notes for or as an inducement to any consent, waiver or amendment of any of the terms or provisions of the Indenture or the Notes unless such consideration is offered to be paid or is paid to all holders of the Notes that consent, waive or agree to amend in the time frame set forth in the solicitation documents relating to such consent, waiver or amendment.

Events of default

Each of the following is an Event of Default:

(1) default in any payment of interest on any Note when due, continued for 30 days, whether or not such payment is prohibited by the provisions described under " Ranking and subordination;"

(2) default in the payment of principal of or premium, if any, on any Note when due at its Stated Maturity, upon optional redemption, upon required repurchase, upon

declaration or otherwise, whether or not such payment is prohibited by the provisions described under " Ranking and subordination;"

(3)

failure by the Company or any Subsidiary Guarantor to comply with its obligations under " Certain covenants Merger and consolidation;"

(4)

failure by the Company to comply for 30 days after notice as provided below with any of its obligations under the covenants described under " Change of control" above or under the covenants described under " Certain covenants" above (in each case, other than (a) a failure to purchase Notes which constitutes an Event of Default under clause (2) above, (b) a failure to comply with " Certain covenants Merger and consolidation" which constitutes an Event of Default under clause (3) above or (c) a failure to comply with " Certain covenants SEC reports" which constitutes an Event of Default under clause (5)(a) below);

(5)

(a) failure by the Company to comply with " Certain covenants SEC Reports" for 180 days; or (b) failure by the Company to comply for 60 days after notice as provided below with its other agreements contained in the Indenture;

(6)

default under any mortgage, indenture or instrument under which there may be issued or by which there may be secured or evidenced any Indebtedness for money borrowed by the Company or any of its Restricted Subsidiaries (or the payment of which is Guaranteed by the Company or any of its Restricted Subsidiaries), other than Indebtedness owed to the Company or a Restricted Subsidiary, whether such Indebtedness or Guarantee now exists, or is created after the Issue Date, which default:

(a)

is caused by a failure to pay principal of, or interest or premium, if any, on such Indebtedness prior to the expiration of the grace period provided in such Indebtedness ("*payment default*"); or

(b)

results in the acceleration of such Indebtedness prior to its maturity (the "*cross acceleration provision*");
and, in each case, the principal amount of any such Indebtedness, together with the principal amount of any other such Indebtedness under which there has been a payment default or the maturity of which has been so accelerated, aggregates $25.0 million or more;

(7)

certain events of bankruptcy, insolvency or reorganization of the Company or a Significant Subsidiary or group of Restricted Subsidiaries that, taken together (as of the latest audited consolidated financial statements for the Company and its Restricted Subsidiaries), would constitute a Significant Subsidiary (the "*bankruptcy provisions*");

(8)

failure by the Company or any Significant Subsidiary or group of Restricted Subsidiaries that, taken together (as of the latest audited consolidated financial statements for the Company and its Restricted Subsidiaries), would constitute a Significant Subsidiary to pay final judgments aggregating in excess of $25.0 million (net of any amounts covered by insurance with a reputable and creditworthy insurance company that has not disclaimed liability therefor in writing), which judgments are not paid, discharged or stayed for a period of 60 days (the "*judgment default provision*"); or

(9) (a) any Subsidiary Guarantee of a Significant Subsidiary or group of Restricted Subsidiaries that taken together as of the latest audited consolidated financial statements for the Company and its Restricted Subsidiaries would constitute a Significant Subsidiary (i) ceases to be in full force and effect (except as contemplated by the terms of the Indenture) for 5 Business Days after notice as provided below or (ii) is declared null and void in a judicial proceeding or (b) any Subsidiary Guarantor that is a Significant Subsidiary or group of Subsidiary Guarantors that taken together as of the latest audited consolidated financial statements of the Company and its Restricted Subsidiaries would constitute a Significant Subsidiary denies or disaffirms its obligations under the Indenture or its Subsidiary Guarantee.

However, a default under clauses (4), (5)(b) and (9)(a)(i) of this paragraph will not constitute an Event of Default until the Trustee or the holders of 25% in principal amount of the outstanding Notes notify the Company of the default and the Company does not cure such default within the time specified in clauses (4), (5)(b) and (9)(a)(i) of this paragraph after receipt of such notice.

During the continuance of a Default under clause (5)(a) above, the interest rate on the Notes shall increase by 0.50% per annum.

If an Event of Default (other than an Event of Default described in clause (7) above) occurs and is continuing, the Trustee by notice to the Company, or the holders of at least 25% in principal amount of the outstanding Notes by notice to the Company and the Trustee, may, and the Trustee at the request of such holders shall, declare the principal of, premium, if any, and accrued and unpaid interest, if any, on all the Notes to be due and payable. Upon such a declaration, such principal, premium and accrued and unpaid interest will be due and payable immediately; *provided, however*, that so long as any Indebtedness permitted by the provisions of the Indenture to be Incurred under the Senior Credit Facility shall be outstanding, no such acceleration shall be effective until the earlier of (a) acceleration of any such Indebtedness under the Senior Credit Facility or (b) five Business Days after the giving of the acceleration notice to the Company and the administrative agent under the Senior Credit Facility of such acceleration. In the event of a declaration of acceleration of the Notes because an Event of Default described in clause (6) under " Events of default" has occurred and is continuing, the declaration of acceleration of the Notes shall be automatically annulled if the default triggering such Event of Default pursuant to clause (6) shall be remedied or cured by the Company or a Restricted Subsidiary or waived by the holders of the relevant Indebtedness within 20 days after the declaration of acceleration with respect thereto and if (1) the annulment of the acceleration of the Notes would not conflict with any judgment or decree of a court of competent jurisdiction and (2) all existing Events of Default, except nonpayment of principal, premium or interest on the Notes that became due solely because of the acceleration of the Notes, have been cured or waived. If an Event of Default described in clause (7) above occurs and is continuing, the principal of, premium, if any, and accrued and unpaid interest on all the Notes will become and be immediately due and payable without any declaration or other act on the part of the Trustee or any holders. The holders of a majority in principal amount of the outstanding Notes may waive all past defaults (except with respect to nonpayment of principal, premium or interest) and rescind any such acceleration with respect to the Notes and its consequences if (1) rescission would not conflict with any judgment or decree of a court of competent jurisdiction and (2) all existing Events of Default, other than the nonpayment of the principal of, premium, if any, and interest on the Notes that have become due solely by such declaration of acceleration, have been cured or waived.

Subject to the provisions of the Indenture relating to the duties of the Trustee, if an Event of Default occurs and is continuing, the Trustee will be under no obligation to exercise any of the rights or powers under the Indenture at the request or direction of any of the holders unless such holders have offered to the Trustee reasonable indemnity or security against any loss, liability or expense. Except to enforce the right to receive payment of principal, premium, if any, or interest when due, no holder may pursue any remedy with respect to the Indenture or the Notes *unless*:

(1) such holder has previously given the Trustee notice that an Event of Default is continuing;

(2) holders of at least 25% in principal amount of the outstanding Notes have requested the Trustee to pursue the remedy;

(3) such holders have offered the Trustee reasonable security or indemnity against any loss, liability or expense;

(4) the Trustee has not complied with such request within 60 days after the receipt of the request and the offer of security or indemnity; and

(5) the holders of a majority in principal amount of the outstanding Notes have not given the Trustee a direction that, in the opinion of the Trustee, is inconsistent with such request within such 60-day period.

Subject to certain restrictions, the holders of a majority in principal amount of the outstanding Notes are given the right to direct the time, method and place of conducting any proceeding for any remedy available to the Trustee or of exercising any trust or power conferred on the Trustee. The Indenture provides that in the event an Event of Default has occurred and is continuing, the Trustee will be required in the exercise of its powers to use the degree of care that a prudent person would use in the conduct of its own affairs. The Trustee, however, may refuse to follow any direction that conflicts with law or the Indenture or that the Trustee determines is unduly prejudicial to the rights of any other holder or that would involve the Trustee in personal liability. Prior to taking any action under the Indenture, the Trustee will be entitled to indemnification satisfactory to it in its sole discretion against all losses and expenses caused by taking or not taking such action.

The Indenture provides that if a Default occurs and is continuing and is known to the Trustee, the Trustee must mail to each holder notice of the Default within 90 days after it occurs. Except in the case of a Default in the payment of principal of, premium, if any, or interest on any Note, the Trustee may withhold notice if and so long as a committee of trust officers of the Trustee in good faith determines that withholding notice is in the interests of the holders.

The Company is required to deliver to the Trustee, within 120 days after the end of each fiscal year, a certificate indicating whether the signers thereof know of any Default that occurred during the previous year. The Company also is required to deliver to the Trustee, within 30 days after the occurrence thereof, written notice of any events which would constitute certain Defaults, their status and what action the Company is taking or proposing to take in respect thereof.

Amendments and waivers

Subject to certain exceptions, the Indenture and the Notes may be amended or supplemented with the consent of the holders of a majority in principal amount of the Notes then outstanding (including without limitation, consents obtained in connection with a purchase of, or tender offer or exchange offer for, Notes) and, subject to certain exceptions, any past default or compliance with any provisions may be waived with the consent of the holders of a majority in principal amount of the Notes then outstanding (including, without limitation, consents obtained in connection with a purchase of, or tender offer or exchange offer for, Notes). However, without the consent of each holder of an outstanding Note affected, no amendment, supplement or waiver may, among other things:

(1) reduce the amount of Notes whose holders must consent to an amendment;

(2) reduce the stated rate of or extend the stated time for payment of interest on any Note;

(3) reduce the principal of or extend the Stated Maturity of any Note;

(4) reduce the premium payable upon the redemption or repurchase of any Note or change the time at which any Note may be redeemed or repurchased as described above under " Optional redemption," " Change of control" or " Certain covenants Limitation on sales of assets and subsidiary stock" whether through an amendment or waiver of provisions in the covenants, definitions or otherwise (except amendments to the definitions of "Change of Control" and "Permitted Holder");

(5) make any Note payable in money other than that stated in the Note;

(6) impair the right of any holder to receive payment of principal, premium, if any, and interest on such holder's Notes on or after the due dates therefor or to institute suit for the enforcement of any payment on or with respect to such holder's Notes;

(7) make any change in the amendment provisions which require each holder's consent or in the waiver provisions;

(8) make any change to the subordination provisions of the Indenture that adversely affects the rights of any holder of Notes; or

(9) modify the Subsidiary Guarantees in any manner adverse to the holders of the Notes.

Notwithstanding the foregoing, without the consent of any holder, the Company, the Guarantors and the Trustee may amend the Indenture and the Notes to:

(1) cure any ambiguity, omission, defect or inconsistency;

(2) provide for the assumption by a successor Person of the obligations of the Company or any Subsidiary Guarantor under the Indenture;

(3) provide for uncertificated Notes in addition to or in place of certificated Notes (*provided* that the uncertificated Notes are issued in registered form for purposes of Section 163(f) of the Code, or in a manner such that the uncertificated Notes are described in Section 163(f) (2) (B) of the Code);

(4) add Guarantees with respect to the Notes or release a Subsidiary Guarantor from its obligations under its Subsidiary Guarantee or the Indenture in accordance with the applicable provisions of the Indenture;

(5) secure the Notes;

(6) add to the covenants of the Company for the benefit of the holders or surrender any right or power conferred upon the Company;

(7) make any change that does not adversely affect the rights of any holder;

(8) comply with any requirement of the SEC in connection with the qualification of the Indenture under the Trust Indenture Act;

(9) provide for the appointment of a successor trustee; provided that the successor trustee is otherwise qualified and eligible to act as such under the terms of the Indenture;

(10) make any change in the subordination provisions of the Indenture that would limit or terminate the benefits available to any holder of Senior Indebtedness of the Company or a holder of Guarantor Senior Indebtedness (or any Representative thereof) under such subordination provisions; or

(11) conform the text of the Indenture, the Notes or the Subsidiary Guarantees to any provision of this "Description of notes" to the extent that such provision in this "Description of notes" is intended to be a verbatim recitation of a provision of the Indenture, the Notes or the Subsidiary Guarantees.

However, no amendment may be made to the subordination provisions of the Indenture that adversely affects the rights of any holder of Senior Indebtedness or Guarantor Senior Indebtedness then outstanding unless the holders of such Senior Indebtedness or Guarantor Senior Indebtedness (or any group or representative thereof authorized to give a consent) consent to such change.

The consent of the holders is not necessary under the Indenture to approve the particular form of any proposed amendment or supplement. It is sufficient if such consent approves the substance of the proposed amendment or supplement. A consent to any amendment, supplement or waiver under the Indenture by any holder of Notes given in connection with a tender of such holder's Notes will not be rendered invalid by such tender. After an amendment or supplement under the Indenture becomes effective, the Company is required to mail to the holders a notice briefly describing such amendment or supplement. However, the failure to give such notice to all the holders, or any defect in the notice will not impair or affect the validity of the amendment or supplement.

Defeasance

The Company at any time may terminate all its obligations under the Notes and the Indenture ("*legal defeasance*"), except for certain obligations, including those respecting the defeasance trust and obligations to register the transfer or exchange of the Notes, to replace mutilated, destroyed, lost or stolen Notes and to maintain a registrar and paying agent in respect of the Notes. If the Company exercises its legal defeasance option, the Subsidiary Guarantees in effect at such time will terminate.

The Company at any time may terminate its obligations described under " Change of control" and under the covenants described under " Certain covenants" (other than " Merger and consolidation"), the operation of the cross-default upon a payment default, the cross acceleration provision, the bankruptcy provisions with respect to Subsidiaries and the judgment default provision described under " Events of default" above and the limitations contained in clause (3) under " Certain covenants Merger and consolidation" above ("*covenant defeasance*").

The Company may exercise its legal defeasance option notwithstanding its prior exercise of its covenant defeasance option. If the Company exercises its legal defeasance option, payment of the Notes may not be accelerated because of an Event of Default with respect to the Notes. If the Company exercises its covenant defeasance option, payment of the Notes may not be accelerated because of an Event of Default specified in clause (4), (5), (6), (7) (with respect only to Subsidiaries), (8) or (9) under " Events of default" above or because of the failure of the Company to comply with clause (3) under " Certain covenants Merger and consolidation" above.

In order to exercise either defeasance option, the Company must irrevocably deposit in trust (the "*defeasance trust*") with the Trustee money or U.S. Government Obligations for the payment of principal, premium, if any, and interest on the Notes to redemption or maturity, as the case may be, and must comply with certain other conditions, including delivery to the Trustee of an Opinion of Counsel (subject to customary exceptions and exclusions) to the effect that holders of the Notes will not recognize income, gain or loss for Federal income tax purposes as a result of such deposit and defeasance and will be subject to Federal income tax on the same amount and in the same manner and at the same times as would have been the case if such deposit and defeasance had not occurred. In the case of legal defeasance only, such Opinion of Counsel must be based on a ruling of the Internal Revenue Service or other change in applicable Federal income tax law.

No personal liability of directors, officers, employees and stockholders

No director, officer, employee, incorporator or stockholder of the Company or any Subsidiary Guarantor, as such, shall have any liability for any obligations of the Company under the Notes, the Indenture or the Subsidiary Guarantees or for any claim based on, in respect of, or by reason of, such obligations or their creation. Each holder by accepting a Note waives and releases all such liability. The waiver and release are part of the consideration for issuance of the Notes. Such waiver may not be effective to waive liabilities under the federal securities laws and it is the view of the SEC that such a waiver is against public policy.

Concerning the trustee

Wells Fargo Bank, National Association, is the Trustee under the Indenture and has been appointed by the Company as Registrar and Paying Agent with regard to the Notes.

Governing law

The Indenture provides that it and the Notes will be governed by, and construed in accordance with, the laws of the State of New York.

Certain definitions

"*Acquired Indebtedness*" means Indebtedness (1) of a Person or any of its Subsidiaries existing at the time such Person becomes a Restricted Subsidiary or (2) assumed in connection with the acquisition of assets from such Person, in each case whether or not Incurred by such Person in connection with, or in anticipation or contemplation of, such Person becoming a Restricted Subsidiary or such acquisition. Acquired Indebtedness shall be deemed to have been Incurred, with respect to clause (1) of the preceding sentence, on the date such Person becomes a Restricted Subsidiary and, with respect to clause (2) of the preceding sentence, on the date of consummation of such acquisition of assets.

"*Additional Assets*" means:

(1) any property, plant, equipment or other asset (excluding current assets) to be used by the Company or a Restricted Subsidiary in a Related Business;

(2) capital expenditures by the Company or a Restricted Subsidiary in a Related Business;

(3) the Capital Stock of a Person that becomes a Restricted Subsidiary as a result of the acquisition of such Capital Stock by the Company or a Restricted Subsidiary; or

(4) Capital Stock constituting a minority interest in any Person that at such time is a Restricted Subsidiary;

provided, however, that, in the case of clauses (3) and (4), such Restricted Subsidiary is primarily engaged in a Related Business.

"*Adjusted Consolidated Net Tangible Assets*" means (without duplication), as of the date of determination, the remainder of:

(a) the sum of:

(i) discounted future net revenues from proved oil and gas reserves of the Company and its Restricted Subsidiaries calculated in accordance with SEC guidelines before any provincial, territorial, state, Federal or foreign income taxes, as estimated by the Company in a reserve report prepared as of the end of the Company's most recently completed fiscal year for which audited financial statements are available, as increased by, as of the date of determination, the estimated discounted future net revenues from

(A) estimated proved oil and gas reserves acquired since such year end, which reserves were not reflected in such year end reserve report, and

(B) estimated oil and gas reserves attributable to upward revisions of estimates of proved oil and gas reserves since such year end due to exploration, development or exploitation activities, in each case calculated in accordance with SEC guidelines (utilizing the prices for the fiscal quarter ending prior to the date of determination),

and decreased by, as of the date of determination, the estimated discounted future net revenues from

(C) estimated proved oil and gas reserves produced or disposed of since such year end, and

(D) estimated oil and gas reserves attributable to downward revisions of estimates of proved oil and gas reserves since such year end due to changes in geological conditions or other factors which would, in accordance with standard industry practice, cause such revisions, in each case calculated on a pre-tax basis and substantially in accordance with SEC guidelines (utilizing the prices for the fiscal quarter ending prior to the date of determination), in each case as estimated by the Company's petroleum engineers or any independent petroleum engineers engaged by the Company for that purpose;

(ii) the capitalized costs that are attributable to oil and gas properties of the Company and its Restricted Subsidiaries to which no proved oil and gas reserves are attributable, based on the Company's books and records as of a date no earlier than the date of the Company's latest available annual or quarterly financial statements;

(iii) the Net Working Capital on a date no earlier than the date of the Company's latest annual or quarterly financial statements; and

(iv) the greater of

(A) the net book value of other tangible assets of the Company and its Restricted Subsidiaries, as of a date no earlier than the date of the Company's latest annual or quarterly financial statement, and

(B) the appraised value, as estimated by independent appraisers, of other tangible assets of the Company and its Restricted Subsidiaries, as of a date no earlier than the date of the Company's latest audited financial statements; minus

(b) the sum of:

(i) Minority Interests;

(ii) any net gas balancing liabilities of the Company and its Restricted Subsidiaries reflected in the Company's latest audited financial statements;

(iii) to the extent included in (a)(i) above, the discounted future net revenues, calculated in accordance with SEC guidelines (utilizing the prices utilized in the Company's year end reserve report), attributable to reserves which are required to be delivered to third parties to fully satisfy the obligations of the Company and its Restricted Subsidiaries with respect to Volumetric Production Payments (determined, if applicable, using the schedules specified with respect thereto); and

(iv) the discounted future net revenues, calculated in accordance with SEC guidelines, attributable to reserves subject to Dollar-Denominated Production Payments which, based on the estimates of production and price assumptions included in determining the discounted future net revenues specified in (a)(i) above, would be necessary to fully satisfy the payment obligations of the Company and its Subsidiaries with respect to Dollar-Denominated Production Payments (determined, if applicable, using the schedules specified with respect thereto).

If the Company changes its method of accounting from the successful efforts method of accounting to the full cost or a similar method, "Adjusted Consolidated Net Tangible Assets" will continue to be calculated as if the Company were still using the successful efforts method of accounting.

"*Affiliate*" of any specified Person means any other Person, directly or indirectly, controlling or controlled by or under direct or indirect common control with such specified Person. For the purposes of this definition, "*control*" when used with respect to any Person means the power to direct the management and policies of such Person, directly or indirectly, whether through the ownership of voting securities, by contract or otherwise; and the terms "*controlling*" and "*controlled*" have meanings correlative to the foregoing; *provided* that exclusively for purposes of " Certain covenants Limitation on affiliate transactions," beneficial ownership of 10% or more of the Voting Stock of a Person shall be deemed to be control.

"*Asset Disposition*" means any direct or indirect sale, lease (other than an operating lease entered into in the ordinary course of business), transfer, issuance or other disposition, or a series of related sales, leases, transfers, issuances or dispositions that are part of a common plan, of shares of Capital Stock of a Subsidiary (other than Foreign Required Minority Shares), property or other assets (each referred to for the purposes of this definition as a "*disposition*") by the Company or any of its Restricted Subsidiaries, including any disposition by means of a merger, consolidation or similar transaction.

Notwithstanding the preceding, the following items shall not be deemed to be Asset Dispositions:

(1) a disposition of assets by a Restricted Subsidiary to the Company or by the Company or a Restricted Subsidiary to a Restricted Subsidiary;

(2) a disposition of Cash Equivalents in the ordinary course of business;

(3) a disposition of Hydrocarbons or Related Assets in the ordinary course of business;

(4) a disposition of obsolete or worn out equipment or equipment that is no longer useful in the conduct of the business of the Company and its Restricted Subsidiaries and that is disposed of in each case in the ordinary course of business;

(5) transactions permitted under " Certain covenants Merger and consolidation;"

(6) an issuance of Capital Stock by a Restricted Subsidiary to the Company or to a Restricted Subsidiary;

(7) for purposes of " Certain covenants Limitation on sales of assets and subsidiary stock" only, the making of a Permitted Investment (but, in the case of an Investment in which the Company or a Restricted Subsidiary receives consideration for such transaction including cash or Cash Equivalents, such transaction shall be deemed to also include an Asset Disposition having a fair market value equal to the aggregate amount of cash and Cash Equivalents so received) or a disposition subject to " Certain covenants Limitation on restricted payments;"

(8) an Asset Swap effected in compliance with " Certain covenants Limitation on sales of assets and subsidiary stock;"

(9) dispositions of assets with an aggregate fair market value since the Issue Date of less than $5.0 million;

(10) the creation of a Permitted Lien and dispositions in connection with Permitted Liens;

(11) dispositions of receivables in connection with the compromise, settlement or collection thereof in the ordinary course of business or in bankruptcy or similar proceedings and exclusive of factoring or similar arrangements;

(12) the issuance by a Restricted Subsidiary of Preferred Stock that is permitted by the covenant described under the caption " Certain covenants Limitation on indebtedness;"

(13) the licensing or sublicensing of intellectual property or other general intangibles and licenses, leases or subleases of other property in the ordinary course of business which do not materially interfere with the business of the Company and its Restricted Subsidiaries;

(14) foreclosure on assets;

(15) any Production Payments and Reserve Sales that are customary in the Oil and Gas Business;

(16) a disposition of Permitted Investments of the type described in clause (7) of the definition thereof;

(17) a disposition of Oil and Gas Properties in connection with tax credit transactions complying with Section 29 or any successor or analogous provisions of the Code;

(18) surrender or waiver of contract rights or the settlement, release or surrender of contract, tort or other claims of any kind;

(19) for purposes of clause (2) of " Certain covenants Limitation on sales of assets and subsidiary stock" only, dispositions of equipment in the form of Capitalized Lease Obligations or mortgage or purchase money financing in an aggregate principal amount not to exceed $25.0 million at any time outstanding; *provided* that any proceeds received in connection with any such transaction must be applied in accordance with " Certain covenants Limitation on sales of assets and subsidiary stock;"

(20) Sale/Leaseback Transactions relating to assets acquired after the Issue Date; provided that each such Sale/Leaseback Transaction is consummated within 180 days after the date of the acquisition of such asset by the Company or such Restricted Subsidiary (each, a "*Qualifying SLB*"); and

(21) dispositions of the Montalvo properties in Ventura County, California.

"*Asset Swap*" means a concurrent purchase and sale or exchange of Oil and Gas Properties between the Company or any of its Restricted Subsidiaries and another Person; *provided* that any cash received must be applied in accordance with " Certain covenants Limitation on sales of assets and subsidiary stock."

"*Attributable Indebtedness*" in respect of a Sale/Leaseback Transaction means, as at the time of determination, the present value (discounted at the interest rate implicit in the transaction) of the total obligations of the lessee for rental payments during the remaining term of the lease included in such Sale/Leaseback Transaction (including any period for which such lease has been extended), determined in accordance with GAAP; *provided, however*, that if such Sale/Leaseback Transaction results in a Capitalized Lease Obligation, the amount of Indebtedness represented thereby will be determined in accordance with the definition of "Capitalized Lease Obligations;" and *provided, further*, obligations relating to Qualifying SLBs shall be deemed not to be Attributable Indebtedness.

"*Average Life*" means, as of the date of determination, with respect to any Indebtedness or Preferred Stock, the quotient obtained by dividing (1) the sum of the products of the numbers of years from the date of determination to the dates of each successive scheduled principal payment of such Indebtedness or redemption or similar payment with respect to such Preferred Stock multiplied by the amount of such payment by (2) the sum of all such payments.

"*Bank Indebtedness*" means any and all amounts, whether outstanding on the Issue Date or Incurred after the Issue Date, payable by the Company or any Subsidiary under or in respect of the Senior Credit Facility and any related notes, collateral documents, letters of credit, bank guarantees, Guarantees executed and delivered by Subsidiaries and any Interest Rate Agreement entered into in connection with the Senior Credit Facility, including principal, premium, if any, interest (including interest accruing on or after the filing of any petition in bankruptcy or for reorganization relating to the Company at the rate specified therein whether or not a claim for post filing interest is allowed in such proceedings), all Hedging Obligations of the Company or any of its Subsidiaries now or hereafter owing to any lender under the Senior Credit Facility or any Affiliate of such a lender, all obligations of the Company or any of its Subsidiaries with respect to cash management services now or hereafter owing to any lender under the Senior Credit Facility or any Affiliate of such a lender, fees, charges, expenses, reimbursement obligations, Guarantees and all other amounts payable thereunder or in respect thereof.

"*Board of Directors*" means, as to any Person, the board of directors of such Person or any duly authorized committee thereof.

"*Business Day*" means each day that is not a Saturday, Sunday or other day on which banking institutions in New York, New York are authorized or required by law to close.

"*Capital Stock*" of any Person means any and all shares, interests, rights to purchase, warrants, options, participations or other equivalents of or interests in (however designated) equity of such Person, including any Preferred Stock and limited liability or partnership interests (whether general or limited), but excluding any debt securities convertible into such equity.

"*Capitalized Lease Obligations*" means an obligation that is required to be classified and accounted for as a capitalized lease for financial reporting purposes in accordance with GAAP, and the amount of Indebtedness represented by such obligation will be the capitalized amount of such obligation at the time any determination thereof is to be made as determined in accordance with GAAP, and the Stated Maturity thereof will be the date of the last payment of rent or any other amount due under such lease prior to the first date such lease may be terminated without penalty.

"*Cash Equivalents*" means:

(1) securities issued or directly and fully guaranteed or insured by the United States Government or any agency or instrumentality of the United States (*provided* that the full faith and credit of the United States is pledged in support thereof), having maturities of not more than one year from the date of acquisition;

(2)

marketable general obligations issued by any state of the United States of America or any political subdivision of any such state or any public instrumentality thereof maturing within one year from the date of acquisition thereof (*provided* that the full faith and credit of the United States is pledged in support thereof) and, at the time of acquisition, having a credit rating of "A" or better from either Standard & Poor's Ratings Group, Inc. or Moody's Investors Service, Inc.;

(3)

certificates of deposit, time deposits, eurodollar time deposits, overnight bank deposits or bankers' acceptances having maturities of not more than one year from the date of acquisition thereof issued by any commercial bank the long-term debt of which is rated at the time of acquisition thereof at least "A" or the equivalent thereof by Standard & Poor's Ratings Group, Inc., or "A" or the equivalent thereof by Moody's Investors Service, Inc., and having combined capital and surplus in excess of $500 million;

(4)

repurchase obligations with a term of not more than 30 days for underlying securities of the types described in clauses (1), (2) and (3) entered into with any bank meeting the qualifications specified in clause (3) above;

(5)

commercial paper rated at the time of acquisition thereof at least "A-2" or the equivalent thereof by Standard & Poor's Ratings Group, Inc. or "P-2" or the equivalent thereof by Moody's Investors Service, Inc., or carrying an equivalent rating by a nationally recognized rating agency, if both of the two named rating agencies cease publishing ratings of investments, and in any case maturing within one year after the date of acquisition thereof; and

(6)

interests in any investment company or money market fund which invests 95% or more of its assets in instruments of the type specified in clauses (1) through (5) above.

"*Change of Control*" means:

(1)

any "person" or "group" of related persons (as such terms are used in Sections 13(d) and 14(d) of the Exchange Act), other than one or more Permitted Holders, becomes the beneficial owner (as defined in Rules 13d-3 and 13d-5 under the Exchange Act, except that such person or group shall be deemed to have "beneficial ownership" of all shares that any such person or group has the right to acquire, whether such right is exercisable immediately or only after the passage of time), directly or indirectly, of more than 35% of the total voting power of the Voting Stock of the Company (or its successor by merger, consolidation or purchase of all or substantially all of its assets) (for the purposes of this clause, such person or group shall be deemed to beneficially own any Voting Stock of the Company held by a parent entity, if such person or group "beneficially owns" (as defined above), directly or indirectly, more than 35% of the voting power of the Voting Stock of such parent entity); or

(2)

the first day on which a majority of the members of the Board of Directors of the Company are not Continuing Directors; or

(3)

the sale, lease, transfer, conveyance or other disposition (other than by way of merger or consolidation), in one or a series of related transactions, of all or substantially all of the assets of the Company and its Restricted Subsidiaries taken as a whole to any "person" (as such term is used in Sections 13(d) and 14(d) of the Exchange Act) other than a Permitted Holder; or

(4) the adoption by the stockholders of the Company of a plan or proposal for the liquidation or dissolution of the Company.

"*Code*" means the Internal Revenue Code of 1986, as amended.

"*Commodity Agreement*" means any commodity futures contract, commodity swap, commodity option or other similar agreement or arrangement, including options, swaps, floors, caps, collars, futures, forward sales or forward purchases involving commodities (including Hydrocarbons and Related Assets), commodity-related revenues or costs (including basis), equities, bonds, or indexes based on any of the foregoing and any other derivative agreement or arrangement based on any of the foregoing.

"*Common Stock*" means with respect to any Person, any and all shares, interest or other participations in, and other equivalents (however designated and whether voting or nonvoting) of such Person's common stock whether or not outstanding on the Issue Date, and includes, without limitation, all series and classes of such common stock.

"*Consolidated Cash Flow"* for any period means, without duplication, the Consolidated Net Income for such period, plus the following to the extent deducted in calculating such Consolidated Net Income:

(1) Consolidated Interest Expense; plus

(2) Consolidated Income Taxes; plus

(3) consolidated depletion and depreciation expense; plus

(4) consolidated amortization expense or impairment charges recorded in connection with the application of Financial Accounting Standard No. 142 "Goodwill and Other Intangibles" and Financial Accounting Standard No. 144 "Accounting for the Impairment or Disposal of Long Lived Assets" and similar provisions; plus

(5) other non-cash charges reducing Consolidated Net Income (excluding any such non-cash charge to the extent it represents an accrual of or reserve for cash charges in any future period or amortization of a prepaid cash expense that was paid in a prior period not included in the calculation); plus

(6) consolidated exploration expense;

minus the sum of:

(A) non-cash items increasing Consolidated Net Income of such Person for such period (excluding any items which represent the reversal of any accrual of, or reserve for, anticipated cash charges made in any prior period); and

(B) to the extent included in calculating such Consolidated Net Income and in excess of any costs or expenses attributable thereto that were deducted in calculating such Consolidated Net Income, the sum of (x) the amount of deferred revenues that are amortized during such period and are attributable to reserves that are subject to Volumetric Production Payments, and (y) amounts recorded in accordance with GAAP as repayments of principal and interest pursuant to Dollar-Denominated Production Payments.

Notwithstanding the preceding sentence, clauses (2) through (6) relating to amounts of a Restricted Subsidiary of a Person will be added to Consolidated Net Income to compute Consolidated Cash Flow of such Person only to the extent (and in the same proportion) that the net income (loss) of such Restricted Subsidiary was included in calculating the Consolidated Net Income of such Person and, to the extent the amounts set forth in clauses (2) through (6) are in excess of those necessary to offset a net loss of such Restricted Subsidiary or if such Restricted Subsidiary has net income for such period included in Consolidated Net Income, only if a corresponding amount would be permitted at the date of determination to be dividended to the Company by such Restricted Subsidiary without prior approval (that has not been obtained), pursuant to the terms of its charter and all agreements, instruments, judgments, decrees, orders, statutes, rules and governmental regulations applicable to that Restricted Subsidiary or its stockholders.

"*Consolidated Coverage Ratio*" means as of any date of determination, with respect to any Person, the ratio of (x) the aggregate amount of Consolidated Cash Flow of such Person for the period of the most recent four consecutive fiscal quarters ending prior to the date of such determination for which financial statements are in existence to (y) Consolidated Interest Expense for such four fiscal quarters, *provided*, *however*, that:

(1) if the Company or any Restricted Subsidiary:

(a) has Incurred any Indebtedness since the beginning of such period that remains outstanding on such date of determination or if the transaction giving rise to the need to calculate the Consolidated Coverage Ratio is an Incurrence of Indebtedness, Consolidated Cash Flow and Consolidated Interest Expense for such period will be calculated after giving effect on a pro forma basis to such Indebtedness as if such Indebtedness had been Incurred on the first day of such period (except that in making such computation, the amount of Indebtedness under any revolving credit facility outstanding on the date of such calculation will be deemed to be (i) the average daily balance of such Indebtedness during such four fiscal quarters or such shorter period for which such facility was outstanding or (ii) if such facility was created after the end of such four fiscal quarters, the average daily balance of such Indebtedness during the period from the date of creation of such facility to the date of such calculation) and the discharge of any other Indebtedness repaid, repurchased, defeased or otherwise discharged with the proceeds of such new Indebtedness as if such discharge had occurred on the first day of such period; and

(b) has repaid, repurchased, defeased or otherwise discharged any Indebtedness since the beginning of the period that is no longer outstanding on such date of determination or if the transaction giving rise to the need to calculate the Consolidated Coverage Ratio involves a discharge of Indebtedness (in each case, other than Indebtedness Incurred under any revolving credit facility unless such Indebtedness has been permanently repaid and the related commitment terminated), Consolidated Cash Flow and Consolidated Interest Expense for such period will be calculated after giving effect on a pro forma basis to such discharge of such Indebtedness, including with the proceeds of such new Indebtedness, as if such discharge had occurred on the first day of such period;

(2) if since the beginning of such period the Company or any Restricted Subsidiary will have made any Asset Disposition or disposed of any company, division, operating unit, segment, business, group of related assets or line of business or if the transaction giving rise to the need to calculate the Consolidated Coverage Ratio is such an Asset Disposition:

(a) the Consolidated Cash Flow for such period will be reduced by an amount equal to the Consolidated Cash Flow (if positive) directly attributable to the assets which are the subject of such disposition for such period or increased by an amount equal to the Consolidated Cash Flow (if negative) directly attributable thereto for such period; and

(b) Consolidated Interest Expense for such period will be reduced by an amount equal to the Consolidated Interest Expense directly attributable to any Indebtedness of the Company or any Restricted Subsidiary repaid, repurchased, defeased or otherwise discharged with respect to the Company and its continuing Restricted Subsidiaries in connection with such disposition for such period (or, if the Capital Stock of any Restricted Subsidiary is sold, the Consolidated Interest Expense for such period directly attributable to the Indebtedness of such Restricted Subsidiary to the extent the Company and its continuing Restricted Subsidiaries are no longer liable for such Indebtedness after such sale);

(3) if since the beginning of such period the Company or any Restricted Subsidiary (by merger or otherwise) will have made an Investment in any Restricted Subsidiary (or any Person which becomes a Restricted Subsidiary or is merged with or into the Company or a Restricted Subsidiary) or an acquisition of assets, including any acquisition of assets occurring in connection with a transaction causing a calculation to be made hereunder, which constitutes all or substantially all of a company, division, operating unit, segment, business, group of related assets or line of business, Consolidated Cash Flow and Consolidated Interest Expense for such period will be calculated after giving pro forma effect thereto (including the Incurrence of any Indebtedness) as if such Investment or acquisition occurred on the first day of such period; and

(4) if since the beginning of such period any Person (that subsequently became a Restricted Subsidiary or was merged with or into the Company or any Restricted Subsidiary since the beginning of such period) will have Incurred any Indebtedness or discharged any Indebtedness, made any disposition or any Investment or acquisition of assets that would have required an adjustment pursuant to clause (1), (2) or (3) above if made by the Company or a Restricted Subsidiary during such period, Consolidated Cash Flow and Consolidated Interest Expense for such period will be calculated after giving pro forma effect thereto as if such Person had been a Restricted Subsidiary on the first day of such period and such transaction or transactions had occurred on the first day of such period.

For purposes of this definition, whenever pro forma effect is to be given to any calculation under this definition, the pro forma calculations will be determined in good faith by a responsible financial or accounting officer of the Company (including pro forma expense and cost reductions calculated on a basis consistent with Regulation S-X under the Securities Act). If any Indebtedness bears a floating rate of interest and is being given pro forma effect, the interest expense on such Indebtedness will be calculated as if the rate in effect on the date of determination had been the applicable rate for the entire period (taking into account any Interest Rate Agreement applicable to such Indebtedness to the extent of the remaining term thereof). If any Indebtedness that is being given pro forma effect bears an interest rate at the option of the Company, the interest rate shall be calculated by applying such optional rate chosen by the Company.

"*Consolidated Income Taxes*" means, with respect to any Person for any period, taxes imposed upon such Person or other payments required to be made by such Person by any governmental authority which taxes or other payments are calculated by reference to the income or profits of such Person or such Person and its Restricted Subsidiaries (to the extent such income or profits were included in computing Consolidated Net Income for such period), regardless of whether such taxes or payments are required to be remitted to any governmental authority.

"*Consolidated Interest Expense*" means, for any period, the total interest expense of the Company and its consolidated Restricted Subsidiaries, whether paid or accrued, plus, to the extent not included in such interest expense and without duplication:

(1) interest expense attributable to Capitalized Lease Obligations and the interest portion of rent expense associated with Attributable Indebtedness in respect of the relevant lease giving rise thereto, determined as if such lease were a capitalized lease in accordance with GAAP and the interest component of any deferred payment obligations;

(2) amortization of debt discount; *provided*, *however*, that any amortization of bond premium will be credited to reduce Consolidated Interest Expense unless, pursuant to GAAP, such amortization of bond premium has otherwise reduced Consolidated Interest Expense;

(3) non-cash interest expense;

(4) commissions, discounts and other fees and charges owed with respect to letters of credit and bankers' acceptance financing;

(5) the interest expense on Indebtedness of another Person that is Guaranteed by such Person or one of its Restricted Subsidiaries or secured by a Lien on assets of such Person or one of its Restricted Subsidiaries;

(6) costs associated with Hedging Obligations (including amortization of fees) *provided, however*, that if Hedging Obligations result in net benefits rather than costs, such benefits shall be credited to reduce Consolidated Interest Expense unless, pursuant to GAAP, such net benefits are otherwise reflected in Consolidated Net Income;

(7) the consolidated interest expense of such Person and its Restricted Subsidiaries that was capitalized during such period;

(8) the product of (a) all dividends paid or payable, in cash, Cash Equivalents or Indebtedness or accrued during such period on any series of Disqualified Stock of such Person or on Preferred Stock of its Restricted Subsidiaries that are not Subsidiary Guarantors payable to a party other than the Company or a Wholly Owned Subsidiary, times (b) a fraction, the numerator of which is one and the denominator of which is one minus the then current combined federal, state, provincial and local statutory tax

rate of such Person, expressed as a decimal, in each case, on a consolidated basis and in accordance with GAAP;

(9) Receivables Fees; and

(10) the cash contributions to any employee stock ownership plan or similar trust to the extent such contributions are used by such plan or trust to pay interest or fees to any Person (other than the Company and its Restricted Subsidiaries) in connection with Indebtedness Incurred by such plan or trust.

minus, to the extent included above, the sum of amortization of debt issuance costs and interest income.

For the purpose of calculating the Consolidated Coverage Ratio, the calculation of Consolidated Interest Expense shall include all interest expense (including any amounts described in clauses (1) through (10) above) relating to any Indebtedness of the Company or any Restricted Subsidiary described in the final paragraph of the definition of "Indebtedness".

For purposes of the foregoing, total interest expense will be determined (i) after giving effect to any net payments made or received by the Company and its Subsidiaries with respect to Interest Rate Agreements and (ii) exclusive of amounts classified as other comprehensive income in the balance sheet of the Company. Notwithstanding anything to the contrary contained herein, commissions, discounts, yield and other fees and charges Incurred in connection with any transaction pursuant to which the Company or its Restricted Subsidiaries may sell, convey or otherwise transfer or grant a security interest in any accounts receivable or related assets shall be included in Consolidated Interest Expense.

"*Consolidated Net Income*" means, for any period, the net income (loss) of the Company and its consolidated Restricted Subsidiaries determined in accordance with GAAP; *provided, however*, that there will not be included in such Consolidated Net Income:

(1) any net income (or loss) of any Person if such Person is not a Restricted Subsidiary, except that:

(a) subject to the limitations contained in clauses (3), (4) and (5) below, the Company's equity in the net income of any such Person for such period will be included in such Consolidated Net Income up to the aggregate amount of cash actually distributed by such Person during such period to the Company or a Restricted Subsidiary as a dividend, distribution or other payment (subject, in the case of a dividend, distribution or other payment to a Restricted Subsidiary, to the limitations contained in clause (2) below); and

(b) the Company's equity in a net loss of any such Person (other than an Unrestricted Subsidiary) for such period will be included in determining such Consolidated Net Income to the extent such loss has been funded with cash from the Company or a Restricted Subsidiary;

(2) any net income (but not loss) of any Restricted Subsidiary if such Subsidiary is subject to restrictions, directly or indirectly, on the payment of dividends or the making of

distributions by such Restricted Subsidiary, directly or indirectly, to the Company, except that:

(a) subject to the limitations contained in clauses (3), (4) and (5) below, the Company's equity in the net income of any such Restricted Subsidiary for such period will be included in such Consolidated Net Income up to the aggregate amount of cash that could have been distributed by such Restricted Subsidiary during such period to the Company or another Restricted Subsidiary as a dividend, distribution or other payment (subject, in the case of a dividend to another Restricted Subsidiary, to the limitation contained in this clause); and

(b) the Company's equity in a net loss of any such Restricted Subsidiary for such period will be included in determining such Consolidated Net Income;

(3) any after-tax gain (loss) realized upon the sale or other disposition of any property, plant or equipment of the Company or its consolidated Restricted Subsidiaries (including pursuant to any Sale/Leaseback Transaction) which is not sold or otherwise disposed of in the ordinary course of business and any gain (loss) realized upon the sale or other disposition of any Capital Stock of any Person;

(4) any after-tax extraordinary gain or loss;

(5) the cumulative effect of a change in accounting principles;

(6) any asset impairment or writedown on or related to Oil and Gas Properties under GAAP or SEC guidelines;

(7) any unrealized non-cash gains or losses or charges in respect of Hedging Obligations (including those resulting from the application of SFAS 133 or similar provisions);

(8) any after-tax gain or loss realized on the termination of any employee pension benefit plan;

(9) non-cash charges relating to grants of performance shares, stock options, stock awards, stock purchase agreements or management compensation plans for officers, directors, employees or consultants of the Company or a Restricted Subsidiary (excluding any such non-cash charge to the extent that it represents an accrual of or reserve for cash charges in any future period or amortization of a prepaid cash expense that was paid in a prior period) to the extent that such non-cash charges are deducted in computing such Consolidated Net Income; *provided* that if the Company or any Restricted Subsidiary of the Company makes a cash payment in respect of a non-cash charge in any period, such cash payment shall (without duplication) be deducted from the Consolidated Net Income of the Company for such period;

(10) any adjustments of a deferred tax liability or asset pursuant to Statement of Financial Accounting Standards No. 109 which result from changes in enacted tax laws or rates; and

(11) costs incurred in connection with acquisitions that were eligible for capitalization treatment under GAAP but instead were expensed at the time of incurrence, *provided* that any such costs shall instead reduce Consolidated Net Income for any period to the extent of any amortization in such period that would have occurred had they had been capitalized).

"*Continuing Directors*" means, as of any date of determination, any member of the Board of Directors of the Company who: (1) was a member of such Board of Directors on the Issue Date; or (2) was nominated for election or elected to such Board of Directors with the approval of a majority of the Continuing Directors who were members of such Board at the time of such nomination or election.

"*Credit Facilities*" means, with respect to the Company or any Subsidiary Guarantor, one or more debt facilities (including, without limitation, the Senior Credit Facility, the uncommitted money market line of credit facility, dated November 3, 2005 between the Company and Societe Generale, or commercial paper facilities with banks or other institutional lenders providing for revolving credit loans, term loans, receivables financing (including through the sale of receivables to such lenders or to special purpose entities formed to borrow from such lenders against such receivables) or letters of credit, in each case, as amended, restated, modified, renewed, refunded, replaced or refinanced in whole or in part from time to time (and whether or not with the original administrative agent and lenders or another administrative agent or agents or other lenders and whether provided under the original Senior Credit Facility or any other credit or other agreement or indenture).

"*Currency Agreement*" means in respect of a Person any foreign exchange contract, currency swap agreement, futures contract, option contract or other similar agreement as to which such Person is a party or a beneficiary.

"*Default*" means any event which is, or after notice or passage of time or both would be, an Event of Default.

"*Designated Senior Indebtedness*" means (1) the Bank Indebtedness (to the extent such Bank Indebtedness constitutes Senior Indebtedness or Guarantor Senior Indebtedness) and (2) any other Senior Indebtedness or Guarantor Senior Indebtedness which, at the date of determination, has an aggregate principal amount outstanding of, or under which, at the date of determination, the holders thereof are committed to lend up to, at least $25.0 million and is specifically designated in the instrument evidencing or governing such Indebtedness as "Designated Senior Indebtedness" for purposes of the Indenture.

"*Disqualified Stock*" means, with respect to any Person, any Capital Stock of such Person which by its terms (or by the terms of any security into which it is convertible or for which it is exchangeable) or upon the happening of any event:

(1) matures or is mandatorily redeemable pursuant to a sinking fund obligation or otherwise;

(2) is convertible or exchangeable for Indebtedness or Disqualified Stock (excluding Capital Stock which is convertible or exchangeable solely at the option of the Company or a Restricted Subsidiary); or

(3) is redeemable at the option of the holder of the Capital Stock in whole or in part,

in each case on or prior to the date that is 91 days after the earlier of the date (a) of the Stated Maturity of the Notes or (b) on which there are no Notes outstanding, *provided* that only the portion of Capital Stock which so matures or is mandatorily redeemable, is so convertible or exchangeable or is so redeemable at the option of the holder thereof prior to such date will be deemed to be Disqualified Stock; *provided, further* that any Capital Stock that would constitute Disqualified Stock solely because the holders thereof have the right to require the Company to repurchase such Capital Stock upon the occurrence of a change of control or asset sale (each defined in a substantially identical manner to the corresponding definitions in the Indenture) shall not constitute Disqualified Stock if the terms of such Capital Stock (and all such securities into which it is convertible or for which it is ratable or exchangeable) provide that the Company may not repurchase or redeem any such Capital Stock (and all such securities into which it is convertible or for which it is ratable or exchangeable) pursuant to such provision prior to compliance by the Company with the provisions of the Indenture described under the captions " Change of control" and " Certain covenants Limitation on sales of assets and subsidiary stock" and such repurchase or redemption complies with " Certain covenants Limitation on restricted payments."

"*Dollar-Denominated Production Payments*" means production payment obligations recorded as liabilities in accordance with GAAP, together with all undertakings and obligations in connection therewith.

"*Domestic Subsidiary*" means any Restricted Subsidiary that is organized under the laws of the United States of America or any state thereof or the District of Columbia.

"*Equity Offering*" means a public or private offering for cash by the Company of its Common Stock, or options, warrants or rights with respect to its Common Stock, other than (x) public offerings with respect to the Company's Common Stock, or options, warrants or rights, registered on Form S-4 or S-8, (y) an issuance to any Subsidiary or (z) until any required Change of Control Offer has expired, any offering of Common Stock issued in connection with a transaction that constitutes a Change of Control.

"*Exchange Act*" means the Securities Exchange Act of 1934, as amended, and the rules and regulations of the SEC promulgated thereunder.

"*Foreign Required Minority Shares*" means directors' qualifying shares and other shares of Capital Stock of a Foreign Subsidiary that are required by the applicable laws and regulations of such foreign jurisdiction to be owned by the government of such foreign jurisdiction or individual or corporate citizens of such foreign jurisdiction in order for such Foreign Subsidiary to transact business in such foreign jurisdiction.

"*Foreign Subsidiary*" means any Restricted Subsidiary that is not organized under the laws of the United States of America or any state thereof or the District of Columbia and any Subsidiary of such Restricted Subsidiary.

"*GAAP*" means generally accepted accounting principles in the United States of America as in effect as of the Issue Date, including those set forth in the opinions and pronouncements of the Accounting Principles Board of the American Institute of Certified Public Accountants and statements and pronouncements of the Financial Accounting Standards Board or in such other statements by such other entity as approved by a significant segment of the accounting profession. All ratios and computations based on GAAP contained in the Indenture will be computed in conformity with GAAP, except that in the event the Company is acquired in a transaction that is accounted for using purchase accounting, the effects of the application of purchase accounting shall be disregarded in the calculation of such ratios and other computations contained in the Indenture.

"*Guarantee*" means any obligation, contingent or otherwise, of any Person directly or indirectly guaranteeing any Indebtedness of any other Person and any obligation, direct or indirect, contingent or otherwise, of such Person:

(1) to purchase or pay (or advance or supply funds for the purchase or payment of) such Indebtedness of such other Person (whether arising by virtue of partnership arrangements, or by agreement to keep-well, to purchase assets, goods, securities or services, to take-or-pay, or to maintain financial statement conditions or otherwise); or

(2) entered into for purposes of assuring in any other manner the obligee of such Indebtedness of the payment thereof or to protect such obligee against loss in respect thereof (in whole or in part); *provided, however,* that the term "Guarantee" will not include endorsements for collection or deposit in the ordinary course of business. The term "Guarantee" used as a verb has a corresponding meaning.

"*Guarantor Senior Indebtedness*" means, with respect to a Subsidiary Guarantor, the following obligations, whether outstanding on the date of the Indenture or thereafter issued, without duplication:

(1) any Guarantee of the Bank Indebtedness by such Subsidiary Guarantor and all other Guarantees by such Subsidiary Guarantor of Senior Indebtedness of the Company or Guarantor Senior Indebtedness of any other Subsidiary Guarantor; and

(2) all obligations consisting of principal of and premium, if any, accrued and unpaid interest on, and fees and other amounts relating to, all other Indebtedness of the Subsidiary Guarantor. Guarantor Senior Indebtedness includes interest accruing on or after the filing of any petition in bankruptcy or for reorganization relating to the Subsidiary Guarantor regardless of whether postfiling interest is allowed in such proceeding.

Notwithstanding anything to the contrary in the preceding paragraph, Guarantor Senior Indebtedness will not include:

(1) any Indebtedness Incurred in violation of the Indenture;

(2) any obligations of such Subsidiary Guarantor to another Subsidiary or the Company;

(3) any liability for Federal, state, local, foreign or other taxes owed or owing by such Subsidiary Guarantor;

(4) any accounts payable or other liability to trade creditors arising in the ordinary course of business (including Guarantees thereof or instruments evidencing such liabilities);

(5) any Indebtedness, Guarantee or obligation of such Subsidiary Guarantor that is expressly subordinate or junior in right of payment to any other Indebtedness, Guarantee or obligation of such Subsidiary Guarantor, including, without limitation, any Guarantor Senior Subordinated Indebtedness and Guarantor Subordinated Obligations of such Guarantor; or

(6) any Capital Stock.

"*Guarantor Senior Subordinated Indebtedness*" means, with respect to a Subsidiary Guarantor, the obligations of such Subsidiary Guarantor under the Subsidiary Guarantee and any other Indebtedness of such Subsidiary Guarantor (whether outstanding on the Issue Date or thereafter Incurred) that ranks equally in right of payment with the obligations of such Subsidiary Guarantor under the Subsidiary Guarantee and is not expressly subordinated by its terms in right of payment to any Indebtedness of such Subsidiary Guarantor which is not Guarantor Senior Indebtedness of such Subsidiary Guarantor.

"*Guarantor Subordinated Obligation*" means, with respect to a Subsidiary Guarantor, any Indebtedness of such Subsidiary Guarantor (whether outstanding on the Issue Date or thereafter Incurred) which is subordinated in right of payment to the obligations of such Subsidiary Guarantor under its Subsidiary Guarantee pursuant to a written agreement.

"*Hedging Obligations*" of any Person means the obligations of such Person pursuant to any Interest Rate Agreement, Currency Agreement or Commodity Agreement.

"*holder*" means a Person in whose name a Note is registered on the Registrar's books.

"*Hydrocarbons*" means oil, natural gas, casinghead gas, drip gasoline, natural gasoline, condensate, distillate, liquid hydrocarbons, gaseous hydrocarbons and all constituents, elements or compounds thereof and products refined or processed therefrom.

"*Incur*" means issue, create, assume, Guarantee, incur or otherwise become liable for; *provided, however,* that any Indebtedness or Capital Stock of a Person existing at the time such Person becomes a Restricted Subsidiary (whether by merger, consolidation, acquisition or otherwise) will be deemed to be Incurred by such Restricted Subsidiary at the time it becomes a Restricted Subsidiary; and the terms "Incurred" and "Incurrence" have meanings correlative to the foregoing.

"*Indebtedness*" means, with respect to any Person on any date of determination (without duplication):

(1) the principal of and premium (if any) in respect of indebtedness of such Person for borrowed money;

(2) the principal of and premium (if any) in respect of obligations of such Person evidenced by bonds, debentures, notes or other similar instruments;

(3) the principal component of all obligations of such Person in respect of letters of credit, bankers' acceptances or other similar instruments (including reimbursement obligations with respect thereto except to the extent such reimbursement obligation relates to a trade payable and such obligation is satisfied within 30 days of Incurrence);

(4) the principal component of all obligations of such Person to pay the deferred and unpaid purchase price of property (except trade payables), which purchase price is due more than six months after the date of placing such property in service or taking delivery and title thereto; *provided* that payments of $102.0 million in the aggregate pursuant to the Carry and Earning Agreement dated June 7, 2006 between the Company and EnCana Oil & Gas (USA) Inc. relating to the North Parachute Ranch property in Piceance Basin, Garfield County, Colorado shall be deemed not to be Indebtedness pursuant to this clause (4);

(5) Capitalized Lease Obligations and all Attributable Indebtedness of such Person;

(6) the principal component or liquidation preference of all obligations of such Person with respect to the redemption, repayment or other repurchase of any Disqualified

Stock or, with respect to any Subsidiary that is not a Subsidiary Guarantor, any Preferred Stock;

(7) the principal component of all Indebtedness of other Persons secured by a Lien on any asset of such Person, whether or not such Indebtedness is assumed by such Person; *provided, however,* that the amount of such Indebtedness will be the lesser of (a) the liquidation value of such asset at such date of determination and (b) the amount of such Indebtedness of such other Persons;

(8) the principal component of Indebtedness of other Persons to the extent Guaranteed by such Person;

(9) to the extent not otherwise included in this definition, net obligations of such Person under Hedging Obligations (the amount of any such obligations to be equal at any time to the termination value of such agreement or arrangement giving rise to such obligation that would be payable by such Person at such time); and

(10) to the extent not otherwise included in this definition, the amount of obligations outstanding under the legal documents entered into as part of a securitization transaction or series of securitization transactions that would be characterized as principal if such transaction were structured as a secured lending transaction rather than as a purchase outstanding relating to a securitization transaction or series of securitization transactions.

Notwithstanding the preceding, Indebtedness shall not include Volumetric Production Payments. The amount of Indebtedness of any Person at any date will be the outstanding balance at such date of all unconditional obligations as described above and the maximum liability, upon the occurrence of the contingency giving rise to the obligation, of any contingent obligations at such date. Notwithstanding the foregoing, money borrowed and set aside at the time of the Incurrence of any Indebtedness in order to pre-fund the payment of interest on such Indebtedness shall not be deemed to be "*Indebtedness*," *provided* that such money is held to secure the payment of such interest.

In addition, "Indebtedness" of any Person shall include Indebtedness described in the preceding paragraph that would not appear as a liability on the balance sheet of such Person if:

(1) such Indebtedness is the obligation of a partnership, limited liability company or similar entity that is not a Restricted Subsidiary (a "*Joint Venture*");

(2) such Person or a Restricted Subsidiary of such Person is a general partner of the Joint Venture (a "*General Partner*"); and

(3) there is recourse, by contract or operation of law, with respect to the payment of such Indebtedness to property or assets of such Person or a Restricted Subsidiary of such Person; and then such Indebtedness shall be included in an amount not to exceed:

  (a) the lesser of (i) the net assets of the General Partner and (ii) the amount of such obligations to the extent that there is recourse, by contract or operation of law, to the property or assets of such Person or a Restricted Subsidiary of such Person; or

  (b) if less than the amount determined pursuant to clause (a) immediately above, the actual amount of such Indebtedness that is recourse to such Person or a Restricted

Subsidiary of such Person, if the Indebtedness is evidenced by a writing and is for a determinable amount.

"*Interest Rate Agreement*" means, with respect to any Person any interest rate protection agreement, interest rate future agreement, interest rate option agreement, interest rate swap agreement, interest rate cap agreement, interest rate collar agreement, interest rate hedge agreement or other similar agreement or arrangement as to which such Person is party or a beneficiary.

"*Investment*" means, with respect to any Person, all investments by such Person in other Persons (including Affiliates) in the form of any direct or indirect advance, loan or other extension of credit (including by way of Guarantee or similar arrangement) or capital contribution to (by means of any transfer of cash or other property to others or any payment for property or services for the account or use of others), or any purchase or acquisition of Capital Stock, Indebtedness or other similar instruments issued by, such Person and all other items that are or would be classified as investments on a balance sheet prepared in accordance with GAAP.

For purposes of " Certain covenants Limitation on restricted payments,"

(1) "Investment" will include the portion (proportionate to the Company's equity interest in a Restricted Subsidiary to be designated as an Unrestricted Subsidiary) of the fair market value of the net assets of such Restricted Subsidiary at the time that such Restricted Subsidiary is designated an Unrestricted Subsidiary; *provided, however,* that upon a redesignation of such Subsidiary as a Restricted Subsidiary, the Company will be deemed to continue to have a permanent "Investment" in an Unrestricted Subsidiary in an amount (if positive) equal to (a) the Company's "Investment" in such Subsidiary at the time of such redesignation less (b) the portion (proportionate to the Company's equity interest in such Subsidiary) of the fair market value of the net assets (as conclusively determined by the Board of Directors of the Company in good faith) of such Subsidiary at the time that such Subsidiary is so re-designated a Restricted Subsidiary; and

(2) any property transferred to or from an Unrestricted Subsidiary will be valued at its fair market value at the time of such transfer, in each case as determined in good faith by the Board of Directors of the Company.

"*Investment Grade Rating*" means a rating equal to or higher than Baa3 (or the equivalent) by Moody's Investors Service, Inc. and BBB- (or the equivalent) by Standard & Poor's Ratings Group, Inc., in each case, with a stable or better outlook.

"*Issue Date*" means October 24, 2006.

"*Lien*" means any mortgage, pledge, security interest, encumbrance, lien or charge of any kind (including any conditional sale or other title retention agreement or lease in the nature thereof).

"*Minority Interest*" means the percentage interest represented by any shares of stock of any class of Capital Stock of a Restricted Subsidiary that are not owned by the Company or a Restricted Subsidiary.

"*Net Available Cash*" from an Asset Disposition means cash payments received (including any cash payments received by way of deferred payment of principal pursuant to a note or installment receivable or otherwise and net proceeds from the sale or other disposition of any securities received as consideration, but only as and when received, but excluding any other consideration received in the form of assumption by the acquiring Person of Indebtedness or other obligations relating to the properties or assets that are the subject of such Asset Disposition or received in any other non-cash form) therefrom, in each case net of:

(1) all legal, accounting, engineering, investment banking, brokerage, title and recording tax expenses, commissions and other fees and expenses Incurred, and all Federal, state, provincial, foreign and local taxes required to be paid or accrued as a liability under GAAP (after taking into account any available tax credits or deductions and any tax sharing agreements), as a consequence of such Asset Disposition, and any relocation expenses incurred or assumed in connection with such Asset Disposition;

(2) all payments made on any Indebtedness which is secured by any assets subject to such Asset Disposition, in accordance with the terms of any Lien upon such assets, or which must by its terms, or in order to obtain a necessary consent to such Asset Disposition, or, by applicable law, be repaid out of the proceeds from such Asset Disposition;

(3) all distributions and other payments required to be made to minority interest holders in Subsidiaries or Joint Ventures or to holders of royalty or similar interests as a result of such Asset Disposition; and

(4) the deduction of appropriate amounts to be provided by the seller as reserves, in accordance with GAAP, (A) for adjustment in respect of the sale price of the assets that were the subject of such Asset Disposition and (B) against any liabilities associated with the assets disposed of in such Asset Disposition and retained by the Company or any Restricted Subsidiary after such Asset Disposition.

"*Net Cash Proceeds*," with respect to any issuance or sale of Capital Stock, means the cash proceeds of such issuance or sale net of attorneys' fees, accountants' fees, underwriters' or placement agents' fees, listing fees, discounts or commissions and brokerage, consultant and other fees and charges actually Incurred in connection with such issuance or sale and net of taxes paid or payable as a result of such issuance or sale (after taking into account any available tax credit or deductions and any tax sharing arrangements).

"*Net Working Capital*" means (a) all current assets of the Company and its Restricted Subsidiaries except current assets constituting non-cash gains on Hedging Obligations resulting from the requirements of FAS 133 and similar provisions, less (b) all current liabilities of the Company and its Restricted Subsidiaries, except current liabilities included in Indebtedness and any current liabilities constituting any non-cash losses or charges on Hedging Obligations resulting from the requirements of FAS 133 and similar provisions, in each case as set forth in the consolidated financial statements of the Company prepared in accordance with GAAP.

"*Non-Guarantor Restricted Subsidiary*" means any Restricted Subsidiary that is not a Subsidiary Guarantor.

"*Non-Recourse Debt*" means Indebtedness of a Person:

(1) as to which neither the Company nor any Restricted Subsidiary (a) provides any Guarantee or credit support of any kind (including any undertaking, guarantee, indemnity, agreement or instrument that would constitute Indebtedness) or (b) is directly or indirectly liable (as a guarantor or otherwise); and

(2) no default with respect to which (including any rights that the holders thereof may have to take enforcement action against an Unrestricted Subsidiary) would permit (upon notice, lapse of time or both) any holder of any other Indebtedness of the Company or any Restricted Subsidiary to declare a default under such other Indebtedness or cause the payment thereof to be accelerated or payable prior to its Stated Maturity.

"*Officer*" means the Chairman of the Board, the Chief Executive Officer, the President, the Chief Financial Officer, any Vice President, the Treasurer or the Secretary of the Company. Officer of any Subsidiary Guarantor has a correlative meaning.

"*Officers' Certificate*" means a certificate signed by two Officers or by an Officer and either an Assistant Treasurer or an Assistant Secretary of the Company.

"*Oil and Gas Business*" means (a) the business of acquiring, exploring, exploiting, developing, producing, operating and disposing of interests in Hydrocarbons and Oil and Gas Properties, (b) the business of gathering, marketing, distributing, treating, processing, storing, refining, selling and transporting of Hydrocarbons and Oil and Gas Properties and products produced in association therewith, (c) other energy-related business, including the ownership and operation of co-generation facilities and steam and electrical transmission businesses, (d) any business relating to oil field sales and services including ownership and operation of drilling rigs, and (e) any business or activity relating to, arising from, or necessary, appropriate or incidental to, the activities described in the foregoing clauses of this definition.

"*Oil and Gas Properties*" means all properties, including equity or other ownership interests therein, owned by such Person which contain or are believed to contain oil and gas reserves.

"*Opinion of Counsel*" means a written opinion from legal counsel who is acceptable to the Trustee. The counsel may be an employee of or counsel to the Company or the Trustee.

"*Pari Passu Indebtedness*" means Indebtedness that ranks equally in right of payment to the Notes.

"*Permitted Business Investment*" means any Investment made in the ordinary course of, and of a nature that is or shall have become customary in, the Oil and Gas Business or any other Related Business including investments or expenditures for actively exploiting, exploring for, acquiring, developing, producing, operating, disposing of interests in, processing, gathering, marketing, distributing, treating, storing, refining, selling or transporting Hydrocarbons, Related Assets and Oil and Gas Properties through agreements, transactions, interests or arrangements which permit one to share risks or costs, comply with regulatory requirements regarding local ownership or satisfy other objectives customarily achieved through the conduct of such businesses jointly with third parties, including:

(1) ownership interests in Oil and Gas Properties, co-generation facilities, refineries, liquid natural gas facilities, processing facilities, gathering systems, pipelines or ancillary real property interests, either directly or through entities the primary business of which is to own or operate any of the foregoing; and

(2) entry into and Investments in the form of or pursuant to, operating agreements, working interests, royalty interests, mineral leases, processing agreements, farm-in agreements, farm-out agreements, contracts for the sale, transportation or exchange of oil and natural gas, production sharing agreements, development agreements, area of mutual interest agreements, unitization agreements, pooling arrangements, joint bidding agreements, service contracts, joint venture agreements, partnership agreements (whether general or limited), limited liability company agreements, subscription agreements, stock purchase agreements, stockholder agreements and other similar agreements with third parties (including Unrestricted Subsidiaries);

provided, however that a "Permitted Business Investment" shall only include Investments in entities that are classified as pass-through entities for U.S. federal, state and local and foreign income tax purposes.

"*Permitted Holders*" means William F. Berry and Winberta Holdings, Ltd. Any person or group whose acquisition of beneficial ownership constitutes a Change of Control in respect of which a Change of Control Offer is made in accordance with the requirements of the Indenture (or would result in a Change of Control Offer in the absence of the waiver of such requirement by holders in accordance with the Indenture) will thereafter constitute additional Permitted Holders.

"*Permitted Investment*" means an Investment by the Company or any Restricted Subsidiary in:

(1) the Company, a Restricted Subsidiary or a Person which will, upon the making of such Investment, become a Restricted Subsidiary; *provided, however*, that the primary business of such Restricted Subsidiary is a Related Business;

(2) another Person if as a result of such Investment such other Person is merged or consolidated with or into, or transfers or conveys all or substantially all its assets to, the Company or a Restricted Subsidiary; *provided, however*, that such Person's primary business is a Related Business;

(3) cash and Cash Equivalents;

(4) receivables owing to the Company or any Restricted Subsidiary created or acquired in the ordinary course of business and payable or dischargeable in accordance with customary trade terms; *provided, however*, that such trade terms may include such concessionary trade terms as the Company or any such Restricted Subsidiary deems reasonable under the circumstances;

(5) payroll, travel and similar advances to cover matters that are expected at the time of such advances ultimately to be treated as expenses for accounting purposes and that are made in the ordinary course of business;

(6) loans or advances to, and Guarantees of obligations of, employees, officers or directors of the Company or any Restricted Subsidiary in the ordinary course of business in an aggregate amount not in excess of $2.0 million with respect to all loans or advances made since the Issue Date (without giving effect to the forgiveness of any such loan); *provided, however,* that the Company and its Subsidiaries shall comply in all material respects with the provisions of the Sarbanes Oxley Act of 2002 and the rules and regulations promulgated in connection therewith relating to the provision of any such loans and advances as if the Company had filed a registration statement with the SEC;

(7) Capital Stock, obligations or securities received in settlement of debts created in the ordinary course of business and owing to the Company or any Restricted Subsidiary or in satisfaction of judgments or pursuant to any plan of reorganization or similar arrangement upon the bankruptcy or insolvency of a debtor;

(8) Investments made as a result of the receipt of non-cash consideration from an Asset Disposition or other disposition that was made pursuant to and in compliance with " Certain covenants Limitation on sales of assets and subsidiary stock;"

(9) Investments in existence on the Issue Date;

(10) Currency Agreements, Interest Rate Agreements, Commodity Agreements and related Hedging Obligations, which transactions or obligations are Incurred in compliance with " Certain covenants Limitation on indebtedness;"

(11) Investments by the Company or any of its Restricted Subsidiaries, together with all other Investments pursuant to this clause (11), in an aggregate amount at the time of such Investment not to exceed $10.0 million outstanding at any one time (with the fair market value of such Investment being measured at the time made and without giving effect to subsequent changes in value);

(12) Guarantees issued in accordance with " Certain covenants Limitations on indebtedness;"

(13) any Asset Swap made in accordance with " Certain covenants Limitation on sales of assets and subsidiary stock swaps;"

(14) Permitted Business Investments;

(15) Investments constituting prepaid expenses or advances or extensions of credit to customers or suppliers in the ordinary course of business;

(16) endorsements of negotiable instruments and documents in the ordinary course of business;

(17) acquisitions of assets, Capital Stock or other securities by the Company or a Subsidiary for consideration to the extent such consideration consists of Common Stock of the Company; *provided*, *however*, that the Qualified Proceeds from such sale of Capital Stock (to the extent so used) will be excluded from clause (c)(ii) of the covenant described under " Certain covenants Limitation on restricted payments;"

(18) Investments in the form of Capitalized Lease Obligations or mortgage or purchase money financing in an aggregate principal amount not to exceed $25.0 million at any time outstanding;

(19) Investments in the form of bank deposits (other than time deposits); and

(20) Investments in the form of other deposits made in the ordinary course of business and constituting Permitted Liens.

"*Permitted Liens*" means, with respect to any Person:

(1) Liens securing Indebtedness and other obligations under the Senior Credit Facility and related Hedging Obligations and other Senior Indebtedness and liens on assets of Restricted Subsidiaries securing Guarantees of Indebtedness and other obligations under a Credit Facility and other Guarantor Senior Indebtedness permitted to be Incurred under the Indenture;

(2) pledges or deposits by such Person under workers' compensation laws, unemployment insurance laws or similar legislation, or good faith deposits in connection with bids, tenders or contracts (including leases but excluding contracts for the payment of Indebtedness) to which such Person is a party, or deposits to secure public or statutory obligations of such Person or deposits of cash or United States government bonds to secure surety or appeal bonds to which such Person is a party, or deposits as security for contested taxes or import or customs duties or for the payment of rent, in each case Incurred in the ordinary course of business;

(3) Liens imposed by law, including carriers', warehousemen's, mechanics', materialmen's and repairmen's Liens, or related contracts in the ordinary course of business, in each case for sums not yet due or being contested in good faith by appropriate proceedings if a reserve or other appropriate provisions, if any, as shall be required by GAAP shall have been made in respect thereof;

(4) Liens for taxes, assessments or other governmental charges not yet subject to penalties for non-payment or which are being contested in good faith by appropriate proceedings provided appropriate reserves required pursuant to GAAP have been made in respect thereof;

(5) Liens in favor of issuers of surety or performance bonds or letters of credit or bankers' acceptances issued pursuant to the request of and for the account of such Person in the ordinary course of its business; *provided*, *however*, that such letters of credit do not constitute Indebtedness;

(6) encumbrances, ground leases, easements or reservations of, or rights of others for, licenses, rights of way, sewers, electric lines, telegraph and telephone lines and other similar purposes, or zoning, building codes or other restrictions (including, without limitation, minor defects or irregularities in title and similar encumbrances) as to the use of real properties or liens incidental to the conduct of the business of such Person or to the ownership of its properties which do not in the aggregate materially adversely affect the value of said properties or materially impair their use in the operation of the business of such Person;

(7) Liens securing Hedging Obligations permitted under the Indenture;

(8) leases, licenses, subleases and sublicenses of assets (including, without limitation, real property and intellectual property rights) which do not materially interfere with the ordinary conduct of the business of the Company or any of its Restricted Subsidiaries;

(9) judgment Liens not giving rise to an Event of Default so long as such Lien is adequately bonded and any appropriate legal proceedings which may have been duly initiated for the review of such judgment have not been finally terminated or the period within which such proceedings may be initiated has not expired;

(10) Liens for the purpose of securing Indebtedness represented by Capitalized Lease Obligations, mortgage financings, purchase money obligations or other payments Incurred to finance all or any part of the purchase price or cost of construction or improvement of assets or property (other than Capital Stock or other Investments) acquired, constructed or improved by such Person; *provided* that:

(a) the aggregate principal amount of Indebtedness secured by such Liens is otherwise permitted to be Incurred under the Indenture and does not exceed the cost of the assets or property so acquired, constructed or improved; and

(b) such Liens are created within 180 days of construction, acquisition or improvement of such assets or property and do not encumber any other assets or property of such Person other than such assets or property and assets affixed or appurtenant thereto and proceeds thereof;

(11) Liens arising solely by virtue of any statutory or common law provisions relating to banker's Liens, rights of set-off or similar rights or related contracts in the ordinary course of business and remedies as to deposit accounts or other funds maintained with a depositary institution; *provided* that:

(a) such deposit account is not a dedicated cash collateral account and is not subject to restrictions against access by such Person in excess of those set forth by regulations promulgated by the Federal Reserve Board; and

(b) such deposit account is not intended by such Person to provide collateral to the depository institution;

(12) Liens arising from Uniform Commercial Code financing statement filings regarding operating leases entered into by such Person in the ordinary course of business;

(13) Liens existing on the Issue Date (other than Liens permitted under clause (1));

(14) Liens on property or Capital Stock of a Person at the time such Person becomes a Restricted Subsidiary, or is merged with or into or consolidated with or acquired by, the Company or a Restricted Subsidiary; *provided, however*, that such Liens are not created, Incurred or assumed in connection with, or in contemplation of, such event; *provided further, however,* that any such Lien may not extend to any other property owned by the Company or any Restricted Subsidiary other than improvements, additions and accessions to such property, dividends and distributions in respect of such property and proceeds of any of the foregoing;

(15) Liens on property at the time the Company or a Restricted Subsidiary acquired the property, including any acquisition by means of a merger or consolidation with or into the Company or any Restricted Subsidiary; *provided, however*, that such Liens are not created, Incurred or assumed in connection with, or in contemplation of, such acquisition; *provided further, however*, that such Liens may not extend to any other property owned by the Company or any Restricted Subsidiary other than

improvements, additions and accessions to such property, dividends and distributions in respect of such property and proceeds of any of the foregoing;

(16) Liens in favor of the Company or a Restricted Subsidiary;

(17) Liens securing the Notes and Subsidiary Guarantees;

(18) Liens securing Refinancing Indebtedness Incurred to refinance, refund, replace, amend, extend or modify, as a whole or in part, Indebtedness that was previously so secured pursuant to clauses (9), (10), (13), (14), (15), (17) and (18) of this definition, provided that any such Lien is limited to all or part of the same property or assets (plus improvements, additions, accessions, proceeds, dividends and distributions in respect thereof) that secured (or, under the written arrangements under which the original Lien arose, could secure) the Indebtedness being refinanced or is in respect of property that is the security for a Permitted Lien hereunder;

(19) any interest or title of a lessor under any Capitalized Lease Obligation or operating lease;

(20) Liens under industrial revenue, municipal or similar bonds;

(21) Liens in respect of Production Payments and Reserve Sales, which Liens shall be limited to the property that is the subject of such Production Payments and Reserve Sales and proceeds thereof;

(22) Liens arising under farm-out agreements, farm-in agreements, division orders, mineral leases, partnership agreements, joint venture agreements, contracts for the sale, purchase, exchange, transportation, gathering or processing of Hydrocarbons and Related Assets, unitizations and pooling designations, declarations, orders and agreements, development agreements, operating agreements, production sales contracts, area of mutual interest agreements, gas balancing or deferred production agreements, injection, repressuring and recycling agreements, salt water or other disposal agreements, seismic or geophysical permits or agreements, and other agreements which are customary in any Related Business; *provided, however*, in all instances that such Liens are limited to the assets that are the subject of the relevant agreement, program, order or contract and improvements, additions and accessions thereto, and proceeds of any of the foregoing;

(23) Liens on pipelines or pipeline facilities that arise by operation of law;

(24) Liens encumbering assets under construction (and improvements, additions and accessions thereto and proceeds of any of the foregoing) arising from progress or partial payments by a customer of the Company or its Restricted Subsidiaries relating to such assets;

(25) Liens arising under the Indenture in favor of the Trustee for its own benefit and similar Liens in favor of other trustees, agents and representatives arising under instruments governing Indebtedness permitted to be incurred under the Indenture, *provided*, that such Liens are solely for the benefit of the trustees, agents, or representatives in their capacities as such and not for the benefit of the holders of such Indebtedness;

(26) Liens arising from the deposit of funds or securities in trust for the purpose of decreasing or defeasing Indebtedness so long as such deposit of funds or securities and

such decreasing or defeasing of Indebtedness are permitted under the covenant described under "Certain Covenants Limitation on restricted payments;" and

(27) Liens securing Indebtedness (other than Subordinated Obligations and Guarantor Subordinated Obligations) and other unsubordinated obligations in an aggregate amount outstanding at any one time not to exceed $15.0 million.

"*Person*" means any individual, corporation, partnership, joint venture, association, joint-stock company, trust, unincorporated organization, limited liability company, government or any agency or political subdivision hereof or any other entity.

"*Preferred Stock*," as applied to the Capital Stock of any corporation, means Capital Stock of any class or classes (however designated) which is preferred as to the payment of dividends, or as to the distribution of assets upon any voluntary or involuntary liquidation or dissolution of such corporation, over shares of Capital Stock of any other class of such corporation.

"*Production Payments and Reserve Sales*" means the grant or transfer by the Company or a Restricted Subsidiary to any Person of a royalty, overriding royalty, net profits interest, production payment (including Volumetric Production Payments and Dollar-Denominated Production Payments), partnership or other interest in oil and gas properties, reserves or the right to receive all or a portion of the production or the proceeds from the sale of production attributable to such properties where the holder of such interest has recourse solely to such production or proceeds of production, subject to the obligation of the grantor or transferor to operate and maintain, or cause the subject interests to be operated and maintained, in a reasonably prudent manner or other customary standard or subject to the obligation of the grantor or transferor to indemnify for environmental, title or other matters customary in the Oil and Gas Business, including any such grants or transfers pursuant to incentive compensation programs on terms that are reasonably customary in the Oil and Gas Business for geologists, geophysicists or other providers of technical services to the Company or a Restricted Subsidiary.

"*Qualified Proceeds*" means any of the following or any combination thereof: (1) Net Cash Proceeds, (2) Cash Equivalents, (3) assets that are used or useful in a Related Business and (4) the Capital Stock of any Person engaged in a Related Business that becomes a Restricted Subsidiary of the Company or merges with or into the Company or a Restricted Subsidiary of the Company.

"*Rating Agencies*" means Standard & Poor's Ratings Group, Inc. and Moody's Investors Service, Inc. or if Standard & Poor's Ratings Group, Inc. or Moody's Investors Service, Inc. or both shall not make a rating on the Notes publicly available, a nationally recognized statistical rating agency or agencies, as the case may be, selected by the Company (as certified by a resolution of the Board of Directors) which shall be substituted for Standard & Poor's Ratings Group, Inc. or Moody's Investors Service, Inc. or both, as the case may be.

"*Receivable*" means a right to receive payment arising from a sale or lease of goods or the performance of services by a Person pursuant to an arrangement with another Person pursuant to which such other Person is obligated to pay for goods or services under terms that permit the purchase of such goods and services on credit and shall include, in any event, any items of property that would be classified as an "account," "chattel paper," "payment intangible" or "instrument" under the Uniform Commercial Code as in effect in the State of New York and any "supporting obligations" as so defined.

"*Receivables Fees*" means any fees or interest paid to purchasers or lenders providing the financing in connection with a securitization transaction, factoring agreement or other similar agreement, including any such amounts paid by discounting the face amount of Receivables or participations therein transferred in connection with a securitization transaction, factoring agreement or other similar arrangement, regardless of whether any such transaction is structured as on-balance sheet or off-balance sheet or through a Restricted Subsidiary or an Unrestricted Subsidiary.

"*Refinancing Indebtedness*" means Indebtedness that is Incurred to refund, refinance, replace, exchange, renew, repay or extend (including pursuant to any defeasance or discharge mechanism) (collectively, "*refinance*"; "*refinances*" and "*refinanced*" shall each have a correlative meaning) any Indebtedness existing on the Issue Date or Incurred in compliance with the Indenture (including Indebtedness of the Company that refinances Indebtedness of any Restricted Subsidiary and Indebtedness of any Restricted Subsidiary that refinances Indebtedness of another Restricted Subsidiary) including Indebtedness that refinances Refinancing Indebtedness, *provided, however,* that:

(1) (a) if the Stated Maturity of the Indebtedness being refinanced is earlier than the Stated Maturity of the Notes, the Refinancing Indebtedness has a Stated Maturity no earlier than the Stated Maturity of the Indebtedness being refinanced or (b) if the Stated Maturity of the Indebtedness being refinanced is later than the Stated Maturity of the Notes, the Refinancing Indebtedness has a Stated Maturity at least 91 days later than the Stated Maturity of the Notes;

(2) the Refinancing Indebtedness has an Average Life at the time such Refinancing Indebtedness is Incurred that is equal to or greater than the Average Life of the Indebtedness being refinanced;

(3) such Refinancing Indebtedness is Incurred in an aggregate principal amount (or if issued with original issue discount, an aggregate issue price) that is equal to or less than the sum of the aggregate principal amount (or if issued with original issue discount, the aggregate accreted value) then outstanding of the Indebtedness being refinanced (plus, without duplication, any additional Indebtedness Incurred to pay interest or premiums required by the instruments governing such existing Indebtedness and costs and fees Incurred in connection therewith); and

(4) if the Indebtedness being refinanced is subordinated in right of payment to the Notes or the Subsidiary Guarantee, such Refinancing Indebtedness is subordinated in right of payment to the Notes or the Subsidiary Guarantee on terms at least as favorable to the holders as those contained in the documentation governing the Indebtedness being refinanced.

"*Related Assets*" means steam, electricity, by-products of the utilization of Hydrocarbons, products produced in association with Hydrocarbons, minerals, and other assets commonly created, recovered or produced in the course of the conduct of any Related Business.

"*Related Business*" means (1) any business which is the same as or related, ancillary or complementary to any of the businesses of the Company and its Restricted Subsidiaries on the Issue Date, (2) the Oil and Gas Business and (3) the business of acquiring, exploiting, developing, producing, operating, gathering, marketing, treating, processing, storing, refining, selling and transporting Related Assets.

"*Representative*" means any trustee, agent or representative (if any) of an issue of Senior Indebtedness; *provided* that when used in connection with the Senior Credit Facility, the term "Representative" shall refer to the administrative agent under the Senior Credit Facility.

"*Restricted Investment*" means any Investment other than a Permitted Investment.

"*Restricted Subsidiary*" means any Subsidiary of the Company other than an Unrestricted Subsidiary.

"*Sale/Leaseback Transaction*" means an arrangement relating to property now owned or hereafter acquired whereby the Company or a Restricted Subsidiary transfers such property to a Person and the Company or a Restricted Subsidiary leases it from such Person.

"*SEC*" means the United States Securities and Exchange Commission.

"*Securities Act*" means the Securities Act of 1933, as amended, and the rules and regulations of the SEC promulgated thereunder.

"*Senior Credit Facility*" means the Credit Agreement dated as of April 28, 2006 among the Company, Wells Fargo Bank, National Association, as Administrative Agent, and the lenders parties thereto from time to time, as the same may be amended, restated, modified, renewed, refunded, replaced or refinanced in whole or in part from time to time, with the same or different agents or lenders (including increasing the amount loaned or the aggregate commitments of the lenders thereunder, *provided* that such additional Indebtedness is Incurred in accordance with the covenant described under " Certain covenants Limitation on indebtedness"); *provided* that a Senior Credit Facility shall not (1) include Indebtedness issued, created or Incurred pursuant to a registered offering of securities under the Securities Act or a private placement of securities (including under Rule 144A or Regulation S) pursuant to an exemption from the registration requirements of the Securities Act or (2) relate to Indebtedness that does not consist exclusively of Senior Indebtedness or Guarantor Senior Indebtedness.

"*Senior Indebtedness*" means, whether outstanding on the Issue Date or thereafter issued, created, Incurred or assumed, the Bank Indebtedness and all amounts payable by the Company under or in respect of all other Indebtedness of the Company, including premiums and accrued and unpaid interest (including interest accruing on or after the filing of any petition in bankruptcy or for reorganization relating to the Company at the rate specified in the documentation with respect thereto whether or not a claim for post filing interest is allowed in such proceeding) and fees relating thereto; *provided, however,* that Senior Indebtedness will not include:

(1) any Indebtedness Incurred in violation of the Indenture;

(2) any obligation of the Company to any Subsidiary;

(3) any liability for Federal, state, foreign, local or other taxes owed or owing by the Company;

(4) any accounts payable or other liability to trade creditors arising in the ordinary course of business (including Guarantees thereof or instruments evidencing such liabilities);

(5) any Indebtedness, Guarantee or obligation of the Company that is expressly subordinate or junior in right of payment to any other Indebtedness, Guarantee or obligation of the Company, including, without limitation, any Senior Subordinated Indebtedness and any Subordinated Obligations; or

(6) any Capital Stock.

"*Senior Subordinated Indebtedness*" means the Notes and any other Indebtedness of the Company that ranks equally with the Notes in right of payment and is not subordinated by its terms in right of payment to any Indebtedness or other obligation of the Company which is not Senior Indebtedness.

"*Significant Subsidiary*" means any Restricted Subsidiary that would be a "Significant Subsidiary" of the Company within the meaning of Rule 1-02 under Regulation S-X promulgated by the SEC.

"*Stated Maturity*" means, with respect to any security, the date specified in such security as the fixed date on which the payment of principal of such security is due and payable, including pursuant to any mandatory redemption provision, but shall not include any contingent obligations to repay, redeem or repurchase any such principal prior to the date originally scheduled for the payment thereof.

"*Subordinated Obligation*" means any Indebtedness of the Company (whether outstanding on the Issue Date or thereafter Incurred) which is subordinated in right of payment to the Notes pursuant to a written agreement.

"*Subsidiary*" of any Person means (a) any corporation or other business entity (other than a legal partnership, limited liability company or similar entity) of which more than 50% of the total ordinary voting power of shares of Capital Stock entitled (without regard to the occurrence of any contingency) to vote in the election of directors, managers or trustees thereof (or persons performing similar functions) or (b) any legal partnership, limited liability company or similar entity of which more than 50% of the capital accounts, distribution rights, total equity and voting interests or general or limited partnership interests, as applicable, is, in the case of clauses (a) and (b), at the time owned or controlled, directly or indirectly, by (1) such Person, (2) such Person and one or more Subsidiaries of such Person or (3) one or more Subsidiaries of such Person. Unless otherwise specified herein, each reference to a Subsidiary will refer to a Subsidiary of the Company.

"*Subsidiary Guarantee*" means, individually, any Guarantee of payment of the Notes by a Subsidiary Guarantor pursuant to the terms of the Indenture and any supplemental indenture thereto, and, collectively, all such Guarantees. Each such Subsidiary Guarantee will be in the form prescribed by the Indenture.

"*Subsidiary Guarantor*" means any Restricted Subsidiary that provides a Subsidiary Guarantee after the Issue Date in accordance with the Indenture; *provided* that upon release or discharge of such Restricted Subsidiary from its Subsidiary Guarantee in accordance with the Indenture, such Restricted Subsidiary ceases to be a Subsidiary Guarantor.

"*Unrestricted Subsidiary*" means:

(1) any Subsidiary of the Company that at the time of determination shall be designated an Unrestricted Subsidiary by the Board of Directors of the Company in the manner provided below; and

(2) any Subsidiary of an Unrestricted Subsidiary.

The Board of Directors of the Company may designate any Subsidiary of the Company (including any newly acquired or newly formed Subsidiary or a Person becoming a Subsidiary through merger or consolidation or Investment therein) to be an Unrestricted Subsidiary only if:

(1) such Subsidiary and its Subsidiaries do not own any Capital Stock or Indebtedness of or have any Investment in, or own or hold any Lien on any property of, any other Subsidiary of the Company which is not a Subsidiary of the Subsidiary to be so designated or otherwise an Unrestricted Subsidiary;

(2) all the Indebtedness of such Subsidiary and its Subsidiaries shall, at the date of designation, and will at all times thereafter, consist of Non-Recourse Debt;

(3) such designation and the Investment of the Company in such Subsidiary complies with " Certain covenants Limitation on restricted payments;"

(4) such Subsidiary, either alone or in the aggregate with all other Unrestricted Subsidiaries, does not operate, directly or indirectly, all or substantially all of the business of the Company and its Subsidiaries;

(5) such Subsidiary is a Person with respect to which neither the Company nor any of its Restricted Subsidiaries has any direct or indirect obligation:

(a) to subscribe for additional Capital Stock of such Person; or

(b) to maintain or preserve such Person's financial condition or to cause such Person to achieve any specified levels of operating results; and

(6) on the date such Subsidiary is designated an Unrestricted Subsidiary, such Subsidiary is not a party to any agreement, contract, arrangement or understanding with the Company or any Restricted Subsidiary with terms substantially less favorable to the Company than those that might have been obtained from Persons who are not Affiliates of the Company.

Any such designation by the Board of Directors of the Company shall be evidenced to the Trustee by filing with the Trustee a resolution of the Board of Directors of the Company giving effect to such designation and an Officers' Certificate certifying that such designation complies with the foregoing conditions. If, at any time, any Unrestricted Subsidiary would fail to meet the foregoing requirements as an Unrestricted Subsidiary, it shall thereafter cease to be an Unrestricted Subsidiary for purposes of the Indenture and any Indebtedness of such Subsidiary shall be deemed to be Incurred as of such date.

The Board of Directors of the Company may designate any Unrestricted Subsidiary to be a Restricted Subsidiary; *provided* that immediately after giving effect to such designation, no Default or Event of Default shall have occurred and be continuing or would occur as a consequence thereof and the Company could Incur at least $1.00 of additional Indebtedness pursuant to the first paragraph of the " Certain covenants Limitation on indebtedness" covenant on a pro forma basis taking into account such designation.

"*U.S. Government Obligations*" means securities that are (a) direct obligations of the United States of America for the timely payment of which its full faith and credit is pledged or (b) obligations of a Person controlled or supervised by and acting as an agency or instrumentality of the United States of America the timely payment of which is unconditionally guaranteed as a full faith and credit obligation of the United States of America, which, in either case, are not callable or redeemable at the option of the issuer thereof, and shall also include a depositary receipt issued by a bank (as defined in Section 3(a)(2) of the Securities Act), as custodian with respect to any such U.S. Government Obligations or a specific payment of principal of or interest on any such U.S. Government Obligations held by such custodian for the account of the holder of such depositary receipt; *provided*that (except as required by law) such custodian is not authorized to make any deduction from the amount payable to the holder of such depositary receipt from any amount received by the custodian in respect of the U.S. Government Obligations or the specific payment of principal of or interest on the U.S. Government Obligations evidenced by such depositary receipt.

"*Volumetric Production Payments*" means production payment obligations recorded as deferred revenue in accordance with GAAP, together with all undertakings and obligations in connection therewith.

"*Voting Stock*" of a Person means all classes of Capital Stock of such Person then outstanding and normally entitled to vote in the election of directors, managers or trustees, as applicable.

"*Wholly Owned Subsidiary*" means a Restricted Subsidiary, all of the Capital Stock of which (other than Foreign Required Minority Shares) is owned by the Company or another Wholly Owned Subsidiary.

Material U.S. federal income tax consequences to non-U.S. holders

General

The following is a summary of the material U.S. federal income and estate tax considerations relating to the purchase, ownership and disposition of the notes by initial non-U.S. holders. It is not a complete analysis of all the potential tax considerations relating to the notes. This summary is based upon the provisions of the Internal Revenue Code of 1986, as amended, or the Code, Treasury regulations promulgated under the Code, and currently effective administrative rulings and judicial decisions. These authorities may be changed, perhaps with retroactive effect, so as to result in U.S. federal income tax consequences different from those set forth below. We have not sought any ruling from the Internal Revenue Service, or I.R.S., or an opinion of counsel with respect to the statements made herein concerning the notes, and we cannot assure you that the I.R.S will agree with such statements. This summary does not address the tax considerations arising under the laws of any foreign, state or local jurisdiction.

This summary assumes that the notes are held as capital assets by a non-U.S. holder who acquires the notes upon their original issuance pursuant to this prospectus at the notes' initial offering price.

A "non-U.S. holder" means a holder of the notes (other than a partnership) that is not for U.S. federal income tax purposes any of the following:

- an individual citizen or resident of the United States;
- a corporation (or any other entity treated as a corporation for U.S. federal income tax purposes) created or organized in or under the laws of the United States, any state thereof or the District of Columbia;
- an estate the income of which is subject to U.S. federal income taxation regardless of its source; or
- a trust if it (1) is subject to the primary supervision of a court within the United States and one or more United States persons have the authority to control all substantial decisions of the trust or (2) has a valid election in effect under applicable United States Treasury regulations to be treated as a United States person.

This summary of material U.S. federal income and estate tax considerations is for general information only and is not tax advice. You are urged to consult your tax advisor with respect to the application of U.S. federal income and estate tax laws to your particular situation, as well as any tax consequences arising under the U.S. federal gift tax rules or under the laws of any state, local, foreign or other taxing jurisdiction or under any applicable tax treaty. In addition, this summary does not represent a detailed description of the U.S. federal income and estate tax consequences applicable to you if you are subject to special treatment under the U.S. federal income tax laws (including if you are a United States expatriate, "controlled foreign corporation," "passive foreign investment company" or a partnership or other pass-through entity for U.S. federal income tax purposes). We cannot assure you that a change in law will not alter significantly the tax considerations that we describe in this summary.

If a partnership holds the notes, the tax treatment of a partner will generally depend upon the status of the partner and the activities of the partnership. If you are a partner of a partnership holding our notes, you should consult your tax advisors.

Payments of interest

The 30% U.S. federal withholding tax (or lower applicable treaty rate) generally will not apply to any payment to a non-U.S. holder of interest on a note that is not effectively connected with a U.S. trade or business provided that:

- the non-U.S. holder does not actually or constructively (under applicable attribution rules) own 10% or more of the total combined voting power of our voting stock, within the meaning of Section 871(h)(3) of the Code and applicable Treasury regulations;

- the non-U.S. holder is not a controlled foreign corporation that is related to us directly or indirectly through stock ownership;

- the non-U.S. holder is not a bank whose receipt of interest on the notes is described in Section 881(c)(3)(A) of the Code; and

- (a) the non-U.S. holder provides its name and address, and certifies, under penalties of perjury, that it is not a United States person (which certification may be made on an I.R.S. Form W-8BEN) or (b) a securities clearing organization, bank, or other financial institution that holds customers' securities in the ordinary course of its business holds the note on a non-U.S. holder's behalf and certifies, under penalties of perjury, either that it has received I.R.S. Form W-8BEN from the holder or from another qualifying financial institution intermediary or that it is permitted to establish and has established the holder's foreign status through other documentary evidence, and otherwise complies with applicable requirements. If the notes are held by or through certain foreign intermediaries or certain foreign partnerships, such foreign intermediaries or partnerships must also satisfy the certification requirements of applicable Treasury regulations.

If a non-U.S. holder cannot satisfy the requirements described above, payments of interest will be subject to the 30% U.S. federal withholding tax, unless the holder provides us with a properly executed (1) I.R.S. Form W-8BEN (or other applicable form) claiming an exemption from or reduction in withholding under an applicable tax treaty or (2) I.R.S. Form W-8ECI (or other applicable form) stating that interest paid on the note is not subject to withholding tax because it is effectively connected with the holder's conduct of a trade or business in the United States.

If a non-U.S. holder is engaged in a trade or business in the United States and interest on a note is effectively connected with the conduct of that trade or business (and, if required by an applicable income tax treaty, is attributable to a U.S. permanent establishment), it will instead be required to pay U.S. federal income tax on that interest on a net income basis in the same manner as if the holder were a U.S. holder. In addition, if a non-U.S. holder is a foreign corporation, it may be subject to a branch profits tax equal to 30% (or lower applicable treaty rate) of its earnings and profits for the taxable year, subject to adjustments, that are effectively connected with its conduct of a trade or business in the United States. For this purpose, interest on the notes which is effectively connected with your conduct of a trade or business in the United States would be included in your earnings and profits.

Disposition of notes

Any gain recognized upon the sale, exchange, redemption or other taxable disposition of a note (except with respect to accrued and unpaid interest, which would be taxable as such) will not be subject to the 30% U.S. federal withholding tax. Such gain also generally will not be subject to U.S. federal income tax unless:

- that gain is effectively connected with a non-U.S. holder's conduct of a trade or business in the United States; or

- the non-U.S. holder is an individual who is present in the United States for 183 days or more in the taxable year of the disposition, and certain other conditions are met.

A non-U.S. holder described in the first bullet point above will generally be required to pay U.S. federal income tax on the net gain derived from the sale, except as otherwise required by an applicable tax treaty, and if such holder is a foreign corporation, it may also be required to pay a branch profits tax at a 30% rate, or a lower rate if so specified by an applicable tax treaty.

U.S. Federal Estate Tax

The estate of a non-U.S. holder will not be subject to U.S. federal estate tax on notes beneficially owned by the holder at the time of death, provided that any payment to the holder on the notes would be eligible for exemption from the 30% U.S. federal withholding tax described above under " Payments of interest" without regard to the statement requirement described in the fourth bullet point of that section.

Information reporting and backup withholding

In general, we must report to the I.R.S. and to each non-U.S. holder the amount of interest on the notes paid to such non-U.S. holder and the amount of tax, if any, withheld with respect to those payments. Copies of the information returns reporting such interest payments and any withholding may also be made available to the tax authorities in the country in which the non-U.S. holder resides under the provisions of an applicable tax treaty. Backup withholding may apply to certain payments of principal, premium (if any) and interest on the notes to non-U.S. holders, as well as to the proceeds of certain sales of notes made through brokers, unless the holder has made appropriate certifications as to its foreign status, or has otherwise established an exemption. The certification of foreign status described above in the fourth bullet point under " Payments of interest" is generally effective to establish an exemption from backup withholding, provided that we do not have actual knowledge or reason to know that you are a United States person.

Any amounts withheld under the backup withholding rules will generally be allowed as a refund or a credit against a non-U.S. holder's U.S. federal income tax liability provided that it furnishes the required information to the I.R.S. on a timely basis.

Certain ERISA considerations

The following is a summary of certain considerations associated with the purchase of the notes by employee benefit plans that are subject to Title I of the U.S. Employee Retirement Income Security Act of 1974, as amended ("ERISA"), plans, individual retirement accounts and other arrangements that are subject to Section 4975 of the Code or provisions under any federal, state, local, non-U.S. or other laws or regulations that are similar to such provisions of the Code or ERISA (collectively, "Similar Laws"), and entities whose underlying assets are considered to include "plan assets" of such plans, accounts and arrangements (each, a "Plan").

General fiduciary matters

ERISA and the Code impose certain duties on persons who are fiduciaries of a Plan subject to Title I of ERISA or Section 4975 of the Code (an "ERISA Plan") and prohibit certain transactions involving the assets of an ERISA Plan and its fiduciaries or other interested parties. Under ERISA and the Code, any person who exercises any discretionary authority or control over the administration of such an ERISA Plan, or who renders investment advice for a fee or other compensation to such an ERISA Plan, is generally considered to be a fiduciary of the ERISA Plan. In considering an investment in the notes of a portion of the assets of any Plan, a fiduciary should determine whether the investment is in accordance with the documents and instruments governing the Plan and the applicable provisions of ERISA, the Code or any Similar Law relating to a fiduciary's duties to the Plan including, without limitation, the prudence, diversification, delegation of control and prohibited transaction provisions of ERISA, the Code and any other applicable Similar Laws.

Prohibited transaction issues

Section 406 of ERISA and Section 4975 of the code prohibit ERISA Plans from engaging in specified transactions involving plan assets with persons or entities who are "parties in interest," within the meaning of ERISA, or "disqualified persons," within the meaning of Section 4975 of the Code, unless an exemption is available. A party in interest or disqualified person who engaged in a non-exempt prohibited transaction may be subject to excise taxes and other penalties and liabilities under ERISA and the Code. In addition, the fiduciary of the ERISA Plan that engaged in such a non-exempt prohibited transaction may be subject to penalties and liabilities under ERISA and the Code. The acquisition and/or holding of the notes by an ERISA Plan with respect to which any of Berry Petroleum Company or the initial purchasers is considered a party in interest or a disqualified person may constitute or result in a direct or indirect prohibited transaction under Section 406 of ERISA and/or Section 4975 of the Code, unless the investment is acquired and is held in accordance with an applicable statutory, class or individual prohibited transaction class exemption. In this regard, the U.S. Department of Labor has issued prohibited transaction class exemptions, or "PTCEs," that may apply to the acquisition and holding of the notes. These class exemptions include, without limitation, PTCE 84-14 respecting transactions determined by independent qualified professional asset managers, PTCE 90-1 respecting insurance company pooled separate accounts, PTCE 91-38 respecting bank collective investment funds, PTCE 95-60 respecting life insurance company general accounts and PTCE 96-23 respecting transactions determined by in house asset managers, although there can be no assurance that all of the conditions of any such exemptions will be satisfied. Because of the foregoing, the notes should not be purchased or held by a person investing "plan assets" of any Plan, unless such purchase and holding will not constitute a non-exempt prohibited transaction under ERISA and the Code or similar violation of any applicable Similar Laws.

Representation

Accordingly, by acceptance of a note, each purchaser and subsequent transferee of a note will be deemed to have represented and warranted that either (i) no portion of the assets used by such purchaser or transferee to acquire and hold the notes constitutes assets of any Plan or (ii) the purchase and holding of the notes by such purchaser or transferee will not constitute a non-exempt prohibited transaction under Section 406 of ERISA or Section 4975 of the Code or similar violation under any applicable Similar Laws.

The foregoing discussion is general in nature and is not intended to be all-inclusive. Due to the complexity of these rules and the penalties that may be imposed upon persons involved in non-exempt prohibited transactions, it is particularly important that fiduciaries, or other persons considering purchasing the notes on behalf of, or with the assets of, any Plan, consult with their counsel regarding the potential applicability of ERISA, Section 4975 of the Code and any Similar Laws to such investment and whether an exemption would be applicable to the purchase and holding of the notes.

Underwriting

Subject to the terms and conditions in the underwriting agreement between us and the underwriters, we have agreed to sell to each underwriter, and each underwriter has severally agreed to purchase from us, the principal amount of notes that appears opposite its name in the table below:

Underwriter		Principal amount
J.P. Morgan Securities Inc.	$	90,000,000
Citigroup Global Markets Inc.		28,000,000
Wells Fargo Securities, LLC		28,000,000
Goldman, Sachs & Co.		16,000,000
SG Americas Securities, LLC		12,000,000
BNP Paribas Securities Corp.		12,000,000
Wedbush Morgan Securities Inc.		3,500,000
Comerica Securities, Inc.		3,500,000
Piper Jaffray & Co.		3,500,000
First Albany Capital Inc.		3,500,000
Total	$	200,000,000

The underwriters have agreed to purchase all of the notes if any of them are purchased.

The underwriters initially propose to offer the notes to the public at the public offering price that appears on the cover page of this prospectus. The underwriters may offer the notes to selected dealers at the public offering price minus a concession of up to 0.25% of the principal amount. In addition, the underwriters may allow, and those selected dealers may reallow, a concession of up to 0.25% of the principal amount to certain other dealers. After the initial offering, the underwriters may change the public offering price and any other selling terms. The underwriters may offer and sell notes through certain of their affiliates.

In the underwriting agreement, we have agreed that:

- We will not offer or sell any of our debt securities (other than the notes) for a period of 90 days after the date of this prospectus supplement without the prior consent of J.P. Morgan Securities, Inc.

- We will indemnify the underwriters against certain liabilities, including liabilities under the Securities Act of 1933, or contribute to payments that the underwriters may be required to make in respect of those liabilities.

The notes are new issues of securities with no established trading market. We do not intend to apply for the notes to be listed on any securities exchange or to arrange for the notes to be quoted on any quotation system. The underwriters have advised us that they intend to make a market in the notes. However, they are not obligated to do so and they may discontinue any market making at any time in their sole discretion. Therefore, we cannot assure you that a liquid trading market will develop for the notes, that you will be able to sell your notes at a particular time or that the prices that you receive when you sell will be favorable.

With effect from and including the date on which the Prospectus Directive is implemented in that Relevant Member State (the Relevant Implementation Date), each underwriter has not made and will not make an offer of notes to the public in that Relevant Member State prior to the publication of a prospectus in relation to the notes which has been approved by the competent authority in that Relevant Member State or, where appropriate, approved in another Relevant Member State and notified to the competent authority in that Relevant Member State, all in accordance with the Prospectus Directive, except that it may, with effect from and including the Relevant Implementation Date, make an offer of notes to the public in that Relevant Member State at any time:

to legal entities which are authorized or regulated to operate in the financial markets or, if not so authorized or regulated, whose corporate purpose is solely to invest in securities;

to any legal entity which has two or more of (1) an average of at least 250 employees during the last financial year; (2) a total balance sheet of more than €43,000,000 and (3) an annual net turnover of more than €50,000,000, as shown in its last annual or consolidated accounts; or

in any other circumstances which do not require the publication by us of a prospectus pursuant to Article 3 of the Prospectus Directive.

For the purposes of this provision, the expression an "offer of notes to the public" in relation to any notes in any Relevant Member State means the communication in any form and by any means of sufficient information on the terms of the offer and the notes to be offered so as to enable an investor to decide to purchase or subscribe the notes, as the same may be varied in that Member State by any measure implementing the Prospectus Directive in that Member State and the expression Prospectus Directive means Directive 2003/71/EC and includes any relevant implementing measure in each Relevant Member State.

Each underwriter has represented and agreed that:

it has only communicated or caused to be communicated and will only communicate or cause to be communicated an invitation or inducement to engage in investment activity (within the meaning of Section 21 of the Financial Services and Markets Act 2000) received by it in connection with the issue or sale of the notes in circumstances in which Section 21(1) of the Financial Services and Markets Act 2000 does not apply to us; and

it has complied and will comply with all applicable provisions of the Financial Services and Markets Act 2000 with respect to anything done by it in relation to the notes in, from or otherwise involving the United Kingdom.

In connection with this offering of the notes, the underwriters may engage in overallotments, stabilizing transactions and short covering transactions in accordance with Regulation M under the Securities Exchange Act of 1934. Overallotment involves sales in excess of the offering size, which creates a short position for the underwriters. Stabilizing transactions involve bids to purchase the notes in the open market for the purpose of pegging, fixing or maintaining the price of the notes, as applicable. Short covering transactions involve purchases of the notes in the open market after the distribution has been completed in order to cover short positions. Stabilizing transactions and short covering transactions may cause the price of the notes to be higher than it would otherwise be in the absence of those transactions. If either underwriter engages in stabilizing or short covering transactions, it may discontinue them at any time.

It is expected that delivery of the notes will be made against payment therefor on or about October 24, 2006, which is the fourth business day following the date hereof (such settlement cycle being referred to as "T+4"). Under Rule 15c6-1 under the Exchange Act trades in the secondary market generally are required to settle in three business days unless the parties to any such trade expressly agree otherwise. Accordingly, purchasers who wish to trade the notes on the date of pricing or the next three succeeding business days will be required, by virtue of the fact that the notes initially will settle in T+4, to specify an alternative settlement cycle at the time of any such trade to prevent failed settlement. Purchasers of the notes who wish to trade the notes on the date of pricing should consult their own advisors.

Certain of the underwriters and their affiliates have in the past and may in the future provide investment banking, commercial banking, derivative transactions and financial advisory services to us and our affiliates in the ordinary course of business. In particular, affiliates of J.P. Morgan Securities Inc., Citigroup Global Markets Inc., Wells Fargo Securities, LLC, SG Americas Securities, LLC, BNP Paribas Securities Corp., Wedbush Morgan Securities Inc., Comerica Securities, Inc. and Piper Jaffray & Co. are lenders to us under our senior unsecured revolving credit facility and affiliates of SG Americas Securities, LLC, BNP Paribas Securities Corp., Wells Fargo Securities, LLC, J.P. Morgan Securities, Inc., and Citigroup Global Markets Inc. are currently counterparties as to various derivative transactions with us. In addition, an affiliate of SG Americas Securities, LLC is the lender under our senior unsecured money market line of credit. We intend to use more than 10% of the net proceeds of this offering to repay indebtedness owed by us to certain affiliates of the underwriters who are lenders under our senior unsecured revolving credit facility. See "Use of proceeds." Accordingly, the offering is being made in compliance with the requirements of Rule 2710(h) of the Conduct Rules of the National Association of Securities Dealers, Inc. This rule provides generally that if more than 10% of the net proceeds from the sale of debt securities, not including underwriting compensation, is paid to the underwriters of such debt securities or their affiliates, the yield on the debt securities may not be lower than that recommended by a "qualified independent underwriter" meeting certain standards. Goldman, Sachs & Co. is assuming the responsibilities of acting as the qualified independent underwriter in connection with the offering. The yield on the notes, when sold to the public at the public offering price set forth on the cover page of this prospectus, is no lower than that recommended by Goldman, Sachs & Co.

Legal matters

The validity of the notes offered under this prospectus will be passed upon for us by Akin, Gump, Strauss, Hauer & Feld LLP, Austin, Texas and, with respect to certain legal matters, by Musick, Peeler & Garrett LLP, Westlake Village, California. Certain legal matters in connection with this offering will be passed upon for the underwriters by Simpson Thacher & Bartlett LLP, New York, New York.

Reserve engineers

Certain information included in this prospectus regarding estimated quantities of oil and natural gas reserves owned by us, the future net revenues from those reserves and their present value is based on estimates of the reserves and present values prepared by or derived from estimates prepared by DeGolyer and MacNaughton, independent consulting petroleum engineers, and all such information has been so incorporated in reliance on the authority of such firm as experts regarding the matters contained in their report. Future estimates of oil and natural gas reserves and related information hereafter incorporated by reference in this prospectus and the registration statement will be incorporated in reliance upon the reports of the firm examining such oil and gas reserves and related information and upon the authority of that firm as experts regarding the matters contained in their reports, to the extent the firm has consented to the use of their reports.

Glossary of oil and gas terms

Below are explanations of some commonly used terms in the oil and gas business.

API American Petroleum Institute.

API gravity The industry standard method of expressing specific gravity of crude oils. Higher API gravities mean lower specific gravity and lighter oils.

Basis risk The risk associated with the sales point price for oil or gas production varying from the reference (or settlement) price for a particular hedging transaction.

Bbl One stock tank barrel, or 42 U.S. gallons liquid volume, used herein in reference to crude oil or condensate.

Bcf Billion cubic feet.

BOE Barrel of oil equivalent.

BSPD Barrels of steam per day.

Btu British thermal unit; the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

CBM Coal bed methane. The primary energy source of natural gas is a substance called methane. Coal bed methane is simply methane found in coal seams. It is produced by non-traditional means. Often a coal seam is saturated with water, while methane is held in the coal by water pressure.

CPUC California Public Utilities Commission, a California government agency which regulates privately owned electric, telecommunications, natural gas, water and transportation companies.

Cash flow hedge Derivative instruments used to mitigate the risk of variability in cash flows from crude oil and natural gas sales due to changes in market prices. These derivative instruments either fix the price a party receives for its production or, in the case of option contracts, set a minimum price or a price within a fixed range.

Cogeneration The simultaneous production of steam and electricity using a single fuel source (natural gas).

Completion The installation of permanent equipment for the production of oil or natural gas, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

/D per day.

DD&A Depreciation, depletion and amortization.

Developed acreage The number of acres that are allocated or assignable to producing wells or wells capable of production.

Development well A well drilled within the proved area of an oil or natural gas field to the depth of a stratigraphic horizon known to be productive, including a well drilled to find and produce probable reserves.

Dry hole or well A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

EOR Enhanced oil recovery; efforts to improve the flow of oil from a reservoir that has already been produced by conventional means.

Exploitation Drilling wells in areas proven to be productive.

Exploration or exploratory well A well drilled to find and produce oil or natural gas reserves that is not a development well.

Farm-out A transfer of all or part of the operating rights from the working interest owner to an asignee, who assumes all or some of the burden of development, in return for an interest in the property.

FERC Federal Energy Regulatory Commission, a government agency which regulates the transmission of oil and natural gas by pipeline and wholesale sales of electricity in interstate commerce.

Field An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature or stratigraphic condition.

Field posting price The amount a buyer of crude oil will pay to a producer per barrel depending on the oil field it is produced from. Contractual arrangements may cause the actual sales price to differ from the posted price.

Gross acres or gross wells The total acres or wells in which a working interest is owned.

Heat rate The ratio of fuel energy input per unit of net work output. This is a measure of a power plant's thermal efficiency and is generally expressed as Btu per net kilowatt-hour.

Heavy oil Oil with an API gravity below 20 degrees.

HH Henry Hub; the standard delivery point for natural gas traded on the NYMEX (Sabine Pipe Line Company's Henry Hub in Louisiana).

Kilowatt (KW) 1,000 watts, which are the standard measure of electrical power.

MBbls One thousand barrels of crude oil or other liquid hydrocarbons.

Mcf One thousand cubic feet.

MBOE One thousand BOE.

MMBOE One million BOE.

MMBtu One million Btus.

MMcf One million cubic feet.

MW Megawatt; one million watts.

Net acres or net wells The sum of the fractional working interests owned in gross acres or gross wells, as the case may be.

NYMEX The New York Mercantile Exchange.

Productive well A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Proved developed producing reserves Proved developed reserves that are expected to be recovered from completion intervals currently open in existing wells and capable of production to market.

Proved developed reserves Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as proved developed reserves only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved developed nonproducing reserves Proved developed reserves expected to be recovered from zones behind casing in existing wells.

Proved reserves Proved oil and gas reserves are the 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, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions. Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, and (B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir. Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the proved classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based. Estimates of proved reserves do not include the following: (A) oil that may become available from known reservoirs but is classified separately as indicated additional reserves; (B) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (C) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and (D) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

Proved undeveloped reserves Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

PURPA Public Utility Regulatory Policies Act of 1978, as amended, a federal regulation which provides incentives for the development of cogeneration facilities such as those owned by the Company.

QF Qualifying facilities; a cogeneration facility which produces 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 which meets certain energy efficiency standards.

SRAC Short run avoided costs; an energy payment that reflects the utility's avoided short-term variable cost to produce electricity.

SO1 contract The SO1 is a standard form power purchase agreement authorized by the CPUC for the sale by a QF of as-available energy and capacity to a utility. Both the energy payment and capacity payment are based on the avoided cost of the utility and are subject to change by the CPUC during the term of the agreement. There are no energy or capacity delivery obligations under this contract.

SO2 contract The SO2 is a standard form power purchase agreement authorized by the CPUC for the sale by a QF of firm energy and capacity to a utility. The energy payment is based on the avoided cost of the utility and is subject to change by the CPUC during the term of the agreement. The capacity payment is defined in the agreement at the time of execution, and is subject to specified performance obligations by the QF.

Undeveloped acreage Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

WTI West Texas Intermediate; the benchmark United States crude oil with an API gravity of approximately 40 degrees.

Working interest The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.

Workover Operations on a producing well to restore or increase production.

PROSPECTUS

BERRY PETROLEUM COMPANY

Debt Securities

Preferred Stock

Class A Common Stock

Warrants

The following are types of securities that we may offer, issue and sell from time to time, together or separately: debt securities, which may be senior debt securities or subordinated debt securities and may be convertible; shares of our preferred stock; shares of our Class A Common Stock; and warrants to purchase debt or equity securities.

This prospectus contains summaries of the general terms of these securities. At the time of each offering we will provide the specific terms, manner of offering and the initial public offering price of the securities in a supplement to this prospectus. The prospectus supplements may also add, update or change information contained in this prospectus. You should carefully read this prospectus and the applicable prospectus supplement before you decide to invest. This prospectus may not be used to sell securities unless accompanied by a prospectus supplement.

We may offer and sell these securities through one or more underwriters, dealers and agents, through underwriting syndicates managed or co-managed by one or more underwriters, or directly to purchasers, on a continuous or delayed basis. The prospectus supplement for each offering of securities will describe in detail the plan of distribution for that offering.

Our Class A Common Stock is listed on the New York Stock Exchange under the symbol "BRY." Each prospectus supplement will indicate if the securities offered thereby will be listed on any securities exchange.

You should consider carefully the risk factors beginning on page 4 of this prospectus before purchasing any of our securities.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

This prospectus is dated June 15, 2006.

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ABOUT THIS PROSPECTUS

This prospectus is part of a "shelf" registration statement that we filed with the U.S. Securities and Exchange Commission ("SEC"). By using a shelf registration statement, we may sell from time to time in one or more offerings any combination of the securities described in this prospectus. For further information about the securities and us, you should refer to our registration statement and its exhibits. The registration statement can be obtained from the SEC as described below under the heading "Where You Can Find More Information." References in this prospectus to "we," "our" or "us" refer to Berry Petroleum Company and its direct and indirect subsidiaries.

This prospectus provides you with a general description of the securities we may offer. Each time we sell securities, we will provide a prospectus supplement that contains more specific information about the terms of those securities. The prospectus supplement may also add, update or change information contained in this prospectus. You should read both this prospectus and any prospectus supplement together with the additional information included in our reports, proxy statements and other information filed with the SEC. If there is any inconsistency between the information in this prospectus and any prospectus supplement, you should rely on the information in the prospectus supplement.

You should rely only on information contained or incorporated by reference in this prospectus and any applicable prospectus supplement. We have not authorized anyone to provide different information. If anyone provides you with different or inconsistent information, you should not rely on it. You should assume that the information contained in this prospectus and information that we previously filed with the SEC and incorporated by reference in this prospectus is accurate as of the date on the front cover of this prospectus. Our business, financial condition, results of operations and prospects may have changed since that date. We are not making an offer to sell these securities in any jurisdiction where the offer or sale is not permitted.

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 Exchange Act (excluding, unless otherwise provided therein or herein, information furnished pursuant to Item 2.02 and Item 7.01 on any Current Report on Form 8-K) after the effectiveness of this registration statement and before the termination of the 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 Current Reports on Form 8-K and 8-K/A filed on February 2, 2006, February 8, 2006, March 23, 2006 and June 8, 2006;

- 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;

- 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; and

- All other documents filed by us with the SEC under Sections 13 and 14 of the Securities Exchange Act of 1934 after the date of this prospectus but before the end of the offering of the securities made by this prospectus.

As a recipient of this prospectus, you may request a copy of any document we incorporate by reference, except exhibits to the documents that are not specifically incorporated by reference, at no cost to you, by writing or calling us at:

Berry Petroleum Company
Attn: Investor Relations
5201 Truxtun Avenue, Suite 300
Bakersfield, California 93309
(661) 616-3900

WHERE YOU CAN FIND MORE INFORMATION

We file annual, quarterly and current reports, proxy statements and other information with the SEC. Our filings are available over the Internet at the SEC's web site at http://www.sec.gov and at our web site at http://www.bry.com. Information on our website or any other website is not incorporated by reference in this prospectus and does not constitute part of this prospectus.

This prospectus is part of a registration statement and, as permitted by SEC rules, does not contain all of the information included in the registration statement. Whenever a reference is made in this prospectus to any of our contracts or other documents, the reference may not be complete and, for a copy of the contract or document, you should refer to the exhibits that are part of the registration statement. You may also read and copy any document we file with the SEC at the SEC's public reference rooms at:

100 F Street, N.E.
Room 1580
Washington, D.C. 20549

You may call the SEC at 1-800-SEC-0330 for more information on the public reference rooms and their copy charges. You may also inspect the reports and other information we file with the SEC at:

New York Stock Exchange
20 Broad Street
New York, New York 10005.

FORWARD-LOOKING STATEMENTS

Safe harbor under the "Private Securities Reform Act of 1995." Any statements in this prospectus that are not historical facts are forward-looking statements that involve risks and uncertainties. Words such as "expect," "could," "would," "may," "believe," "estimate," "anticipate," "intend," "plans," other forms of those words and others indicate forward-looking statements, but their absence does not mean that a statement is not forward-looking. A statement is forward-looking if the discussion involves strategy, beliefs, plans, targets, or intentions.

Forward-looking statements are made based on our management's current expectations and beliefs concerning future developments and their potential effects upon us. Important factors which could affect actual results are discussed in detail in the following pages of this document.

BERRY PETROLEUM COMPANY

We are an independent energy company engaged in the production, development, acquisition, exploitation and exploration of 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. Currently, our principal reserves and producing properties are located in the San Joaquin Valley, Los Angeles and Ventura Basins in California, the Uinta Basin in northeastern Utah and the Denver-Julesburg and Piceance Basins in Colorado.

Berry Petroleum Company is a Delaware corporation. 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.

RISK FACTORS

You should carefully consider the risks described below, in addition to the other information set forth or incorporated by reference in this prospectus, before purchasing our securities. If any of the following risks actually occur, our business, operating results and financial condition could be materially adversely affected. Additional risks not currently known to us or that we currently deem immaterial may also have a material adverse effect on us.

RISKS RELATED TO US AND 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. 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 and our ability to borrow and raise additional capital. The amount we can borrow under our 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;
- price and availability of alternative fuels;
- weather conditions;
- level of consumer demand;
- price of foreign imports;
- world-wide economic conditions;
- political conditions in oil and gas producing regions; and
- domestic and foreign governmental regulations.

We have crude oil hedges on 10,000 Bbl/D for 4 years beginning in 2006. We have an oil collar in place based on WTI pricing with a $47.50 floor and a $70 ceiling. We have also hedged a portion of our natural gas production from 2006 through 2008 utilizing collars at various price levels.

Our heavy crude 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. Our objective is to diversify our predominantly heavy crude oil base with light crude oil and natural gas.

In November 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.

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 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. Our Utah light crude also is currently priced at $9.00 below WTI through September 30, 2006. Beginning October 1, 2006 through September 30, 2007, 1,500 Bbl/D of our Utah light crude oil barrels then contracted for sale will be sold at the refiner's posting price. 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 black wax crude, pipeline capacity and specifications, upsets in the mid-stream or downstream sectors of the industry, trade restrictions, governmental regulations, etc. We may be adversely impacted by a widening differential on the products sold.

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.

Currently all Brundage Canyon crude oil production, which is approximately 40 degree API gravity, is sold under a contract at WTI less a fixed differential approximating $9.00 per barrel. However, effective October 1, 2006, the pricing of the production will be at the refiner's posted price and the production subject to this contract will be 1,500 Bbl/D. This contract expires on September 30, 2007. Production from this area approximates 4,800 Bbl/D. We are investigating other market opportunities for the remainder of this crude oil. The majority of this crude oil, while light, is a "paraffinic" crude, and can be processed efficiently by only a limited number of refineries. Increasing production of this type crude in this region, as well as increasing Canadian crude exports, is resulting in a downward pricing pressure. If market prices continue to deteriorate, we may allocate capital expenditures to projects which produce natural gas and crude oils with lower paraffinic content and/or a better margin until the refinery constraint is resolved.

We may be subject to the risk of adding additional steam generation equipment if the electrical market deteriorates significantly. We may be subject to the risk of adding additional steam generation equipment if the electrical market deteriorates significantly. We are dependent on several cogeneration facilities that provide over half of our steam requirement. These facilities are dependent on reasonable electrical contracts. If, for any reason, we were unable to enter into an electrical contract or were to lose an 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 investment may adversely affect our production, capital outlays and cash provided by operating activities. We have electricity contracts covering most of our electricity generation which contracts expire in 2009.

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. This volume is approximately one-third of our current requirement.

Our use of oil and gas price hedging contracts involves credit risk and may limit future revenues from price increases and 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 to achieve more predictable cash flow and to reduce our exposure to a significant decline in the price of crude oil. While the use of hedging transactions limits the downside risk of price declines, their use may also limit future revenues from price increases. Hedging transactions also involve the risk that the counterparty may be unable to satisfy its obligations. We utilize several counterparties for our hedging contracts.

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, 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 and labor required to operate and develop their properties. 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.

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, local and other laws and regulations that could adversely affect the cost, manner or feasibility of doing business. Our development, exploration, production and marketing operations are regulated extensively at the federal, state 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 and other governmental laws and regulations have increased the costs to plan, design, drill, install, operate and abandon oil and natural gas wells. Under these laws and regulations, we could also be liable for personal injuries, property damage and other damages. Failure to comply with these laws and regulations may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, public interest in environmental protection has increased in recent years, and environmental organizations oppose certain drilling projects and/or access to prospective lands and file litigation to attempt to stop projects.

Part of the regulatory environment in which we operate includes, in some cases, federal requirements for obtaining environmental assessments, environmental impact studies and/or plans of development before commencing exploration and production activities. In addition, our activities are 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 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 or costs could have a negative effect on our ability to explore on or develop its 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.

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. As of June 1, 2006, we own three drilling rigs and have additional one-year contract commitments on another three drilling rigs.

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 HOLDING OUR COMMON STOCK

The market price of our common stock is volatile. The trading price of our common stock and the price at which we may sell common stock in the future are subject to large fluctuations in response to any of the following:

- limited trading volume in our common stock;
- quarterly variations in operating results;
- our involvement in litigation;
- general financial market conditions;
- prices of oil and natural gas;

announcements by us and our competitors;

our liquidity;

our ability to raise additional funds;

changes in government and/or tribal regulations;

success or failure of exploration projects and development; and

other events.

We have certain anti-takeover provisions that could inhibit an acquisition of the common stock at a premium price. The rights that have been issued under our shareholder rights plan would cause substantial dilution to anyone who attempted to acquire us on terms not approved by our board of directors. A change of control (as defined in our agreement) will generate an event of default under our bank credit agreements and will make any borrowings under these agreements immediately due. These provisions may have the effect of discouraging unsolicited takeover proposals. The shareholder rights plan and the change of control provisions relating to our long-term indebtedness together may discourage transactions that could entail the payment to shareholders of a premium over the prevailing market price of the common stock.

Sales of substantial amounts of shares of our common stock could cause the price of our common stock to decrease. This prospectus covers the potential issuance by us of a substantial number of shares of our common stock. Our stock price may decrease due to the additional amount of shares available in the market.

RATIO OF EARNINGS TO FIXED CHARGES

The following table presents our historical ratio of earnings to fixed charges for the three months ended March 31, 2006 and for each of the years in the five-year period ended December 31, 2005.

	Three Months Ended March 31, 2006	Year Ended December 31,				
		2005	2004	2003	2002	2001
Ratio of Earnings to Fixed Charges	18.5x	28.9x	45.3x	28.1x	36.9x	8.9x

For purposes of this table, "earnings" consists of income before income taxes plus fixed charges and less capitalized interest. "Fixed charges" consists of interest expense and capitalized interest.

USE OF PROCEEDS

Unless we have indicated otherwise in the accompanying prospectus supplement, we expect to use the net proceeds we receive from any offering of these securities for our general corporate purposes, including working capital, repayment or reduction of debt, capital expenditures, acquisitions of additional oil and natural gas properties or companies owning oil and natural gas properties and repurchases and redemptions of securities. Pending any specific application, we may initially invest funds in short-term marketable securities or apply them to the reduction of other short-term indebtedness.

SELECTED HISTORICAL CONSOLIDATED FINANCIAL DATA

On May 17, 2006, our Board of Directors approved a two-for-one split of our common stock. Stockholders of record as of May 17, 2006 were entitled to one additional share for every share outstanding, which was distributed on June 2, 2006. The following table sets forth the restated earnings per share, cash dividends declared per share and average shares outstanding data to reflect the effect of the stock split and other selected financial data (in thousands, except per share amounts):

	Three Months Ended March 31,		Year Ended December 31,				
	2006	2005	2005	2004	2003	2002	2001
OPERATING RESULTS:							
Operating revenue	$ 117,594	$ 87,995	$ 406,725	$ 274,946	$ 180,864	$ 131,369	$ 137,757
Net income	23,251	22,505	112,356	69,187	32,363	29,210	20,985
Basic earnings per share:							
Net income	$ 0.53	$ 0.51	$ 2.55	$ 1.58	$ 0.74	$ 0.67	$ 0.48
Diluted earnings per share:							
Net income	$ 0.52	$ 0.50	$ 2.50	$ 1.54	$ 0.73	$ 0.67	$ 0.47
Weighted average number of shares outstanding:							
Basic	43,988	43,962	44,082	43,788	43,544	43,482	43,946
Assuming dilution	45,004	44,940	44,980	44,940	44,062	43,804	44,324
Dividends per share	$ 0.065	$ 0.06	$ 0.30	$ 0.26	$ 0.235	$ 0.20	$ 0.20

	March 31, 2006	December 31, 2005	2004	2003	2002	2001
BALANCE SHEET INFORMATION:						
Working capital	$ (40,221)	$ (54,757)	$ (3,840)	$ (3,540)	$ (2,892)	$ 6,314
Total assets	$ 824,975	$ 635,051	$ 412,104	$ 340,377	$ 259,325	$ 238,779
Long-term debt	$ 249,000	$ 75,000	$ 28,000	$ 50,000	$ 15,000	$ 25,000
Shareholders' equity	$ 331,661	$ 334,210	$ 263,086	$ 197,338	$ 172,774	$ 153,590

The selected historical data in the table above for the three-month periods ended March 31, 2006 and 2005 were derived from our unaudited consolidated financial statements. The data for the five years ended December 31, 2005 were derived from our audited consolidated financial statements.

Financial information incorporated by reference into this prospectus from our Annual Report on Form 10-K for the fiscal year ended December 31, 2005 has not been restated to reflect the two-for-one stock split.

DESCRIPTION OF DEBT SECURITIES

The debt securities will either be senior debt securities or subordinated debt securities. Senior debt securities will be issued under a senior indenture and subordinated debt securities will be issued under a subordinated indenture. Unless otherwise specified in the applicable prospectus supplement, the trustee under the indentures will be Wells Fargo Bank, National Association. The forms of indentures are filed as exhibits to the registration statement of which this prospectus forms a part. We will include in a supplement to this prospectus the specific terms of each series of debt securities being offered, including the terms, if any, on which a series of debt securities may be convertible into or exchangeable for our common stock, preferred stock or other debt securities. The statements and descriptions in this prospectus or in any prospectus supplement regarding provisions of the indentures and debt securities are summaries thereof, do not purport to be complete and are subject to, and are qualified in their entirety by reference to, all of the provisions of the indentures (and any amendments or supplements we may enter into from time to time which are permitted under each indenture) and the debt securities, including the definitions therein of certain terms.

Unless otherwise specified in a prospectus supplement, the debt securities will be direct unsecured obligations of Berry Petroleum Company. The senior debt securities will rank equally with any of our other senior and unsubordinated debt. The subordinated debt securities will be subordinate and junior in right of payment to any senior indebtedness. The indentures do not limit the aggregate principal amount of debt securities that we may issue and provide that we may issue debt securities from time to time in one or more series, in each case with the same or various maturities, at par or at a discount. Unless indicated in a prospectus supplement, we may issue additional debt securities of a particular series without the consent of the holders of the debt securities of such series outstanding at the time of the issuance. Any such additional debt securities, together with all other outstanding debt securities of that series, will constitute a single series of debt securities under the applicable indenture.

DESCRIPTION OF PREFERRED STOCK

This section summarizes the general terms of the preferred stock that we may offer. The prospectus supplement relating to a particular series of preferred stock offered will describe the specific terms of that series, which may be in addition to or different from the general terms summarized in this section. The summary in this section and in any prospectus supplement does not describe every aspect of the preferred stock and is subject to and qualified in its entirety by reference to all the provisions of our restated certificate of incorporation, the certificate of designation relating to the applicable series of preferred stock and the Delaware General Corporation Law. The certificate of designation will be filed as an exhibit to or incorporated by reference in the registration statement.

Our restated certificate of incorporation authorizes us to issue 2,000,000 shares of preferred stock, par value of $.01 per share. As of June 1, 2006, no shares of preferred stock were outstanding, and 250,000 were reserved for issuance under our Shareholder Rights Agreement. We may issue preferred stock from time to time in one or more classes or series with such rights and preferences, including voting, dividend and conversion rights and other terms, as our board of directors may establish without any further authorization by the shareholders.

The preferred stock that we may offer will be issued in one or more classes or series. The prospectus supplement relating to the particular class or series of preferred stock will describe the specific terms of the class or series, including:

- the designation and stated value, if any, per share and the number of shares offered;
- the amount of liquidation preference per share and any priority relative to any other class or series of preferred stock or common stock;
- the initial public offering price at which shares will be issued;
- the dividend rate (or method of calculation), the dates on which dividends will be payable and the dates from which dividends will commence to cumulate, if any;
- any redemption or sinking fund provisions;
- any conversion or exchange rights;

any voting rights; and

any other rights, preferences, privileges, limitations and restrictions.

General

The holders of preferred stock will have no preemptive rights. Upon issuance against full payment of the purchase price, the preferred stock will be fully paid and non-assessable. Unless otherwise provided in the prospectus supplement relating to the particular class or series, the preferred stock will have the rights described below.

Dividends

The preferred stock will be preferred over any class or series of common stock as to payment of dividends. Before we can declare, pay or set apart for payment any dividends or distributions, other than dividends or distributions payable in common stock, on the common stock, we will pay dividends to the holders of shares of each class and series of preferred stock entitled to receive dividends when, as and if declared by our board of directors. We will pay those dividends either in cash, shares of common stock or preferred stock or otherwise, at the rate and on the date or dates set forth in the prospectus supplement. For each class or series of preferred stock, the dividends on each share of the class or series will be cumulative from the date of issue of the share unless some other date is set forth in the prospectus supplement relating to the series. Accruals of dividends will not bear interest.

Liquidation

The preferred stock will be preferred over the common stock as to asset distributions so that the holders of each class and series of preferred stock will be entitled to be paid the amount stated in the applicable prospectus supplement upon our voluntary or involuntary liquidation, dissolution or winding up and before any distribution is made to the holders of common stock. If upon any liquidation, dissolution or winding up, our net assets are insufficient to permit the payment in full of the respective amounts to which the holders of all outstanding preferred stock are entitled, unless otherwise described in a prospectus supplement, our entire remaining net assets will be distributed among the holders of each class and series of preferred stock in amounts proportional to the full amounts to which the holders of each class and series are entitled.

Redemption or Conversion

The shares of any class or series of preferred stock will be redeemable or will be convertible into shares of common stock or any other class or series of preferred stock to the extent described in the prospectus supplement relating to the series.

DESCRIPTION OF COMMON STOCK

We are authorized to issue up to 100,000,000 shares of Class A Common Stock, par value $.01 per share, and up to 3,000,000 shares of Class B Common Stock, par value $.01 per share. As of June 2, 2006, there were 42,218,526 shares of Class A Common Stock and 1,797,784 shares of Class B Common Stock outstanding.

If we issue any common stock under this prospectus, we will issue shares of Class A Common Stock. This section summarizes the general terms of our Class A Common Stock and

Class B Common Stock. The prospectus supplement relating to the common stock offered will state the number of shares offered, the initial offering price and market price, dividend information and any other relevant information. The summary in this section and in the prospectus supplement does not describe every aspect of the common stock and is subject to and qualified in its entirety by reference to all the provisions of our restated certificate of incorporation and bylaws and the Delaware General Corporation Law.

General

Shares of Class A Common Stock and Class B Stock are each entitled to one vote and 95% of one vote, respectively. Each share of Class B Stock is entitled to a $0.50 per share preference in the event of liquidation or dissolution. Further, each share of Class B Stock is convertible into one share of Class A Common Stock at the option of the holder. All shares of common stock have equal rights to participate in dividends. Stockholders have the right to vote their shares on a cumulative basis with respect to the election of directors. Shares of common stock carry no conversion rights, other than the right to convert shares of Class B Common Stock into Shares of Class A Common Stock, carry no preemptive or subscription rights and are not subject to redemption. All outstanding shares of common stock are, and any shares of common stock issued upon conversion of any convertible securities will be, fully paid and non-assessable. We may pay dividends on the common stock when, as and if declared by our board of directors. Dividends may be declared in the discretion of the board of directors from funds legally available, subject to any restrictions under agreements related to our indebtedness.

The outstanding shares of Class A Common Stock are listed on the New York Stock Exchange and trade under the symbol "BRY." The transfer agent, registrar and dividend disbursement agent for the common stock is Mellon Investor Services.

Shareholder Rights

In November 1999, we adopted a Shareholder Rights Agreement and declared a dividend distribution of one Right for each outstanding share of Class A Common Stock and Class B Common Stock on December 8, 1999. As a result of a subsequent 2-for-1 stock split, one-half of a Right is now associated with each outstanding share of Class A Common Stock and Class B Common Stock. Each Right, when exercisable, entitles the holder to purchase one one-hundredth of a share of a Series B Junior Participating Preferred Stock, or in certain cases other securities, for $38.00. The exercise price and number of shares issuable are subject to adjustment to prevent dilution. The Rights would become exercisable, unless earlier redeemed by us, 10 days following a public announcement that a person or group has acquired, or obtained the right to acquire, 20% or more of the outstanding shares of Class A Common Stock or 10 business days following the commencement of a tender or exchange offer for such outstanding shares which would result in such person or group acquiring 20% or more of the outstanding shares of Class A Common Stock, either event occurring without our prior consent.

The Rights will expire on December 8, 2009 or may be redeemed by us at $.01 per Right prior to that date unless they have theretofore become exercisable. The Rights do not have voting or dividend rights, and until they become exercisable, have no diluting effect on our earnings. A total of 250,000 shares of our preferred stock has been designated Series B Junior Participating Preferred Stock and reserved for issuance upon exercise of the Rights.

DESCRIPTION OF WARRANTS

The following is a description of the general terms and provisions of the warrants. The particular terms of any series of warrants will be described in a prospectus supplement. If so indicated in a prospectus supplement, the terms of that series may differ from the terms set forth below.

General

We may issue warrants to purchase debt securities, preferred stock or common stock. Warrants may be issued independently or together with any debt securities, preferred stock or common stock and may be attached to or separate from the debt securities, preferred stock or common stock. Each series of warrants will be issued under a separate warrant agreement to be entered into between us and a warrant agent. The warrant agent will act solely as our agent in connection with the warrants and will not assume any obligation or relationship of agency or trust for or with any holders or beneficial owners of warrants.

You should review the applicable prospectus supplement for the specific terms of any warrants that may be offered including the following:

- the title of the warrants;
- the aggregate number of the warrants;
- the price or prices at which the warrants will be issued;
- the designation, aggregate principal amount, denominations and terms of the debt securities purchasable upon exercise of a warrant to purchase debt securities and the price at which the debt securities may be purchased upon exercise;
- the designation, stated value, terms (including liquidation, dividend, conversion and voting rights), number of shares and purchase price per share of the class or series of preferred stock purchasable upon the exercise of warrants to purchase shares of preferred stock;
- the number of shares and the purchase price per share of common stock purchasable upon the exercise of warrants to purchase shares of common stock;
- if applicable, the date on and after which the warrants and the related securities will be separately transferable;
- the date on which the right to exercise the warrants will commence and the date on which the right will expire;
- if applicable, the minimum or maximum number of warrants that may be exercised at any one time;
- information relating to book-entry procedures, if any;
- if applicable, a discussion of material United States federal income tax considerations; and
- any other terms of the warrants, including terms, procedures and limitations relating to the exchange and exercise of the warrants.

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VALIDITY OF OFFERED SECURITIES

The validity of the offered securities and other matters in connection with any offering of the securities will be passed upon for us by Musick, Peeler & Garrett LLP, Westlake Village, California, and for the underwriters or agents, if any, by a firm named in the prospectus supplement relating to the particular security.

EXPERTS

The financial statements and management's assessment of the effectiveness of internal control over financial reporting (which is included in Management's Report on Internal Control over Financial Reporting) incorporated in this Prospectus by reference to the Annual Report on Form 10-K for the year ended December 31, 2005 have been so incorporated in reliance on the report of PricewaterhouseCoopers LLP, an independent registered public accounting firm, given on the authority of said firm as experts in auditing and accounting.

Certain information incorporated by reference in this prospectus regarding estimated quantities of oil and natural gas reserves owned by us, the future net revenues from those reserves and their present value is based on estimates of the reserves and present values prepared by or derived from estimates prepared by DeGolyer and MacNaughton, independent consulting petroleum engineers, and all such information has been so incorporated in reliance on the authority of such firm as experts regarding the matters contained in their report. Future estimates of oil and natural gas reserves and related information hereafter incorporated by reference in this prospectus and the registration statement will be incorporated in reliance upon the reports of the firm examining such oil and gas reserves and related information and upon the authority of that firm as experts regarding the matters contained in their reports, to the extent the firm has consented to the use of their reports.

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