BERRY PETROLEUM CO
Form 10-K
February 28, 2007

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

x Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended **December 31, 2006**
Commission file number **1-9735**

BERRY PETROLEUM COMPANY
(Exact name of registrant as specified in its charter)

DELAWARE	**77-0079387**
(State of incorporation or organization)	(I.R.S. Employer Identification Number)

5201 Truxtun Avenue, Suite 300
Bakersfield, California 93309
(Address of principal executive offices, including zip code)

Registrant's telephone number, including area code: **(661) 616-3900**

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Class A Common Stock, $.01 par value (including associated stock purchase rights)	**New York Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act: None
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
YES x NO o
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
YES o NO x
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. YES x NO o
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant’s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of “accelerated filer and large accelerated filer” in Rule 12b-2 of the Exchange Act. (Check one):
Large accelerated filerx Accelerated filero Non-accelerated filero
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). YES o NO x

As of June 30, 2006, the aggregate market value of the voting and non-voting common stock held by non-affiliates was $1,202,477,929. As of February 9, 2007, the registrant had 42,120,651 shares of Class A Common Stock outstanding. The registrant also had 1,797,784 shares of Class B Stock outstanding on February 9, 2007 all of which are held by an affiliate of the registrant.

DOCUMENTS INCORPORATED BY REFERENCE

Part III is incorporated by reference from the registrant's definitive Proxy Statement for its Annual Meeting of Shareholders to be filed, pursuant to Regulation 14A, no later than 120 days after the close of the registrant's fiscal year.

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PART I

Item 1. Business

General. 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. In 2003, we purchased and began operating properties in the Rocky Mountain/Mid-Continent region. Our corporate headquarters are in Bakersfield, California and we have a regional office in Denver, Colorado. Information contained in this report on Form 10-K reflects our business during the year ended December 31, 2006 unless noted otherwise.

Our website is located at http://www.bry.com. The website can be used to access recent news releases and Securities and Exchange Commission (SEC) filings, crude oil price postings, our Annual Report, Proxy Statement, Board committee charters, code of business conduct and ethics, the code of ethics for senior financial officers, and other items of interest. SEC filings, including supplemental schedules and exhibits, can also be accessed free of charge through the SEC website at http://www.sec.gov.

Corporate strategy. Our objective is to increase shareholder value 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 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 hydrocarbon resources in place in the San Joaquin Valley basin, California (diatomite) and an emerging resource play in the Uinta basin, Utah (Lake Canyon). We have a proven track record of developing reserves and increasing production in all of our operating regions.
- ***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/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 (DJ) basin and two transactions in 2006 pursuant to which we have committed over $312 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 extensive 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.
- ***Accumulating significant acreage positions near our producing operations.*** We have been successful in adding strategic acreage positions in less than three years with the intent of appraising the potential of the acreage for the economic production of hydrocarbons. As of December 31, 2006 these positions include 483,000 and 145,400 gross acres in the DJ 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 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 also intend to 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. Therefore we will 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 to utilize long-term sales contracts with the objective of achieving the cash flow necessary for the development of our assets.

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 acquisitions in three core areas in the Rocky Mountain/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, 2006 our implied reserve life was 15.3 years and our implied proved developed reserve life was 10.4 years.
- ***Track record of efficient proved reserve and production growth.*** For the three years ended December 31, 2006, our average annual reserve replacement rate was 260% at an average cost of $12.74 per barrel of oil equivalent (BOE). See Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operation for further explanation of the reserve replacement rate. During the same period our proved reserves and production increased at an annualized compounded rate of 11.2% and 15.7%, respectively. We were able to deliver that growth predominantly through low-risk drilling. We have 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.*** 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.
- ***Operational control and financial flexibility.*** We exercise operating control over approximately 99% of our proved reserve base. We generally prefer to retain operating control over our properties, allowing us to control operating costs more effectively, the timing of development activities and technological enhancements, the marketing of production and the 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 and timing 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 to secure operating cash flows in order to fund our capital expenditures program. Our long-term crude oil contracts with refiners 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.

Proved Reserves and Revenues. As of December 31, 2006, our estimated proved reserves were 150.3 million BOE, of which 66% are heavy crude oil, 9% light crude oil and 25% natural gas. We have a geographically diverse asset base with 66% of our reserves located in California, and 34% in the Rocky Mountain/Mid-Continent region. Of our proved reserves 68% were proved developed. Proved undeveloped reserves make up 32% of our proved total. The projected capital to develop these proved undeveloped reserves is $382 million, at an estimated cost of approximately $7.96 per BOE. Approximately 78% of the capital to develop these reserves is expected to be expended in the next five years. Production in 2006 was 9.3 million BOE, up 11% from production of 8.4 million BOE in 2005.

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, 2006) of approximately 15.3 years as compared to 14.6 years at year-end 2005.

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We have six asset teams, three in California and three in the Rocky Mountain/Mid-Continent region. California's three teams are South Midway-Sunset (SMWSS), North Midway-Sunset (NMWSS) (which includes diatomite) and Southern California (Socal) (which includes Poso Creek, Ethel D, Placerita and Montalvo). The three Rocky Mountain/Mid-Continent region teams are DJ, Uinta and Piceance. The following table sets forth the estimated quantities of proved reserves and production attributable to our asset teams as of December 31, 2006. We operate 99% of these assets:

State	Name	Type	Average 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	SMWSS	Heavy oil	10,101	*39.8%*	50,124	*33.4%*	$179.3	*40.2%*
UT	Uinta	Light oil/Natural gas	5,949	*23.4*	21,093	*14.0*	101.1	*22.7*
CA	Socal	Heavy oil	4,824	*19.0*	33,441	*22.2*	100.8	*22.6*
CO	DJ	Natural gas	2,676	*10.5*	18,620	*12.4*	34.0	*7.6*
CA	NMWSS	Heavy oil	1,125	*4.4*	16,343	*10.9*	23.8	*5.3*
CO	Piceance	Natural gas	723	*2.9*	10,641	*7.1*	7.3	*1.6*
Totals			**25,398**	***100%***	**150,262**	***100%***	**$446.3**	***100%***

We continue to engage DeGolyer and MacNaughton (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, 2006. 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, 2006. See Supplemental Information About Oil & Gas Producing Activities (Unaudited) for our oil and gas reserve disclosures.

Acquisitions. See Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operation.

Operations. In California, we operate all of our principal oil and gas producing properties. The Midway-Sunset and Socal assets contain predominantly heavy crude oil which requires heat (except Montalvo, which averages production from below 11,500 feet deep), supplied in the form of steam, which is injected into the oil producing formations to reduce the oil viscosity, thereby allowing the oil to flow to the wellbore for production. We utilize cyclic steam and/or steam flood recovery methods on all assets in addition to primary recovery methods at our Montalvo field. 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/Mid-Continent region, crude oil produced from the Uinta assets 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 DJ basin gas assets is transported to one of three main pipelines. Our Piceance basin natural gas is gathered and sold to an affiliate of our industry partner. We have pipeline gathering systems and gas compression facilities for delivery into various interstate gas lines.

Crude Oil and Natural Gas Marketing.

Economy. The global and California crude oil markets continue to remain strong though volatile. Product prices continued to exhibit an overall-strengthening trend through August 2006 and then retreated somewhat. The range of West Texas Intermediate (WTI) crude prices for 2006, based upon NYMEX settlements, was a low of $55.81 and a high of $77.03. We expect that crude prices will continue to be volatile in 2007.

	2006	2005	2004
Average NYMEX settlement price for WTI	$ 66.25	$ 56.70	$ 41.47
Average posted price for Berry's:			
Utah light crude oil	56.34	53.03	38.60
California 13 degree API heavy crude oil	54.38	44.36	32.84
Average crude price differential between WTI and Berry's:			
Utah light crude oil	9.91	3.67	2.87
California 13 degree API heavy crude oil	11.87	12.34	8.63

The above posting prices and differentials are not necessarily amounts paid or received by us due to the contracts discussed below. While the crude oil price differential between WTI and California's heavy crude differential widened dramatically during 2004 and 2005, it was relatively stable in 2006. On December 31, 2006 the differential was $11.69 and ranged from a low of $11.39 to a high of $12.73 per barrel during the year. Crude oil price differentials between WTI and Utah's light crude oil were fairly consistent during 2004 and 2005 and were between $3 and $5 per barrel, but differentials widened considerably in 2006. On December 31, 2006 the differential was $13.75 and ranged from a low of $5.50 to a high of $13.75 per barrel during the year.

Oil Contracts. We market our crude oil production to competing buyers including independent and major oil refining companies.

California - We have the ability to deliver significant volumes of crude oil over a multi-year period. 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. This contract allowed us to improve our California revenues by $21 million over the posted price in 2006.

Prior to November 2005, 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.

Utah - As of December 31, 2006, our Utah light crude oil is sold under multiple contracts with different purchasers for varying pricing terms and ranging from one month to nine months. As of December 31, 2006 we had firm contracts for 4,250 barrels per day (Bbl/D). These contracts are currently priced at approximately $13 to $20 per barrel below WTI with certain volumes tied to field posting, and in some cases our realized price is further reduced by transportation charges. As operator we deliver all produced volumes pursuant to these contracts, although our working interest partners or royalty owners may take their respective volumes in kind and market their own volumes. Our net volumes from our Brundage Canyon properties approximate 80% of the total gross volumes. Assuming all the Brundage Canyon wells are producing, the gross production could exceed these contracted volumes. We experienced increasing difficulty in locating additional buyers of our crude oil production from this region in 2006. Our Utah crude oil is a paraffinic crude, locally known as a black wax 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.

On February 27, 2007, we entered into a multi-staged crude oil sales contract with a subsidiary of Holly Corporation (Holly) for our Uinta basin crude oil. Under the agreement, Holly will begin purchasing 3,200 Bbl/D beginning July 1, 2007. Upon completion of their Woods Cross refinery expansion in Salt Lake City, which is expected in mid 2008, Holly will increase their total purchased volumes to 5,000 Bbl/D through June 30, 2013. Pricing under the contract, which includes transportation, is a fixed percentage of WTI and approximates our expected field posted price of $13 to $16 below WTI. This contract provides the pricing assurance we need to proceed with the long-term development of our Uinta basin assets. 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 3,500 Bbl/D, our revenues were lower by approximately $9.2 million in 2006 as compared to 2005. If this pricing continues throughout 2007, with our Holly contract in place and on the same volumes, we estimate our revenues will be lower by approximately $8.6 million versus our 2006 revenues. We may adjust our capital expenditures in the Uinta basin due to various factors, including the timing of refinery demand for the Uinta barrels and the actual or expected change in our realized price.

Natural Gas Marketing. We market produced natural gas from Colorado, Kansas, 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.

	2006	2005	2004
Annual average closing price per MMBtu for:			
NYMEX Henry Hub (HH) prompt month natural gas contract	$ 6.98	$ 9.01	$ 6.18
Rocky Mountain Questar first-of-month indices (Brundage Canyon sales)	5.36	6.73	5.05
Rocky Mountain CIG first-of-month indices (Tri-State and Piceance sales)	5.63	6.95	5.17
Average natural gas price per MMBtu differential between NYMEX HH and:			
Questar	1.86	2.28	1.13
CIG	1.60	2.06	1.01

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:

Firm Transportation Summary.

Name	From	To	Quantity (Avg. MMBtu/D)	Term	2006 base costs per MMBtu	Remaining contractual obligation (in thousands)
Kern River Pipeline	Opal, WY	Kern County, CA	12,000	5/2003 to 4/2013	$ 0.643	$ 17,826
Rockies Express Pipeline	Piceance	Clarington, OH	10,000	1/2008 to 12/2017	1.094(1)	38,703
Questar Pipeline	Brundage Canyon	Salt Lake City, UT	2,500	9/2003 to 4/2012	0.174	846
Questar Pipeline	Brundage Canyon	Salt Lake City, UT	2,800	9/2003 to 9/2007	0.174	136
KMIGT	Yuma County, CO	Grant, KS	2,500	1/2005 to 10/2013	0.227	1,416
Cheyenne Plains Gas Pipeline	Tri-State, CO	Panhandle Eastern Pipeline	11,000	1/2007 to 12/2016	0.370	14,868
Total			40,800			$ 73,795

(1) We will experience lower rates from first in-service date until the pipeline is complete.

Royalties. See Item 7A Quantitative and Qualitative Disclosures about Market Risk.

Hedging. See Item 7A Quantitative and Qualitative Disclosures about Market Risk and Note 15 to the financial statements.

Concentration of Credit Risk. See Note 4 to the financial statements.

<u>Steaming Operations.</u>

Cogeneration Steam Supply. As of December 31, 2006, approximately 62% of our proved reserves, or 93 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 consistently focused on minimizing our steam cost. We believe one of the main methods to keep steam costs low is through the ownership and efficient operation of three cogeneration facilities located on our properties. Two of these cogeneration facilities, a 38 megawatt (MW) and an 18 MW facility, are located in our Midway-Sunset field. We also own a 42 MW cogeneration facility which is 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 better able to 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 barrels of steam per day (BSPD) capacity as of December 31, 2006 is as follows:

Total steam generation capacity of Cogeneration plants	38,000
Additional steam purchased under contract with a third party	2,000
Total steam generation capacity of conventional boilers	67,000
Total steam capacity	107,000

The average volume of steam injected for the years ended December 31, 2006 and 2005 was 81,246 and 70,032 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, control over the 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 are adding additional steam capacity for our development projects at Midway-Sunset, primarily diatomite, and Poso Creek to achieve maximum production from these properties. We regularly review our options to secure the most economical source for obtaining additional steam.

We operated most of our conventional steam generators in 2006 to achieve our goal of increasing heavy oil production. Approximately 65% 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 gas. Approximately 26% of supply volume is purchased in Wyoming and moved to the Midway-Sunset field using our firm transportation capacity on the Kern River Pipeline. This gas is purchased based upon the Rocky Mountain Northwest Pipeline (NWPL) index. The remaining 9% of supply volume for the Poso Creek steaming operations is purchased based upon the PG&E Citygate index.

		2006		2005		2004
Average SoCal Border Monthly Index Price per MMBtu	$	6.29	$	7.37	$	5.60
Average Rocky Mountain NWPL Monthly Index Price per MMBtu		5.66		6.96		5.24
Average PG&E Citygate Monthly Index Price per MMBtu		6.70		7.72		5.85

We historically have been 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 (Tri-State) Niobrara gas acquisition. Thus, in 2006 and looking forward, we have been a net seller of gas and will benefit operationally when gas prices are higher. Increased production at Tri-State and the acquisition and development of the Piceance basin assets, which are all gas, has allowed us to improve our long natural gas position in 2006. The balance between natural gas consumed and produced during the fourth quarter ended December 31, 2006 was approximately as follows (MMBtu/D):

Natural gas consumed in:	
Cogeneration operations	27,000
Conventional boilers	18,000
Total natural gas consumed	45,000
Less: Our estimate of approximate natural gas consumed to produce electricity (1)	(22,000)
Total approximate natural gas volumes consumed to produce steam	23,000
Natural gas produced:	

Tri-State (Niobrara)	19,000
Brundage Canyon (associated gas)	15,000
Piceance and other	8,000
Total natural gas volumes produced in operations	42,000

(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 megawatts (MW), of which we consume approximately 8 MW for use in our operations. Each facility is centrally located on an oil producing property. Thus 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 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 Qualifying Facility (QF) under the Public Utilities Regulatory Policy Act of 1978, as amended (PURPA), to two California public utilities; Southern California Edison Company (Edison) and PG&E, under long-term contracts approved by the California Public Utilities Commission (CPUC). These contracts are referred to as standard offer (SO) contracts under which we are paid an energy payment that reflects the utility’s Short Run Avoided Cost (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 SO1contract. 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 further contracts with QFs. It is not known when the CPUC will issue a decision on SRAC pricing revisions. Also, 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 6% of our total approximate barrels of steam per day (BSPD). The modified SRAC pricing terms of this contract reflected a fixed energy price of 5.37 cents/kilowatt hour (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 adjust the prices retroactively 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 $45 million to $55 million range for 2007.

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. The facility also must meet certain energy efficiency standards. Each of our cogeneration facilities is a QF, pursuant to PURPA.

Facility and Contract Summary.

Purchaser

Location and Facility	Type of Contract		Contract Expiration	Approximate Megawatts Available for Sale	Approximate Megawatts Consumed in Operations	Approximate Barrels of Steam Per Day
Placerita						
Placerita Unit 1	SO2	Edison	Mar-09 (1)	20	-	6,500
Placerita Unit 2	SO1	Edison	Dec-09	16	4	6,500
Midway-Sunset						
Cogen 18	SO1	PG&E	Dec-09	12	4	6,700
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 have little control over the price we receive for our crude oil and natural gas. As such, higher costs, fees and taxes assessed at the producer level cannot necessarily be passed on to our customers. In acquisition activities, competition is intense 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 business strengths (identified on page 4) and our determination to grow our business.

Employees. On December 31, 2006, we had 243 full-time employees, up from 209 full-time employees on December 31, 2005.

Capital Expenditures Summary (Excluding Acquisitions).

The following is a summary of the developmental capital expenditures incurred during 2006 and 2005 and budgeted capital expenditures for 2007 (in thousands):

	2007 (Budgeted) (1)	2006	2005
CALIFORNIA			
Midway-Sunset field			
New wells	$ 46,108	$ 42,350	$ 17,369
Remedials/workovers	2,355	2,261	1,079
Facilities - oil & gas	19,156	20,558	7,879
Facilities - cogeneration	55	415	3,053
General	1,875	479	1,271
	69,549	66,063	30,651
Other California fields			
New wells	10,270	8,641	6,965
Remedials/workovers	2,185	2,788	5,303
Facilities - oil & gas	5,230	6,599	3,677
Facilities - cogeneration	2,616	177	1,446
General	245	25	46
	20,546	18,230	17,437
Total California	90,095	84,293	48,088
ROCKY MOUNTAIN/MID-CONTINENT			
Uinta Basin			
New wells	34,689	103,183	50,354
Remedials/workovers	-	1,213	3,415
Facilities	3,098	5,966	1,860
General	-	1,072	4
	37,787	111,434	55,633
Piceance Basin			
New wells	94,534	36,654	-
Facilities	23,190	3,561	-
	117,724	40,215	-
DJ Basin			
New wells/workovers	12,241	19,468	11,257
Remedials/workovers	1,248	1,511	693
Facilities	5,151	7,883	2,569
General	366	427	387
Land and seismic	880	-	-
	19,886	29,289	14,906
Williston Basin - New wells	-	1,611	-
Total Rocky Mountain and Mid-Continent	175,397	182,549	70,539
Other Fixed Assets	2,000	19,574	647
TOTAL	$ 267,492	$ 286,416	$ 119,274

(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 Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operation.*

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

	2006	2005	2004
Net annual production: (1)			
Oil (Mbbl)	7,182	7,081	7,044
Gas (MMcf)	12,526	7,919	2,839
Total equivalent barrels (MBOE) (2)	9,270	8,401	7,517
Average sales price:			
Oil (per Bbl) before hedging	$ 52.92	$ 47.04	$ 33.43
Oil (per Bbl) after hedging	50.55	40.83	29.89
Gas (per Mcf) before hedging	5.48	7.88	6.13
Gas (per Mcf) after hedging	5.57	7.73	6.12
Per BOE before hedging	48.38	47.01	33.64
Per BOE after hedging	46.67	41.62	30.32
Average operating cost - oil and gas production (per BOE)	12.69	11.79	10.09

Mbbl - Thousands of barrels
MMcf - Million cubic feet
Bcf - Billion cubic feet
BOE - Barrels of oil equivalent
MBOE - Thousand barrels of oil equivalent
(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 thousand cubic feet (Mcf) of natural gas to 1 barrel (Bbl) of oil. A barrel of oil is equivalent to 42 U.S. gallons

Acreage and Wells. As of December 31, 2006, our properties accounted for the following developed and undeveloped acres:

	Developed Acres		Undeveloped Acres		Total	
	Gross	Net	Gross	Net	Gross	Net
California	7,559	7,559	7,038	7,038	14,597	14,597
Colorado	86,504	70,504	166,994	80,602	253,498	151,106
Illinois	-	-	6,161	5,552	6,161	5,552
Kansas	-	-	467,623	293,311	467,623	293,311
Nebraska	-	-	124,025	57,756	124,025	57,756
North Dakota	-	-	207,476	49,186	207,476	49,186
Utah (1) (2)	13,960	13,800	145,425	88,454	159,385	102,254
Wyoming	3,800	750	3,146	1,130	6,946	1,880
Other	80	19	-	-	80	19
	111,903	92,632	1,127,888	583,029	1,239,791	675,661

(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 and 125,000 gross (23,000 net) acres at Lake Canyon (shallow) and Lake Canyon (deep), respectively, which we can earn upon fulfilling specific drilling obligations.

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, 2006, we have 3,050 gross productive wells (2,531 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:

		2006		2005		2004
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells drilled (1):						
Productive	7	3	13	6	5	5
Dry (2)	5	1	1	1	-	-
Development wells drilled:						
Productive	532	356	213	176	123	111
Dry (2)	7	5	7	5	-	-
Total wells drilled:						
Productive	539	359	226	182	128	116
Dry (2)	12	6	8	6	-	-

(1) 2005 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.

		2006
	Gross	Net
Total productive wells drilled:		
Oil	258	254
Gas	281	105

Dry hole, abandonment and impairment. See Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operation.

Company Owned Drilling Rigs. During 2005 and 2006, we purchased three drilling rigs, two of which are operational. Our third rig is being refurbished and is scheduled to begin drilling in the Piceance in 2007. Owning these rigs allows us to successfully meet a portion of our drilling needs in the Uinta and Piceance basins. See Note 10 to the financial statements.

Other. At year-end, we had no subsidiaries, no special purpose entities and no off-balance sheet debt. We did not enter into any material related party transactions in 2006.

Environmental and Other Regulations. We are committed to responsible management of the environment and prudent health and safety policies, 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 to 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 Item 1A 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 regulations include requiring permits for the drilling of wells, the drilling bonds and the 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 notifying of 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, to Native American oil and gas leases and other exploration agreements, fees, taxes, or 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 the Federal Energy Regulatory Commission (FERC) provided incentives for the development of cogeneration facilities such as ours. A domestic electricity generating project must be a QF under FERC regulations in order to benefit from 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. Such a determination has not been made for our service areas in California. This amendment does not affect any of our current SO contracts. FERC issued an order on October 20, 2006 implementing this amendment to PURPA and on December 20, 2006 issued a subsequent order granting limited rehearing of the October 20, 2006 order. FERC regulations also permit QFs and utilities to negotiate agreements for utility purchases of power at rates lower than the utilities' avoided costs.

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.

Forward Looking Statements

“Safe harbor under the Private Securities Litigation Reform Act of 1995:” Any statements in this Form 10-K that are not historical facts are forward-looking statements that involve risks and uncertainties. Words such as “will,” “might,” “intend,” “continue,” “target(s),” “expect,” “achieve,” “strategy,” “future,” “may,” “could,” “goal(s),”, “forecast,” “anticipate,” or other words or phrases, or the negative of those words, and other words of similar meaning indicate forward-looking statements and important factors which could affect actual results. Forward-looking statements are made based on management’s current expectations and beliefs concerning future developments and their potential effects upon Berry Petroleum Company. These items are discussed at length in Part I, Item 1A on page 15 of this Form 10-K filed with the Securities and Exchange Commission, under the heading “Risk Factors.”

Item 1A. Risk Factors

Other Factors Affecting the Company's Business and Financial Results

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 our debt and our ability to borrow and raise additional capital. The amount we can borrow under our senior unsecured revolving credit facility (see Note 6 to the financial statements) 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, and perceptions of 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

We have multiple hedges placed on our oil and gas production. See Item 7A Quantitative and Qualitative Disclosures About Market Risk.

Our heavy crude in California is less economic than lighter crude oil and natural gas. As of December 31, 2006, approximately 66% of our proved reserves, or 99 million barrels, consisted of heavy oil. Light crude oil represented 9% and natural gas represented 25% 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 NYMEX, the U.S. benchmark crude oil, 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.

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 oil sells at a discount to WTI, 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 contracts are currently priced at approximately $13 to $20 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. See firm transportation summary schedule at Item 1 Business.

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.

Utah - As of December 31, 2006, our Utah light crude oil is sold under multiple contracts with different purchasers for varying pricing terms and ranging from one month to nine months. As of December 31, 2006 we had firm contracts for 4,250 barrels per day (Bbl/D). These contracts are currently priced at approximately $13 to $20 per barrel below WTI with certain volumes tied to field posting, and in some cases our realized price is further reduced by transportation charges. As operator we deliver all produced volumes pursuant to these contracts, although our working interest partners or royalty owners may take their respective volumes in kind and market their own volumes. Our net volumes from our Brundage Canyon properties approximate 80% of the total gross volumes. Assuming all the Brundage Canyon wells are producing, the gross production could exceed these contracted volumes. We experienced increasing difficulty in locating additional buyers of our crude oil production from this region in 2006. Our Utah crude oil is a paraffinic crude, locally known as a black wax 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.

On February 27, 2007, we entered into a multi-staged crude oil sales contract with a subsidiary of Holly Corporation (Holly) for our Uinta basin crude oil. Under the agreement, Holly will begin purchasing 3,200 Bbl/D beginning July 1, 2007. Upon completion of their Woods Cross refinery expansion in Salt Lake City, which is expected in mid 2008, Holly will increase their total purchased volumes to 5,000 Bbl/D through June 30, 2013. Pricing under the contract, which includes transportation, is a fixed percentage of WTI and approximates our expected field posted price of $13 to $16 below WTI. 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 3,500 Bbl/D, our revenues were lower by approximately $9.2 million in 2006 as compared to 2005. If this pricing continues throughout 2007, with our Holly contract in place and on the same volumes, we estimate our revenues will be lower by approximately $8.6 million versus our 2006 revenues. We may adjust our capital expenditures in the Uinta basin due to various factors, including the timing of refinery demand for the Uinta barrels and the actual or expected change in our realized price.

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, combined, provide approximately 40% 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 necessary to 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 approximately 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 and natural gas. 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, develop or to 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 to 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 the impact of basis differentials, or if there are substantial downward adjustments to our estimated proved reserves, increases in estimates of development and/or operating 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. See Item 7A Quantitative and Qualitative Disclosures About Market Risk for our hedge position on February 9, 2007.

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 of 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. For instance, 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 insurance coverage we deem appropriate 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. 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.

Recent and future environmental regulations, including additional 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 and gas we produce. On September 27, 2006, California’s governor signed into law Assembly Bill (AB) 32, which establishes a statewide cap on greenhouse gases (GHG) for 2020 based on 1990 emission levels. The California Air Resources Board (CARB) has been designated as the lead agency to establish and adopt regulations to implement AB 32 (GHG Regulations) by January 1, 2012. We will continue to monitor the establishment of GHG Regulations through industry trade groups and other organizations in which we are a member. While California’s GHG Regulations apply only to operations within California, similar regulations may be adopted in other states in which we conduct business or on a Federal level in the future.

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. 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. Such a determination has not been made for our service areas in California. This amendment does not affect any of our current SO contracts. FERC issued an order on October 20, 2006 implementing this amendment to PURPA and on December 20, 2006 issued a subsequent order granting limited rehearing of the October 20, 2006 order. FERC regulations also permit QFs and utilities to negotiate agreements for utility purchases of power at rates lower than the utilities' avoided costs.

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 with additional development potential and properties with minimal production at acquisition but significant growth potential, 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 December 31, 2006, we own three drilling rigs, one of which is drilling on our property, and have additional one-year contract commitments on another three drilling rigs. See contractual obligations in Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operation.

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.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Information required by Item 2 Properties is included under Item 1 Business.

Item 3. Legal Proceedings

While we are, from time to time, a party to certain lawsuits in the ordinary course of business, we do not believe any of such existing lawsuits will have a material adverse effect on our operations, financial condition, or liquidity.

Item 4. Submission of Matters to a Vote of Security Holders

No matters were submitted to a vote of security holders during the most recently ended fiscal quarter.

Executive Officers. Listed below are the names, ages (as of December 31, 2006) and positions of our executive officers and their business experience during at least the past five years. All our officers are reappointed in May of each year at an organizational meeting of the Board of Directors. There are no family relationships between any of the executive officers and members of the Board of Directors.

ROBERT F. HEINEMANN, 53, has been President and Chief Executive Officer since June 2004. Mr. Heinemann was Chairman of the Board and interim President and Chief Executive Officer from April 2004 to June 2004. From December 2003 to March 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 CEO. Mr. Heinemann joined the Board in March of 2003. 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, with his last responsibilities as Vice President of Mobil Technology Company and General Manager of the Mobil Exploration and Producing Technical Center.

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 an Assistant Secretary.

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 an Assistant Secretary.

DAN ANDERSON, 44, has been Vice President of Rocky Mountain/Mid-Continent Production since October 2005. Mr. Anderson was Rocky Mountain/Mid-Continent Manager of Engineering from August 2003 through October 2005. Mr. Anderson 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 us. Mr. Ayers served as a Manager of 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, previously served as the Production Engineering Supervisor for Atlantic Richfield Corp. (ARCO) 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/Mid-Continent Exploration since October 2005. Mr. Kelso was Rocky Mountain/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 held the position of Vice President of Exploration and Development at Redstone Resources, Inc. from 2000 to 2001.

SHAWN M. CANADAY, 31, 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 presently an Assistant Secretary. Effective March 2, 2007, Mr. Canaday will replace Mr. Wilson as Controller.

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

STEVEN B. WILSON, 43, has been Controller since January 2007. Mr. Wilson had been Assistant Controller since November 2003 and before joining us in November 2003, served as the vice president of finance and administration for Accela, Inc., a software development company, for three years. Prior to that, he held finance functions in select companies and in public accounting. Effective March 2, 2007, Mr. Wilson will replace Mr. Canaday as Treasurer and will also be an Assistant Secretary.

PART II

Item 5. Market for the Registrant’s Common Equity and Related Shareholder Matters and Issuer Purchases of Equity Securities

Shares of Class A Common Stock (Common Stock) and Class B Stock, referred to collectively as the "Capital Stock," are each entitled to one vote and 95% of one vote, respectively. Each share of Class B Stock is entitled to a $.50 per share preference in the event of liquidation or dissolution. Further, each share of Class B Stock is convertible into one share of Common Stock at the option of the holder.

In November 1999, we adopted a Shareholder Rights Agreement and declared a dividend distribution of one such Right for each outstanding share of Capital Stock on December 8, 1999. Each share of Capital Stock issued after December 8, 1999 includes one Right. The Rights expire on December 8, 2009. See Note 7 to the financial statements.

Our Class A Common Stock is listed on the New York Stock Exchange (NYSE) under the symbol BRY. The Class B Stock is not publicly traded. The market data and dividends for 2006 and 2005 are shown below:

	2006			2005		
	High	Price Range Low	Dividends Per Share	High (1)	Price Range Low (1)	Dividends Per Share (1)
First Quarter	$ 39.98	$ 28.60	$ .065	$ 33.05	$ 21.93	$ .060
Second Quarter	39.00	27.27	.065	27.48	20.39	.060
Third Quarter	35.77	26.07	.095	33.50	26.15	.115
Fourth Quarter	33.69	25.71	.075	34.33	26.15	.065
Total Dividend Paid			$ .300			$ .300

	February 9, 2007	December 31, 2006	December 31, 2005 (1)
Berry's Common Stock closing price per share as reported on NYSE Composite Transaction Reporting System	$ 30.55	$ 31.01	$ 28.60

(1) The 2005 amounts have been restated to give retroactive effect to the two-for-one stock split that became effective on May 17, 2006.

The number of holders of record of our Common Stock was 543 as of February 9, 2007. There was one Class B Shareholder of record as of February 9, 2007.

Dividends. We paid a special dividend of $.02 per share on September 29, 2006 and increased our regular quarterly dividend by 15%, from $.065 to $.075 per share beginning with the September 2006 dividend. Our regular annual dividend is currently $.30 per share, payable quarterly in March, June, September and December. We paid a special dividend of $.05 per share on September 29, 2005 and increased our regular quarterly dividend by 8%, from $.06 to $.065 per share beginning with the September 2005 dividend.

Since our formation in 1985 through December 31, 2006, we have paid dividends on our Common Stock for 69 consecutive quarters and previous to that for eight consecutive semi-annual periods. We intend to continue the payment of dividends, although future dividend payments will depend upon our level of earnings, operating cash flow, capital commitments, financial covenants and other relevant factors. Dividend payments are limited by covenants in our 1) credit facility to the greater of $20 million or 75% of net income, and 2) bond indenture of up to $20 million annually irrespective of our coverage ratio or net income and up to $10 million in the event we are in a non-payment default.

As of December 31, 2006, dividends declared on 7,793,080 shares of certain Common Stock are restricted, whereby we pay 37.5% of the dividends declared on these shares to the surviving member of a group of individuals, the B group, for as long as this remaining member shall live.

Equity Compensation Plan Information.

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance
Equity compensation plans approved by security holders	3,318,991	$20.97	1,252,344
Equity compensation plans not approved by security holders	none	none	none

Issuer Purchases of Equity Securities.

In June 2005, we announced that our Board of Directors authorized a share repurchase program for up to an aggregate of $50 million of our outstanding Class A Common Stock. From June 2005 through December 31, 2006, we have purchased 818,000 shares in the open market for approximately $25 million. In 2006, our repurchases increased diluted earnings by $.03 per share.

In December 2005, we adopted a plan under Rule 10b5-1 of the Securities Exchange Act of 1934 to facilitate the repurchase of our shares of common stock. Rule 10b5-1 allows a company to purchase its shares at times when it would not normally be in the market due to possession of nonpublic information, such as the time immediately preceding its quarterly earnings releases. This plan expired on December 1, 2006. This 10b5-1 plan was authorized under, and administered consistent with, our $50 million share repurchase program. We may repurchase shares in the open market from time to time during our normal trading windows or under a new plan under 10b5-1. All repurchases of common stock are made in compliance with regulations set forth by the SEC and are subject to market conditions, applicable legal requirements and to other factors.

This share repurchase program does not obligate us to acquire any particular amount of common stock and the plan may be suspended at any time at our discretion.

Period	Total number of shares purchased	Average price paid per share	Total number of shares purchased as part of publicly announced plans or programs	Maximum number (or approximate dollar value) of shares that may yet be purchased under the plans or programs
Fiscal Year 2005 (1)	217,800	$ 29.00	217,800	$ 43,684,500
First Quarter 2006	60,000	30.04	60,000	41,882,036
Second Quarter 2006	347,700	31.55	347,700	30,912,780
Third Quarter 2006	92,500	32.37	92,500	27,918,703
October 2006	100,000	29.48	100,000	24,971,116
Total	818,000	$ 30.60	818,000	$ 24,971,116

(1) The 2005 share amounts have been restated to give retroactive effect to the two-for-one stock split that became effective on May 17, 2006.

Performance Graph

This graph shall not be deemed “filed” for purposes of Section 18 of the Securities and Exchange Act of 1934 (the “Exchange Act”) or otherwise subject to the liabilities of that section nor shall it be deemed incorporated by reference in any filing under the Securities Act of 1933 or the Exchange Act, regardless of any general incorporation language in such filing.

Total returns assume $100 invested on December 31, 2001 in shares of Berry Petroleum Company, the Russell 2000, the Standard & Poors 500 Index (S&P 500) and two Peer Groups, assuming reinvestment of dividends for each measurement period. In the proxy statement filed in 2006, we added Peer Group 1, which contains 10 companies, which we used for comparisons that year, and in this Form 10-K we added Peer Group 2. We believe Peer Group 2 is a better comparison index for our performance graph based on similar types of assets and market capitalization.

We intend to discontinue the use Peer Group 1 after this year's report on Form 10-K. The information shown is historical and is not necessarily indicative of future performance. The ten companies which make up Peer Group 1 are as follows: Bill Barrett Corp. (publicly traded since December 10, 2004), Cabot Oil & Gas Corp., Cimarex Energy Co. (publicly traded since September 30, 2002), Comstock Resources Inc., Denbury Resources Inc., Encore Acquisition Co. (publicly traded since March 9, 2001), Energy Partners Ltd., Range Resources Corp., St. Mary Land & Exploration Co. and Whiting Petroleum Corp. (publicly traded since November 20, 2003).

The 16 companies which make up Peer Group 2 (to be used going forward) are as follows: Bill Barrett Corp., Cabot Oil & Gas Corp., Cimarex Energy Co., Comstock Resources Inc., Denbury Resources Inc., Encore Acquisition Co., Forest Oil Corp., Houston Exploration Co., Petrohawk Energy Corp., Plains Exploration & Production Co., Quicksilver Resources Inc., Range Resources Corp., St. Mary Land & Exploration Co., Stone Energy Corp., Swift Energy Co., Whiting Petroleum Corp.

	12/01	12/02	12/03	12/04	12/05	12/06
Berry Petroleum Company	100.00	111.30	135.80	325.26	393.93	431.40
S & P 500	100.00	77.90	100.24	111.15	116.61	135.03
Russell 2000	100.00	79.52	117.09	138.55	144.86	171.47
Peer Group 1	100.00	125.10	172.17	267.33	393.25	402.45
Peer Group 2	100.00	101.28	133.38	202.06	291.67	294.64

Item 6. Selected Financial Data

The following table sets forth certain financial information and is qualified in its entirety by reference to the historical financial statements and notes thereto included in Item 8 Financial Statements and Supplementary Data. The statement of income and balance sheet data included in this table for each of the five years in the period ended December 31, 2006 were derived from the audited financial statements and the accompanying notes to those financial statements (in thousands, except per share, per BOE and % data).

	2006	2005	2004	2003	2002
Audited Financial Information					
Statement of Income Data:					
Sales of oil and gas	$ 430,197	$ 349,691	$ 226,876	$ 135,848	$ 102,026
Sales of electricity	52,932	55,230	47,644	44,200	27,691
Operating costs - oil and gas production	117,624	99,066	73,838	57,830	41,108
Operating costs - electricity generation	48,281	55,086	46,191	42,351	26,747
Production taxes	14,674	11,506	6,431	3,097	2,907
General and administrative expenses (G&A)	36,841	21,396	22,504	14,495	10,417
Depreciation, depletion & amortization (DD&A)					
Oil and gas production	67,668	38,150	29,752	17,258	13,388
Electricity generation	3,343	3,260	3,490	3,256	3,064
Net income	107,943	112,356	69,187	32,363	29,210
Basic net income per share (1)	2.46	2.55	1.58	.74	.67
Diluted net income per share (1)	2.41	2.50	1.54	.73	.67
Weighted average number of shares outstanding (basic) (1)	43,948	44,082	43,788	43,544	43,482
Weighted average number of shares outstanding (diluted) (1)	44,774	44,980	44,940	44,062	43,804
Balance Sheet Data:					
Working capital	$ (100,594)	$ (54,757)	$ (3,840)	$ (3,540)	$ (2,892)
Total assets	1,198,997	635,051	412,104	340,377	259,325
Long-term debt	390,000	75,000	28,000	50,000	15,000
Shareholders' equity	427,700	334,210	263,086	197,338	172,774
Cash dividends per share (1)	.30	.30	.26	.24	.20
Operating Data:					
Cash flow from operations	243,229	187,780	124,613	64,825	57,895
Exploration and development of oil and gas properties	265,110	118,718	71,556	41,061	30,163
Property/facility acquisitions	257,840	112,249	2,845	48,579	5,880
Additions to vehicles, drilling rigs and other fixed assets	21,306	11,762	669	494	469
Unaudited Operating Data					
Oil and gas producing operations (per BOE):					
Average sales price before hedging	$ 48.38	$ 47.01	$ 33.64	$ 24.48	$ 20.11
Average sales price after hedging	46.67	41.62	30.32	22.52	19.39
Average operating costs - oil and gas production	12.69	11.79	10.09	9.57	7.83
Production taxes	1.58	1.37	.86	.51	.55
G&A	3.98	2.55	2.99	2.40	1.98
DD&A - oil and gas production	7.30	4.54	3.96	2.86	2.55
Production (MBOE)	9,270	8,401	7,517	6,040	5,251
Production (MMWh)	757	741	776	767	748
Proved Reserves Information:					
Total BOE	150,262	126,285	109,836	109,920	101,719

Standardized measure (2)	$ 1,182,268	$ 1,251,380	$ 686,748	$ 528,220	$ 449,857
Year-end average BOE price for PV10 purposes	41.23	48.21	29.87	25.89	24.91
Other:					
Return on average shareholders' equity	28.33%	37.63%	31.06%	17.50%	17.90%
Return on average capital employed	18.21%	32.74%	26.29%	15.44%	16.42%

(1) All earnings per share and share amounts have been restated to give retroactive effect to the two-for-one stock split that became effective on May 17, 2006.
(2) See Supplemental Information About Oil & Gas Producing Activities.

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Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation

Overview. Our mission is to increase shareholder value 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 2006.

- Achieved record production which averaged 25,398 BOE/D, up 10% from 2005
- Achieved record cash from operating activities of $243 million, up 29% from 2005
- Achieved net income of $108 million, down 4% from 2005
- Added 33.4 million BOE of proved reserves before production ending 2006 at 150.3 million BOE
- Achieved reserve replacement rate of 359%
- Expended $554 million of capital expenditures, including $286 million of developmental capital expenditures
- Acquired operatorship and 50% working interest in 6,300 gross acres of 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 Garden Gulch assets
- Announced development of our diatomite asset (heavy oil) with a 100 well drilling program scheduled for 2007 in the Midway-Sunset field, California
- Discovered light oil accumulations in the Green River and Wasatch formations at Lake Canyon, Uinta basin, Utah
- Added financial capacity by increasing our senior unsecured revolving credit facility to $750 million with an initial borrowing base of $500 million
- Issued $200 million of ten year 8.25% senior subordinated notes in October 2006
- Completed two-for-one split of Class A Common Stock and Class B Stock
- Increased our regular quarterly dividend by 15% to $.075 per share ($.30 annually) and declared a special dividend of $.02 per share

Notable Items and Expectations for 2007.

- Expecting 2007 developmental capital expenditures to approximate $227 million to $267 million
- Targeting a 20% to 25% increase in 2007 year end proved reserves, or 175 to 185 MMBOE
- Beginning major development of our Piceance assets with over 55 to 65 wells planned
- Targeting net average production of between 27,000 and 28,000 BOE/D
- Entered into a long-term crude oil sales contract for our Uinta basin, Utah production
- Potential divestiture of non-strategic assets to focus on our large resource development opportunities

Overview of the Fourth Quarter of 2006. We achieved record production of 26,887 BOE/D even though we reduced production in the Uinta basin (estimated impact to the fourth quarter of 2006 was approximately 2,000 Bbl/D) due to an unscheduled refinery shutdown. The refinery resumed operations in mid-January 2007. Our price differential for our black wax crude oil in the Uinta basin widened causing lower realizations and negatively impacted our earnings for the quarter. Improving the demand for this crude has been a major challenge. This situation, and generally weaker oil and gas prices, lowered our realized prices by 11% compared to the third quarter of 2006.

View to 2007. Our challenge for 2007 is to manage our business in a rapidly changing price and operating environment while adding significant reserves through the drill bit. We have an extensive inventory of development drilling in several basins, and expect our program to be the most influenced by production and reserve growth in the Piceance basin. We intend our capital program, excluding acquisitions, to closely reflect our cash flow from operations. Additional funds may be provided by the divestiture of several non-strategic assets, including our Montalvo properties, Bakken acreage and others. We have six asset teams, three in California and three in the Rocky Mountain/Mid-Continent region, and each team has specific targets on production, reserve growth, capital expenditures and operating costs. We believe managing our assets in this manner will maximize operational efficiencies and add the most value to our shareholders. We will manage our balance sheet prudently, and while we are focused on the continuing development of our existing assets, we will continue to evaluate acquisition opportunities that fit our growth strategy.

View to the First Quarter of 2007. Crude oil prices (WTI) were volatile in the first quarter ranging from $50.48 per barrel WTI to $61.39 per barrel and we expect oil and gas prices to remain volatile in 2007. On February 27, 2007 we entered into a long-term (six year) crude oil sales contract for our Uinta basin production. This contract will allow us to improve our margins on these barrels beginning on July 1, 2007 and provides us assurance of deliverability and return on our investment. We are accelerating our investment in our Poso Creek, California properties due to its excellent response to our 2006 development activity. Our total net production volumes in the first quarter are expected to average between 24,000 and 26,000 BOE/D.

Piceance Basin - Our New Core Area. In 2006, we made two separate significant investments in the gas rich Piceance basin in Colorado, targeting the Williams Fork section of the Mesaverde formation. We spent $312 million (balance of $54 million due in 2007) to acquire a high working interest in several prime blocks of acreage located in the Grand Valley field. Most of the acreage was undeveloped and we added only 4.3 MMBOE in proved reserves from these acquisitions. We believe we have accumulated a very sizable resource base which will allow us to add significant proved reserves over the next five years. We believe we have over 1,000 drilling locations on this acreage. We are anticipating initial gross production ranging from 1.3 to 2.0 MMcf per well with the ultimate risked gross recovery of approximately 1.5 Bcf per well. Well costs are expected to be in the $1.8 million to $2.5 million range per well and we are targeting average depths of between 10,000 feet to 12,000 feet. We anticipate running four rigs in 2007 to develop this asset.

Capital expenditures. Our capital expenditures for 2006 totaled $553 million consisting of $258 million for acquisitions, $265 million for exploration and development, $21 million for drilling rigs and other assets and $9 million of capitalized interest. We funded these items from $243 million of operating cash flow and $310 million from additional borrowings. This compares to our total capital expenditures in 2005 of $243 million, which consisted of $112 million of acquisitions, $119 million in exploration and development and $12 million in drilling rigs and other assets.

Excluding the acquisition price of new properties, in 2007 we have a developmental capital program of approximately $267 million and we will make a final payment of $54 million associated with our Piceance joint venture. We are proceeding with this program, but may revise our plans due to lower commodity price expectations, to the timing of crude deliveries out of the Uinta basin, to equipment availability, to permitting or other factors.

Our 2007 capital program allows us to continue high activity levels and as a result, we are targeting 2007 production to average between 27,000 BOE/D to 28,000 BOE/D. In 2007, we expect production to be approximately 62% heavy oil, 11% light oil and 27% natural gas and anticipate funding our development capital program primarily from internally generated cash flow. We have currently secured the necessary equipment and are meeting permit requirements to achieve the 2007 program.

Development, Exploitation and Exploration Activity. We drilled 568 gross (382 net) wells during 2006, realizing a gross success rate of 98 percent. Excluding any future acquisitions, our targeted 2007 developmental capital budget is $267 million. As of December 31, 2006, we have four rigs drilling on our properties under long-term contracts and have several more rigs scheduled to begin in early 2007.

Drilling Activity. The following table sets forth certain information regarding drilling activities for the year ended December 31, 2006:

	Gross Wells	Net Wells
SMWSS	50	50

NMWSS	81	80
Socal *(1)*	38	38
Piceance	68	11
Uinta *(2)*	108	106
DJ *(3)*	223	97
Totals	**568**	**382**

(1) Includes 1 gross well (1 net well) that was a dry hole at North Midway-Sunset.

(2) Includes 2 gross wells (2 net wells) that were dry holes at Coyote Flats.

(3) Includes 5 gross wells (2.4 net wells) that were dry holes in Tri-State and 4 gross wells (.3 net well) that were dry holes in Bakken.

Net Oil and Gas Producing Properties at December 31, 2006.

Name, State	% Average Working Interest	Total Net Acres	Proved Reserves (BOE) in thousands	Proved Developed Reserves (BOE) in thousands	% of Total Proved Reserves	Proved Undeveloped Reserves (BOE) in thousands	% of Total Proved Reserves	Average Depth of Producing Reservoir (feet)
SMWSS, CA	99	2,081	50,124	43,668	*29.1%*	6,455	*4.3%*	1,700
Uinta, UT	100	13,800	21,093	11,922	*7.9*	9,171	*6.1*	6,000
Socal, CA	100	3,580	33,441	17,972	*12.0*	15,469	*10.3*	1,200 to 11,500
DJ, CO/KS/NE	47	67,344	18,620	10,374	*6.9*	8,246	*5.5*	2,600
NMWSS, CA	100	1,898	16,343	16,343	*10.9*	-	-	1,500
Piceance, CO	5 to 95	3,160	10,641	1,991	*1.3*	8,650	*5.7*	9,300
Totals			**150,262**	**102,270**	***68.1%***	**47,991**	***31.9%***	

Our asset base has changed considerably since early 2003. As of December 31, 2006, we had 150 MMBOE of proved reserves and have abundant drilling inventories at several of our core areas. Generally, our California assets are mature (diatomite and Poso Creek are the exception) and generate more cash flow from operations than is required to reinvest in these assets. We have high capital needs in the Piceance, Uinta and the DJ basins, where we have large undeveloped resources. We anticipate spending most of our operating cash flow over the next several years in converting the recoverable hydrocarbons to production, cash flow and earnings.

California

California's three asset teams are South Midway-Sunset (SMWSS), North Midway-Sunset (NMWSS) (which includes diatomite) and Southern California (Socal) (which include Poso Creek, Ethel D, Placerita and Montalvo). Approximately $91 million will be invested in California projects in 2007 with $9 million, $55 million and $27 million allocated for the SMWSS, NMWSS and Socal assets, respectively.

SMWSS, San Joaquin Valley Basin (SJVB) - We own and operate working interests in 38 properties, including 23 owned in fee, in the Midway-Sunset field. Production from this field relies on thermal EOR methods, primarily cyclic steaming.

2006 - Development activities were focused on horizontal drilling.

2007 - Capital is focused on further horizontal infill well drilling, targeting steam injection wells and improved subsurface well monitoring.

Production averaged approximately 10,000 Bbl/D in 2006. This is our most mature thermally enhanced asset and we are developing and testing new concepts to place heat into the remaining oil column to maximize recovery and value. We are also improving our steam monitoring capabilities to verify efficient steam placement.

NMWSS, SJVB - On November 1, 2006, we announced our plans to commence development of our Midway-Sunset diatomite oil project in California based on the performance of a two-year pilot program. We believe the project will be a significant asset for our California operations and for Berry. The project will add material production and reserves as a part of our growth strategy. Over the next four years, we intend to invest an additional $210 million in capital to drill 520 shallow development wells in the fairway of the asset and add steam generation and processing facilities. We expect this development will increase production by up to 7,000 Bbl/D by 2010 (in 2006 the project averaged 325 Bbl/D). As we develop the fairway, we will also appraise the potential of recovering additional reserves in the outer portions of our acreage in subsequent development phases. We believe that the fairway contains 55% of the oil resource and has reservoir properties similar to our initial pilot. This will enable a repeatable development like those used in our other California assets.

2006 - Completed commercial testing.

2007 - Capital is focused on drilling the diatomite first phase development wells and adding steam generation equipment and various facilities. We will also be initiating steam drive pilots in one of our largest remaining hydrocarbon resources in the Tulare sands on our Main Camp property in the Midway-Sunset field.

During 2006 we redeveloped our Pan property on the non-diatomite section of NMWSS by drilling over 40 infill locations and adding steam generation capacity and associated production facilities. Production responded by increasing from approximately 100 Bbl/D to a peak of over 800 Bbl/D. Further infill drilling locations are currently being evaluated.

Socal, SJVB and Los Angeles Basin - We acquired the Poso Creek properties in early 2003 and have proceeded with a successful thermal EOR redevelopment. At acquisition the property was producing less than 50 BOE/D and we averaged 940 Bbl/D in 2006.

2006 - Activity was directed at delineating the extent of the reservoir, infill drilling and expansion of the steam drive pilot. Production from this property increased as a result of thermal redevelopment steadily throughout the year from approximately 500 Bbl/D to over 1,500 Bbl/D at December 31, 2006. Additional steam generation capacity was added during the first half of the year along with 15 infill/delineation wells and late in the fourth quarter we began drilling 20 additional infill wells.

2007 - Capital is directed at drilling 34 infill producer locations, adding additional steam generation capacity and expanding the steam drive area.

In the Placerita field in the Los Angeles basin, we own and operate working interests in 13 properties, including 9 leases and 4 fee properties. Production relies on thermal recovery methods, primarily steam flooding.

2006 - We reassessed our existing steam drive and discovered additional remaining reserves within the existing mature steam drive area. Several infill wells were drilled and confirmed our assessment. Further reservoir analysis/simulation is in progress to determine the optimum recovery method.

2007 - Capital is directed at steam flood modifications and facility improvements.

We will also be initiating steam drive pilots in the other largest remaining hydrocarbon resources in the Monarch sands at Ethel D property in the Midway-Sunset field. We are pursuing the divestment of our Montalvo properties in Ventura County, California and have no capital allocated to the asset, which produced over 700 Bbl/D in 2006.

Rocky Mountain/Mid-Continent

We reorganized the structure of the Rocky Mountain/Mid-Continent region into three regional asset teams in late 2006 to strengthen our technical and business focus in the region. The three asset teams are centered around the Piceance basin Mesaverde gas development, the Uinta basin Green River and Wasatch oil exploitation and the DJ basin Niobrara gas projects. Approximately $176 million will be invested in Rocky Mountain region projects in 2007 with $118 million, $37 million and $21 million earmarked for the Piceance, Uinta and DJ basins, respectively.

Piceance Basin, Colorado - In February 2006, we acquired a 50% working interest in 6,300 gross acres in the Garden Gulch property in the Grand Valley natural gas field in the Piceance basin of western Colorado for approximately $159 million. Then in June 2006, we entered into an agreement with an industry partner to jointly develop (our commitment under the agreement is approximately $153 million) the North Parachute Ranch property in the Grand Valley field in the Piceance immediately east of the Garden Gulch property. In accordance with the agreement we acquired a 5% non-operating working interest on 6,300 gross acres and a net operating working interest of 95% in 4,300 gross acres. We have financial commitments under both the 5% and the 95% working interests. See Note 5 to the financial statements. This agreement for the North Parachute Ranch property expands upon our reserves and drilling opportunities with an additional 400 locations. Production from these wells is expected to be similar to Garden Gulch wells, with initial gross production rates ranging from 1.3 to 2.0 MMcf/D.

2006 - We drilled 17 gross wells, 15 on the Garden Gulch property and two on the North Parachute Ranch property. Our industry partner drilled 53 gross wells upon which we earned 5% non-operating working interest. Our net production in 2006 averaged 4,300 Mcf/D. We have contracts for four rigs as of December 31, 2006 to proceed with our development plan. We have made significant progress in gearing up for extensive development of this asset, including additional outlets for gas sales. The Garden Gulch acreage now has 13 wells producing and initial production from the North Parachute Ranch property began late in the fourth quarter.

2007 - Capital is directed at drilling 55 to 65 Mesaverde wells along with associated land, facility and water disposal projects.

Uinta Basin, Utah - The Brundage Canyon leasehold in Duchesne County, northeastern Utah consists of federal, tribal and private leases.

2006 - We continued the development of the Green River formation, including testing 20-acre infill wells to assist full development, including a 20-acre spacing pilot. During the year infield gas gathering infrastructure was upgraded with additional compression and a gas processing facility to handle increasing volumes of natural gas. In the fourth quarter of 2006, an Environmental Assessment (EA) was completed in the Ashley National Forest, clearing the way for 14 drillsites and up to 29 wells. We were able to drill and complete one well before winter access restrictions went into effect. In 2006, we drilled 101 total net wells in Brundage with 100% success rate. Daily net production averaged approximately 5,800 BOE/D.

2007 - Capital is directed at the Ashley Forest, additional 20-acre infills and high-graded locations across the field. The majority of this development program is targeted for the second half of the year due to winter wildlife stipulations.

In the Lake Canyon prospect, we hold, with an industry partner, a 169,000 gross acre block which is located immediately west of our Brundage Canyon producing properties. We will drill and operate the shallow wells which target light oil and natural gas in the Green River formation and retain up to a 75% working interest. Our partner will drill and operate deep wells which target hydrocarbons in the Mesaverde and Wasatch formations. We will hold up to a 25% working interest in these deep wells. The Ute Tribe has the option to participate in each well and obtain a 25% working interest which would reduce our and our partner’s participation.

2006 - In January 2006, we announced commercial success from our first two wells on this acreage, from the same Green River formation that is productive immediately east (approximately three miles) in our Brundage Canyon field. 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, as the Ute Tribe elected to participate. In the third quarter, with Tribal participation, we drilled four additional shallow Green River wells that are all productive.

In the second quarter of 2006, our industry partner initiated production from a deep well completed in the Wasatch formation. Due to the success of this Wasatch discovery well, our industry partner drilled two additional Wasatch wells in the fourth quarter of 2006. These wells are currently waiting on completion. We have an 18.75% working interest in these two wells, as the Ute Tribe elected to participate in one of the two wells. Our daily net production from the Lake Canyon wells averaged approximately 87 BOE/D.

2007 - We are in the permitting process for an additional 16 shallow Green River wells which are intended to continue exploratory and development drilling on the eastern portion of our Lake Canyon acreage. Our working interest in these wells will be either 75% or 56.25% depending on Tribal participation. Our industry partner is also permitting additional deep wells for their 2007 drilling program. Our 2007 capital is directed at a methodical appraisal covering a sizeable portion of this acreage block, targeting Green River and Wasatch reservoirs.

In December 2004, we entered into a development agreement with an industry partner to develop their Coyote Flats prospect. The property is located approximately 45 miles southwest of our Brundage Canyon property.

2006 - We have three successful appraisal Ferron gas wells on the east side of the Scofield reservoir which have each tested flow rates exceeding 1,000 Mcf/D. We renegotiated the farm out obligation terms with our industry partner to earn a 50% working interest in the approximate 69,250 gross (33,500 net) acres in the project without drilling the remaining Emery coalbed methane wells. Our earning obligation was satisfied by installing a gathering system, compression and 13 mile gas pipeline to connect the three previously announced Ferron gas discoveries to sales pipelines. Construction is complete and first sales were established in December 2006. Two of the three wells are currently on production with the third being temporarily shut-in pending a water disposal solution. Our daily net production is approximately 780 Mcf/D.

2007 - No capital has been directed at this project, pending results from production tests on the three discovery wells.

DJ Basin (includes eastern Colorado producing assets) - In 2005, we made three acquisitions for approximately $111 million establishing a core area in the Tri-State region (Eastern Colorado, western Kansas and southwestern Nebraska) totaling approximately 100,000 net producing acres and 315,000 net total acres. Our primary acquisition was the Niobrara gas producing assets in Yuma County in northeastern Colorado in which we have a working interest of approximately 52%. Our other two acquisitions in the region consisted of undeveloped prospective acreage where our working interests range from 40% to 50%.

2006 - We drilled 205 wells to add production from both proved undeveloped and probable reserves and five exploratory wells and our net production averaged 16,100 Mcf/D. We participated in five 3-D seismic surveys covering in excess of 130 square miles. In the third quarter, we installed additional compression, gas gathering pipelines and high pressure pipelines that expand the capacity and connections to new markets on the Cheyenne Plains Lateral system. In our Kansas Tri-State prospect, we have drilled and completed a successful exploratory well that is an extension to our Prairie Star production in Cheyenne County, Kansas and have drilled two dry holes in the year.

2007 - Capital is directed at development drilling for Yuma County reserve growth, additional 3-D seismic in Colorado and Kansas and additional exploration in Kansas.

Obstacles and Risks to Accomplishment of Strategies and Goals. See Item 1A Risk Factors for a detailed discussion of factors that affect our business, financial condition and results of operations.

Results of Operations. Approximately 88% of our revenues are generated through the sale of oil and natural gas production under either negotiated contracts or spot gas purchase contracts at market prices. The remaining 12% of our revenues are primarily derived from electricity sales from cogeneration facilities which supply approximately 40% of our steam requirement for use in our California thermal heavy oil operations. We have invested in these facilities for the purpose of lowering our steam costs which are significant in the production of heavy crude oil.

Revenues. Sales of oil and gas were up 23% in 2006 compared to 2005 and up 89% from 2004. 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 2006 were due to a tighter supply and demand balance and the nervousness of the market about possible supply disruptions. Oil and natural gas prices contributed roughly half of the revenue increase and the increase in production volumes contributed the other half. Approximately 77% of our oil and gas sales volumes in 2006 were crude oil, with 82% of the crude oil being heavy oil produced in California which was sold under contracts based on the higher of WTI minus a fixed differential or the average posted price plus a premium. Our oil contracts allowed us to improve our California revenues over the posted price by approximately $21 million, $41 million and $13 million in 2006, 2005 and 2004, respectively.

The following companywide results are in millions (except per share data) for the years ended December 31:

	2006	2005	2004
Sales of oil	$ 360	$ 289	$ 210
Sales of gas	70	61	17
Total sales of oil and gas	$ 430	$ 350	$ 227
Sales of electricity	53	55	48
Interest and other income, net	3	2	-
Total revenues and other income	$ 486	$ 407	$ 275
Net income	$ 108	$ 112	$ 69
Earnings per share (diluted)	$ 2.41	$ 2.50	$ 1.54

The following companywide results are in millions (except per share data) for the three months ended:

	December 31, 2006	December 31, 2005	September 30, 2006
Sales of oil	$ 84	$ 75	$ 98
Sales of gas	18	23	18
Total sales of oil and gas	$ 102	$ 98	$ 116
Sales of electricity	13	18	