BERRY PETROLEUM CO
Form 10-K
March 31, 2005

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, 2004**
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**

(Former name, former address and former fiscal year, if changed since last report)

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 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 an accelerated filer (as defined in Rule 12b-2 of the Act). YES x NO o

As of June 30, 2004, the aggregate market value of the voting stock held by non-affiliates was $519,158,260. As of March 14, 2005, the registrant had 21,119,120 shares of Class A Common Stock outstanding. The registrant also had 898,892 shares of Class B Stock outstanding on March 14, 2005 all of which is 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

Company Website

The Company has a website located at http://www.bry.com. The website can be used to access recent news releases and Securities and Exchange Commission filings, crude oil price postings, the Company's 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. The contents of the Company's website are not incorporated into this document. Securities and Exchange Commission filings, including supplemental schedules and exhibits can also be accessed free of charge through the SEC website at http://www.sec.gov.

General

Berry Petroleum Company, (Berry or Company), is an independent energy company engaged in the production, development, acquisition, exploitation and exploration of crude oil and natural gas. While the Company was incorporated in Delaware in 1985 and has been a publicly traded company since 1987, it can trace its roots in California oil production back to 1909. Currently, Berry's principal reserves and producing properties are located in the San Joaquin Valley, Los Angeles and Ventura Basins in California, the Uinta Basin in northeastern Utah and the Denver-Julesburg Basin in Colorado, Kansas and Nebraska. The Company's corporate headquarters are located in Bakersfield, California. The Company has a regional office in Denver, Colorado to manage its assets in the Rocky Mountain and Mid-Continent regions. Management believes that these facilities are adequate for its current operations and anticipated growth. Information contained in this report on Form 10-K reflects the business of the Company during the year ended December 31, 2004 unless noted otherwise.

The Company's mission is to increase shareholder value, primarily through maximizing the value and cash flow of the Company's assets. To achieve this, Berry's corporate strategy is to increase its net proved reserves annually, grow production annually and, in the process, increase both net income and cash flow in total and per share. To increase proved reserves and production, the Company will compete to acquire oil and gas properties with principally proved reserves and exploitation potential or sizeable acreage positions that the Company believes can ultimately contain substantial reserves which can be developed at reasonable costs. Additionally, the Company will continue to focus on the further development of its properties through developmental drilling, well completions, remedial work and by application of enhanced oil recovery (EOR) methods, as applicable. In conjunction with the goals of maximizing profitability and the exploitation and development of its substantial heavy crude oil base in California, the Company owns three cogeneration facilities which are intended to provide an efficient and secure long-term supply of steam necessary for the economic production of heavy oil. Berry views these assets as a key part of its long-term success. Berry believes that its primary strengths are its ability to maintain a cost-efficient operation, its ability to acquire attractive producing properties which have significant development, exploitation and enhancement potential and sizable prospective acreage blocks in or near producing areas, its strong financial position and its experienced management team and staff. The Company has identified the Rocky Mountain and Mid-Continent regions as its primary areas of interest for growth. The Company believes that it can be successful in growing its reserve base and production in a profitable manner by investing in certain assets in these regions and California. Additionally, it provides substantial opportunity for the Company to diversify its existing predominantly heavy crude oil base into light oil and natural gas. Strategically, the Company desires to increase its natural gas reserves and production as the Company consumes approximately 37,000 MMBtu daily as fuel for steam generation which is utilized in its California heavy oil operations. The Company has an unsecured credit facility with a current borrowing base of $200 million (at year-end 2004, $172 million is available) which may be utilized in adding reserves and production through acquisitions.

Proved Reserves

As of December 31, 2004, the Company's estimated proved reserves were 110 million barrels of oil equivalent, (BOE), of which 87% are heavy crude oil, 9% light crude oil and 4% natural gas. A significant portion of these proved reserves are owned in fee. Geographically, 88% of the Company’s reserves are located in California and 12% in the Rocky Mountain region. Proved undeveloped reserves make up 26% of the Company's proved total. The projected capital to develop these reserves is $114 million, at an estimated cost of approximately $4.00 per BOE. Over 90% of the capital to develop these reserves is expected to be expended in the next five years. Production in 2004 was 7.5 million BOE, up 25% from production of 6.0 million BOE in 2003. Based on average daily fourth quarter production for each year, the Company’s reserves-to-production ratio was 14.1 years at year-end 2004, reduced from 16.2 years at year-end 2003. This reduction is primarily due to the shorter reserve life of the Company's Rocky Mountain assets compared to its California assets.

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Acquisitions

The Company actively pursued its growth strategy during the year. In September 2004, the Company and an industry partner were the successful bidders on certain leases offered by the Bureau of Land Management (BLM). These leases representing approximately 17,000 gross (8,500 net) acres are located southeast of the Company's Brundage Canyon producing properties. The issuance of leases for this acreage is subject to final approval by the BLM. The Company paid approximately $3.3 million for its interest in this acreage, which is included in other non-current assets on the Company's Balance Sheet as of December 31, 2004.

In July 2004, the Company and Bill Barrett Corporation, entered into a joint exploration and development agreement with the Ute Indian Tribe to explore and develop approximately 124,500 gross (62,250 net) prospective acres of tribal lands in the Uinta Basin in Utah. The Company also purchased an interest in 44,500 gross (22,250 net) acres of privately owned lands near this tribal acreage. The 169,000 gross acre block is located immediately west of the Company’s Brundage Canyon producing properties. The Company will drill and operate the shallow wells which target light oil in the Green River formation and retain up to a 75% working interest. The Company's partner will drill and operate the deep wells which target natural gas in the Mesaverde and Wasatch formations. Berry 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 the Company’s and its partner's participation. This acquisition is a strategic fit as it builds on the Company's success at Brundage Canyon and increases the potential for the discovery of additional light oil and natural gas. The Company's minimum obligation under its exploration and development agreement is $10.5 million.

In December 2004, the Company signed a development agreement with Petro-Canada Resources (USA) Inc., to develop Petro-Canada's Coyote Flats prospect in Utah, approximately 45 miles southwest of the Company's Brundage Canyon producing properties. Berry will be the operator and upon completing a defined drilling program, will own an interest in approximately 69,250 gross (33,500 net) undeveloped acres. The Company estimates its total cost under this agreement will be approximately $10.3 million which will vary based on drilling costs. Upon completion of the program, the Company and its 50% partner, Petro-Canada Resources, will jointly determine future development plans.

In December 2004 the Company announced and, in January 2005, completed the acquisition of certain natural gas producing assets in the Niobrara field located in eastern Colorado for approximately $105 million utilizing the Company's existing credit facility. These properties consist of approximately 127,000 gross (69,500 net) acres. The Company has a working interest of approximately 52%. Production, as of March 1, 2005, is 9 MMcf (million cubic feet) of natural gas per day net to Berry's interest, with estimated proved natural gas reserves of 87 Bcf (billion cubic feet).

In January 2005, the Company purchased from Bill Barrett Corporation a working interest in approximately 390,000 gross (172,250 net) prospective acres located in eastern Colorado, western Kansas and southwestern Nebraska (the Tri-State acreage). The Company and its 50% partner will jointly explore and develop shallow Niobrara biogenic natural gas, Sharon Springs Shale gas and deeper Pennsylvanian formation oil assets on the acreage. The Company paid approximately $5 million for its working interest in the acreage. The Company believes the potential of the Tri-State area can be exploited by using new drilling techniques, with 3-D seismic technology to assess structural complexity, estimate potentially recoverable oil and gas and determine drilling locations.

2005 Outlook

The Company is targeting a 12% increase in production in 2005 which includes the production from the Niobrara gas assets. Additionally, crude pricing looks very favorable for 2005. Additionally, the Company maintains a hedging program which is designed to moderate the effects of a severe crude oil price downturn and protect certain operating margins in the Company's California operations. The Company has approximately 7,750 barrels per day hedged for calendar 2005 at approximately NYMEX West Texas Intermediate (WTI) of $40.75 per barrel. The Company's existing hedge position can be viewed on its website at: http://www.bry.com/index.php?page=hedging. The contents of the Company's website are not incorporated into this document

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Excluding any future acquisitions, in 2005 the Company plans to spend approximately $107 million on drilling 177 net wells and performing 92 workovers. The Company intends to fund 100% of its capital program out of internally generated cash flow. Major areas of focus in 2005 will be:

- California production - Projects include expanding the thermal development of the Poso Creek field, the evaluation of the Company's diatomite pilot at North Midway-Sunset and additional drilling of infill horizontal wells at South Midway-Sunset.

- Rockies & Mid-Continent production - In 2005, the Company will continue the development of the Brundage Canyon producing property on 80-acre spacing, test the potential of 40-acre infill drilling and appraise the northern and southern limits of the field. On the recently acquired Niobrara gas assets, the Company plans to drill approximately 60 wells as part of its ongoing development program and the initiation of the 40-acre infill program from the existing 80-acre development.

- Rockies & Mid-Continent prospects - The Company and its joint venture partner, will begin testing the oil potential of the Lake Canyon acreage with at least two shallow test wells at approximately 6,000 feet in the Green River trend. These initial drill sites will be approximately three miles west of the Company's Brundage Canyon producing property and have the potential of providing the Company with development opportunities comparable to Brundage Canyon. Drilling of the first deep natural gas test well in Lake Canyon is scheduled for the fourth quarter of 2005. The Company intends to drill its obligation wells at Coyote Flats, (45 miles southwest of Brundage Canyon) which will target the Ferron sands and Emery coals. Additionally, the Company will participate with its partner to begin testing the Sharon Springs Shale gas, Niobrara biogenic natural gas, along with the deeper Pennsylvanian formation oil prospects in its recently acquired Tri-State acreage in Colorado, Nebraska and Kansas.

    - In September 2004, the Company entered into a farm-out agreement pursuant to which Bill Barrett Corporation had the right to earn a 75% working interest in the deep Mesaverde formation and deeper horizons within the Brundage Canyon field by drilling a deep exploratory test. The Company's partner commenced the drilling of its initial deep exploratory well in Brundage Canyon in November 2004 and abandoned it in January 2005, pending the further evaluation of a 3-D seismic survey and assessment of optimal completion technology. No costs were incurred by the Company related to the drilling or abandonment of this well.

Operations

Berry operates all of its principal oil and gas producing properties. In California, the Midway-Sunset, Poso Creek and Placerita fields contain predominantly heavy crude oil which requires heat, supplied in the form of steam, injected into the oil producing formations to reduce the oil viscosity which allows the oil to flow to the well-bore for production. Berry utilizes cyclic steam and/or steam flood recovery methods in all of these fields and primary recovery methods at its Montalvo field. Berry is able to produce its heavy oil at its Montalvo field without steam since the majority of the producing reservoir is at a depth in excess of 11,000 feet and thus the reservoir temperature is high enough to produce the oil without the assistance of additional heat from steam. In Utah, the Brundage Canyon field consists of light gravity crude and associated natural gas produced from a depth of approximately 6,000 feet.

In California, 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 lease automatic custody transfer units or gauged before sale and subsequently transferred into crude oil pipelines owned by other companies or transported via truck. Crude oil produced from the Brundage Canyon field is transported by truck, while its gas production, net of field usage, is transported by gathering or distribution pipelines to two main shipper pipelines.

Natural gas produced from the Niobrara gas assets is transported by Company and third party distribution lines to two main shipper pipelines.

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Revenues

Total revenues for 2004 increased by $94 million or 52% over 2003. Total revenues and the percentage of revenues by source for the prior three years are as follows:

	2004	2003	2002
Total revenues (in millions)	$ 275	$ 181	$ 131
Sales of oil and gas	83%	75%	78%
Sales of electricity	17%	24%	21%
Other	-	1%	1%

Crude Oil and Natural Gas Marketing

The global and California crude oil markets continue to remain strong. While the Organization of Petroleum Exporting Countries successfully managed crude oil prices despite petroleum product demand weakness due to worldwide economic slowdowns and political instability during 2002 and 2003, increased market demand and lower inventory levels were key factors during 2004. Product prices began to rise in 2002 and continued to exhibit an overall-strengthening trend in 2003 and 2004. The range of West Texas Intermediate (WTI) crude prices for 2004 was a low of $32.48 and a high of $55.17. The NYMEX settlement price for WTI, the U.S. benchmark crude oil, averaged $41.47 for 2004 compared to $30.99 for 2003 and $26.15 for 2002. The average posted price for the Company’s 13 degree API heavy crude oil was $32.84 for 2004 compared to $25.27 for 2003 and $20.67 for 2002. The average posted price for the Company’s Utah light crude oil was $39.62 for 2004 compared to $29.14 for 2003. The Company expects that crude prices will continue to be volatile in 2005.

While crude oil price differentials between WTI and California’s heavy crude were fairly consistent in both 2002 and 2003 at just under $6.00 per barrel, the differential widened dramatically during 2004. The crude price differential between WTI and California’s heavy crude oil averaged $8.57, $5.73 and $5.48 per barrel for 2004, 2003 and 2002, respectively. On December 31, 2004 the differential ended the year at $14.19. This differential has averaged over $14.00 per barrel in the first two months of 2005, and the Company is concerned that this differential may remain high for an extended period of time. Subsequent to the termination of the Company's current crude oil sales contract on December 31, 2004, a widening differential between WTI and California crude oil could adversely affect the Company's revenues, profitability and cash flows from its heavy oil operations. The Company will enter into a new contract if favorable terms can be achieved or may sell its crude oil into the spot market.

A price-sensitive royalty burdens one of the Company’s California properties which produces approximately 4,000 barrels per day. This royalty is 75% of the amount of the heavy oil posted price above a base price which was $14.88 in 2004. This base price escalates at 2% annually, thus the threshold price is $15.18 per barrel in 2005.

Berry markets its crude oil production to competing buyers including independent marketers but primarily to major oil refining companies. Because of the Company’s ability to deliver significant volumes of crude oil over a multi-year period, the Company was able to secure a thirty-nine month sales agreement, beginning in late 2002, with a major oil company whereby the Company sells over 90% of its California production under a negotiated pricing mechanism. This contract expires on December 31, 2005. Pricing in this agreement is 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. Both methods are calculated using a monthly determination. In addition to providing a premium above field postings, the agreement effectively eliminates the Company’s exposure to the risk of widening WTI to California heavy crude price differentials and allows the Company to effectively hedge its production based on WTI pricing. This contract allowed the Company to improve its revenues over the posted price by approximately $13 million in 2004. The Brundage

Canyon crude oil, which is approximately 40 degree API gravity, is also linked to WTI and is priced at WTI less a fixed differential approximating $2.00 per barrel. This contract expires on September 30, 2006.

Berry markets produced natural gas from Utah, Wyoming and California. In October 2003, the Company began marketing produced gas from the Brundage Canyon field. Some of the natural gas from Brundage Canyon is sold in the Salt Lake City market at a Questar monthly index related price with an adjustment for transportation. Brundage Canyon volume in excess of Berry's firm pipeline transportation volume is sold at the field at a Questar daily spot related price. The Company owns a non-operated working interest in the South Joe Creek field in the Powder River Basin in Wyoming. Berry began marketing its working interest share of production in-kind from South Joe Creek in December 2002, at Glenrock, Wyoming at monthly

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Colorado Interstate Gas (CIG) index related prices. Additionally, produced gas from the Niobrara field in Colorado is also sold at monthly CIG index related price

For 2004, the first-of-month indices approximated $5.60 per MMBtu for SoCal Border, $5.15 per MMBtu for Rockies CIG and $5.05 for Rockies Questar. The closing price for the NYMEX prompt month natural gas contract averaged $6.18, $5.84 and $3.37 for years 2004, 2003 and 2002, respectively.

The Company has physical access to interstate gas pipelines, such as the Kern River Pipeline and the Questar Pipeline, as well as California intrastate systems owned by Southern California Gas Company and Pacific Gas & Electric (PG&E), to move gas to or from market. To avoid negative financial impacts to the Company should California pipeline capacity become constrained, the Company entered into a long-term gas transportation contract with Kern River Gas Transmission Company for 12,000 MMBtu/D. This is a ten year contract which began in May 2003. There is a proceeding currently before the Federal Energy Regulatory Commission (FERC) that may result in an upward adjustment in the transportation charge under this contract. The Company does not believe any such adjustment would have a material adverse impact on its operations. The Company also holds two firm transportation contracts on the Questar Pipeline system in Utah totaling 5,300 MMBtu/D.

From time to time, the Company enters into crude oil and natural gas hedge contracts, the terms of which depend on various factors, including Management's view of future crude oil and natural gas prices and the Company's future financial commitments. This price hedging program is designed to moderate the effects of a severe crude oil price downturn and protect certain operating margins in the Company's California operations. Currently, the hedges are in the form of swaps, however, the Company may use a variety of hedge instruments in the future. The Company's hedging activities resulted in a net reduction in revenue per BOE to the Company of $3.31 in 2004, $1.96 in 2003 and $.72 in 2002.

The following table summarizes the hedge position of the Company as of March 1, 2005:

Term	Average Barrels Per Day	Average Swap Price	Term	Average MMBtu Per Day	Average Swap Price
Crude Oil Sales			**Natural Gas Sales (CIG)**		
(NYMEX WTI)					
			Full Year 2005	1,000	$ 6.21
1st Quarter 2005	8,000	$ 41.38			
			Natural Gas Purchases		
2nd Quarter 2005	8,000	$ 40.58	**(SoCal Border)**		
3rd Quarter 2005	7,500	$ 40.84	1st Quarter 2005	9,000	$ 5.60
4th Quarter 2005	7,500	$ 40.67	2nd Quarter 2005	8,000	$ 5.19
1st Quarter 2006 (1)	1,250	$ 45.32	3rd Quarter 2005	6,667	$ 5.09
2nd Quarter 2006 (1)	1,250	$ 44.49	4th Quarter 2005	6,000	$ 5.05
3rd Quarter 2006 (1)	1,250	$ 43.78	1st Quarter 2006	5,000	$ 4.85

(1) These contracts were entered into subsequent to December 31, 2004.

Payments to the Company's counterparties are triggered when the monthly average prices are above the swap price in the case of the Company's crude oil and natural gas sales hedges and below the swap price for the Company's natural gas purchase hedge positions. Conversely, payments from our counterparties are received when the monthly average prices are below the swap price for the Company's crude oil and natural gas sales hedges and above the swap price for the Company's natural gas purchase hedge positions. Management regularly monitors the crude oil and natural gas markets and the Company’s financial commitments to determine if, when, and at what level some form of crude oil and/or natural gas hedging or other price protection is appropriate.

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Steaming Operations

Cogeneration Steam Supply

As of December 31, 2004, approximately 82% of the Company's proved reserves, or 90 million barrels, consisted of heavy crude oil produced from depths shallower than 2,000 feet. The Company, in pursuing its goal of being a cost-efficient heavy oil producer, has remained focused on minimizing its steam cost. One of the main methods of keeping steam costs low is through the ownership and efficient operation of cogeneration facilities. Two of these cogeneration facilities, a 38 megawatt (MW) and an 18 MW facility are located in the Company’s South Midway-Sunset field. The Company also owns a 42 MW cogeneration facility located in the Placerita field. Steam generation from these facilities, with a total steam capacity of approximately 38,000 barrels of steam per day (BSPD), is more efficient than conventional steam generation as both steam and electricity are concurrently produced from a common fuel stream. The Company also purchases approximately 2,000 BSPD under contract on favorable terms from a non-Company owned cogeneration facility.

Conventional Steam Generation

In addition to these cogeneration plants, the Company owns sixteen conventional boilers. The quantity of boilers operated at any point in time is dependent on the steam volume required for the Company to achieve its targeted production and on the price of natural gas compared to the price of crude oil sold. The total rated capacity of the conventional boilers is approximately 43,000 BSPD.

The cost of natural gas purchased (excluding transportation) per MMBtu averaged $5.46, $4.88 and $3.13 for 2004, 2003 and 2002, respectively. Most of the Company’s conventional steam generators were run in 2004 to achieve the Company’s goal of increasing heavy oil production to record levels.

The Company believes that it may become necessary to add additional steam capacity for its future development projects at Midway-Sunset, Placerita and Poso Creek to allow for full development of its properties. The Company regularly reviews its most economical source for obtaining additional steam to achieve its growth objectives.

Operational Control

Ownership of these varied steam generation facilities and sources allows for maximum control over the steam supply, location, and to some extent the aggregated cost. The Company’s steam supply and flexibility are crucial for the maximization of oil production, cost control and ultimate reserve recovery.

Electricity Generation

The total annual average electrical generation of the Company’s three cogeneration facilities is approximately 93 megawatts (MW), of which the Company consumes approximately 8 MW for use in its operations. The three facilities can also supply approximately 38,000 BSPD. Each facility is centrally located on an oil producing property such that the steam generated by the facility is capable of being delivered to the wells that require steam for the enhanced oil recovery process. The Company’s investment in its cogeneration facilities have been for the express purpose of lowering the steam costs in its heavy oil operations and securing operating control of the respective steam generation. Expenses of operating the cogeneration plants are analyzed regularly to determine that they are advantageous versus conventional steam boilers. In 2004, the Company revised its allocation of cogeneration costs to oil and gas operations. 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.

Electricity Sales Contracts

Historically, the Company has sold electricity produced by its cogeneration facilities to two California public utilities, Southern California Edison Company (Edison) and Pacific Gas and Electric (PG&E), under long-term contracts. These contracts are referred to as Standard Offer (SO) contracts under which the Company is 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. The capacity payments are either fixed throughout the term of the agreement or can be adjusted from time to time by the California Public Utilities Commission (CPUC). The SRAC energy price is determined by a formula that reflects the utility's marginal fuel cost and a conversion efficiency that represents a hypothetical utility resource to generate electricity in the absence of the cogenerator. Natural gas is now the marginal fuel for California utilities so this formula provides a hedge against the Company's cost of gas to produce electricity and steam in its

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cogeneration facilities. A proceeding is now underway at the CPUC to review and revise the methodology used to determine SRAC energy prices. This proceeding is currently scheduled to be completed by the end of 2005. There is no assurance that any new methodology will continue to provide a hedge against the Company's fuel cost or that a revised pricing mechanism will be as beneficial as the current contract pricing.

The original SO contract for Placerita Unit 1 continues in effect through March 2009. The modified SRAC pricing terms reflect a fixed energy price of 5.37 cents/kilowatt per hour (KWh) until June 2006, at which time the energy price reverts to the SRAC pricing methodology. In 2002, the CPUC ordered the California utilities to offer SO contracts to certain cogeneration facilities with expired SO contracts, known as Qualifying Facilities or QFs, for a maximum term of one year. The Company met these requirements and entered into new SO contracts with Edison for its Placerita Unit 2 and with PG&E for its Cogen 38 and Cogen 18 facilities effective January 2003. These three new SO contracts resulted in improved electrical pricing in 2003 over 2002. All three SO contracts terminated on December 31, 2003, as originally ordered by the CPUC.

On December 18, 2003, the CPUC ordered the California utilities to continue to offer SO contracts to certain QFs with expired SO contracts, such as the Company, for a one year term beginning January 1, 2004. In the same decision, the CPUC also directed its staff to initiate a comprehensive review and revision of the SRAC pricing methodology. Edison appealed the legality of the December 18, 2003 CPUC decision that ordered the additional one-year extension of SO contracts, at the CPUC, but was unsuccessful. The Company executed a one year extension of its SO contract with Edison, effective January 1, 2004 for the Placerita Unit 2 facility, and executed similar one year extensions of its SO contracts with PG&E for its Cogen 38 and Cogen 18 facilities. Those one year extensions terminated as scheduled on December 31, 2004.

On January 22, 2004, the CPUC issued a decision that establishes the rules under which the California utilities will produce or procure energy for their customers for the next 5 to 10 years. Among other things, this decision ordered the California utilities to offer SO contracts to certain QFs whose SO contracts will terminate prior to December 31, 2005, such as the Company, for a term of 5 years. The SRAC price paid under these SO contracts is subject to the same prospective adjustments that were required in the prior CPUC decision that ordered the one-year extension. In December 2004, the Company executed a five year SO contract with Edison for the Placerita Unit 2 facility, and five year SO contracts with PG&E for the Cogen 18 and Cogen 38 facilities, each effective January 1, 2005. Edison and PG&E have challenged, in the California Court of Appeal, the legality of the CPUC decision that ordered the utilities to enter into the one-year SO contracts for 2004, and the decision that ordered the utilities to enter into five-year SO contracts. Arguments in this case were heard by the court in March 2005. The Company believes that QFs, such as the Company's facilities, provide an important source of distributive power generation into California's electricity grid, and as such, that the Company's facilities will be economic to operate for at least the current five-year contract term.

Facility and Contract Summary

Location and Facility	Type of Contract	Purchaser	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	20	-	6,600
Placerita Unit 2	SO1	Edison	Dec-09	16	4	6,700

South Midway-Sunset						
Cogen 18	SO1	PG&E	Dec-09	12	4	6,600
Cogen 38	SO1	PG&E	Dec-09	37	-	18,000

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Environmental and Other Regulations

Berry Petroleum Company is committed to responsible management of the environment, health and safety, as these areas relate to the Company's operations. The Company strives to achieve the long-term goal of sustainable development within the framework of sound environmental, health and safety practices and standards. Berry makes environmental, health and safety protection an integral part of all business activities, from the acquisition and management of its resources through the decommissioning and reclamation of its wells and facilities.

All facets of the Company's operations are affected by a myriad of federal, state, regional and local laws, rules and regulations. Berry is further affected by changes in such laws and by constantly changing administrative regulations. Furthermore, government agencies may impose substantial liabilities if the Company fails to comply with such regulations or for any contamination resulting from the Company's operations.

Therefore, Berry has 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 its operations. The costs incurred to ensure compliance with environmental, health and safety laws and other regulations are inextricably connected to normal operating expenses such that the Company is unable to separate the expenses related to these matters.

Currently, California environmental laws and regulations are being revised to lower emissions from stationary sources. Although these requirements do have a substantial impact upon the energy industry, generally these requirements do not appear to affect the Company any differently, or to any greater or lesser extent, than other companies in California. Berry believes that compliance with environmental laws and regulations will not have a material adverse effect on the Company's operations or financial condition. There can be no assurances, however, that changes in, or additions to, laws and regulations regarding the protection of the environment will not have such an impact in the future.

Berry maintains insurance coverage that it believes is customary in the industry although it is not fully insured against all environmental or other risks. The Company is not aware of any environmental claims existing as of December 31, 2004 that would have a material impact upon the Company's financial position, results of operations, or liquidity.

Regulation of Oil and Gas

The oil and gas industry is extensively regulated by numerous federal, state and local authorities, including Native American tribes. Legislation affecting the oil and gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, and Native American tribes are authorized by statute to issue rules and regulations binding on the oil and gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and gas industry increases the Company's cost of doing business and, consequently, may affect profitability, these burdens generally do not affect the Company any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

The Company's operations are subject to various types of regulation at federal, state, local and Native American tribal levels. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. Most states, and some counties, municipalities and Native American tribes, in which the Company operates also regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;
- the rates of production or "allowables;"

- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells; and
- notice to surface owners and other third parties.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce the Company's interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and natural gas the Company can produce from its wells or limit the number of wells or the locations at which it can drill.

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Moreover, each state generally imposes a property, production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction.

A portion of the Company's leases in the Uinta Basin are, and some of the Company's future leases in this and other areas may be, regulated by Native American tribes. In addition to regulation by various federal, state and local agencies and authorities, an entirely separate and distinct set of laws and regulations applies to lessees, operators and other parties within the boundaries of Native American reservations. Various federal agencies within the U.S. Department of the Interior, particularly the Minerals Management Service and the Bureau of Indian Affairs, together with each Native American tribe, promulgate and enforce regulations pertaining to oil and gas operations on Native American reservations. These regulations include lease provisions, royalty matters, drilling and production requirements, environmental standards, and numerous other matters.

Native American tribes are subject to various federal statutes and oversight by the Bureau of Indian Affairs. However, each Native American tribe is a sovereign nation and has the right to enforce certain other laws and regulations entirely independent from federal, state and local statutes and regulations, as long as they do not supersede or conflict with such federal statutes. These tribal laws and regulations include various fees, taxes, requirements to employ Native American tribal members, and numerous other conditions that apply to lessees, operators, and contractors conducting operations within the boundaries of a Native American reservation. Further, lessees and operators within a Native American reservation are subject to the Native American tribal court system, unless there is a specific waiver of sovereign immunity by the Native American tribe allowing resolution of disputes between the Native American tribe and those lessees or operators to occur in federal or state court.

Therefore, the Company is subject to various laws and regulations pertaining to Native American tribal surface ownership, Native American oil and gas leases and other exploration agreements, fees, taxes, and other burdens, obligations and issues unique to oil and gas ownership and operations within Native American reservations. One or more of these requirements may increase the Company's cost of doing business on Native American tribal lands and have an impact on the economic viability of any well or project on those lands.

Federal Energy Regulation

The enactment of the Public Utility Regulatory Policies Act of 1978, as amended (PURPA), and the adoption of regulations thereunder by the FERC provided incentives for the development of cogeneration facilities such as those owned by the Company. A domestic electricity generating project must be a Qualifying Facility (QF) under FERC regulations in order to take advantage of certain rate and regulatory incentives provided by PURPA.

PURPA provides two primary benefits to QFs. First, QFs generally are relieved of compliance with extensive federal and state regulations that control the financial structure of an electricity generating plant and the prices and terms on which electricity may be sold by the plant. Second, FERC’s regulations promulgated under PURPA require that electric utilities purchase electricity generated by QFs at a price based on the purchasing utility’s avoided cost, and that the utility sell back-up power to the QF on a non-discriminatory basis. The term "avoided cost" is defined as the incremental cost to an electric utility of electric energy or capacity, or both, which, but for the purchase from QFs, such utility would generate for itself or purchase from another source. FERC regulations also permit QFs and utilities to negotiate agreements for utility purchases of power at rates lower than the utilities’ avoided costs. In California, the utility’s avoided cost is generally referred to as Short Run Avoided Cost or SRAC.

In order to be a QF, a cogeneration facility must produce not only electricity, but also useful thermal energy for use in an industrial or commercial process for heating or cooling applications in certain proportions to the facility's total energy output, and must meet certain energy efficiency standards. Also, a QF must not be controlled or more than 50% owned by one or more electric utilities or by most electric utility holding companies, or one or more subsidiaries of such a utility or holding company or any combination thereof. Each of the Company's cogeneration facilities is a QF, pursuant to PURPA.

State Energy Regulation

The CPUC has broad authority to regulate both the rates charged by, and the financial activities of, electric utilities operating in this state 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 the Company, 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 the Company is not subject to regulation by the CPUC, the CPUC's implementation of PURPA is of critical importance to the Company.

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Competition

The oil and gas industry is highly competitive. As an independent producer, the Company does not own any refining or retail outlets and, therefore, it has little control over the price it receives for its crude oil. As such, higher costs, fees and taxes assessed at the producer level cannot necessarily be passed on to the Company's customers. In acquisition activities, significant competition exists as integrated and independent companies and individual producers are active bidders for desirable oil and gas properties. Although many of these competitors have greater financial and other resources than the Company, Management believes that Berry is in a position to compete effectively due to its low cost structure, transaction flexibility, strong financial position, experience and determination.

Employees

On December 31, 2004, the Company had 157 full-time employees, up from 129 full-time employees on December 31, 2003. As of March 1, 2005, and following the acquisition of the Niobrara gas producing assets in Colorado, the Company has 181 employees. On-site production operation services, such as pumping, maintenance, inspection and testing, are generally provided by independent contractors.

Oil and Gas Properties

Unless otherwise noted, gross acreage, net wells, fourth quarter production, and 2004 year-end reserves are used in the property descriptions below.

San Joaquin Valley Basin

Midway-Sunset, California - Berry owns and operates working interests in 38 properties consisting of 4,528 acres located in the Midway-Sunset field. The Company estimates these properties account for approximately 63% of the Company's proved oil and gas reserves and approximately 57% of its current daily production. Of these properties, 23 are owned in fee and the Company's average working interest in this field is approximately 95%. The wells produce from an average depth of approximately 1,200 feet, and rely on thermal EOR methods, primarily cyclic steaming.

During 2004, development activities at Midway-Sunset continued to be focused on horizontal drilling to improve ultimate recovery of original oil-in-place, reduce the development and operating costs of properties and to accelerate production. Additionally, a steam flood pilot was initiated in the diatomite formation. In 2005, the Company plans to drill an additional 54 wells, including 8 horizontal wells and 26 wells in the diatomite formation.

Poso Creek, California - The McVan property, consisting of 560 acres in the Poso Creek field, was purchased in March 2003. An additional 120 acres were acquired in 2004 offsetting the Company's existing position to the southeast. Year-end 2004 proved reserves comprise 2% of Berry’s proved oil and gas reserves while year-end production has increased to over 400 barrels per day.

During 2004, one service well was drilled and a ten well workover program was completed. Steam injection was also reinitiated at the McVan property in 2004. Plans for 2005 include the drilling of four new development wells, further well workovers and the return to production of a number of idle wells.

Los Angeles Basin

Placerita, California - The Company’s assets in the Placerita field consist of nine leases and four fee properties totaling approximately 965 acres. The average depth of these wells is 1,800 feet and the properties rely on thermal recovery methods, primarily steam flooding. The property accounts for approximately 16% of proved reserves and

13% of current daily production.

During 2004, three new wells were drilled to begin redevelopment on the Castruccio property which the Company acquired several years ago. In 2005, the Company plans to drill 12 wells in the north end of the field to continue a major expansion of the existing steam flood.

Ventura Basin

Montalvo, California - Berry owns a 100% working interest in six leases totaling 8,563 acres in the Ventura Basin comprising the entire Montalvo field. The State of California is the lessor for two of the six leases. The Company estimates current proved reserves from Montalvo account for approximately 6% of Berry's proved oil and gas reserves and approximately 4% of Berry's current daily production. The wells produce from an average depth of approximately 11,500 feet. No new wells were drilled in 2004; however one well was remediated and returned to production. During 2005, one idle well is scheduled to be returned to production.

Uinta Basin

Brundage Canyon, Utah - The Brundage Canyon leasehold in Duchesne County, Utah consists of federal, tribal and private leases totaling 47,300 gross acres (45,420 net). The Company estimates that the Brundage Canyon properties account for approximately 12% of proved oil and gas reserves and approximately 23% of current daily production. There are 164 wells in the Brundage Canyon field producing oil and associated natural gas with an average well depth of 6,000 feet.

In 2004, the Company continued its focus on development of the Brundage Canyon property, drilling 54 wells including several 40-acre infill tests. The Company's objectives for 2005 include the drilling of 59 additional wells, including nine 40-acre infill wells and the recompletion of 20 existing wells.

In September 2004, the Company entered into a farm-out agreement pursuant to which Bill Barrett Corporation had the right to earn a 75% working interest in the deep Mesaverde formation and deeper horizons within the Brundage Canyon Field by drilling a deep exploratory test. The Company's partner commenced the drilling of its initial deep exploratory well in Brundage Canyon in November 2004 and abandoned it in January 2005, pending the further evaluation of a 3-D seismic survey and assessment of the optimal completion technology.

Lake Canyon Prospect, Utah - In 2004, the Company and Bill Barrett Corporation entered into a joint exploration and development agreement with the Ute Indian Tribe to explore and develop approximately 124,500 gross (62,250 net) prospective acres of tribal lands in the Uinta Basin in Utah. The Company also purchased an interest in approximately 44,500 gross (22,250 net) acres of privately owned lands near the tribal acreage. The 169,000 gross acre block is located immediately west of the Company's Brundage Canyon producing properties. The Company will drill and operate the shallow wells which target light oil in the Green River formation and retain up to a 75% working interest. The Company's partner will drill and operate the deep wells which target natural gas in the Mesaverde and Wasatch formations. Berry 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 the Company's and its partner's participation. The Company plans to drill two shallow test wells in the Green River trend and participate in one deep test well in the Mesaverde formation in 2005.

Coyote Flats Prospect, Utah - In December 2004, the Company entered into a development agreement with Petro-Canada Resources (USA) Inc. to develop their Coyote Flats prospect in the Uinta Basin. The property is located approximately 45 miles southwest of the Company's Brundage Canyon property. The Company is obligated to drill three test wells into the Ferron sand to a depth of approximately 7,500 feet and also drill a six well Emery coalbed methane pilot, found at approximately 4,500 feet. Upon the completion of this total nine well drilling program, the Company will earn an interest in the approximately 69,250 gross (33,500 net) acres. The Company has drilled one Ferron sand test well in early 2005 which was deemed to be a dry hole. The Company plans to drill the remaining two Ferron sand test wells and the Emery coalbed methane pilot wells during 2005. Future development plans will be determined jointly by the Company and its 50% partner, Petro-Canada Resources.

Denver-Julesburg Basin

Niobrara Field, Colorado - In January 2005, the Company acquired certain interests in the Niobrara field in northeastern Colorado for approximately $105 million. The properties consist of approximately 127,000 gross (69,500 net) acres and the Company has a 52% working interest. Current production is approximately 9 MMcf of natural gas per day. The acquisition also includes approximately 200 miles of a pipeline gathering system and gas compression facilities for delivery into interstate gas lines. In 2005, the Company plans to drill approximately 60 gross wells as part of its ongoing development program and the initiation of the 40-acre infill program from the existing 80-acre development.

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Tri-State Prospect, Colorado, Nebraska and Kansas - In January 2005, the Company acquired a working interest in approximately 390,000 gross (172,250 net) prospective acres, located in eastern Colorado, western Kansas and southwestern Nebraska, from Bill Barrett Corporation. The 50% joint venture will apply seismic technologies to explore and, if successful, develop the Niobrara formation for biogenic gas, which lies at less than 2,000 feet, and apply seismic technologies to evaluate oil potential in the Pennsylvanian formations at depths of 4,000 to 4,800 feet. The Company believes the potential of the Tri-State area can be exploited by using new drilling techniques, with 3-D seismic technology to assess structural complexity, and estimate potentially recoverable oil and gas and determine drilling locations. The Company plans to drill 8 gross wells (4 net) in 2005.

Other

South Joe Creek, Wyoming - The Company holds a 15.83% non-operated working interest in the South Joe Creek coalbed methane field which represents interests in federal, state and private leases totaling 5,106 acres in the northeastern portion of the Powder River Basin in Wyoming. The property has 96 wells (14 net). The property accounts for 1% of production while reserves are minimal. There are no plans at this time to drill any new wells in 2005.

Mickelson Creek, Wyoming - In 2003, the Company purchased three federal leases located in the Mickelson Creek field in Sublette County, Wyoming. There are currently five wells on the 2,800 acre property. Reserves and production from these properties are minimal. The Company plans to drill two wells on this property in 2005.

Kansas and Illinois Coalbed Methane (CBM) Projects - The Company holds 163,000 and 55,000 net acres in Eastern Kansas and Central Illinois, respectively, as prospective acreage for coalbed methane production. The Company drilled a pilot in each state in late 2002, and in 2003 the Company determined both these pilots were non-commercial. As such, the Company has no reserves or production in either state as of December 31, 2004. The Company continues to assess the potential of these properties.

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The following is a summary of the Company's capital expenditures incurred during 2004 and 2003 and budgeted capital expenditures for 2005.

CAPITAL EXPENDITURES SUMMARY
(in thousands)

	2005 (Budgeted) (1)	2004	2003
CALIFORNIA			
Midway-Sunset Field			
New wells	$ 11,012	$ 11,376	$ 10,710
Remedials/workovers	420	1,415	1,718
Facilities - oil & gas	6,850	4,045	3,136
Facilities - cogeneration	3,435	1,055	231
General	2,001	2,144	187
	23,718	20,035	15,982
Other California Fields			
New wells	5,295	426	6,509
Remedials/workovers	4,463	1,589	1,084
Facilities - oil & gas	2,470	3,416	1,676
Facilities - cogeneration	250	555	370
	12,478	5,986	9,639
Total California	36,196	26,021	25,621
ROCKIES AND MID-CONTINENT			
Uinta Basin			
New wells	47,914	39,467	14,298
Remedials/workovers	2,050	4,597	234
Facilities	4,332	1,979	146
	54,296	46,043	14,678
DJ Basin			
New wells/workovers	5,660	-	-