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, 2005**
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	**New York Stock Exchange**
(including associated stock purchase rights)	

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, 2005, the aggregate market value of the voting and non-voting common stock held by non-affiliates was $962,312,197. As of February 10, 2006, the registrant had 21,077,915 shares of Class A Common Stock outstanding. The registrant also had 898,892 shares of Class B Stock outstanding on February 10, 2006 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.

BERRY PETROLEUM COMPANY
TABLE OF CONTENTS
PART I

PART II

PART III

PART IV

PART I

Item 1. Business

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 California, Utah and Colorado. The Company has its corporate headquarters in Bakersfield, California and a regional office in Denver, Colorado. The Company is increasing office space in both locations to accommodate growth. Information contained in this report on Form 10-K reflects the business of the Company during the year ended December 31, 2005 unless noted otherwise.

The Company's 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, 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. 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. Berry Petroleum Company's mission is to increase shareholder value, primarily through increasing the net asset value, and maximizing the cash flow and earnings of the Company's assets. The strategies to accomplish these goals include:

- ***Growing production and reserves from existing assets while managing expenses*** - The Company intends to increase production and reserves annually and increase both net income and cash flow in total and per share. The Company will continue to focus on the further development of its properties through developmental drilling, down-spacing, well completions, remedial work and by application of enhanced oil recovery (EOR) methods, and optimization technologies, as applicable. With respect to the California heavy oil reserves, 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.
- ***Acquiring more light oil and natural gas assets with significant growth potential in the Rocky Mountain and Mid-Continent region*** - The Company will compete to acquire oil and gas properties with proved reserves, probable reserves and/or sizeable acreage positions that the Company believes contain substantial reserves which can be developed at reasonable costs. As part of its resource diversification strategy, Berry desires to add natural gas production and reserves to complement its significant crude oil resource base. The Company has identified the Rocky Mountain and Mid-Continent region as its primary areas of interest for diversification.
- ***Appraising the Company's exploitation and exploration projects in an expedient manner*** - The Company has been successful in adding significant acreage positions in the last two years with the intent of drilling exploration wells to test the potential of the acreage for the economic production of hydrocarbons. Its goal is to appraise this potential as quickly as is prudently possible.
- ***Investing the Company's capital in an efficient, disciplined manner*** - Investing the Company's capital prudently is of paramount importance in achieving long-term success. The oil and gas business is very capital intensive so managing the business with a focus on utilizing the available capital on projects where it is likely to have success in increasing production and/or reserves at attractive returns to shareholders. A portion of the Company's capital will be directed to higher risk projects that have the potential for higher reward.
- ***Utilizing joint ventures with respected partners to enter new basins*** - The Company believes that it is beneficial to utilize the skills and knowledge of other industry participants upon entering new basins or areas of operations as it can reduce the risk and improve the success in the area.

Berry has the industry talent, experience, organization and motivation to accomplish the above strategies to fulfill its mission of increasing shareholder value. Berry also has the financial capacity and skill sets to accomplish these strategies. In addition to internally generated funds, it has a $500 million unsecured credit facility with a current borrowing base of $350 million which may be utilized in adding prospective acreage, reserves and/or production through acquisitions.

Proved Reserves and Revenues. As of December 31, 2005, the Company's estimated proved reserves were 126 million barrels of oil equivalent, (BOE), of which 74% are heavy crude oil, 8% light crude oil and 18% natural gas. Nearly 40% of reserves are owned in fee. Geographically, 74% of the Company's reserves are located in California and 26% in the Rocky Mountain and Mid-Continent region. Proved undeveloped reserves make up 28% of the Company's proved total. The projected capital to develop these proved undeveloped reserves is $201million, at an estimated cost of approximately $5.54 per BOE. Approximately 77% of the capital to develop these reserves is expected to be expended in the next five years. Production in 2005 was 8.4 million BOE, up 12% from production of 7.5 million BOE in 2004. The Company's reserves-to-production ratio was unchanged at 14.6 years at year-end 2005, compared to year-end 2004.

Table of Contents

The following table depicts all of the Company’s producing assets as of December 31, 2005. Berry operates all of the assets, except Wyoming:

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

The Company continued to engage DeGolyer and MacNaughton (D&M) to appraise the extent and value of its proved oil and gas reserves and the future net revenues to be derived from properties of the Company for the year ended December 31, 2005. D&M is an independent oil and gas consulting firm located in Dallas, Texas. In preparing their reports, D&M reviewed and examined geologic, economic, engineering and other data considered applicable to properly determine the reserves of the Company. They also examined the reasonableness of certain economic assumptions regarding forecasted operating and development costs and recovery rates in light of the economic environment on December 31, 2005. See Supplemental Information About Oil & Gas Producing Activities (Unaudited) for the Company's oil and gas reserve disclosures.

Acquisitions. See Item 7 Management’s Discussion and Analysis of Financial Condition and Results of Operations.

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

In the Rocky Mountain and Mid-Continent region, crude oil produced from the Brundage Canyon field is transported by truck, while its gas production, net of field usage, is transported by gathering or distribution systems to the Questar Pipeline. Natural gas produced from the eastern Colorado Niobrara gas assets is transported by Company and third party gathering lines to one of two main pipelines. The Company has a pipeline gathering system and gas compression facilities for delivery into these two interstate gas lines in this region.

Crude Oil and Natural Gas Marketing

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

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

The above posting prices and differentials are not necessarily amounts paid or received by the Company due to the contracts discussed below. While the crude oil price differential between WTI and California's heavy crude was fairly consistent with historical averages in 2003 at just under $6.00 per barrel, the differential widened dramatically during 2004 and 2005. On December 31, 2005 the differential was $11.61 and ranged from a low of $10.27 to a high of $14.83 per barrel during the year. Crude oil price differentials between WTI and Utah's light crude oil were fairly consistent during 2003, 2004 and 2005 and were between $3 and $5 per barrel. On December 31, 2005 the differential was $4.67 and ranged from a low of $3.73 to a high of $4.77 per barrel during the year.

Oil Contracts. Berry markets its crude oil production to competing buyers including independent and major oil refining companies. Because of the Company's ability to deliver significant volumes of crude oil over a multi-year period, the Company secured a three-year sales agreement, beginning in late 2002, with a major oil company whereby the Company sold over 90% of its 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 the Company to improve its California revenues over the posted price by approximately $41 million and $13 million in 2005 and 2004, respectively.

On November 21, 2005, the Company entered into a new crude oil sales contract for its 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 the Company's option. The agreement effectively eliminates the Company's exposure to the risk of a widening WTI to California heavy crude price differential over the next four years and allows the Company to effectively hedge its production based on WTI pricing similar to the previous contract. If this contract had been in place during 2005, it would have allowed the Company to improve its California revenues over the posted prices by approximately $25 million in 2005, but $16 million below what was actually received by the Company under the contract in place in 2005.

Brundage Canyon crude oil production, which is approximately 40 degree API gravity, is sold under contract at WTI less a fixed differential approximating $2.00 per barrel. This contract expires on September 30, 2006. Any new contract will be negotiated based on market prices. The Company believes the differential has widened by several dollars per barrel. The majority of this crude oil, while light, is a "paraffinic" crude, and can be processed efficiently by only a limited number of stranded inland refineries. The production of this type crude is increasing regionally and beginning to strain the capacity of these refineries. Other new crude sources from the region are pressuring pricing. If these refineries limit the volumes of this parraffinic crude oil they are willing to process, it could impact the marketability of this type of crude which, for Berry, represents approximately 3,500 Bbl/D of production or approximately 15% of total current production. The Company is investigating its market opportunities for this crude oil. If market prices continue to deteriorate, the Company may allocate its capital expenditures to projects which produce natural gas and crude oils with lower paraffinic content until the refinery constraint is resolved.

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

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

The Company has physical access to interstate gas pipelines to move gas to or from market. To assure delivery of gas, the Company has entered into several long-term gas transportation contracts as follows:

Firm Transportation Summary

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

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.

Steaming Operations

Cogeneration Steam Supply. As of December 31, 2005, approximately 74% of the Company's proved reserves, or 93 million barrels, consisted of heavy crude oil produced from depths of less than 2,000 feet. The Company, in pursuing its goal of being a cost-efficient heavy oil producer in California, 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 Midway-Sunset field. The Company also owns 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, the Company is able to better control its cost of producing steam.

Conventional Steam Generation. In addition to these cogeneration plants, the Company owns 16 conventional boilers. The quantity of boilers operated at any point in time is dependent on 1) the steam volume required for the Company to achieve its 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, 2005 is as follows:

Total steam generation capacity of Cogeneration plants	38,000
Additional steam purchased under contract with third party	2,000
Total steam generation capacity of conventional boilers	43,000
Total steam capacity	83,000

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

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

The Company believes that it may become necessary to add additional steam capacity for its future development projects at Midway-Sunset 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.

Most of the Company’s conventional steam generators operated in 2005 to achieve the Company’s goal of increasing heavy oil production to record levels. Approximately 70% of the volume of natural gas purchased to generate steam and electricity is based upon SoCal Border indices. While there are no transportation charges for gas purchased at the SoCal Border location, all locations except the central portion of the Midway-Sunset field pay distribution/transportation charges to either SoCal Gas or Pacific Gas &

Electric (PG&E) to have the gas delivered to the field. The remaining 30% of supply volume is purchased in Wyoming and moved to the Midway-Sunset field using the Company's firm transport on the Kern River Pipeline. This gas is purchased based upon the Rocky Mountain Northwest Pipeline (NWPL) index.

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

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

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

(1) The Company estimates 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 the Company's three cogeneration facilities is approximately 93 megawatts (MW), of which the Company consumes approximately 8 MW for use in its operations. Each facility is centrally located on an oil producing property such that the steam generated by the facility is capable of being delivered to the wells that require steam for the enhanced oil recovery process. The Company's investment in its cogeneration facilities has 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 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 the Company's cogeneration plants, the price of natural gas used for fuel in generating electricity and steam, and the terms of the Company's power contracts. The Company views any profit or loss from the generation of electricity as a decrease or increase, respectively, to its total cost of producing its heavy oil in California. DD&A related to the Company's cogeneration facilities is allocated between electricity operations and oil and gas operations using a similar allocation method.

Sales Contracts. Historically, the Company has sold electricity produced by its cogeneration facilities to two California public utilities, Southern California Edison Company (Edison) and 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. An SO2 contract is more beneficial as it receives a higher capacity payment than an SO1 contract. The SRAC energy price is currently determined by a formula 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 the Company's cost of gas to produce electricity and steam in its cogeneration facilities. A proceeding is now underway at the California Public Utilities Commission (CPUC) to review and revise the methodology used to determine SRAC energy prices. This proceeding is currently scheduled to be completed by the third quarter of 2006. 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, which makes up approximately 17% of total approximate barrels of steam per day. The modified SRAC pricing terms of this contract reflect a fixed energy price of 5.37 cents/kilowatt hour (KWh) through June 2006, at which time the energy price reverts to the SRAC pricing methodology. The Company will be paid a reduced capacity payment that is fixed through the term of the contract.

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. Pursuant to these contracts, the Company is 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 SO contracts, and similar one-year SO contracts that were ordered for 2004. The Court ruled that the CPUC had the right to order the utilities to execute these contracts. The Court also ruled that the CPUC was obligated to review the prices paid under the contracts and to retroactively adjust the prices to the extent it was later determined that such prices did not comply with the requirements of the Public Utilities Regulatory Policy Act of 1978, as amended (PURPA).

The Company believes that Qualifying Facilities (QF), 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. Based on the current pricing mechanism for its electricity under the contracts (which includes electricity purchased for internal use), the Company expects that its electricity revenues will be in the $50 million to $60 million range for 2006.

Facility and Contract Summary

Location and Facility	Type of Contract	Purchaser	Contract Expiration	Approximate Megawatts Available for Sale	Approximate Megawatts Consumed in Operations	Approximate Barrels of Steam Per Day
Placerita						
Placerita Unit 1	SO2	Edison	Jun-06 (1)	20	-	6,600
Placerita Unit 2	SO1	Edison	Dec-09	16	4	6,700
Midway-Sunset						
Cogen 18	SO1	PG&E	Dec-09	12	4	6,600
Cogen 38	SO1	PG&E	Dec-09	37	-	18,000

(1) After expiration at June 2006, the contract will convert to SO1 through its expiration at March 2009.

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 and prospective acreage. 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 efficient operating cost structure, transaction flexibility, strong financial position, experience and determination.

Employees. On December 31, 2005, the Company had 209 full-time employees, up from 156 full-time employees on December 31, 2004.

Berry's Net Oil and Gas Producing Properties at December 31, 2005.

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

San Joaquin Valley Basin

Midway-Sunset, California - Berry owns and operates working interests in 38 properties, including 23 owned in fee, in the Midway-Sunset field. Production from this field relies on thermal enhanced oil recovery (EOR) methods, primarily cyclic steaming.

2005 - 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.
2006 - Capital of $40 million ($15 million for development and $25 million for exploration/appraisal) is directed to 1) development - maximizing the recovery from horizontal wells, improving steam efficiency and expanding two steam flood projects and 2) exploration/appraisal - expanding of the Diatomite project which includes up to 50 wells and related facilities.

Poso Creek, California - Berry acquired these properties beginning in 2003 and is evaluating the potential for thermal EOR.

2005 - The Company initiated a steam flood on the property.
2006 - Capital of $5 million is directed at drilling infill wells and, upon success, expanding the steam flood area.

Los Angeles Basin

Placerita, California - Berry owns and operates working interests in 13 properties, including 9 leases and 4 fee properties, in the Placerita field. Production relies on thermal recovery methods, primarily steam flooding.

2005 - Began major recompletion effort in mature steam flood and drilled 10 wells on northern acreage.
2006 - Capital of $8 million is directed at converting northern leases to steam flood, expanding another steam flood project and focusing on utilizing optimization technology to improve recovery.

Ventura Basin

Montalvo, California - Berry owns 6 leases in the Ventura Basin comprising the entire Montalvo field. The State of California is the lessor for 2 of these leases. The wells produce heavy oil and due to the depth of the reservoir, steam injection is not necessary.

2005 - Berry performed several well recompletions.
2006 - Capital of $8 million is directed at testing the western Sespe reservoir through additional drilling and adding production in the Colonia zone.

Uinta Basin

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

2005 - The Company continued its focus on development of the Brundage Canyon property, drilling 53 wells including 33 infill wells to validate 40-acre spacing.
2006 - Capital of $58 million is directed at continuing the development of the Green River formation, including testing 20-acre infills.

Lake Canyon Prospect, Utah - The Company holds, with an industry partner, a 169,000 gross acre block which 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 and natural gas 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 Ute Tribe did participate in the first two shallow Green River wells.

2005 - The Company drilled 2 shallow Green River oil and gas wells and participated in a 57 square mile 3-D seismic survey. In October 2005, the Company’s partner began drilling a deep Mesaverde gas test well that reached targeted depth of 14,500 feet in December. This deep well is being evaluated. In January 2006, the Company announced that its 2 shallow wells have commercial quantities of oil and gas.
2006 - Capital of $4 million is directed at an additional 4 shallow wells and participation in deep Mesaverde tests. Upon further success with the shallow wells, the Company will accelerate development and capital on this project.

Coyote Flats Prospect, Utah - In December 2004, the Company entered into a development agreement with an industry partner to develop their Coyote Flats prospect. The property is located approximately 45 miles southwest of the Company's Brundage Canyon property. The Company is obligated to drill four test wells into the Ferron sand to a depth of approximately 7,500 feet and also drill a five well Emery coalbed methane (CBM) pilot, found at approximately 4,500 feet. Upon the completion of this total nine well drilling program, the Company will earn a 50% working interest in the approximately 69,250 gross (33,500 net) acres. The Company expects to complete this nine well drilling program in 2006.

2005 - The Company has drilled 3 Ferron sand test wells in 2005, one of which was a dry hole. The Company began its CBM development with 1 well drilled.
2006 - Capital of $5 million is directed at fulfilling Berry's obligation wells, which consists of four CBM wells and one Ferron well. A gas pipeline is also planned to tie in gas production for sale in mid-summer.

Big Wash Unit, Utah - The Company, and an industry partner, owns working interest in 3 acreage blocks, the largest being the Big Wash Unit, which is located one mile southeast of Brundage Canyon.

2005 - Participated in one deep Mesaverde test in 2005, and the well (net working interest to Berry of 16%) is an economic producer.
2006 - Capital of $2 million is directed at participating in one exploratory gas well in the deep Mesaverde and one exploratory oil well in the shallow Green River formation.

Denver-Julesburg Basin

Tri-State Area (includes eastern Colorado producing assets) - This area is comprised of the following three acquisitions during 2005 totaling approximately 315,000 net acres, including approximately 100,000 net acres of producing acreage:
- Niobrara gas producing assets in Yuma County in northeastern Colorado in which the Company has approximately 52% working interest.
- Eastern Colorado, western Kansas and southwestern Nebraska in which the Company has approximately 50% working interest. The Company's joint venture (JV) will apply seismic technologies to explore and, if successful, develop the Niobrara formation for gas and Sharon Springs shale 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 feet to 4,800 feet.
- Colorado's Phillips and Sedgwick Counties in which the Company has approximately 50% working interest. This Niobrara leasehold position is adjacent to and immediately north of Berry's producing natural gas assets in Yuma County.

2005 - In 2005, the Company drilled approximately 103 gross wells as part of its ongoing development program and the initiation of the 40-acre infill program from the existing 80-acre development. The JV's initial exploratory wells at Prairie Star Sherman County, Kansas are commercial. Additionally, the JV drilled 7 gross wells (4 net) in 2005 at Prairie Star.
2006 - Capital of $25 million ($17 million development and $8 million exploration) is directed at drilling over 160 wells to add production from both proved undeveloped and probable reserves and over 30 exploratory wells, based on various seismic data and interpretation. The Company will also participate in at least five 3-D seismic surveys covering in excess of 250 square miles.

Williston Basin

Bakken Play, North Dakota - In 2005, the Company completed several transactions and Berry now has total working interests of 50% in 186,000 gross acres (46,000 net) located in the Williston Basin in North Dakota. These acquisitions, totaling approximately $9 million, provide the Company an entry into the emerging Bakken oil play in the Williston Basin. The acreage covers several contiguous blocks located primarily on the eastern flank of the Nesson Anticline. Development activity in the Middle Bakken play is generally expanding to the area surrounding the Nesson Anticline.

2005 - The Company participated in one exploratory well which is undergoing evaluation.
2006 - Capital of $4 million is directed at participating in at least four exploratory horizontal wells. Berry does not anticipate being the operator of any of these wells.

Piceance Basin

Grand Valley, Colorado - On January 27, 2006 the Company announced that it had entered into an agreement with a private seller to acquire a 50% working interest in natural gas assets (6,314 gross acres) in the Piceance Basin of western Colorado for approximately $150 million. Berry internally estimates 26 billion cubic feet (Bcf) of proved reserves. Berry has identified over 600 drilling locations based on 10-acre development. Berry will be targeting gas in the Williams Fork section of the Mesaverde formation. The Company increased its 2006 capital budget by an additional $48 million to $208 million to develop this resource. There are two drilling rigs dedicated to this project and based on the productivity of this acreage and surrounding producing operations, Berry is seeking to add additional drilling rigs to accelerate development. Estimated production, net to Berry's interests as of March 1, 2006 is 1 million cubic feet per day. The transaction closed on February 28, 2006.

2006 - Capital of $48 million is directed at beginning the extensive development of the acreage. The Company intends to drill over 30 wells in 2006 and, depending on rig availability and commodity prices, may increase its capital committed to the project.

The following is a summary of the Company's capital expenditures incurred during 2005 and 2004 and budgeted capital expenditures for 2006:

CAPITAL EXPENDITURES SUMMARY
(in thousands)

	2006 (Budgeted) (1)	2005	2004
CALIFORNIA			
Midway-Sunset field			
New wells	$ 23,380	$ 17,369	$ 11,376
Remedials/workovers	1,145	1,079	1,415
Facilities - oil & gas	14,493	7,879	4,045
Facilities - cogeneration	543	3,053	1,055
General	540	1,271	2,144
	40,101	30,651	20,035
Other California fields			
New wells	10,647	6,965	426
Remedials/workovers	2,650	5,303	1,589
Facilities - oil & gas	7,202	3,677	3,416
Facilities - cogeneration	400	1,446	555
General	110	46	-
	21,009	17,437	5,986
Total California	61,110	48,088	26,021
ROCKY MOUNTAIN AND MID-CONTINENT			
Uinta Basin			
New wells	64,100	50,354	39,467
Remedials/workovers	1,496	3,415	4,597
Facilities	2,500	1,860	1,979
General	552	4	-
	68,648	55,633	46,043
Piceance Basin			
New wells	47,615	-	-
	47,615	-	-
DJ Basin			
New wells/workovers	14,819	11,257	-
Remedials/workovers	275	693	-
Facilities	5,215	2,569	-
General	4,838	387	-
Land and seismic	-	-	-
	25,147	14,906	-
Williston Basin - New wells	4,400	-	161
Total Rocky Mountain and Mid-Continent	145,810	70,539	46,204
Other Fixed Assets	770	647	-
TOTAL	$ 207,690	$ 119,274	$ 72,225

(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 Operations.

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

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

Mbbl - Thousands of barrels
MMcf - Million cubic feet
BOE - Barrels of oil equivalent
MBOE - Thousand barrels of oil equivalent
(1) Net production represents that owned by Berry and produced to its 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, 2005, the Company's properties accounted for the following developed and undeveloped acres:

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

(1) Includes 44,583 gross undeveloped acres (22,292 net) where the Company has an interest in 75% of the deep rights and 25% of the shallow rights.
(2) Does not include 125,000 gross (70,000 net) acres, 125,000 gross (23,000 net) acres and 69,000 gross (34,000 net) acres at Lake Canyon (shallow), Lake Canyon (deep) and Coyote Flats, respectively, which the Company can earn upon fulfilling specific drilling obligations.

Gross acres represent acres in which Berry has a working interest; net acres represent Berry's aggregate working interests in the gross acres.

As of December 31, 2005, the Company has 2,035 gross oil wells (1,951 net) and 976 gross gas wells (419 net). Gross wells represent the total number of wells in which Berry has a working interest. Net wells represent the number of gross wells multiplied by the percentages of the working interests owned by Berry. 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 Berry's drilling activities for the periods indicated:

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

(1) 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.
(2) Does not include one gross well drilled by the Company's industry partner that is being evaluated at December 31, 2005.

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

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

California Drilling Rig. The Company entered into a three-year drilling contract for the services of an automated drilling rig. This rig provides a means for Berry to meet at least half of its California new well drilling needs for the next three years, with the other half being met by conventional drilling rigs. The three-year drilling contract begins upon commissioning of the rig which is expected in the second quarter of 2006.

Rocky Mountain and Mid-Continent Region Drilling Rigs. During 2005, the Company purchased two drilling rigs. The first rig is leased to a drilling company under a three year contract, while the second rig is currently being refurbished in preparation for leasing under a similar drilling contract. Owning these rigs allows the Company to successfully meet a portion of its drilling needs in the Uinta Basin over the next several years, while both rigs carry purchase options available to the drilling company.

Other. At year-end, the Company had no subsidiaries, no special purpose entities and no off-balance sheet debt. The Company did not enter into any significant related party transactions in 2005. See Note 17 to the financial statements for discussion regarding Canyon Drilling, LLC.

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 normal operating expenses and are not material to the Company's 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. Berry maintains insurance coverage that it believes is customary in the industry although it is not fully insured against all environmental or other risks.

Regulation of Oil and Gas. The oil and gas industry, including the Company's operations, is extensively regulated by numerous federal, state and local authorities, and with respect to tribal lands, and one Native American tribe.

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

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

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

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)," or other comparable 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 16 of this Form 10-K filed with the Securities and Exchange Commission, under the heading "Other Factors Affecting the Company's Business and Financial Results" in the section titled "Management's Discussion and Analysis of Financial Condition and Results of Operations."

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

Among the factors that can cause fluctuations are:

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

The Company has crude oil hedges on 10,000 Bbl/D for 4 years beginning in 2006. We have an oil collar in place based on WTI pricing with a $47.50 floor and a $70 ceiling.

Our heavy crude in California is less economic than lighter crude oil and natural gas. As of December 31, 2005, approximately 74% of our proved reserves or 93 million barrels, consisted of heavy oil, light crude oil represented 8% and natural gas represented 18% of our oil and gas reserves. Our objective is to diversify our predominantly heavy crude oil base with light crude oil and natural gas.

In November 2005, the Company entered into a new crude oil sales contract for its California production for deliveries beginning February 1, 2006 and ending January 31, 2010. The per barrel price, calculated on a monthly basis and blended across the various producing locations, is the higher of 1) the WTI NYMEX crude oil price less a fixed differential approximating $8.15, or 2) heavy oil field postings plus a premium of approximately $1.35.

A widening of commodity differentials may adversely impact our revenues and per barrel economics. Both our produced crude oil and natural gas are subject to pricing in the local markets where the production occurs. It is customary that such products are priced based on local or regional supply and demand factors. California heavy crude sells at a discount to WTI, the U.S. benchmark crude oil, primarily due to the additional cost to refine gasoline or light product out of a barrel of heavy crude. Our Utah light crude also is currently priced at $2.00 below WTI. Natural gas field prices are normally priced off of Henry Hub NYMEX price, the benchmark for U.S. natural gas. While we attempt to contract for the best possible price in each of our producing locations, there is no assurance that past price differentials will continue into the future. Numerous factors may influence local pricing, such as refinery capacity, particularly for black wax crude, pipeline capacity and specifications, upsets in the mid-stream or downstream sectors of the industry, trade restrictions, governmental regulations, etc. We may be adversely impacted by a widening differential on the products sold.

Market conditions or operational impediments may hinder our access to crude oil and natural gas markets or delay our production. Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines, processing facilities and refineries owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business. We may be required to shut in wells for a lack of a market or because of inadequacy or unavailability of natural gas pipeline, 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.

Brundage Canyon crude oil production, which is approximately 40 degree API gravity, is sold under contract at WTI less a fixed differential approximating $2.00 per barrel. This contract expires on September 30, 2006. Any new contract will be negotiated based on market prices. We believe the differential has widened by several dollars per barrel. The majority of this crude oil, while light, is a “paraffinic” crude, and can be processed efficiently by only a limited number of stranded inland refineries. The production of this type crude is increasing regionally and beginning to strain the capacity of these refineries. Other new crude sources from the region are pressuring pricing. If these refineries limit the volumes of this parraffinic crude oil they are willing to process, it could impact the marketability of this type of crude which, for Berry, represents approximately 3,500 Bbl/D of production or approximately 15% of total current production. We are investigating the market opportunities for this crude oil. If market prices continue to deteriorate, we may allocate capital expenditures to projects which produce natural gas and crude oils with lower paraffinic content until the refinery constraint is resolved.

We may be subject to the risk of adding additional steam generation equipment if the electrical market deteriorates significantly. We may be subject to the risk of adding additional steam generation equipment if the electrical market deteriorates significantly. We are dependent on several cogeneration facilities that provide over half of our steam requirement. These facilities are dependent on reasonable electrical contracts. If, for any reason, we were unable to enter into an electrical contract or were to lose an existing contract, we may not be able to supply 100% of the steam requirements necessary to maximize production from our heavy oil assets. An additional investment in various steam sources may be necessary to replace such steam, and there may be risks and delays in being able to install conventional steam equipment due to permitting requirements. The financial cost and timing of such investment may adversely affect our production, capital outlays and cash provided by operating activities. We have electricity contracts covering most of our electricity generation which contracts expire in 2009.

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

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

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

Actual quantities of recoverable oil and gas reserves and future cash flows from those reserves , future production, oil and gas prices, revenues, taxes, development expenditures and operating expenses most likely will vary from estimates. Estimating accumulations of oil and gas is complex. The process relies on interpretations of available geologic, geophysical, engineering and production data. The extent, quality and reliability of this data can vary. The process also requires certain economic assumptions, such as oil and gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds, some of which are mandated by the SEC. The accuracy of a reserve estimate is a function of:
- quality and quantity of available data;
- interpretation of that data; and
- accuracy of various mandated economic assumptions.

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

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

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

We capitalize costs to acquire, find and develop our oil and gas properties under the successful efforts accounting method. If net capitalized costs of our oil and gas properties exceed fair value, we must charge the amount of the excess to earnings. We review the carrying value of our properties annually and at any time when events or circumstances indicate a review is necessary, based on prices in effect as of the end of the reporting period. The carrying value of oil and gas properties is computed on a field-by-field basis. Once incurred, a writedown of oil and gas properties is not reversible at a later date even if oil or gas prices increase. See Item 7A Quantitative and Qualitative Disclosures About Market Risk for the Company's hedge position on February 10, 2006.

Competitive industry conditions may negatively affect our ability to conduct operations. Competition in the oil and gas industry is intense, particularly with respect to the acquisition of producing properties and proved undeveloped acreage. Major and independent oil and gas companies actively bid for desirable oil and gas properties, as well as for the equipment and labor required to operate and develop their properties. Many of our competitors have financial resources that are substantially greater, which may adversely affect our ability to compete within the industry.

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

- obtaining government and tribal required permits;
- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions;
- compliance with governmental or landowner requirements; and
- shortages or delays in the availability of drilling rigs and the delivery of equipment and/or services.

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

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

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

- injury or loss of life;
- severe damage or destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- investigatory and clean-up responsibilities;
- regulatory investigation and penalties;
- suspension of operations; and
- repairs to resume operations.

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

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

Part of the regulatory environment in which we operate includes, in some cases, federal requirements for obtaining environmental assessments, environmental impact studies and/or plans of development before commencing exploration and production activities. In addition, our activities are subject to the regulation by oil and natural gas-producing states and one Native American tribe of conservation practices and protection of correlative rights. These regulations affect our operations and limit the quantity of oil and natural gas we may produce and sell. A major risk inherent in our drilling plans is the need to obtain drilling permits from state, local and Native American tribal authorities. Delays in obtaining regulatory approvals or drilling permits, the failure to obtain a drilling permit for a well or the receipt of a permit with unreasonable conditions or costs could have a negative effect on our ability to explore on or develop its properties. Additionally, the oil and natural gas regulatory environment could change in ways that might substantially increase the financial and managerial costs to comply with the requirements of these laws and regulations and, consequently, adversely affect our profitability.

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

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

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

There are risks in acquiring producing properties, including difficulties in integrating acquired properties into our business, additional liabilities and expenses associated with acquired properties, diversion of Management attention, and costs of increased scope, geographic diversity and complexity of our operations. Increasing our reserve base through acquisitions is an important part of our business strategy. Our failure to integrate acquired businesses successfully into our existing business, or the expense incurred in consummating future acquisitions, could result in our incurring unanticipated expenses and losses. In addition, we may have to assume cleanup or reclamation obligations or other unanticipated liabilities in connection with these acquisitions. The scope and cost of these obligations may ultimately be materially greater than estimated at the time of the acquisition.

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

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

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

We have limited control over the activities on properties that we do not operate. Although we operate most of the properties in which we have an interest, other companies operate some of the properties. We have limited ability to influence or control the operation or future development of these nonoperated properties or the amount of capital expenditures that we are required to fund their operation. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence or control the operation and future development of these properties could have a material adverse effect on the realization of our targeted returns or lead to unexpected future costs.

We may not adhere to our proposed drilling schedule. Our final determination of whether to drill any scheduled or budgeted wells will depend on a number of factors, including:

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

Although we have identified or budgeted for numerous drilling prospects, we may not be able to lease or drill those prospects within our expected time frame, or at all. In addition, our drilling schedule may vary from our expectations because of future uncertainties and rig availability and access to our drilling locations utilizing available roads. As of December 31, 2005, the Company owns two drilling rigs and has additional one-year contract commitments on another two drilling rigs. See Note 10 to the financial statements.

We may incur losses as a result of title deficiencies. We purchase working and revenue interests in the oil and natural gas leasehold interests upon which we will perform our exploration activities from third parties or directly from the mineral fee owners. The existence of a material title deficiency can render a lease worthless and can adversely affect our results of operations and financial condition. Title insurance covering mineral leaseholds is not generally available and, often, we forego the expense of retaining lawyers to examine the title to the mineral interest to be placed under lease or already placed under lease until the drilling block is assembled and ready to be drilled. As is customary in our industry, we rely upon the judgment of oil and natural gas lease brokers or independent landmen who perform the field work in examining records in the appropriate governmental offices and abstract facilities before attempting to acquire or place under lease a specific mineral interest. We, in some cases, perform curative work to correct deficiencies in the marketability of the title to us. The work might include obtaining affidavits of heirship or causing an estate to be administered. In cases involving more serious title problems, the amount paid for affected oil and natural gas leases can be generally lost, and the target area can become undrillable.

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.

Estimates may differ from actual. The preparation of financial statements in conformity with accounting principles generally accepted in the U.S. requires Management to make estimates and assumptions that affect the reported amounts of assets and liabilities and related disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. Actual results may differ from these estimates and assumptions used in preparation of its financial statements. Significant estimates with regard to these financial statements include the estimate of proved oil and gas reserve quantities, the related present value of estimated future net cash flows therefrom, the costs to develop and abandon oil and gas properties, the valuation of derivative positions and stock-based compensation valuation.

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 the Company is, from time to time, a party to certain lawsuits in the ordinary course of business, the Company does not believe any of such existing lawsuits will have a material adverse effect on the Company's 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 of the Registrant. Listed below are the names, ages (as of December 31, 2005) and positions of the executive officers of Berry and their business experience during at least the past five years. All officers of the Company are appointed 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, 52, 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 Company's 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, 49, 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 for the Company.

MICHAEL DUGINSKI, 39, 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 for the Company.

LOGAN MAGRUDER, 49, has been Executive Vice President of the Rocky Mountains and Mid-Continent region since October 2005. Mr. Magruder was Senior Vice President of the Rocky Mountain and Mid-Continent region from June 2004 through October 2005 and was Vice President of the Rocky Mountain and Mid-Continent region from August 2003 through June 2004. Mr. Magruder, a petroleum engineer, was a consultant for the Company from February 2003 through August 2003. Mr. Magruder was previously Vice President of U.S. Operations for Calpine Natural Gas Company from 2001 to 2003. Prior to Calpine, Mr. Magruder was employed by Barrett Resources as Vice President of Engineering and Operations from 1996 to 2001.

DAN ANDERSON, 43, has been Vice President of Rocky Mountains and Mid-Continent Production since October 2005. Mr. Anderson was Rocky Mountain and Mid-Continent Manager of Engineering from August 2003 through October 2005. Mr. Anderson 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.

GEORGE T. CRAWFORD, 45, has been Vice President of California Production since October 2005. Mr. Crawford was Vice President of Production from December 2000 through October 2005 and was Manager of Production from January 1999 to December 2000. Mr. Crawford, a petroleum engineer, was previously the Production Engineering Supervisor for Atlantic Richfield Corp. (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, 50, has been Vice President of Rocky Mountains and Mid-Continent Exploration since October 2005. Mr. Kelso was Rocky Mountain and Mid-Continent Exploration Manager from August 2003 through October 2005. Mr. Kelso, a petroleum geologist, was previously a Senior Staff Geologist assigned to Rocky Mountain assets with Williams Production RMT, from January 2002 through August 2003. He previously was the Vice President of Exploration and Development at Redstone Resources, Inc. from 2000 to 2001.

BRIAN L. REHKOPF, 58, has been Vice President of Technology since October 2005. Mr. Rehkopf was Vice President of Engineering from March 2000 through October 2005 and was Manager of Engineering from September 1997 to March 2000. Mr. Rehkopf, a registered petroleum engineer, joined the Company’s engineering department in June 1997 and was previously a Vice President and Asset Manager with ARCO since 1992 and an Operations Engineering Supervisor from 1988 to 1992. Mr. Rehkopf is also an Assistant Secretary for the Company.

SHAWN M. CANADAY, 30, has been Treasurer since December 2004 and was Senior Financial Analyst from November 2003 until December 2004. Mr. Canaday has worked in the oil and gas industry since 1998 in various finance functions at ChevronTexaco and in public accounting. Mr. Canaday is also an Assistant Secretary for the Company.

DONALD A. DALE, 59, has been Controller since December 1985.

KENNETH A. OLSON, 50, has been Corporate Secretary since December 1985 and was Treasurer from August 1988 until December 2004.

PART II

Item 5. Market for the Registrant’s Common Equity, 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 $1.00 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, the Company 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.

Berry's 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 2005 and 2004 are shown below:

	2005			2004		
	Price Range		Dividends	Price Range		Dividends
	High	Low	Per Share	High	Low	Per Share
First Quarter	$ 66.09	$ 43.85	$ .12	$ 27.30	$ 18.25	$ 0.11
Second Quarter	54.95	40.78	.12	31.07	25.09	0.11
Third Quarter	67.00	52.30	.23	38.44	27.73	0.18
Fourth Quarter	68.66	52.30	.13	50.58	35.16	0.12
Total Dividend Paid			$ .60			$ .52

	February 10, 2006	December 31, 2005	December 31, 2004
Berry’s Common Stock closing price per share as reported on NYSE Composite Transaction Reporting System	$ 68.90	$ 57.20	$ 47.70

The number of holders of record of the Company's Common Stock was 605 as of February 10, 2006. There was one Class B Shareholder of record as of February 10, 2006.

Dividends. The Company paid a special dividend of $.10 per share on September 29, 2005 and increased its regular quarterly dividend by 8%, from $.12 to $.13 per share beginning with the September 29, 2005 dividend. The Company's regular annual dividend is currently $.52 per share, payable quarterly in March, June, September and December. The Company paid a special dividend of $.06 per share on September 29, 2004 and increased its regular quarterly dividend by 9%, from $.11 to $.12 per share beginning with the September 2004 dividend.

Since Berry Petroleum Company's formation in 1985 through December 31, 2005, the Company has paid dividends on its Common Stock for 65 consecutive quarters and previous to that for eight consecutive semi-annual periods. The Company intends to continue the payment of dividends, although future dividend payments will depend upon the Company's level of earnings, operating cash flow, capital commitments, financial covenants and other relevant factors. Dividend payments are limited by covenants in the Company's credit facility to the greater of $20 million or 75% of net income.

As of December 31, 2005, dividends declared on 3,984,080 shares of certain Common Stock are restricted, whereby 37.5% of the dividends declared on these shares are paid by the Company 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	1,625,763	$33.52	1,080,187
Equity compensation plans not approved by security holders	-	-	-

In June 2005, the Company announced that its Board of Directors authorized a share repurchase program for up to an aggregate of $50 million of the Company's outstanding Class A Common Stock. Through December 31, 2005, the Company repurchased 108,900 shares for approximately $6.3 million, which increased diluted earnings by $.01 per share.

In December 2005, the Company adopted a plan under Rule 10b5-1 of the Securities Exchange Act of 1934 to facilitate the repurchase of its 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. In addition to share repurchases by the Rule 10b5-1 plan, Berry expects to continue repurchases in the open market from time to time during its normal trading windows. This 10b5-1 plan is authorized under, and is administered consistent with, the Company's $50 million share repurchase program. 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 other factors.

This program does not obligate the Company to acquire any particular amount of common stock and the plan may be suspended at any time at the Company's discretion.

Issuer Purchases of Equity Securities

Period	(a) Total number of shares purchased	(b) Average price paid per share	(c) Total number of shares purchased as part of publicly announced plans or programs	(d) Maximum number (or approximate dollar value) of shares that may yet be purchased under the plans or programs
Third Quarter 2005	43,900	$58.48	43,900	$47,433,000
November 2005	16,300	57.25	16,300	46,500,000
December 2005	48,700	57.80	48,700	43,684,500
Total	**108,900**	**$57.99**	**108,900**	**$43,684,500**

Item 6. Selected Financial Data

The following table sets forth certain financial information with respect to the Company and is qualified in its entirety by reference to the historical financial statements and notes thereto of the Company 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, 2005 were derived from the audited financial statements and the accompanying notes to those financial statements (in thousands, except per share, per BOE and % data).

	2005	2004 (3)	2003 (3)	2002 (1) (3)	2001 (1) (3)
Audited Financial Information					
Statement of Income Data:					
Sales of oil and gas	$ 349,691	$ 226,876	$ 135,848	$ 102,026	$ 100,146
Sales of electricity	55,230	47,644	44,200	27,691	35,133
Operating costs - oil and gas production	99,066	73,838	57,830	41,108	34,605
Operating costs - electricity generation	55,086	46,191	42,351	26,747	36,890
Production taxes	11,506	6,431	3,097	2,907	2,479
General and administrative expenses (G&A)	21,396	22,504	14,495	10,417	9.748
Depreciation, depletion & amortization (DD&A)					
Oil and gas production	38,150	29,752	17,258	13,388	13,225
Electricity generation	3,260	3,490	3,256	3,064	3,295
Net income	112,356	69,187	32,363	29,210	20,985
Basic net income per share	5.10	3.16	1.49	1.34	0.96
Diluted net income per share	5.00	3.08	1.47	1.33	0.95
Weighted average number of shares outstanding (basic)	22,041	21,894	21,772	21,741	21,973
Weighted average number of shares outstanding (diluted)	22,490	22,470	22,031	21,902	22,162
Balance Sheet Data:					
Working capital	$ (54,757)	$ (3,840)	$ (3,540)	$ (2,892)	$ 6,314
Total assets	635,051	412,104	340,377	259,325	238,779
Long-term debt	75,000	28,000	50,000	15,000	25,000
Shareholders' equity	334,210	263,086	197,338	172,774	153,590
Cash dividends per share	0.60	0.52	0.47	0.40	0.40
Operating Data:					
Cash flow from operations	187,780	124,613	64,825	57,895	35,433
Exploration and development of oil and gas properties	118,718	71,556	41,061	30,163	14,776
Property/facility acquisitions	112,249	2,845	48,579	5,880	2,273
Additions to vehicles, drilling rigs and other fixed assets	11,762	669	494	469	119
Unaudited Operating Data					
Oil and gas producing operations (per BOE):					
Average sales price before hedging	$ 47.01	$ 33.64	$ 24.48	$ 20.11	$ 19.63
Average sales price after hedging	41.62	30.32	22.52	19.39	19.79
Average operating costs - oil and gas production	11.79	10.09	9.57	7.83	6.86
Production taxes	1.37	.86	.51	.55	.49
G&A	2.55	2.99	2.40	1.98	1.93
DD&A - oil and gas production	4.54	3.96	2.86	2.55	3.28
Production (MBOE)	8,401	7,517	6,040	5,251	5,044
Production (MMWh)	741	776	767	748	483
Proved Reserves Information:					
Total BOE	126,285	109,836	109,920	101,719	102,855
Standardized measure (2)	$ 1,251,380	$ 686,748	$ 528,220	$ 449,857	$ 278,453
Year-end average BOE price for PV10 purposes	48.21	29.87	25.89	24.91	14.13
Other:					
Return on average shareholders' equity	37.63%	31.06%	17.50%	17.90%	14.00%
Return on average total assets	20.15%	18.60%	10.80%	11.70%	8.80%

(1) Information has been revised to reflect the Company's change in allocation of cogeneration costs to oil and gas operations. See Item 7 Management's Discussion and Analysis.

(2) See Supplemental Information About Oil & Gas Producing Activities.
(3) Information has been revised to reflect the Company's change in allocation of technical labor and production taxes. See Note 2 to the financial statements.

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

Corporate Strategy. Berry's mission is to increase shareholder value, primarily through increasing the net asset value and maximizing the cash flow and earnings of its assets. The strategies to accomplish these goals include:

- Growing production and reserves from existing assets while managing expenses
- Acquiring more light oil and natural gas assets with significant growth potential in the Rocky Mountain and Mid-Continent region
- Appraising our exploitation and exploration projects in an expedient manner
- Investing our capital in an efficient, disciplined manner to increase production and reserves
- Utilizing joint ventures with respected partners to enter new basins

Notable Items in 2005.

- Achieved record production which averaged 23,015 BOE/D, up 12% from 2004
- Achieved record cash from operating activities of $188 million, up 50% from 2004
- Achieved record net income of $112 million, up 62% from 2004
- 2005 developmental capital expenditures were $131 million, up 82% from 2004
- Acquired and integrated the eastern Colorado Niobrara natural gas producing assets - acquisition cost of $105 million
- Added 24.9 million BOE of reserves before production ending 2005 at 126.3 million BOE
- Achieved reserve replacement rate of 296%
- Negotiated new four-year crude oil sales contract for California heavy oil production
- Observed positive results on Diatomite play and expanded pilot
- Placed price collars on 10,000 barrels per day of future production from 2006 through 2009
- Added approximately 186,000 gross (46,000 net) acres in the North Dakota Bakken play
- Added approximately 624,000 gross (315,000 net) acres to Tri-State area inventory
- Increased quarterly dividend to $.13 per share and paid special dividend of $.10 per share for total payout of $.60 per share
- Began drilling to assess several prospects including Lake Canyon, Coyote Flats and Tri-State area
- Increased financial capacity by establishing a $500 million unsecured credit facility
- Initiated a $50 million share buyback program

Acquisitions. On January 27, 2005, we acquired certain interests in the Niobrara fields in northeastern Colorado for approximately $105 million. At December 31, 2005 the properties consist of approximately 127,000 gross (100,000 net) acres. Production at acquisition was approximately 9 MMcf of natural gas per day, with estimated proved reserves of 87 Bcf. For the month of December 2005, production averaged approximately 13,800 MMcf per day and reserves were 105 Bcf. The acquisition included approximately 200 miles of a pipeline gathering system and gas compression facilities for delivery into interstate gas lines.

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

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

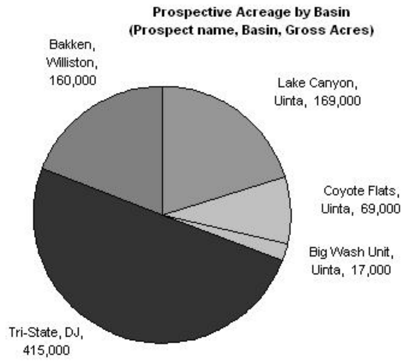
In October 2005, we purchased a 50% working interest in approximately 69,000 gross undeveloped acres (24,000 net) in Colorado's Phillips and Sedgwick Counties. This additional Niobrara leasehold position is adjacent to and immediately north of Berry's producing natural gas assets in Yuma County. We expect to begin shooting a 3-D seismic survey and drilling the first delineation wells in 2006.

On January 27, 2006, we announced an agreement with a private seller to acquire a 50% working interest in natural gas assets in the Piceance Basin of western Colorado for approximately $150 million in cash. Berry internally estimates there are 26 billion cubic feet (Bcf) of proved reserves and has identified over 600 drilling locations based on 10-acre development. We will be the operator in the 6,314 gross acres targeting gas in the Williams Fork section of the Mesaverde formation. We increased the 2006 capital budget by an additional $48 million to $208 million to develop this resource. There are two drilling rigs dedicated to this project, and we will ramp up our drilling activity to four rigs by the end of the year along with complementary services and goods to accelerate the development of this acquisition. Based on the productivity of this acreage and surrounding producing operations, we are seeking to add additional drilling rigs to accelerate development. The transaction closed on February 28, 2006.

Capital Expenditures. Excluding any future acquisitions, in 2006 we plan to spend approximately $208 million. These expenditures will be directed toward developing reserves, increasing oil and gas production and exploration opportunities. For 2006, Berry plans to invest approximately $146 million, or 70%, in our Rocky Mountain and Mid-Continent region assets, and $61 million, or 30%, in our California assets. Approximately half the capital budget is focused on converting probable and possible reserves into proved reserves and on our appraisal and exploratory projects.

This robust capital program allows Berry to continue its record activity levels by planning to drill 476 net wells and perform 55 well workover activities in 2006 versus approximately 188 wells and 140 well workovers in 2005. As a result, we are targeting production growth of 12% to average approximately 25,800 BOE per day, which includes the Piceance Basin acquisition, but before any other acquisitions, and we plan to continue to actively appraise significant acreage positions held for hydrocarbon potential. In 2006, we expect production to be approximately 70% heavy oil, 15% light oil and 15% natural gas and anticipate funding our capital program from internally generated cash flow. Successes may also encourage the initiation of additional discretionary projects. We have currently secured the necessary equipment and are meeting permit requirements to achieve the 2006 program.

Appraisal, Evaluation and Exploitation Activity. Since 2003, we have been active in assembling significant acreage positions which we believe are highly prospective for finding and developing commercial quantities of hydrocarbons. This chart depicts our prospective acreage by basin, all of which is in the Rocky Mountain and Mid-Continent region:



Rocky Mountain and Mid-Continent

We plan to appraise five project areas in this region in 2006 for an estimated $23 million budgeted. These five projects are Lake Canyon, Coyote Flats, Big Wash Unit, Tri-State Area and the Bakken Play. We have interests in over one million gross acres, including both productive and prospective, in the Rocky Mountain and Mid-Continent region and the acreage in the five appraisal projects accounts for about 80% of that total.

Uinta Basin Projects

Lake Canyon - Shallow: On January 13, 2006, we announced commercial success from our first two wells on this acreage. The Nielsen Marsing and Taylor Herrick wells have tested production rates of 98 and 163 BOE/D, respectively, from the same Green River formation that is productive immediately east (approximately 3 miles) in our Brundage Canyon field. Initial performance from these discovery wells suggests that expected reserves per well are on par with the Brundage Canyon field (approximately 80,000 BOE gross) that is currently being developed on 40-acre spacing. Current production from the Taylor Herrick well is not at full capacity as additional facilities are in the process of being installed. Production from the Nielsen Marsing well is selectively limited to two of five completion intervals within the well and will be further optimized by March 2006 when natural gas facilities are completed. We are proceeding with another four wells on the eastern edge of this 169,000 acre block. If the results of these wells are deemed satisfactory, Berry will expand the drilling program and attempt to drill up to another 30 wells over approximately 20,000 acres. The focus will be to begin the methodical appraisal of a sizeable portion of this acreage block. Berry's working interest in these wells will be either 75% or 56.25% depending on the participation of the land owner. The shallow zones are those above the Wasatch which is at approximately 6,500 feet.

Lake Canyon - Deep: Berry's industry partner recently reached total depth of 14,325 feet on its Mesaverde test and set casing to a depth of 11,539 feet. Testing will focus on several Upper Price River and shallower Wasatch intervals where analysis indicates gas potential; the deeper Mesaverde and Blackhawk intervals did not warrant further evaluation. Berry will participate with its industry partner to complete the testing and evaluation of the first deep well on the acreage once pipeline construction into the area is completed, which is currently targeted by May 1, 2006. The second well is scheduled to begin drilling in the fourth quarter of 2006.

Coyote Flats: We will continue to test the viability of the Ferron gas development and Emery CBM pilot with additional drilling.

Big Wash Unit: We will test the shallow oil and deeper gas potential located about two miles southeast of Brundage Canyon.

Denver-Julesburg Basin Projects

Tri-State Area: We will be very active in testing the Niobrara gas potential located in the Tri-State area of Colorado, Kansas and Nebraska. We will participate in 16 exploratory gas wells, drill 11 development wells and acquire additional 3D seismic. Immediately to the north of our producing assets in Yuma County, Colorado, we may drill up to 17 wells based on the acquisition of new seismic data covering the northern acreage.

Williston Basin Projects

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

California-Diatomite

In 2005, oil production from the initial 14 well pilot (6 producers) averaged approximately 135 Bbl/D. Based on promising results from the pilot project, we began an expansion of the pilot with a 25 well program (15 producers) in the third quarter of 2005, and completed it in the fourth quarter. We continue to assess the long-term economic and operating viability of the project as the early wells are an indication of future large-scale development. Results are in accordance with expectations. We are judiciously monitoring the steam to oil ratio (SOR) because we believe achieving an SOR of 6 or less is the threshold for commerciality. SOR measures how much steam is required for injection into the reservoir to produce one barrel of oil. Estimated original oil in place ranges between 200 million to 250 million barrels with targets of a minimum 25% recovery of original oil in place. In 2005, we booked 2.5 million BOE of reserves based on asset performance. We believe that the project continues to remain on track towards commerciality.

In 2006, we are expanding the commercial test of our diatomite resource by investing approximately $25 million in a program that will add another 50 wells (31 producers, 16 steam injectors, and 3 service wells). Since completing our expansion of the initial pilot in December 2005, we now have a total of 39 wells (21 producers, 15 steam injectors, and 3 service wells) that we will be using to monitor reservoir performance. In addition to the drilling program, we will add significant facilities including steam generation equipment and will be optimizing the pattern configuration and layout for the eventual full-field development if commerciality is determined.

Development Activity

Rocky Mountain and Mid-Continent

Approximately $93 million will be invested in this region, with $58 million targeting the continued development drilling of the Green River formation at Brundage Canyon to assist full development and will include a 20-acre spacing pilot. In northeastern Colorado, $17 million will be invested to acquire additional seismic data and drill 150 wells to further develop the Niobrara natural gas production from our producing assets.

California

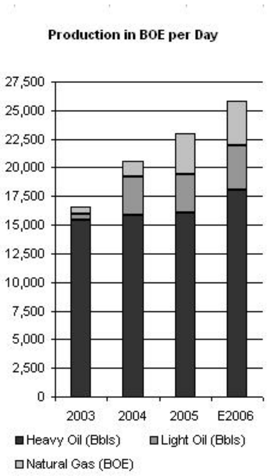
Berry will invest $37 million in its heavy oil properties, utilizing horizontal well and new steam-optimization technologies to maximize recovery from our legacy assets. Development activity at our Poso Creek, Ethel D and Midway-Sunset assets will utilize improved application of steam flood technology to provide production growth.

See Item 1 Business for more information on Development Activity.

Obstacles and Risks to Accomplishment of Strategies and Goals. See Item 1A Other Factors Affecting the Company's Business and Financial Results for a detailed discussion of factors that affect our business, financial condition and results of operations.

Results of Operations. Approximately 86% of Berry's revenues are generated through the sale of oil and natural gas production under either negotiated contracts or spot gas purchase contracts at market prices. Over 83% of these volumes are from oil production, and the majority of those volumes are from heavy oil production in California. The remaining 14% of Berry's revenues are derived from electricity sales from cogeneration facilities which supply over half of Berry’s steam requirement for use in its 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 54% in 2005 compared to 2004 and up 157% from 2003. This significant improvement was due to increases in both oil and gas prices and production levels.



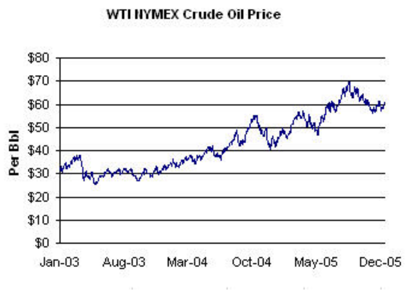
Improvements in production volume are due to acquisitions and sizable capital investments. Improvement in prices during 2005 are due to a tighter supply and demand balance and the nervousness of the market about possible supply disruptions. The increase in oil prices contributed roughly two-thirds of the revenue increase and the increase in production volumes contributed the other third. Approximately 84% of Berry’s oil and gas sales volumes in 2005 were crude oil, with 78% of the crude oil being heavy oil produced in California which was sold under a contract based on the higher of WTI minus a fixed differential or the average posted price plus a premium. This contract ended on January 31, 2006. The contract allowed us to improve our California revenues over the posted price by approximately $38 million and $13 million in 2005 and 2004, respectively.

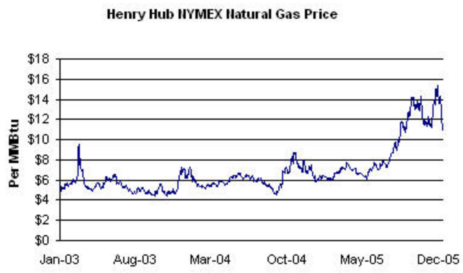
On November 21, 2005, we entered into a new crude oil sales contract for our California production for deliveries beginning February 1, 2006. The per barrel price, calculated on a monthly basis and blended across the various producing locations, is the higher of 1) the WTI NYMEX crude oil price less 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 and allows us to effectively hedge our production based on WTI pricing similar to the previous contract. Initial deliveries under the contract are approximately 15,000 net barrels per day or approximately two-thirds of Berry's total production.

Brundage Canyon crude oil production, which is approximately 40 degree API gravity, is sold under contract at WTI less a fixed differential approximating $2.00 per barrel. This contract expires on September 30, 2006. Any new contract will be negotiated based on market prices. We believe the differential has widened by several dollars per barrel. The majority of this crude oil, while light, is a “paraffinic” crude, and can be processed efficiently by only a limited number of stranded inland refineries. The production of this type crude is increasing regionally and beginning to strain the capacity of these refineries. Other new crude sources from the region are pressuring pricing. If these refineries limit the volumes of this parraffinic crude oil they are willing to process, it could impact the marketability of this type of crude which, for Berry, represents approximately 3,500 Bbl/D of production or approximately 15% of total current production. We are investigating the market opportunities for this crude oil. If market prices continue to deteriorate, we may allocate capital expenditures to projects which produce natural gas and crude oils with lower paraffinic content until the refinery constraint is resolved.

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

	2005	2004	2003
Sales of oil	$ 289	$ 210	$ 130
Sales of gas	61	17	6
Total sales of oil and gas	$ 350	$ 227	$ 136
Sales of electricity	55	48	44
Interest and other income, net	2	-	1
Total revenues and other income	$ 407	$ 275	$ 181
Net income	$ 112	$ 69	$ 32
Earnings per share (diluted)	$ 5.00	$ 3.08	$ 1.47





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

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

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

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

Electricity. Berry consumes natural gas as fuel to operate its 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. We sell our electricity to utilities under Standard Offer contracts, under which our revenues are linked to the cost of natural gas. Natural gas index prices are the primary determinant of Berry's electricity sales price. The correlation between electricity sales and natural gas prices allows us to more effectively manage our cost of producing steam. Revenue and operating costs in the year ended 2005 were up from the year ended 2004 due to 18% higher electricity prices and 34% higher natural gas prices, respectively. We purchased approximately 38 MMBtu/D as fuel for use in our cogeneration facilities in the year ended December 31, 2005.

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

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

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

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

Oil and Gas Operating, Production Taxes, G&A and Interest Expenses. We believe that the most informative way to analyze changes in recurring operating expenses from one period to another is on a per unit-of-production, or BOE, basis. The following table presents information about our operating expenses for each of the years in the two-year period ended December 31, 2005:

	Amount per BOE			Amount (in thousands)		
	2005	2004	Change	2005	2004	Change
Operating costs - oil and gas production	$ 11.79	$ 10.09	17%	$ 99,066	$ 73,838	34%
Production taxes	1.37	.86	59%	11,506	6,431	79%
DD&A - oil and gas production	4.54	3.96	15%	38,150	29,752	28%
G&A	2.55	2. 99	(15)%	21,396	22,504	(5)%
Interest expense	0.72	0.27	167%	6,048	2,067	193%
Total	$ 20.97	$ 18.17	15%	$ 176,166	$ 134,592	31%

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

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

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

As commodity prices remain robust, we anticipate that cost pressures within our industry may continue. Natural gas prices impact our cost structure in California by approximately $1.75 per California BOE for each $1.00 move in natural gas price. The California production target for 2006 is 16,700 BOE/D.

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

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

· General and administrative: Approximately two-thirds of Berry's G&A is compensation or compensation related costs. We intend to remain competitive in workforce compensation to achieve our growth plans. Stock-based compensation expense was $.35 per BOE and $.56 per BOE for the years ended December 31, 2005 and 2004, respectively. Compensation expenses increased due to increased staffing resulting from our growth, and increases in compensation levels and bonuses. Additionally, we incurred increased legal and accounting fees, primarily due to compliance with Sarbanes-Oxley, and growth through acquisitions and other financial reporting related matters. Legal and accounting expenses were $.28 per BOE in 2005 as compared to $.23 per BOE in 2004.

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

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

	Amount per BOE			Amount (in thousands)		
	2004	2003	Change	2004	2003	Change
Operating costs - oil and gas production	$ 10.09	$ 9.57	5%	$ 73,838	$ 57,830	28%
Production taxes	.86	.51	69%	6,431	3,097	108%
DD&A - oil and gas production	3.96	2.86	38%	29,752	17,258	72%
G&A	2.99	2.40	25%	22,504	14,495	55%
Interest expense	0.27	0.23	17%	2,067	1,414	46%
Total	$ 18.17	$ 15.57	17%	$ 134,592	$ 94,094	43%

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

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

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

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

· General and administrative: 2004 was up from 2003 due to stock-based compensation costs increasing by $2.8 million in 2004, or $.56 per BOE, which are primarily non-cash charges resulting from marked-to-market adjustments under the variable method of accounting prior to the change of certain exercise provisions of our stock option plan on July 29, 2004 and non-cash compensation expense under the fair value method of accounting. Compensation expenses increased due to increased staffing resulting from our growth, an increase in compensation levels and bonuses and costs related to a change in chief executive officers. Additionally, we incurred increased legal and accounting fees during 2004, primarily due to compliance with Sarbanes-Oxley and other financial reporting related matters.

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

Estimated 2006 Oil and Gas Operating, G&A and Interest Expenses

	Amount per BOE		
	Anticipated range in 2006	2005	2004
Operating costs-oil and gas production (1)	$ 13.00 to 16.00	$ 11.79	$ 10.09
Production taxes	1.35 to 1.65	1.37	.86
DD&A	5.75 to 6.50	4.54	3.96
G&A	2.75 to 3.00	2.55	2.99
Interest expense	1.35 to 1.60	0.72	.27
Total	$ 24.20 to 28.75	$ 20.97	$ 18.17

(1) Assuming natural gas prices of approximately NYMEX HH $8.50 MMBtu, we plan to inject steam at levels in 2006 comparable to, or slightly higher than 2005 levels.

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

- At December 31, 2004, we were in the process of drilling one exploratory well on our Midway-Sunset property and one exploratory well on our Coyote Flats prospect. These two wells were determined non-commercial in February 2005 and $2.2 million was incurred and expensed in 2005.
- Two exploratory wells at northern Brundage Canyon were expensed for $.6 million.
- Finally, we impaired the remaining carrying value of our Illinois and eastern Kansas prospective CBM acreage acquired in 2002 by $2.9 million.

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

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

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

We experienced an effective tax rate of 31%, 23% and 12% reported in 2005, 2004 and 2003, respectively. The increase in effective tax rate during 2005 is primarily due to a much higher (over 80%) pre-tax income in relation to consistent EOR credits in 2005 over 2004. Our expansion outside of California and investment in non-thermal projects are also key factors in the increase. We have been able to achieve an effective tax rate below the statutory tax rate of approximately 40% through 2005 primarily as a result of significant EOR tax credits earned by our continued investment in the development of thermal EOR projects, both through capital expenditures and continued steam injection. We expect our effective tax rate will be higher as the EOR credit will be non-existent for 2006 and possibly later years, and we expect to have an effective tax rate in the 37% to 39% range in 2006, based on WTI prices averaging between $50 and $70. See Note 9 to the financial statements for further information.

Financial Condition, Liquidity and Capital Resources. Substantial capital is required to replace and grow reserves. We achieve reserve replacement and growth primarily through successful development and exploration drilling and the acquisition of properties. Fluctuations in commodity prices have been the primary reason for short-term changes in our cash flow from operating activities. The net long-term growth in our cash flow from operating activities is the result of growth in production as affected by period to period fluctuations in commodity prices.

Capital Expenditures. We establish a capital budget for each calendar year based on our development opportunities and the expected cash flow from operations for that year. We may revise our capital budget during the year as a result of acquisitions and/or drilling outcomes. Excess cash generated from operations is expected to be applied toward acquisitions, debt reduction or other corporate purposes.

Excluding any future acquisitions, in 2006 we plan to spend approximately $208 million on capital projects and anticipate funding these expenditures from internally generated cash flow. These expenditures will be directed toward developing reserves, increasing oil and gas production and exploration opportunities. For 2006, Berry plans to invest approximately $146 million, or 70%, in our Rocky Mountain and Mid-Continent region assets, and $61 million, or 30%, in our California assets. Approximately half the capital budget is focused on converting probable and possible reserves into proved reserves and on our appraisal and exploratory projects. Total capital expenditures in 2005, excluding acquisitions, were $119 million and included the drilling of approximately 188 new wells and completing 140 workovers on our properties. All capital expenditures, excluding acquisitions, were funded out of internally generated cash flow. See Item 1 Business for further details.

Dividends. The regular quarterly dividend was increased by 8%, from $.12 to $.13 per share, beginning with the September 2005 dividend. The total dividend payable on September 29, 2005 was $.23 per share which included a special $.10 per share dividend. This is the third consecutive year that we have raised the quarterly dividend and distributed a special dividend. This action resulted in a total payout in 2005 of $.60 per share, up 16% from the $.52 per share paid out in 2004 and up 28% from the $.47 per share paid out in 2003.

Working Capital and Cash Flows. Cash flow from operations is dependent upon the price of crude oil and natural gas and our ability to increase production and manage costs. Crude oil and natural gas prices increased in 2005 (see graphs on page 30) and we increased production by 12%.

Our working capital balance fluctuates as a result of the amount of borrowings and the timing of repayments under our credit arrangements. We used our long-term borrowings under our credit facility primarily to fund property acquisitions. Generally, we use excess cash to pay down borrowings under our credit arrangement. As a result, we often have a working capital deficit or a relatively small amount of positive working capital. In 2005, the working capital deficit was substantially greater than 2004. The deficit is primarily made up of changes in the following four balance sheet accounts from 2005 as compared to 2004; a $14.7 million decrease in cash, an $11 million increase in the Formax royalty payable, an $11.5 million increase in the short-term line of credit which is used to improve cash management and a $9 million increase in fair value of derivatives (net liability) which is associated with our increased use of hedging in 2005.

The table below compares financial condition, liquidity and capital resources changes for the years ended December 31 (in millions, except for production and average prices):

	2005	2004	Change
Production (BOE/D)	23,015	20,537	+12%
Average oil and gas sales prices, per BOE after hedging	$ 41.62	$ 30.32	+37%
Net cash provided by operating activities	$ 188	$ 125	+50%
Working capital	$ (54.8)	$ (3.8)	(134)%
Sales of oil and gas	$ 350	$ 227	+54%
Long-term debt	$ 75	$ 28	+168%
Capital expenditures, including acquisitions and deposits on acquisitions	$ 231	$ 85.3	+171%
Dividends paid	$ 13.2	$ 11.4	+16%

In June 2005, a share repurchase program was authorized for up to an aggregate of $50 million of Berry's outstanding Class A Common Stock. Through December 31, 2005, we had repurchased 108,900 shares for approximately $6.3 million. See Note 7 to the financial statements.

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

Credit Facility. See Note 6 to the financial statements for more information. We have a $500 million unsecured credit facility, which has a current borrowing base of $350 million and is an integral part of our financing structure that provides improved access to capital and the flexibility to support growth plans.

Contractual Obligations. Refer to Note 10 to the financial statements.

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

A critical accounting policy is one that is important to the portrayal of the Company's financial condition and results, and requires Management to make difficult subjective and/or complex judgments. Critical accounting policies cover accounting matters that are inherently uncertain because the future resolution of such matters is unknown. The Company believes the following accounting policies are critical policies.

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

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

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

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

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

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

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

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

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

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

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

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

Recent Accounting Pronouncements. In December 2004, SFAS No. 123(R), *Share-Based Payment*, was issued which establishes standards for transactions in which an entity exchanges its equity instruments for goods or services. This standard requires an issuer to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award. This eliminates the exception to account for such awards using the intrinsic method previously allowable under Accounting Principles Board (APB) Opinion No. 25. In April 2005 the SEC issued a rule that SFAS No. 123(R) will be effective for annual reporting periods beginning on or after June 15, 2005. As a result, the Company expects to adopt this statement on January 1, 2006. The Company previously adopted the fair value recognition provisions of SFAS No. 123, *Accounting for Stock-Based Compensation*. Accordingly the Company believes SFAS No. 123(R) will not have a material impact on its financial statements; however, it continues to assess the potential impact that the adoption of SFAS No. 123(R) will have on the classification of tax deductions for stock-based compensation in the statements of cash flows.

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

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

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

In February 2006, SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments—an amendment of FASB Statements No. 133 and 140* was issued. This Statement resolves issues addressed in Statement 133 Implementation Issue No. D1, *Application of Statement 133 to Beneficial Interests in Securitized Financial Assets*. SFAS No. 155 will become effective for the Company's fiscal year after September 15, 2006. The impact of SFAS No. 155 will depend on the nature and extent of any new derivative instruments entered into after the effective date.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

As discussed in Note 15 to the financial statements, to minimize the effect of a downturn in oil and gas prices and protect the profitability of the Company and the economics of the Company's development plans, from time to time the Company enters into crude oil and natural gas hedge contracts. The terms of contracts depend on various factors, including Management's view of future crude oil and natural gas prices and the Company's future financial commitments. This price hedging program is designed to moderate the effects of a severe crude oil and natural gas price downturn while allowing Berry to participate in the upside. In California, Berry benefits from lower natural gas pricing and elsewhere, Berry benefits from higher natural gas pricing. The Company has, and may hedge both natural gas purchases and sales as determined appropriate by Management. 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 in accordance with Board established policy.

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

The following table summarizes the hedge position of the Company as of December 31, 2005:

Term	Average Barrels Per Day	Average Price	Term	Average MMBtu Per Day	Average Price
Crude Oil Sales (NYMEX WTI)			**Natural Gas Sales (CIG)**		
Swaps			**Swaps**		
1st Quarter 2006	3,000	$ 50.90	1st Quarter 2006	3,000	$ 7.49
2nd Quarter 2006	3,000	$ 50.20			
3rd Quarter 2006	3,000	$ 49.56			
			Natural Gas Purchases (SoCal Border)		
Collars		Floor/Ceiling Prices	**Swaps**		
1st through 3rd Quarter 2006	7,000	$47.50 / $70	1st Quarter 2006	5,000	$ 4.85
4th Quarter 2006	10,000	$47.50 / $70	2nd Quarter 2006	5,000	$ 4.85
Full year 2007	10,000	$47.50 / $70			
Full year 2008	10,000	$47.50 / $70			
Full year 2009	10,000	$47.50 / $70			

On March 1, 2006, the Company entered into the following derivative instruments:

Term	Average MMBtu Per Day	Average Price	Term	Average MMBtu Per Day	Average Price
Natural Gas Sales (NYMEX HH)			**Natural Gas Sales (NYMEX HH)**		
Swaps			**Collars**		Floor/Ceiling Prices
2nd Quarter 2006	4,000	$ 6.96	4th Quarter 2006	8,000	$8 / $9.72
3rd Quarter 2006	6,000	$ 7.35	1st Quarter 2007	12,000	$8 / $16.70
			2nd Quarter 2007	13,000	$8 / $8.82
			3rd Quarter 2007	14,000	$8 / $9.10
			4th Quarter 2007	15,000	$8 / $11.39
			1st Quarter 2008	16,000	$8 / $15.65
			2nd Quarter 2008	17,000	$7.50 / $8.40
			3rd Quarter 2008	19,000	$7.50 / $8.50
			4th Quarter 2008	21,000	$8 / $9.50

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.

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

While the Company has designated its hedges as cash flow hedges in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, it is possible that a portion of the hedge related to the movement in the WTI to California heavy crude oil price differential may be determined to be ineffective. Likewise, the Company may have some ineffectiveness in its natural gas hedges put into place on March 1, 2006, due to the movement of HH pricing as compared to actual sales points. If this occurs, the ineffective portion will directly impact net income rather than being reported as Other Comprehensive Income. While Management believes that the differential will narrow and move closer toward its historical level over time, there are no assurances as to the movement in the differential. If the differential were to change significantly, it is possible that the Company’s hedges, when marked-to-market, could have a material impact on earnings in any given quarter and, thus, add increased volatility to the Company’s net income. The marked-to-market values reflect the liquidation values of such hedges and not necessarily the values of the hedges if they are held to maturity. Irrespective of the unrealized gains reflected in Other Comprehensive Income, the ultimate impact to net income over the life of the hedges will reflect the actual settlement values. All of these hedges have historically been deemed to be cash flow hedges with the marked-to-market valuations provided by external sources, based on prices that are actually quoted.

At December 31, 2005, Accumulated Other Comprehensive Loss, net of income taxes, consisted of $24.4 million of unrealized losses from the Company's crude oil and natural gas hedges. Deferred net losses recorded in Accumulated Other Comprehensive Loss at December 31, 2005 are expected to be reclassified to earnings through 2006 for the Company’s swaps and at current prices the Company’s collars are not expected to impact earnings.

	2005	2004	2003
Net reduction of sales of oil and gas revenue due to hedging activities (in millions)	$ 45.3	$ 24.9	$ 11.8
Net reduction of cost of gas due to hedging activities (in millions)	$ 5.0	$ 1.3	$ .1
Net reduction in revenue per BOE due to hedging activities	$ 5.39	$ 3.32	$ 1.96

The use of hedging transactions may involve basis risk. The Company's oil hedges are based on reported settlement prices on the NYMEX. The basis risk between NYMEX and the Company's California heavy crude oil is mitigated by the Company's crude oil sales contracts. On November 21, 2005, the Company entered into a new crude oil sales contract for its California production for deliveries beginning February 1, 2006. 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 the Company's option. The Company has redesignated its existing crude oil collars as cash flow hedges related to California crude oil production, and there was no related effect to Other Comprehensive Income with regard to this redesignation.

Pricing in the existing crude oil sales agreement at Brundage Canyon is based upon average weekly WTI minus a fixed differential of approximately $2 per barrel through September 30, 2006. Any new contract will be negotiated based on market prices. Upon the expiration of these crude oil contracts, and absent any new contracts, the Company will be exposed to fluctuations in the basis differentials between WTI and the posted price for its crude oil at its various producing locations until new contracts which lock in such differential can be obtained.

The use of hedging transactions also involves the risk that the counterparties will be unable to meet the financial terms of such transactions. With respect to the Company's hedging activities, the Company utilizes multiple counterparties on its hedges and monitors each counterparty's credit rating. The Company also attempts to minimize credit exposure to counterparties through diversification.

Based on NYMEX futures prices as of December 31, 2005, (WTI $62.71; HH $10.83) and due to the backwardated nature of the futures prices as of that date, the Company would expect to make pre-tax future cash payments or to receive payments over the remaining term of its crude oil and natural gas hedges in place as follows:

	12/31/05	Impact of percent change in futures prices on earnings			
	NYMEX Futures	-20%	-10%	+ 10%	+ 20%
Average WTI Price	$ 62.71	$ 50.17	$ 56.44	$ 68.98	$ 75.25
Crude Oil gain/(loss) (in millions)	(10.4)	(.1)	(5.2)	(17.5)	(92.8)
Average HH Price	10.83	8.67	9.75	11.92	13.00
Natural Gas gain/(loss) (in millions)	3.8	2.4	3.1	4.4	5.1
Net pre-tax future cash (payments) and receipts by year (in millions):					
2006	$ (6.6)	$ 2.3	$ (2.1)	$ (11.5)	$ (32.3)
2007	-	-	-	(1.6)	(24.8)
2008	-	-	-	-	(18.7)
2009	-	-	-	-	(11.9)
Total	$ (6.6)	$ 2.3	$ (2.1)	$ (13.1)	$ (87.7)

Interest Rates. The Company's exposure to changes in interest rates results primarily from long-term debt. Total long-term debt outstanding at December 31, 2005 and 2004 was $75 million and $28 million, respectively. Interest on amounts borrowed is charged at LIBOR plus 1.0% to 1.75%. Based on year-end 2005 borrowings, a 1% change in interest rates would not have a material impact on the Company's financial statements.

Item 8. Financial Statements and Supplementary Data

Financial statement schedules have been omitted since they are either not required, are not applicable, or the required information is shown in the financial statements and related notes.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Berry Petroleum Company:

We have completed integrated audits of Berry Petroleum Company's December 31, 2005 and 2004 financial statements and of its internal control over financial reporting as of December 31, 2005, and an audit of its December 31, 2003 financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Financial statements

In our opinion, the financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Berry Petroleum Company at December 31, 2005 and 2004, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2005 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

Internal control over financial reporting

Also, in our opinion, management's assessment, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 9A, that the Company maintained effective internal control over financial reporting as of December 31, 2005 based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control - Integrated Framework* issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

Los Angeles, California
March 1, 2006

BERRY PETROLEUM COMPANY
Balance Sheets
December 31, 2005 and 2004
(In Thousands, Except Share Information)

	2005	2004
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,990	$ 16,690
Short-term investments available for sale	661	659
Accounts receivable	59,672	34,621
Deferred income taxes	4,547	3,558
Fair value of derivatives	3,618	3,243
Prepaid expenses and other	4,398	2,230
Total current assets	74,886	61,001
Oil and gas properties (successful efforts basis), buildings and equipment, net	552,984	338,706
Deposits on potential property acquisitions	-	10,221
Long-term deferred income taxes	1,600	-
Other assets	5,581	2,176
	$ 635,051	$ 412,104
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 57,783	$ 27,750
Revenue and royalties payable	34,920	23,945
Accrued liabilities	8,805	6,132
Line of credit	11,500	-
Income taxes payable	1,237	1,067
Fair value of derivatives	15,398	5,947
Total current liabilities	129,643	64,841
Long-term liabilities:		
Deferred income taxes	55,804	47,963
Long-term debt	75,000	28,000
Abandonment obligation	10,675	8,214
Unearned revenue	866	-
Fair value of derivatives	28,853	-
	171,198	84,177
Commitments and contingencies (Notes 10 and 11)		
Shareholders' equity:		
Preferred stock, $.01 par value, 2,000,000 shares authorized; no shares outstanding	-	-
Capital stock, $.01 par value:		
Class A Common Stock, 50,000,000 shares authorized; 21,099,906 shares issued and outstanding (21,060,420 in 2004)	211	210
Class B Stock, 1,500,000 shares authorized; 898,892 shares issued and outstanding (liquidation preference of $899)	9	9
Capital in excess of par value	56,064	60,676
Accumulated other comprehensive loss	(24,380)	(987)
Retained earnings	302,306	203,178
Total shareholders' equity	334,210	263,086
	$ 635,051	$ 412,104

The accompanying notes are an integral part of these financial statements.

BERRY PETROLEUM COMPANY
Statements of Income
Years ended December 31, 2005, 2004 and 2003
(In Thousands, Except Per Share Data)

	2005	2004	2003
REVENUES			
Sales of oil and gas	$ 349,691	$ 226,876	$ 135,848
Sales of electricity	55,230	47,644	44,200
Interest and other income, net	1,804	426	816
	406,725	274,946	180,864
EXPENSES			
Operating costs - oil and gas production	99,066	73,838	57,830
Operating costs - electricity generation	55,086	46,191	42,351
Production taxes	11,506	6,431	3,097
Exploration costs	3,649	-	-
Depreciation, depletion & amortization - oil and gas production	38,150	29,752	17,258
Depreciation, depletion & amortization - electricity generation	3,260	3,490	3,256
General and administrative	21,396	22,504	14,495
Interest	6,048	2,067	1,414
Dry hole, abandonment and impairment	5,705	745	4,195
Loss on disposal of assets	-	410	-
	243,866	185,428	143,896
Income before income taxes	162,859	89,518	36,968
Provision for income taxes	50,503	20,331	4,605
Net income	$ 112, 356	$ 69,187	$ 32,363
Basic net income per share	$ 5.10	$ 3.16	$ 1.49
Diluted net income per share	$ 5.00	$ 3.08	$ 1.47
Weighted average number of shares of capital stock outstanding (used to calculate basic net income per share)	22,041	21,894	21,772
Effect of dilutive securities:			
Stock options	390	523	215
Other	59	53	44
Weighted average number of shares of capital stock used to calculate diluted net income per share	22,490	22,470	22,031

Statements of Comprehensive Income
Years Ended December 31, 2005, 2004 and 2003
(In Thousands)

	2005	2004	2003
Net income	$ 112,356	$ 69,187	$ 32,363
Unrealized gains (losses) on derivatives, net of income taxes of ($16,677), ($521), and ($2,421), respectively	(25,015)	(781)	(3,632)
Reclassification of realized gains (losses) included in net income net of income taxes of $1,081, $2,284 and $1,712, respectively	1,622	3,426	2,569
Comprehensive income	$ 88,963	$ 71,832	$ 31,300

The accompanying notes are an integral part of these financial statements.

BERRY PETROLEUM COMPANY
Statements of Shareholders' Equity
Years Ended December 31, 2005, 2004 and 2003
(In Thousands, Except Per Share Data)

	Class A	Class B	Capital in Excess of Par Value	Deferred Stock-Based Compensation	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Shareholders' Equity
Balances at January 1, 2003	$ 209	$ 9	$ 52,214	$ (346)	$ 123,257	$ (2,569)	$ 172,774
Accrued compensation costs	-	-	3,319	-	-	-	3,319
Deferred director fees - stock compensation	-	-	169	-	-	-	169
Unearned stock-based compensation	-	-	773	(773)	-	-	-
Amortization of deferred stock option compensation	-	-	-	11	-	-	11
Cash dividends declared - $.47 per share	-	-	-	-	(10,235)	-	(10,235)
Unrealized loss on derivatives	-	-	-	-	-	(1,063)	(1,063)
Net income	-	-	-	-	32,363	-	32,363
Balances at December 31, 2003	209	9	56,475	(1,108)	145,385	(3,632)	197,338
Adoption of SFAS 123	-	-	(243)	1,108	-	-	865
Stock-based compensation (155,269 shares)	1	-	3,451	-	-	-	3,452
Deferred director fees - stock compensation	-	-	993	-	-	-	993
Cash dividends declared - $.52 per share	-	-	-	-	(11,394)	-	(11,394)
Unrealized gain on derivatives	-	-	-	-	-	2,645	2,645
Net income	-	-	-	-	69,187	-	69,187
Balances at December 31, 2004	210	9	60,676	-	203,178	(987)	263,086
Share repurchase (108,900 shares)	(2)	-	(6,314)	-	-	-	(6,316)
Stock-based compensation (147,179 shares)	3	-	1,360	-	-	-	1,363
Deferred director fees - stock compensation	-	-	342	-	-	-	342
Cash dividends declared - $.60 per share	-	-	-	-	(13,228)	-	(13,228)
Unrealized loss on derivatives	-	-	-	-	-	(23,393)	(23,393)
Net income	-	-	-	-	112,356	-	112,356
Balances at December 31, 2005	$ 211	$ 9	$ 56,064	$ -	$ 302,306	$ (24,380)	$ 334,210

The accompanying notes are an integral part of these financial statements.

BERRY PETROLEUM COMPANY
Statements of Cash Flows
Years Ended December 31, 2005, 2004 and 2003
(In Thousands)

	2005	2004	2003
Cash flows from operating activities:			
Net income	$ 112,356	$ 69,187	$ 32,363
Depreciation, depletion and amortization	41,410	33,242	20,514
Dry hole, abandonment and impairment	4,324	(569)	3,756
Stock-based compensation expense	1,703	5,309	2,872
Deferred income taxes, net	20,847	10,815	1,496
Other, net	278	794	400
Increase in current assets other than cash, cash equivalents and short-term investments	(26,717)	(11,310)	(9,034)
Increase in current liabilities other than line of credit	33,579	17,145	12,458
Net cash provided by operating activities	187,780	124,613	64,825
Cash flows from investing activities:			
Exploration and development of oil and gas properties	(118,718)	(71,556)	(41,061)
Property acquisitions	(112,249)	(2,845)	(48,579)
Additions to vehicles, drilling rigs and other fixed assets	(11,762)	(669)	(494)
Deposits on potential acquisitions	-	(10,221)	-
Proceeds from sale of assets	130	101	1,890
Other, net	-	3	521
Net cash used in investing activities	(242,599)	(85,187)	(87,723)
Cash flows from financing activities:			
Proceeds from issuance of line of credit	18,000	-	-
Payment of line of credit	(6,500)	-	-
Proceeds from issuance of long-term debt	144,000	-	40,000
Payment of long-term debt	(97,000)	(22,000)	(5,000)
Dividends paid	(13,228)	(11,394)	(10,235)
Book overdraft	1,921	-	-
Repurchase of shares	(6,315)	-	-
Other, net	(759)	-	(1,075)
Net cash provided by (used in) financing activities	40,119	(33,394)	23,690
Net (decrease) increase in cash and cash equivalents	(14,700)	6,032	792
Cash and cash equivalents at beginning of year	16,690	10,658	9,866
Cash and cash equivalents at end of year	$ 1,990	$ 16,690	$ 10,658
Supplemental disclosures of cash flow information:			
Interest paid	$ 5,275	$ 1,243	$ 2,125
Income taxes paid	$ 26,544	$ 11,652	$ 2,510
Supplemental non-cash activity:			
Increase (decrease) in fair value of derivatives:			
Current (net of income taxes of $(3,631), $1,202, and ($635), respectively)	$ (5,446)	$ 1,804	$ (952)
Non-current (net of income taxes of $(11,965), $561, and ($74), respectively)	(17,947)	841	(111)
Net increase (decrease) to accumulated other comprehensive income	$ (23,393)	$ 2,645	$ (1,063)

The accompanying notes are an integral part of these financial statements.

BERRY PETROLEUM COMPANY
Notes to the Financial Statements

1. General

The Company is an independent energy company engaged in the production, development, acquisition, exploitation and exploration of crude oil and natural gas. The Company has 74% of its oil and gas reserves in California and 26% in the Rocky Mountain and Mid-Continent region. Approximately 70% of the Company's production is in California, most of which is heavy crude oil and is sold to a Bakersfield, California refinery. The Company has invested in cogeneration facilities which provide steam required for the extraction of heavy oil and which generates electricity for sale. Production of light crude oil and natural gas in the Rocky Mountain and Mid-Continent region accounts for approximately 30% of the Company’s production.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires Management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

2. Summary of Significant Accounting Policies

Cash and cash equivalents - The Company considers all highly liquid investments purchased with a remaining maturity of three months or less to be cash equivalents. The Company’s cash management process provides for the daily funding of checks as they are presented to the bank. Included in accounts payable at December 31, 2005 is $1.9 million representing outstanding checks in excess of the bank balance (book overdraft).

Short-term investments - All short-term investments are classified as available for sale. Short-term investments consist principally of United States treasury notes and corporate notes with remaining maturities of more than three months at date of acquisition and are carried at fair value. The Company utilizes specific identification in computing realized gains and losses on investments sold.

Accounts receivable - Trade accounts receivable are recorded at the invoiced amount and do not bear interest. The Company does not have any off-balance-sheet credit exposure related to its customers. The Company assesses credit risk and allowance for doubtful accounts on a customer specific basis. As of December 31, 2005 and 2004, the Company does not have an allowance for doubtful accounts.

Income taxes - Income taxes are provided based on the liability method of accounting. The provision for income taxes is based on reported pre-tax financial statement income. Deferred tax assets and liabilities are recognized for the future expected tax consequences of temporary differences between income tax and financial reporting, and principally relate to differences in the tax bases of assets and liabilities and their reported amounts using enacted tax rates in effect for the year in which differences are expected to reverse. If it is more likely than not that some portion or all of a deferred tax asset will not be realized, a valuation allowance is recognized.

Hedging - SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended, requires that all derivative instruments subject to the requirements of the statement be measured at fair value and recognized as assets or liabilities in the balance sheet. The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and the resulting designation is generally established at the inception of a derivative. For derivatives designated as cash flow hedges and meeting the effectiveness guidelines of SFAS No. 133, changes in fair value, to the extent effective, are recognized in other comprehensive income until the hedged item is recognized in earnings. The hedging relationship between the hedging instruments and hedged items, such as oil and gas, must be highly effective in achieving the offset of changes in cash flows attributable to the hedged risk, both at the inception of the hedge and on an ongoing basis. The Company measures hedge effectiveness at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time, or in the case of options based on the change in intrinsic value. Any change in fair value of a derivative resulting from ineffectiveness or an excluded component of the gain/loss, such as time value for option contracts, is recognized immediately in the statements of income. Gains and losses on hedging instruments and adjustments of the carrying amounts of hedged items are included in revenues for hedges related to the Company's crude oil and natural gas sales and in operating expenses for hedges related to the Company's natural gas consumption. The resulting cash flows are reported as cash flows from operating activities. See Note 15 - Hedging.

BERRY PETROLEUM COMPANY
Notes to the Financial Statements

2. Summary of Significant Accounting Policies (Cont'd)

Oil and gas properties, buildings and equipment - The Company accounts for its oil and gas exploration and development costs using the successful efforts method. Geological and geophysical costs and the costs of carrying and retaining undeveloped properties are expensed as incurred. Exploratory well costs are capitalized pending further evaluation of whether economically recoverable reserves have been found. If economically recoverable reserves are not found, exploratory well costs are expensed as dry holes. All exploratory wells are evaluated for economic viability within one year of well completion and the related capitalized costs are reviewed quarterly. Exploratory wells that discover potentially economic reserves that are in areas where a major capital expenditure would be required before production could begin, and where the economic viability of that major capital expenditure depends upon the successful completion of further exploratory work in the area, remain capitalized if the well found a sufficient quantity of reserves to justify its completion as a producing well and the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project. The costs of development wells are capitalized whether productive or nonproductive.

Depletion of oil and gas producing properties is computed using the units-of-production method. Depreciation of lease and well equipment, including cogeneration facilities and other steam generation equipment and facilities, is computed using the units-of-production method or on a straight-line basis over estimated useful lives ranging from 10 to 20 years. Buildings and equipment are recorded at cost. Depreciation is provided on a straight-line basis over estimated useful lives ranging from 5 to 30 years for buildings and improvements and 3 to 10 years for machinery and equipment. Estimated residual salvage value is considered when determining depreciation, depletion and amortization (DD&A) rates.

Assets are grouped at the field level and if it is determined that the book value of long-lived assets cannot be recovered by estimated future undiscounted cash flows, they are written down to fair value. When assets are sold, the applicable costs and accumulated depreciation and depletion are removed from the accounts and any gain or loss is included in income. Expenditures for maintenance and repairs are expensed as incurred.

Asset retirement obligations - The Company has significant obligations to plug and abandon oil and natural gas wells and related equipment at the end of oil and gas production operations. The computation of the Company's asset retirement obligations (ARO) is prepared in accordance with SFAS No. 143, *Accounting for Asset Retirement Obligations*. Under this standard, the Company records the fair value of the future abandonment as capitalized abandonment costs in Oil and Gas Properties with an offsetting abandonment liability. The Company obtains estimates from third parties and uses the present value of estimated cash flows related to its ARO to determine the fair value. The capitalized abandonment costs are amortized with other property costs using the units-of-production method. The Company increases the liability monthly by recording accretion expense using the Company’s credit adjusted interest rate. Accretion expense is included in DD&A in the Company’s financial statements.

Revenue recognition - Revenues associated with sales of crude oil, natural gas, and electricity are recognized when title passes to the customer, net of royalties, discounts and allowances, as applicable. Electricity and natural gas produced by the Company and used in the Company’s operations are not included in revenues. Revenues from crude oil and natural gas production from properties in which the Company has an interest with other producers are recognized on the basis of the Company's net working interest (entitlement method).

Conventional steam costs - The costs of producing conventional steam are included in “Operating costs - oil and gas production.”

Cogeneration operations - The Company’s investment in its cogeneration facilities has been for the express purpose of lowering steam costs in its heavy oil operations and securing operating control of the respective steam generation. Such cogeneration operations produce electricity and steam. The Company allocates steam costs to its oil and gas operating costs based on the conversion efficiency of the cogeneration facilities plus certain direct costs in producing steam. Electricity revenue represents sales to the utilities. Electricity used in oil and gas operations is allocated at cost. Electricity consumption included in oil and gas operating costs for the years ended December 31, 2005, 2004 and 2003 was $5.7 million, $5 million and $4.2 million, respectively.

Shipping and handling costs - Shipping and handling costs, which consist primarily of natural gas transportation costs, are included in both "Operating costs - oil and gas production" or "Operating costs - electricity generation,” as applicable. Natural gas transportation costs included in these categories were $5.8 million, $5.4 million and $4 million, for 2005, 2004 and 2003, respectively.

BERRY PETROLEUM COMPANY
Notes to the Financial Statements

2. Summary of Significant Accounting Policies (Cont'd)

Production taxes - Consist primarily of severance and ad valorem taxes.

Stock-based compensation - Effective January 1, 2004, the Company voluntarily adopted the fair value method of accounting for its stock option plan as prescribed by SFAS 123, *Accounting for Stock-Based Compensation*. The modified prospective method was selected as described in SFAS 148, *Accounting for Stock-Based Compensation - Transition and Disclosure*. Under this method, the Company recognizes stock option compensation expense as if it had applied the fair value method to account for unvested stock options from its original effective date. Stock option compensation expense is recognized from the date of grant to the vesting date.

From January 1, 2004 to July 29, 2004 a portion of the Company's stock option compensation was calculated under variable accounting; however, the majority of stock option compensation was accounted for under the fair value method. In accordance with variable plan accounting, the Company recognized a corresponding liability determined by a marked-to-market valuation of the Company's stock at each financial reporting date. The Company revised certain stock option exercise provisions of the plan and, subsequent to July 29, 2004, variable plan accounting was no longer required.

Had compensation cost for the Company’s stock-based compensation plan (see Note 12) been based upon the fair value at the grant dates for awards under the plan consistent with SFAS No. 123, the Company’s compensation cost, net of related tax effects, net income and earnings per share would have been recorded as the pro forma amounts indicated below (in thousands, except per share data):

		2003
Net income, as reported	$	32,363
Plus compensation cost (net of tax), as reported		2,335
Less compensation cost (net of tax), pro forma		(1,323)
Net income, pro forma	$	33,375
Basic net income per share:		
As reported	$	1.49
Pro forma	$	1.53
Diluted net income per share:		
As reported	$	1.47
Pro forma	$	1.52

Under SFAS No. 123, compensation cost would be recognized for the fair value of the employee's option rights. The fair value of each option grant was estimated on the date of grant using the Black-Scholes option-pricing model with the following assumptions:

	2003
Yield	2.87%
Expected option life - years	7.0
Volatility	27.87%
Risk-free interest rate	3.86%

Comprehensive income (loss) - Comprehensive income (loss) includes net earnings (loss) as well as unrealized gains and losses on derivative instruments, recorded net of tax.

BERRY PETROLEUM COMPANY
Notes to the Financial Statements

2. Summary of Significant Accounting Policies (Cont'd)

Net income per share - Basic net income per share is computed by dividing income available to shareholders (the numerator) by the weighted average number of shares of capital stock outstanding (the denominator). The Company's Class B Stock is included in the denominator of basic and diluted net income. The computation of diluted net income per share is similar to the computation of basic net income per share except that the denominator is increased to include the dilutive effect of the additional common shares that would have been outstanding if all convertible securities had been converted to common shares during the period.

Environmental expenditures - The Company reviews, on a quarterly basis, its estimates of costs of the cleanup of various sites, including sites in which governmental agencies have designated the Company as a potentially responsible party. When it is probable that obligations have been incurred and where a minimum cost or a reasonable estimate of the cost of compliance or remediation can be determined, the applicable amount is accrued. For other potential liabilities, the timing of accruals coincides with the related ongoing site assessments. Any liabilities arising hereunder are not discounted.

Accounting for business combinations - The Company has accounted for all of its business combinations using the purchase method, which is the only method permitted under SFAS 141, *Accounting for Business Combinations*. Under the purchase method of accounting, a business combination is accounted for at a purchase price based upon the fair value of the consideration given, whether in the form of cash, assets, stock or the assumption of liabilities. The assets and liabilities acquired are measured at their fair values, and the purchase price is allocated to the assets and liabilities based upon these fair values. The excess of the fair value of assets acquired and liabilities assumed over the cost of an acquired entity, if any, is allocated as a pro rata reduction of the amounts that otherwise would have been assigned to certain acquired assets. The Company has not recognized any goodwill from any business combinations.

Recent accounting developments - In December 2004, SFAS No. 123(R), *Share-Based Payment*, was issued which establishes standards for transactions in which an entity exchanges its equity instruments for goods or services. This standard requires an issuer to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award. This eliminates the exception to account for such awards using the intrinsic method previously allowable under Accounting Principles Board (APB) Opinion No. 25. In April 2005 the SEC issued a rule that SFAS No. 123(R) will be effective for annual reporting periods beginning on or after June 15, 2005. As a result, the Company expects to adopt this statement on January 1, 2006. The Company previously adopted the fair value recognition provisions of SFAS No. 123, *Accounting for Stock-Based Compensation*. Accordingly the Company believes SFAS No. 123(R) will not have a material impact on its financial statements; however, it continues to assess the potential impact that the adoption of SFAS No. 123(R) will have on the classification of tax deductions for stock-based compensation in the statements of cash flows.

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

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

BERRY PETROLEUM COMPANY
Notes to the Financial Statements

2. Summary of Significant Accounting Policies (Cont'd)

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

In February 2006, SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments—an amendment of FASB Statements No. 133 and 140* was issued. This Statement resolves issues addressed in Statement 133 Implementation Issue No. D1, *Application of Statement 133 to Beneficial Interests in Securitized Financial Assets*. SFAS No. 155 will become effective for the Company's fiscal year after September 15, 2006. The impact of SFAS No. 155 will depend on the nature and extent of any new derivative instruments entered into after the effective date.

Revisions to the classification of technical labor costs and production taxes - In connection with the preparation of the 2005 financial statements the Company is reclassifying technical labor between general and administrative expenses and operating costs-oil and gas and reclassifying production taxes out of operating costs-oil and gas into a separate line. These reclassifications had no impact on net income or net cash provided by operating activities and did not effect previously reported total revenues, total operating expenses, net income or net cash provided by operating activities. Accordingly, the Company has revised prior classifications for the year ended December 31, 2004 as follows (in thousands):

	2004	2003
Operating costs - oil and gas		
As previously reported	$ 82,419	$ 62,554
As revised	73,838	57,830
Difference	$ 8,581	$ 4,724
Production taxes		
As previously reported	$ -	$ -
As revised	6,431	3,097
Difference	$ (6,431)	$ (3,097)
G&A expenses		
As previously reported	$ 20,354	$ 12,868
As revised	22,504	14,495
Difference	$ (2,150)	$ (1,627)

3. Fair Value of Financial Instruments

Cash equivalents consist principally of commercial paper investments. Cash equivalents of $2 million and $16.7 million at December 31, 2005 and 2004, respectively, are stated at cost, which approximates market.

The Company's short-term investments available for sale at December 31, 2005 and 2004 consist of United States treasury notes that mature in less than one year and are carried at fair value. For the three years ended December 31, 2005, realized and unrealized gains and losses were insignificant to the financial statements. A United States treasury note with a market value of $.7 million is pledged as collateral to the California State Lands Commission as a performance bond on the Company's Montalvo properties. The carrying value of the Company's long-term debt approximates its fair value since the interest rate is variable.

BERRY PETROLEUM COMPANY
Notes to the Financial Statements

4. Concentration of Credit Risks

The Company sells oil, gas and natural gas liquids to pipelines, refineries and oil companies and electricity to utility companies. Credit is extended based on an evaluation of the customer's financial condition and historical payment record.

Because of the Company's ability to deliver significant volumes of crude oil over a multi-year period, the Company secured a thirty-nine month sales agreement, beginning in late 2002, with a major California refiner whereby the Company sold over 90% of its 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. Both methods were calculated using a monthly determination. In addition to providing a premium above field postings, the agreement effectively eliminated the Company's exposure to the risk of widening WTI to California heavy crude price differentials and allowed the Company to effectively hedge its production based on WTI pricing.

On November 21, 2005, the Company entered into a new crude oil sales contract for its California production for deliveries beginning February 1, 2006. 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 the Company's option.

For the three years ended December 31, 2005, the Company has experienced no credit losses on the sale of oil, gas and natural gas liquids.

The Company places its temporary cash investments with high quality financial institutions and limits the amount of credit exposure to any one financial institution. For the three years ended December 31, 2005, the Company has not incurred losses related to these investments. With respect to the Company's hedging activities, the Company utilizes more than one counterparty on its hedges and monitors each counterparty's credit rating.

The following summarizes the accounts receivable balances at December 31, 2005 and 2004 and sales activity with significant customers for each of the years ended December 31, 2005, 2004 and 2003 (in thousands). The Company does not believe that the loss of any one customer would impact the marketability of its California crude oil, gas, natural gas liquids or electricity sold. Due to the possibility of refinery constraints in the Utah region, it is possible that the loss of the current crude oil sales customer could impact the marketability of a portion of the Company's Utah crude oil volumes. The Company is investigating its market opportunities for this Utah crude oil.

	Accounts Receivable For the Year Ended December 31,		Sales For the Year Ended December 31,		
Customer	2005	2004	2005	2004	2003
Oil & Gas Sales:					
A	$ 24,389	$ 18,391	$ 291,093	$ 202,966	$ 142,422
B	6,929	5,465	81,342	58,807	5,566
C	1,086	670	11,863	9,138	6,524
	$ 32,404	$ 24,526	$ 384,298	$ 270,911	$ 154,512
Electricity Sales:					
D	$ 4,375	$ 3,402	$ 24,391	$ 21,755	$ 20,334
E	7,806	2,764	30,893	26,524	24,616
	$ 12,181	$ 6,166	$ 55,284	$ 48,279	$ 44,950

Sales amounts will not agree to the Statements of Income due primarily to the effects of hedging and price sensitive royalties paid on a portion of the Company's crude oil sales, which are netted in "Sales of oil and gas" on the Statements of Income.

BERRY PETROLEUM COMPANY
Notes to the Financial Statements

5. Oil and Gas Properties, Buildings and Equipment

Oil and gas properties, buildings and equipment consist of the following at December 31 (in thousands):

	2005	2004
Oil and gas:		
Proved properties:		
Producing properties, including intangible drilling costs	$ 437,032	$ 260,566
Lease and well equipment*(1)*	275,346	236,932
	712,378	497,498
Unproved properties		
Properties, including intangible drilling costs	36,440	5,569
Lease and well equipment	267	2,498
	36,707	8,067
	749,085	505,565
Less accumulated depreciation, depletion and amortization	208,597	168,994
	540,488	336,571
Commercial and other:		
Land	496	297
Buildings and improvements	4,351	3,703
Machinery and equipment	17,016	6,681
	21,863	10,681
Less accumulated depreciation	9,367	8,546
	12,496	2,135
	$ 552,984	$ 338,706

(1)*Includes cogeneration facility costs.*

The following sets forth costs incurred for oil and gas property acquisition, development and exploration activities, whether capitalized or expensed (in thousands):

	2005	2004	2003
Property acquisitions (1)			
Proved properties	$ 97,348	$ 440	$ 49,326
Unproved properties	24,566	2,405	853
Development (2)	112,255	66,664	42,391
Exploration	7,661	5,506	788
	$ 241,830	$ 75,015	$ 93,358

(1) Costs incurred for proved and unproved property acquisitions in 2005 include the reclassification of 2004 deposits of $5,505 and $4,716, respectively..
(2) *Development costs include $.6 million, $.7 million and $.9 million that were charged to expense during 2005, 2004 and 2003, respectively.*

BERRY PETROLEUM COMPANY
Notes to the Financial Statements

5. Oil and Gas Properties, Buildings and Equipment (Cont'd)

In 2005, the Tri-State area is comprised of the following three acquisitions totaling approximately 315,000 net acres:

- Niobrara gas producing assets in Yuma County in northeastern Colorado in which the Company has approximately 52% working interest were purchased for approximately $105 million.
- Eastern Colorado, western Kansas and southwestern Nebraska assets in which the Company has approximately 50% working interest were purchased for approximately $5 million.
- Colorado’s Phillips and Sedgwick Counties in which the Company has approximately 50% working interest were purchased for approximately $.9 million. This Niobrara leasehold position is adjacent to and immediately north of Berry’s producing natural gas assets in Yuma County.

In 2005, the Company completed several transactions whereby it now has working interests in 186,000 gross acres (46,000 net) located in the Williston Basin in North Dakota. These lease acquisitions, totaling approximately $11 million, cover several contiguous blocks located primarily on the eastern flank of the Nesson Anticline.

In July 2004, the Company purchased approximately 169,000 gross acres with an industry partner in the Lake Canyon prospect in Utah, of which 124,500 gross (62,250 net) acres are leased from the Ute Tribe and 44,500 gross (22,250 net) acres are fee lands. Total cost to Berry was approximately $2 million. The Company will drill and operate shallow wells which target light oil in the Green River formation and retain a 75% working interest. The Company’s partner will drill and operate deeper wells and the Company will retain a 25% working interest. The Ute Tribe has the option to participate in all wells and retain up to a 25% working interest. As of December 31, 2005, the Company's minimum obligation under its agreement is $9.6 million through 2009.

In 2003, the Company purchased leases totaling 45,380 acres in the Brundage Canyon field in Utah for approximately $45 million and the McVan property totaling 560 acres in the Poso Creek field in Kern County, California for approximately $2.6 million. The Company capitalized approximately $2.6 million in future abandonment obligations related to the 2003 acquisitions.

Results of operations from oil and gas producing and exploration activities (in thousands):	2005	2004	2003
Sales to unaffiliated parties	$ 349,691	$ 226,876	$ 135,848
Production costs	(110,572)	(80,269)	(60,927)
Depreciation, depletion and amortization	(38,150)	(29,752)	(17,258)
Dry hole, abandonment and impairment	(5,705)	(745)	(4,195)
	195,264	116,110	53,468
Income tax expenses	(59,664)	(33,840)	(9,340)
Results of operations from producing and exploration activities	$ 135,600	$ 82,270	$ 44,128

The following table provides an aging of capitalized exploratory well costs based on the date the drilling was completed and the number of wells for which exploratory well costs have been capitalized for a period of greater than one year since the completion of drilling (in thousands, except number of projects):

	2005	2004	2003
Capitalized exploratory well costs that have been capitalized for a period of one year or less	$ 6,037	$ 2,941	$ 511
Capitalized exploratory well costs that have been capitalized for a period greater than one year	-	511	-
Balance at December 31	$ 6,037	$ 3,452	$ 511
Number of projects that have exploratory well costs that have been capitalized for a period of greater than one year	-	1	-

BERRY PETROLEUM COMPANY
Notes to the Financial Statements

5. Oil and Gas Properties, Buildings and Equipment (Cont'd)

The following table reflects the net changes in capitalized exploratory well costs during the years ended 2005, 2004 and 2003 (in thousands):

	2005	2004	2003
Beginning balance at January 1	$ 3,452	$ 511	$ 1,684
Additions to capitalized exploratory well costs pending the determination of proved reserves	8,840	3,420	1,081
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(3,369)	-	-
Capitalized exploratory well costs charged to expense	(2,886)	479	2,254
Ending balance at December 31	$ 6,037	$ 3,452	$ 511

In 2004, included in the amount of exploratory well costs that have been capitalized for a period of greater than one year since completion of drilling are costs of $.5 million that have been capitalized since 2003. These costs are related to the Company's diatomite project in the Midway-Sunset field and have been reclassified from exploratory well costs in 2005.

Dry hole, abandonment and impairment.
The $5.7 million reflected on the Company's income statement under dry hole, abandonment and impairment is made up of the following three items:
- At December 31, 2004, the Company was in the process of drilling one exploratory well on its Midway-Sunset property and one exploratory well on its Coyote Flats prospect. These two wells were determined non-commercial in February 2005 and $2.2 million was incurred and expensed in 2005.
- Two exploratory wells at northern Brundage Canyon were expensed for $.6 million.
- Finally, the Company impaired the remaining carrying value of its Illinois and eastern Kansas prospective CBM acreage acquired in 2002 by $2.9 million.

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

6. Long-term and Short-term Debt Obligations

	2005	2004
Long-term debt for the years ended December 31 (in thousands):		
Revolving bank facility	$ 75,000	$ 28,000

Long-term debt
In June 2005, the Company completed a new unsecured five year bank credit agreement (the Agreement) with a banking syndicate. The Agreement is a revolving credit facility for up to $500 million with nine banks and replaces the previous $200 million facility which was due to mature in 2006. Initial borrowings were $125 million which represented an amount equal to the borrowings outstanding under the previous credit facility and the initial borrowing base was established as $350 million. This transaction is considered a modification of a debt instrument due to modification of terms in accordance with Emerging Issues Task Force, (EITF) 98-14, *Debtor's Accounting forChanges in Line of Credit or Revolving Debt Arrangements*.

The credit available under the Agreement is $264 million at December 31, 2005 without any increase to the borrowing base. The maximum amount available is subject to an annual redetermination of the borrowing base in accordance with the lender's customary procedures and practices. Both the Company and the banks have bilateral rights to one additional redetermination each year.

BERRY PETROLEUM COMPANY
Notes to the Financial Statements

6. Long-term and Short-term Debt Obligations (Cont'd)

The Agreement matures on July 1, 2010. Interest on amounts borrowed is charged at LIBOR plus a margin of 1.00% to 1.75%, or the higher of the lead bank's prime rate or the federal funds rate plus .50% plus a margin of 0% to .50% at the Company's option, with margins on the various rate options based on the ratio of credit outstanding to the borrowing base. The Company is required under the Agreement to pay an annual commitment fee of .25% to .38% on the unused portion of the credit facility.

The weighted average interest rate on outstanding borrowings at December 31, 2005 and 2004 was 4.9% and 3.37%, respectively. The Agreement contains restrictive covenants which, among other things, require the Company to maintain a certain debt to EBITDA ratio and a minimum current ratio, as defined. The Company was in compliance with all such covenants as of December 31, 2005.

Short-term debt
In November 2005, the Company completed a new unsecured uncommitted money market line of credit (Line of Credit). Borrowings under the Line of Credit may be up to $30 million for a maximum of 30 days. The Line of Credit may be terminated at any time upon written notice by either the Company or the lender. At December 31, 2005 the outstanding balance under this Line of Credit was $11.5 million. Interest on amounts borrowed is charged at LIBOR plus a margin of approximately 1%. The weighted average interest rate on outstanding borrowings at December 31, 2005 was 5.4%.

7. Shareholders' Equity

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 $1.00 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.

The Company's Capital Stock activity follows (in number of shares):

	Class A	Class B
December 31, 2002	20,852,695	898,892
Shares issued from option exercises	51,683	-
Shares repurchased and retired	(6)	-
December 31, 2003	20,904,372	898,892
Shares issued from option exercises	155,269	-
Shares issued under Director deferred compensation plan	797	-
Shares repurchased and retired	(18)	-
December 31, 2004	21,060,420	898,892
Shares issued from option exercises	147,179	-
Shares issued under Director deferred compensation plan	1,207	-
Shares repurchased and retired	(108,900)	-
December 31, 2005	21,099,906	898,892

In June 2005, the Company announced that its Board of Directors authorized a share repurchase program for up to an aggregate of $50 million of the Company's outstanding Class A Common Stock. Through December 31, 2005, the Company repurchased 108,900 shares for approximately $6.3 million.

In December 2005, the Company adopted a plan under Rule 10b5-1 of the Securities Exchange Act of 1934 to facilitate the repurchase of its 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 10b5-1 plan is authorized under, and is administered consistent with, the Company's $50 million share repurchase program. 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 other factors.

BERRY PETROLEUM COMPANY
Notes to the Financial Statements

7. Shareholders' Equity (Cont'd)

This program does not obligate the Company to acquire any particular amount of common stock and the plan may be suspended at any time at the Company's discretion.

Dividends

In 2005, the Company paid a special dividend of $.10 per share on September 29, 2005 and increased its regular quarterly dividend by 8%, from $.12 to $.13 per share beginning with the September 29, 2005 dividend. The Company's annual dividend is currently $.52 per share, paid quarterly in March, June, September and December.

In 2004, the Company paid a special dividend of $.06 per share on September 29, 2004 and increased its regular quarterly dividend by 9%, from $.11 to $.12 per share beginning with the September 2004 dividend. In 2003, the Company paid a special dividend of $.04 per share on May 2, 2003 and increased its regular quarterly dividend by 10%, from $.10 to $.11 per share beginning with the June 2003 dividend.

As of December 31, 2005, dividends declared on 3,984,080 shares of certain Common Stock are restricted, whereby 37.5% of the dividends declared on these shares are paid by the Company to the surviving member of a group of individuals, the B Group, as long as this remaining member shall live.

Dividend payments are limited by a covenant in the Company's credit facility to the greater of $20 million or 75% of net income.

Shareholder Rights Plan

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

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

8. Asset Retirement Obligations

Under SFAS 143, the following table summarizes the change in abandonment obligation for the years ended December 31 (in thousands):

	2005	2004
Beginning balance at January 1	$ 8,214	$ 7,311
Liabilities incurred	2,952	769
Liabilities settled	(1,382)	(570)
Accretion expense	891	704
Ending balance at December 31	$ 10,675	$ 8,214

BERRY PETROLEUM COMPANY
Notes to the Financial Statements

9. Income Taxes

The provision for income taxes consists of the following (in thousands):

	2005	2004	2003
Current:			
Federal	$ 22,666	$ 7,073	$ 2,490
State	6,990	2,443	619
	29,656	9,516	3,109
Deferred:			
Federal	20,640	11,959	2,027
State	207	(1,144)	(531)
	20,847	10,815	1,496
Total	$ 50,503	$ 20,331	$ 4,605

The current deferred tax assets and liabilities are offset and presented as a single amount in the financial statements. Similarly, the non-current deferred tax assets and liabilities are presented in the same manner. The following table summarizes the components of the total deferred tax assets and liabilities before such financial statement offsets. The components of the net deferred tax liability consist of the following at December 31 (in thousands):

	2005	2004
Deferred tax asset:		
Federal benefit of state taxes	$ 2,712	$ 1,308
Credit carryforwards	31,929	26,478
Stock option costs	2,352	1,700
Derivatives	16,253	658
Other, net	139	1,610
	53,385	31,754
Deferred tax liability:		
Depreciation and depletion	(102,754)	(76,311)
Other, net	(289)	152
	(103,043)	(76,159)
Net deferred tax liability	$ (49,658)	$ (44,405)

At December 31, 2005, the Company's net deferred tax assets and liabilities were recorded as a current asset of $4.5 million and a net long-term liability of $54.2 million. At December 31, 2004, the Company's net deferred tax assets and liabilities were recorded as a current asset of $3.6 million and a long-term liability of $48 million.

BERRY PETROLEUM COMPANY
Notes to the Financial Statements

9. Income Taxes (Cont'd)

Reconciliation of the statutory federal income tax rate to the effective income tax rate follows:

	2005	2004	2003
Tax computed at statutory federal rate	35%	35%	35%
State income taxes, net of federal benefit	3	1	1
Tax credits	(7)	(9)	(24)
Recognition of tax basis of properties	-	(5)	-
Other	-	1	-
Effective tax rate	31%	23%	12%

The Company has approximately $23 million of federal and $17 million of state (California) EOR tax credit carryforwards available to reduce future income taxes. The EOR credits will begin to expire, if unused, in 2024 and 2015 for federal and California, respectively.

10. Commitments

The Company's contractual obligations as of December 31, 2005 are as follows (in thousands):

Contractual Obligations	Total	2006	2007	2008	2009	2010	Thereafter
Long-term debt and interest	$ 79,500	$ -	$ -	$ -	$ 79,500	$ -	$ -
Abandonment obligations	10,675	315	360	539	556	556	8,349
Operating lease obligations	802	538	138	108	18	-	-
Drilling and rig obligations	16,698	8,948	2,400	2,950	2,400	-	-
Firm natural gas transportation contracts	36,454	3,706	4,574	4,398	4,386	4,386	15,004
Total	$ 144,129	$ 13,507	$ 7,472	$ 7,995	$ 86,860	$ 4,942	$ 23,353

Long-term debt and interest - Long-term debt and related interest of approximately 6% on the long-term debt borrowings can be paid before its maturity date without significant penalty.

Operating leases - The Company leases corporate and field offices in California and in Denver. Rent expense with respect to the Company's lease commitments for the years ended December 31, 2005, 2004 and 2003 was $.6 million, $.6 million, and $.5 million, respectively.

Drilling obligation - The Company intends to participate in the drilling of over 16 gross wells on its Lake Canyon prospect over the next four years. The Company's minimum obligation under its exploration and development agreement is $9.6 million.

Drilling rig obligation - The Company is obligated in operating lease agreements for two drilling rigs, each for one year ending in 2006.

Firm natural gas transportation - The Company entered into several firm transportation contracts which provide the Company additional flexibility in securing its natural gas supply and allows the Company to potentially benefit from lower natural gas prices in the Rocky Mountains compared to natural gas prices in California.

BERRY PETROLEUM COMPANY
Notes to the Financial Statements

11. Contingencies

The Company has accrued environmental liabilities for all sites, including sites in which governmental agencies have designated the Company as a potentially responsible party, where it is probable that a loss will be incurred and the minimum cost or amount of loss can be reasonably estimated. However, because of the uncertainties associated with environmental assessment and remediation activities, future expense to remediate the currently identified sites, and sites identified in the future, if any, could be higher than the liability currently accrued. Amounts currently accrued are not significant to the financial position of the Company and Management believes, based upon current site assessments, that the ultimate resolution of these matters will not require substantial additional accruals. The Company is involved in various other lawsuits, claims and inquiries, most of which are routine to the nature of its business. In the opinion of Management, the resolution of these matters will not have a material effect on the Company's financial position, results of operations or liquidity.

12. Equity Compensation Plans

On December 2, 1994, the Board of Directors of the Company adopted the Berry Petroleum Company 1994 Stock Option Plan which was restated and amended in December 1997 and December 2001 (the 1994 Plan or Plan) and approved by the shareholders in May 1998 and May 2002, respectively. The 1994 Plan provided for the granting of stock options to purchase up to an aggregate of 3,000,000 shares of Common Stock. All options, with the exception of the formula grants to non-employee Directors, were granted at the discretion of the Compensation Committee of the Board of Directors. The term of each option did not exceed ten years from the date the options were granted. The 1994 Plan expired on December 2, 2004, and the shareholders approved a new equity incentive plan in May 2005.

The 2005 Equity Incentive Plan (the 2005 Plan) provides for granting of equity compensation to purchase up to an aggregate of 1,450,000 shares of Common Stock. All equity grants are at market value on the date of grant and at the discretion of the Compensation Committee or the Board of Directors. The term of each employee grant did not exceed ten years from the grant date and vest 25% per year for 4 years. The 2005 Plan also allows for grants to non-employee Directors. During 2005, each of the non-employee Directors received 5,000 options at the market value on the date of grant. The options granted to the non-employee Directors vest immediately.

Stock Options

Effective January 1, 2004, the Company voluntarily adopted the fair value method of accounting for its stock option plans as prescribed by SFAS 123, *Accounting for Stock-Based Compensation.* The modified prospective method was selected as described in SFAS 148, *Accounting for Stock-Based Compensation - Transition and Disclosure*. Under this method, the Company recognized stock option compensation expense as if it had applied the fair value method to account for unvested stock options from its original effective date. Compensation expense under the fair value method for the years ended December 31, 2005 and 2004 was $2.9 million and $1.5 million, respectively. Additionally, the Company recorded $4.4 million and $3.9 million for the years ended December 31, 2004 and 2003, respectively, in compensation expense under the variable method of accounting prior to the modification of certain exercise provisions of the Company's 1994 Plan on July 29, 2004.

The fair value of each option award is estimated on the date of grant using the Black-Scholes option pricing model that uses the assumptions noted in the following table. Expected volatilities are based on the historical volatility of the Company's stock. The Company uses historical data to estimate option exercises and employee terminations within the valuation model; separate groups of employees that have similar historical exercise behavior are considered separately for valuation purposes. The expected term of options granted is based on historical exercise behavior and represents the period of time that options granted are expected to be outstanding; the range given below results from certain groups of employees exhibiting different exercise behavior. The risk free rate for periods within the contractual life of the option is based on U.S. Treasury rates in effect at the time of grant.

	2005	2004
Expected volatility	28% - 32%	25%
Weighted-average volatility	32%	25%
Expected dividends	.92% - 1.3%	1.27% - 2.45%
Expected term (in years)	4 - 5	4 - 7
Risk-free rate	3.8% - 4.4%	3.4% - 4.4%

BERRY PETROLEUM COMPANY
Notes to the Financial Statements

12. Equity Compensation Plans (Cont'd)

The following table summarizes information related to stock options outstanding and exercisable as of December 31, 2005:

Range of Exercise Prices	Options Outstanding	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Options Exercisable	Weighted Average Exercise Price
$10.63 - $23.76	707,575	$17.27	6.61	514,475	$16.80
$23.77 - $36.90	103,500	28.79	8.47	25,875	28.79
$36.91 - $50.04	479,875	43.21	8.94	131,188	43.26
$50.05 - $63.18	264,463	61.25	9.95	40,000	61.29
Total	1,555,413	$33.52	8.02	711,538	$24.61

Weighted average option exercise price information for the years ended December 31 is as follows:

	2005	2004	2003
Outstanding at January 1	$ 25.41	$ 16.50	$ 15.17
Granted during the year	59.13	40.60	19.31
Exercised during the year	16.80	15.73	13.15
Cancelled/expired during the year	37.36	18.02	16.55
Outstanding at December 31	33.52	25.41	16.50
Exercisable at December 31	24.61	17.61	15.62

The following is a summary of stock option activity for the years ended December 31 is as follows:

	2005	2004	2003
Balance outstanding, January 1	1,565,625	1,701,925	1,604,575
Granted	299,463	567,750	411,500
Exercised	(302,600)	(581,550)	(294,150)
Canceled/expired	(7,075)	(122,500)	(20,000)
Balance outstanding, December 31	1,555,413	1,565,625	1,701,925
Balance exercisable at December 31	711,538	688,275	1,037,275
Available for future grant	1,150,537	-	615,600
Weighted average remaining contractual life (years)	8	8	7
Weighted average fair value per option granted during the year based on the Black-Scholes pricing model	$ 19.16	$ 10.10	$ 5.11

BERRY PETROLEUM COMPANY
Notes to the Financial Statements

12. Equity Compensation Plans (Cont'd)

The total intrinsic value of options exercised during the years ended December 31, 2005, 2004 and 2003, was $12.6 million, $7.2 million and $1.6 million, respectively. At December 31, 2005, the intrinsic value of options outstanding was $36.8 million and the intrinsic value of exercisable options was $26.2 million.

As of December 31, 2005, there was $8.2 million of total unrecognized compensation cost related to stock options granted under the Plan. This cost is expected to be recognized over a weighted-average period over 4 years.

Restricted Stock Units

Under the 2005 Equity Incentive Plan, the Company began a long-term incentive program whereby restricted stock units (RSUs) are available for grant to certain employees and vest 25% per year over 4 years. In 2005, 70,950 RSUs were granted with a weighted average fair value per unit granted during the year of $61.29. As of December 31, 2005, there was $3.7 million of total unrecognized compensation cost related to RSUs granted under the Plan. This cost is expected to be recognized over a weighted-average period of 4 years, which is also the weighted average remaining contractual life. Unearned compensation under the restricted stock award plan is amortized over the vesting period. The Company will pay cash compensation on the RSUs in an equivalent amount of actual dividends paid on a per share basis of the Company’s outstanding common stock.

13. 401(k) Plan

The Company sponsors a defined contribution thrift plan under section 401(k) of the Internal Revenue Code to assist all eligible employees in providing for retirement or other future financial needs. Employee contributions (up to 6% of earnings) were matched by the Company at a range of $1 for $1 up to a maximum of $1.50 for $1 based on monthly profit levels for the Company. Effective November 1, 1992, the 401(k) Plan was modified to provide for increased Company matching of employee contributions whereby the monthly Company matching contributions will range from 6% to 9% of eligible participating employee earnings, if certain financial targets are achieved. The Company's contributions to the 401(k) Plan were $1.1 million, $.8 million and $.5 million in 2005, 2004 and 2003, respectively. Approximately 99% of full-time employees participate in the Plan. In December 2005, the 401(k) Plan was amended whereby effective January 1, 2006, the Company’s matching contribution will be $1 for $1 up to a maximum of 8% of an employee’s eligible compensation.

14. Director Deferred Compensation Plan

The Company established a non-employee director deferred stock and compensation plan to permit eligible directors, in recognition of their contributions to the Company, to receive fees as compensation and defer recognition of their compensation in whole or in part to a Stock Unit Account or an Interest Account. When the eligible director ceases to be a director, the distribution from the Stock Unit Account shall be made in shares using an established market value date and the distribution from the Interest Account shall be made in cash. The aggregate number of shares which may be issued to eligible directors under the plan shall not exceed 250,000, subject to adjustment for corporate transactions that change the amount of outstanding stock. The plan may be amended at any time, not more than once every six months, by the Compensation Committee or the Board of Directors and shall terminate, unless extended, on May 31, 2008.

Amounts allocated to the Stock Unit Account have the right to receive an amount equal to the dividends per share declared by the Company on the applicable dividend payment date and this “dividend equivalent” shall be treated as reinvested in an additional number of units and credited to their account using an established market value date. Amounts allocated to the Interest Account are credited with interest at an established interest rate.

Shares earned and deferred in accordance with the plan as of December 31, 2005, 2004 and 2003 were 6,885, 7,481 and 11,037, respectively.

BERRY PETROLEUM COMPANY
Notes to the Financial Statements

15. Hedging

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 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 and collars, however, the Company may use a variety of hedge instruments in the future. 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. All of these hedges have historically been deemed to be cash flow hedges with the marked-to-market valuations provided by external sources, based on prices that are actually quoted.

In June 2005, the Company entered into derivative instruments (zero-cost collars) for approximately 10,000 Bbl/D for the period January 1, 2006 through December 31, 2009. Based on WTI pricing, the floor is $47.50 and the ceiling is $70 per barrel. Upon entering into the new crude oil sales contract for California production in November 2005, the Company redesignated its existing crude oil collars as cash flow hedges related to California crude oil production, and there was no related effect to Other Comprehensive Income with regard to this redesignation. The use of hedging transactions also involves the risk that the counterparties will be unable to meet the financial terms of such transactions. With respect to the Company's hedging activities, the Company utilizes multiple counterparties on its hedges and monitors each counterparty's credit rating. After the June hedge transaction, a significant credit risk concentration existed in one broker. In July 2005, the Company reduced the concentration as the hedges were transferred to multiple counterparties. The Company is not required to issue collateral on these hedging transactions.

At December 31, 2005 and 2004, Accumulated Other Comprehensive Loss consisted of $24.4 million and $1 million, respectively, net of tax of unrealized losses from the Company's crude oil and natural gas swaps and collars. Deferred net losses recorded in Accumulated Other Comprehensive Loss at December 31, 2005 are expected to be reclassified to earnings over the life of the underlying hedging contracts.

16. Pro Forma Results (unaudited)

On January 27, 2005, the Company acquired certain interests in the Niobrara field in northeastern Colorado for approximately $105 million (J-W Acquisition) to increase natural gas reserves and production. Assets purchased include $93 million of gas properties, $6 million of pipeline, and $ 5 million of compression equipment. Liabilities assumed included $1 million of asset retirement obligations.

The unaudited pro forma results presented below for the year ended December 31, 2005 and 2004 have been prepared to give effect to the J-W Acquisition on the Company's results of operations under the purchase method of accounting as if it had been consummated on January 1, 2004. The unaudited pro forma results do not purport to represent the results of operations that actually would have occurred on such date or to project the Company's results of operations for any future date or period. (in thousands, except per share data):

	2005	2004
Proforma Revenue	$ 408,088	$ 295,243
Proforma Income from operations	190,970	121,688
Proforma Net income	112,660	72,393
Proforma Basic earnings per share	5.11	3.31
Proforma Diluted earnings per share	5.01	3.22

BERRY PETROLEUM COMPANY
Notes to the Financial Statements

17. Lease Receivable

Canyon Drilling LLC (“Canyon”), a 100% owned Colorado entity, was dissolved in the third quarter of 2005. Canyon owned a drilling rig which was leased to a third party. After the dissolution, the drilling rig is 100% owned by the Company. Concurrent with the dissolution of Canyon, the original lease was terminated and a revised three-year lease agreement was executed which has similar terms to the original lease. The revised lease includes a three year purchase option. The total net investment in the revised lease is approximately $3.4 million and is accounted for as a direct financing lease as defined by SFAS No. 13, *Accounting for Leases*. Net investment in this lease as of December 31, 2005 is as follows (in thousands):

Net minimum lease payments receivable	$ 4,781
Unearned income	(1,382)
Net investment in direct financing lease	$ 3,399

Estimated future minimum lease payments, including the purchase option, to be received as of December 31, 2005 are as follows (in thousands):

2006	$ 504
2007	504
2008	3,773
Total	$ 4,781

Drilling Rigs

During 2005, the Company purchased two drilling rigs. The first rig is leased to a drilling company under a three-year contract (see above), while the second rig is currently being refurbished in preparation for leasing under a similar drilling contract. Both rigs carry purchase options available to the drilling company.

18. Quarterly Financial Data (unaudited)

The following is a tabulation of unaudited quarterly operating results for 2005 and 2004 (in thousands, except per share data).

2005	Operating Revenues	Gross Profit (2)	Net Income	Basic Net Income Per Share	Diluted Net Income Per Share
First Quarter	$ 87,847	$ 41,931	$ 22,505	$ 1.02	$ 1.00
Second Quarter	92,339	45,092	25,260	1.14	1.13
Third Quarter	109,372	59,880	34,219	1.55	1.52
Fourth Quarter	115,363	52,754	30,372	1.39	1.35
	$ 404,921	$ 199,657	$ 112,356	$ 5.10	$ 5.00
2004					
First Quarter	$ 57,139	$ 20,948	$ 10,364	$ 0.48	$ 0.47
Second Quarter	64,046	25,591	15,278	0.70	0.68
Third Quarter	72,904	31,716	18,229	0.83	0.82
Fourth Quarter (1)	80,431	36,989	25,316	1.15	1.11
	$ 274,520	$ 115,244	$ 69,187	$ 3.16	$ 3.08

(1) During the fourth quarter of 2004, the Company recorded a net tax benefit of approximately $2.3 million, primarily due to the recognition of deferred tax assets related to certain properties and other tax items.
(2) Information has been revised in 2004 to reflect the Company's change in allocation of technical labor as disclosed in Note 2.

BERRY PETROLEUM COMPANY
Notes to the Financial Statements

19. Subsequent Events

On January 27, 2006 the Company announced that it had entered into an agreement with a private seller to acquire a 50% working interest in natural gas assets in the Piceance Basin of western Colorado for approximately $159 million to increase natural gas reserves and production. The acquisition was funded under the Company's existing credit facility. The effective date of the transaction is October 1, 2005. The Company purchased 100% interests in Piceance Operating Company (which owns a 50% working interest in the acquired assets). The Company will finalize its purchase price allocation after determining the post-closing adjustments. The transaction closed on February 28, 2006.
In February 2006, the Company purchased a third drilling rig for approximately $5 million for use in its Piceance Basin development program.

On March 1, 2006, the Board of Directors of the Company approved a two-for-one split of the Company's Class A Common Stock (Common Stock) and Class B Stock, subject to shareholder approval of an increase in authorized shares.The stock split will require that shareholders authorize the issuance of new shares at the Company’s May 17, 2006 annual meeting. Berry's shareholders will be asked to approve an increase in the Company's authorized shares of Common Stock to 100 million from the current 50 million shares and the Class B Stock to 3.0 million shares from 1.5 million shares. If approved, Berry’s transfer agent will distribute to each holder of record as of the close of business on May 17, 2006, one additional share for every share of stock held. The split will be in the form of a stock dividend, which will be distributed on June 2, 2006. Berry’s Common Stock should begin trading on a post-split basis June 5, 2006. Based on shares outstanding on March 1, 2006, Berry would have approximately 42.2 million shares of Common Stock and 1.8 million shares of Class B Stock outstanding following the proposed stock split.

Supplemental Information About Oil & Gas Producing Activities (Unaudited)

The following estimates of proved oil and gas reserves, both developed and undeveloped, represent interests owned by the Company located solely within the United States. Proved reserves represent estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed oil and gas reserves are the quantities expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells for which relatively major expenditures are required for completion.

Disclosures of oil and gas reserves which follow are based on estimates prepared by independent engineering consultants as of December 31, 2005, 2004 and 2003. Such estimates are subject to numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. These estimates do not include probable or possible reserves. The information provided does not represent Management's estimate of the Company's expected future cash flows or value of proved oil and gas reserves.

BERRY PETROLEUM COMPANY

Supplemental Information About Oil & Gas Producing Activities (Unaudited)(Cont'd)

Changes in estimated reserve quantities

The net interest in estimated quantities of proved developed and undeveloped reserves of crude oil and natural gas at December 31, 2005, 2004 and 2003, and changes in such quantities during each of the years then ended were as follows (in thousands):

	2005			2004			2003		
	Oil Mbbls	Gas Mmcf	BOE	Oil Mbbls	Gas Mmcf	BOE	Oil Mbbls	Gas Mmcf	BOE
Proved developed and Undeveloped reserves:									
Beginning of year	105,549	25,724	109,836	106,640	19,680	109,920	100,744	5,850	101,719
Revision of previous estimates	(681)	4,084	-	2,975	8,246	4,349	(82)	293	(33)
Improved recovery	753	-	753	2,021	-	2,021	1,271	-	1,271
Extensions and discoveries	6,228	24,605	10,329	2,736	714	2,855	1,853	2,005	2,187
Property sales	(1,035)	-	(1,035)	(127)	(77)	(140)	-	-	-
Production	(7,081)	(7,919)	(8,401)	(7,044)	(2,839)	(7,517)	(5,827)	(1,277)	(6,040)
Purchase of reserves in place (1)	-	88,817	14,803	132	-	132	8,681	12,809	10,816
Royalties converted to working interest	-	-	-	(1,784)	-	(1,784)	-	-	-
End of year	103,733	135,311	126,285	105,549	25,724	109,836	106,640	19,680	109,920
Proved developed reserves:									
Beginning of year	78,207	20,048	81,549	78,145	12,207	80,180	72,889	3,252	73,431
End of year	78,308	70,519	90,061	78,207	20,048	81,549	78,145	12,207	80,180

(1) Refer to Note 16 to the financial statements.

The standardized measure has been prepared assuming year end sales prices adjusted for fixed and determinable contractual price changes, current costs and statutory tax rates (adjusted for tax credits and other items), and a ten percent annual discount rate. No deduction has been made for depletion, depreciation or any indirect costs such as general corporate overhead or interest expense. Cash outflows for future production and development costs include cash flows associated with the ultimate settlement of the asset retirement obligation.

Standardized measure of discounted future net cash flows from estimated production of proved oil and gas reserves (in thousands):

	2005	2004	2003
Future cash inflows	$ 6,088,170	$ 3,281,155	$ 2,845,767
Future production costs	(2,297,638)	(1,405,432)	(1,246,340)
Future development costs	(333,722)	(216,859)	(198,279)
Future income tax expenses	(1,115,516)	(355,764)	(324,097)
Future net cash flows	2,341,294	1,303,100	1,077,051
10% annual discount for estimated timing of cash flows	(1,089,914)	(616,352)	(548,831)
Standardized measure of discounted future net cash flows	$ 1,251,380	$ 686,748	$ 528,220
Average sales prices at December 31:			
Oil ($/Bbl)	$ 48.38	$ 29.49	$ 25.77
Gas ($/Mcf)	$ 7.91	$ 6.61	$ 4.94
BOE Price	$ 48.21	$ 29.87	$ 25.89

BERRY PETROLEUM COMPANY

Supplemental Information About Oil & Gas Producing Activities (Unaudited)(Cont'd)

Changes in standardized measure of discounted future net cash flows from proved oil and gas reserves (in thousands):

	2005	2004	2003
Standardized measure - beginning of year	$ 686,748	$ 528,220	$ 449,857
Sales of oil and gas produced, net of production costs	(240,039)	(144,457)	(75,143)
Revisions to estimates of proved reserves:			
Net changes in sales prices and production costs	702,867	190,861	45,292
Revisions of previous quantity estimates	5	40,419	(229)
Improved recovery	12,267	18,787	9,400
Extensions and discoveries	168,291	26,541	16,171
Change in estimated future development costs	(157,068)	(56,314)	(75,841)
Purchases of reserves in place	103,150	962	47,700
Sales of reserves in place	(9,613)	(1,043)	-
Development costs incurred during the period	111,613	65,971	41,461
Accretion of discount	87,650	68,312	59,983
Income taxes	(392,886)	(16,890)	(8,896)
Other	178,395	(21,430)	18,465
Royalties converted to working interest	-	(13,191)	-
Net increase (decrease)	564,632	158,528	78,363
Standardized measure - end of year	$ 1,251,380	$ 686,748	$ 528,220

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of December 31, 2005, the Company has carried out an evaluation under the supervision of, and with the participation of, the Company's Management, including the Company's Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of the Company's disclosure controls and procedures pursuant to Rule 13a-15 under the Securities Exchange Act of 1034, as amended.

Based on their evaluation as of December 31, 2005, the Chief Executive Officer and Chief Financial Officer of the Company have concluded that the Company’s disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e)) under the Securities Exchange Act of 1934) are effective to ensure that the information required to be disclosed by the Company in the reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms.

Management's Report on Internal Control Over Financial Reporting

Internal control over financial reporting is defined in Rule 13a-15(f) and 15d-15(f) promulgated under the Securities Exchange Act of 1934, as amended, as a process designed by, or under the supervision of, the Company's principal executive and principal financial officers, or persons performing similar functions, and effected by the Company's Board of Directors, Management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes in accordance with U.S. generally accepted accounting principles and includes those policies and procedures that:

- pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the Company's assets;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of the Company's Management and Directors; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Additionally, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of Management, including the principal executive officer and principal financial officer, the Company conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its evaluation under the framework in *Internal Control - Integrated Framework*, Management concluded that its internal control over financial reporting was effective as of December 31, 2005.

Management's assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2005 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein.

Changes in Internal Control Over Financial Reporting

There were no changes in the Company's internal control over financial reporting that occurred during the three months ended December 31, 2005 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting. The Company may make changes in its internal control procedures from time to time in the future.

Item 9B. Other Information

On March 1, 2006, the Board of Directors of the Company approved a two-for-one split of the Company's Class A Common Stock (Common Stock) and Class B Stock, subject to shareholder approval of an increase in authorized shares.The stock split will require that shareholders authorize the issuance of new shares at the Company's May 17, 2006 annual meeting. Berry's shareholders will be asked to approve an increase in the Company's authorized shares of Common Stock to 100 million from the current 50 million shares and the Class B Stock to 3.0 million shares from 1.5 million shares. If approved, Berry's transfer agent will distribute to each holder of record as of the close of business on May 17, 2006, one additional share for every share of stock held. The split will be in the form of a stock dividend, which will be distributed on June 2, 2006. Berry's Common Stock should begin trading on a post-split basis June 5, 2006. Based on shares outstanding on March 1, 2006, Berry would have approximately 42.2 million shares of Common Stock and 1.8 million shares of Class B Stock outstanding following the proposed stock split.

On February 28, 2006 the Company completed the acquisition of a 50% working interest in natural gas assets in the Grand Valley field in the Piceance Basin of western Colorado for approximately $159 million. The purchase was funded under the Company's existing credit facility. Berry is the operator and owns a 50% working interest in 6,314 gross acres targeting gas in the Williams Fork section of the Mesaverde formation. Estimated daily production, net to Berry's interest, is approximately 1 million cubic feet of natural gas per day (MMcf/D) from three producing wells. The Company internally estimates 330 billion cubic feet of proved and probable reserves, none of which are included in Berry's 2005 year-end proved reserves of 126 million barrels of oil equivalent (BOE). With this acquisition, the Company's current estimate of its total proved reserves is over 130 million BOE. Berry is increasing its 2006 capital budget by an additional $18 million to $208 million for 2006 to accelerate the development of this resource. Seven wells are currently awaiting completion which is expected by April 1, 2006.

On January 31, 2006 the Company paid cash bonuses to employees related to the Company's and each individual's performance in 2005. Mr Heinemann was paid $500,000, Mr. Goehring $185,500, Mr. Duginski $212,000, Mr. Magruder $212,000 and Mr. Crawford $96,300. Effective January 1, 2006 Mr. Heinemann's salary was increased to $500,000, Mr. Goehring's to $250,000, Mr. Duginski's to $250,000, Mr. Magruder's to $250,000 and Mr. Crawford's to $200,000.

Effective in January 2006 the compensation of the Chairman of the Board, Mr. Martin H. Young, Jr., was increased by providing that he be paid the same meeting fees as all other directors in addition to the annual retainer of $125,000 and a special award of $40,000 was made to Mr. Young in recognition of extraordinary commitment of time and resources by him on behalf of the Company in 2005. Mr. Young has elected to receive all compensation paid for his service to the Company in the form of Company stock under the terms of the Non-Employee Director Deferred Compensation Plan.

PART III

Item 10. Directors and Executive Officers of the Registrant

The information called for by Item 10 is incorporated by reference from information under the captions “Corporate Governance and Board Matters” and “Compliance with Section 16(a) of the Securities Exchange Act of 1934” in the Company’s definitive proxy statement to be filed pursuant to Regulation 14A no later than 120 days after the close of its fiscal year. Information regarding Executive Officers is contained in this report in Part I, Item 1 Business.

Item 11. Executive Compensation

The information called for by Item 11 is incorporated by reference from information under the caption "Executive Compensation" in the Company's definitive proxy statement to be filed pursuant to Regulation 14A no later than 120 days after the close of its fiscal year.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information called for by Item 12 is incorporated by reference from information under the captions "Security Ownership of Directors and Management" and "Principal Shareholders" in the Company's definitive proxy statement to be filed pursuant to Regulation 14A no later than 120 days after the close of its fiscal year.

Item 13. Certain Relationships and Related Transactions

The information called for by Item 13 is incorporated by reference from information under the caption "Certain Relationships and Related Transactions" in the Company's definitive proxy statement to be filed pursuant to Regulation 14A no later than 120 days after the close of its fiscal year.

Item 14. Principal Accounting Fees and Services

The information called for by Item 14 is incorporated by reference from the information under the caption “Fees to Independent Accountants for 2005 and 2004” in the Company’s definitive proxy statement to be filed pursuant to Regulation 14A no later than 120 days after the close of its fiscal year.

PART IV

Item 15. Exhibits, Financial Statement Schedules

A. Financial Statements and Schedules

See Index to Financial Statements and Supplementary Data in Item 8.

B. Exhibits

Exhibit No.	Description of Exhibit
3.1	Registrant's Restated Certificate of Incorporation
3.2*	Registrant's Restated Bylaws dated July 1, 2005 (filed as Exhibit 3.1 to the Registrant's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2005, File No. 1-09735)
4.1*	Registrant's Certificate of Designation, Preferences and Rights of Series B Junior Participating Preferred Stock (filed as Exhibit A to the Registrant's Registration Statement on Form 8-A12B on December 7, 1999, File No. 778438-99-000016)
4.2*	Rights Agreement between Registrant and ChaseMellon Shareholder Services, L.L.C. dated as of December 8, 1999 (filed by the Registrant on Form 8-A12B on December 7, 1999, File No. 778438-99-000016)
10.1	Description of Cash Bonus Plan of Berry Petroleum Company
10.2*	Form of Salary Continuation Agreement dated as of December 5, 1997, by and between Registrant and selected employees of the Company (filed as Exhibit 10.3 to the Registrant’s Annual Report on Form 10-K for the year ended December 31, 1997, File No. 1-9735)
10.3*	Form of Salary Continuation Agreements dated as of March 20, 1987, as amended August 28, 1987, by and between Registrant and selected employees of the Company (filed as Exhibit 10.12 to the Registration Statement on Form S-1 filed on June 7, 1989, File No. 33-29165)
10.4*	Instrument for Settlement of Claims and Mutual Release by and among Registrant, Victory Oil Company, the Crail Fund and Victory Holding Company effective October 31, 1986 (filed as Exhibit 10.13 to Amendment No. 1 to the Registrant's Registration Statement on Form S-4 filed on May 22, 1987, File No. 33-13240)
10.5*	Credit Agreement, dated as of June 27, 2005, by and between the Registrant and Wells Fargo Bank, N.A. and other financial institutions (filed as Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2005, File No. 1-9735)
10.6	First Amendment to Credit Agreement, dated as of December 15, 2005 by and between the Registrant and Wells Fargo Bank, N.A. and other financial institutions
10.7*	Amended and Restated 1994 Stock Option Plan (filed as Exhibit 4.1 to the Registrant’s Registration Statement on Form S-8 filed on August 20, 2002, File No. 333-98379)
10.8*	Berry Petroleum Company 2005 Equity Incentive Plan (filed as Exhibit 4.2 to the Registrant’s Form S-8 filed on July 29, 2005, File No. 333-127018)
10.9*	Form of the Stock Option Agreement, by and between Registrant and selected employees, directors, and consultants (filed as Exhibit 4.3 to the Registrant’s Form S-8 filed on July 29, 2005, File No. 333-127018)
10.10*	Form of the Stock Appreciation Rights Agreement, by and between Registrant and selected employees, directors, and consultants (filed as Exhibit 4.4 to the Registrant’s Form S-8 filed on July 29, 2005, File No. 333-127018)"
10.11*	Form of Stock Award Agreement, by an between Registrant and selected employees, directors, and consultants (filed as Exhibit 99.1 on Form 8-k filed on December 22, 2005, File No. 1-9735)
10.12*	Crude oil purchase contract, dated November 14, 2005 between Registrant and Big West of California, LLC (filed as Exhibit 99.2 on Form 8-k filed on November 22, 2005, File No. 1-9735)
10.13	Non-Employee Director Deferred Stock and Compensation Plan (as amended effective January 1, 2006)
10.14*	Employment Contract dated as of June 16, 2004 by and between the Registrant and Robert F. Heinemann (filed as Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2004, File No. 1-9735)
10.15*	Salary Continuation Agreement dated as of June 16, 2004 by and between the Registrant and Robert F. Heinemann (filed as Exhibit 10.2 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2004, File No. 1-9735)
10.16*	Purchase and sale agreement between the Registrant and J-W Operating Company (filed as Exhibit 99.2 to the Registrant's Current Report on Form 8-K/A filed on February 15, 2005, File No. 1-9735)
10.17	Amended and Restated Purchase and Sale Agreement between Registrant and Orion Energy Partners, LP.
23.1	Consent of PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm
23.2	Consent of DeGolyer and MacNaughton
31.1	Certification of Chief Executive Officer pursuant to SEC Rule 13(a)-14(a)
31.2	Certification of Chief Financial Officer pursuant to SEC Rule 13(a)-14(a)
32.1	Certification of Chief Executive Officer pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
32.2	Certification of Chief Financial Officer pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
99.1*	Form of Indemnity Agreement of Registrant (filed as Exhibit 99.1 in Registrant's Annual Report on Form 10-K filed on March 31, 2005, File No. 1-9735)
99.2*	Form of "B" Group Trust (filed as Exhibit 28.3 to Amendment No. 1 to Registrant's Registration Statement on Form S-4 filed on May 22, 1987, File No. 33-13240)

* Incorporated by reference

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereto duly authorized on March 1, 2006.

BERRY PETROLEUM COMPANY

/s/ Robert F. Heinemann ROBERT F. HEINEMANN President, Chief Executive Officer and Director	/s/ Ralph J. Goehring RALPH J. GOEHRING Executive Vice President and Chief Financial Officer (Principal Financial Officer)	/s/ Donald A. Dale DONALD A. DALE Controller (Principal Accounting Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities on the dates so indicated.

Name	Office	Date
/s/ Martin H. Young, Jr. Martin H. Young, Jr.	Chairman of the Board, Director	March 1, 2006
/s/ Robert F. Heinemann Robert F. Heinemann	President, Chief Executive Officer and Director	March 1, 2006
/s/ William F. Berry William F. Berry	Director	March 1, 2006
/s/ Joseph H. Bryant Joseph H. Bryant	Director	March 1, 2006
/s/ Ralph B. Busch, III Ralph B. Busch, III	Director	March 1, 2006
/s/ William E. Bush, Jr. William E. Bush, Jr.	Director	March 1, 2006
/s/ Stephen L. Cropper Stephen L. Cropper	Director	March 1, 2006
/s/ J. Herbert Gaul, Jr. J. Herbert Gaul, Jr.	Director	March 1, 2006
/s/ Thomas J. Jamieson Thomas J. Jamieson	Director	March 1, 2006
/s/ J. Frank Keller J. Frank Keller	Director	March 1, 2006

Exhibit 3.1

RESTATED CERTIFICATE OF INCORPORATION

OF

BERRY PETROLEUM COMPANY

Reflecting all amendments as of December 31, 2005

The undersigned, for the purposes of restating the Certificate of Incorporation of Berry Petroleum Company, originally filed with the Secretary of State of the State of Delaware on September 30, 1985, do execute this Restated Certificate of Incorporation pursuant to Section 245 of the Delaware General Corporation Law of the State of Delaware (“General Corporation Law”) and do hereby certify as follows:

First: The name of the Corporation is Berry Petroleum Company.

Second: The address of the registered office of the Corporation in the State of Delaware is The Corporation Trust Center, 1209 Orange Street, Wilmington, Delaware 19807, County of New Castle. The name of the registered agent of the Corporation at such address is The Corporation Trust Company.

Third: The purpose of the Corporation is to engage in any lawful act or activity for which corporations may be organized under the General Corporation Law of the State of Delaware.

Fourth: (a) The total number of shares of stock which the Corporation shall have authority to issue is fifty-three million five hundred thousand shares, consisting of fifty million shares of Class A Common Stock (“Class A Stock”) having par value of $.01 per share, one million five hundred thousand shares of Class B Stock having par value of $.01 per share, and two million shares of Preferred Stock having a par value of $.01 per share. The Class A Stock and Class B Stock are sometimes collectively referred to herein as the “Capital Stock.”

(b) Subject to all of the powers, preferences, and rights of Preferred Stock or any series thereof, dividends may be paid on the Capital Stock if, as, and when declared by the Board of Directors, out of any funds of the Corporation legally available for the payment of dividends. Each share of Capital Stock shall participate equally with each other, without preference or distinction, as to the payments of dividends (including stock dividends) and, subject to Paragraph (g) of this Article Fourth, other distributions made with respect to the Capital Stock.

(c) Each share of Class A Stock shall be entitled to one vote and each share of Class B Stock shall be entitled to 95% of one vote on all matters upon which the Capital Stock is entitled to vote. The Class A Stock and Class B Stock shall vote as a single class on all matters upon which the Capital Stock is entitled to vote.

(d) At all elections of directors of the Corporation, each stockholder shall be entitled to as many votes as shall equal the number of votes which (except for this provision as to cumulative voting) he would be entitled to cast for the election of a director with respect to his shares of stock multiplied by the number of directors to be elected, and he may cast all of such votes for a single director or may distribute them among the number to be voted for, or for any two or more of them as he may see fit.

(e) Each share of Class B Stock shall be convertible, at the option of the holder thereof, into one share of fully paid and nonassessable Class A Stock at any time after December 31, 1990 or, prior to January 1, 1991, during the period commencing as of the date of the first announcement of and ending as of the date of the consummation of any of the following (provided that each such period shall in no event be less than 10 days):

(i) any proposed public offering of the Corporation’s Class A Stock;

(ii) any proposed merger, consolidation or other business reorganization or combination of the Corporation with or into any other corporation or entity (other than a transaction in which the Corporation is the surviving entity and the Corporation does not become a subsidiary of another corporation);

(iii) any proposed sale, lease, exchange, or other transfer or disposition of all or any substantial part of the assets of the Corporation or any of its subsidiaries;

(iv) any offer (pursuant to an offer to purchase, a solicitation of an offer to sell, or an invitation to make an offer to sell) or agreement, or a combination thereof, to acquire directly or indirectly shares of Class A Stock for cash, securities, or any other consideration where the shares which are the subject of the offer or agreement or the combination thereof, together with the offeror’s presently beneficially owned shares (calculated pursuant to Article Eighth, Paragraph (b)) will in the aggregate exceed 20% of the outstanding shares of Class A Stocks; or

(v) in the event that the liquidation preferences provided for in subparagraphs (g)(1)(i) and (ii) below shall cease to be applicable by virtue of the provisions of subparagraph (g)(1)(iv) below.

Before any holder of Class B Stock shall be entitled to convert the same into shares of Class A Stock, the holder shall surrender the certificate or certificates therefor, duly endorsed at the principal executive office of the Corporation or of any transfer agent and shall give written notice to the Corporation at such office that the holder elects to convert the same. The Corporation shall, as soon as practicable thereafter, issue and deliver at such office to such holder of Class B Stock a certificate or certificates for the number of shares of Capital Stock to which the holder shall be entitled as set forth above. Such conversion shall be deemed for all purposes to have been made, if made after December 31, 1990, immediately prior to the close of business on the date of such surrender of the shares of Class B Stock to be converted and, if made before January 1, 1991, upon the commencement of the conversion period referred to above, and the person or persons entitled to receive the shares of Class A Stock issuable upon such conversion shall be treated for all purposes as the record holder or holders of such shares of Class A Stock on such date.

If the Corporation shall subdivide its outstanding shares of Class A Stock into a larger number of shares or shall combine its outstanding shares of Class A Stock into a small number of shares, the shares of Class B Stock then outstanding shall likewise be subdivided or combined.

(f) (1) If at any time there is proposed to be presented to the stockholders of the Corporation for their approval (by vote at a meeting or by written consent) any matter (including without limitation a merger, sale of assets or reorganization involving the Corporation) the approval of which under then applicable law would require the vote or consent of the holders of Class A Stock and Class B Stock as separate classes, and the application of subparagraph (g)(1)(iv) below does not alter such class vote or consent requirement in such a way as to permit such matter to be duly approved by the holders of Class A Stock and Class B Stock voting together as a single class, then, in such event and effective as of the applicable record date for determination of stockholders entitled to vote upon or consent to such matter, each outstanding share of Class B Stock shall be converted automatically into one share of Class A Stock; provided, however, that the provisions of this subparagraph (f)(1) shall not apply to any proposal to amend this Certificate of Incorporation if the amendment would increase or decrease the aggregate number of authorized shares of Class A Stock or Class B Stock, increase or decrease the par value of Class A Stock or Class B Stock, or alter or change the powers, preferences or special rights of Class A Stock or Class B Stock so as to affect them adversely.

(2) Upon the occurrence of the event specified in subparagraph (f)(1) above, the outstanding shares of Class B Stock shall be converted automatically without any further action by the holders of such shares and whether or not the certificates representing such shares are surrendered to the Corporation or its transfer agent; provided, however, that the Corporation shall not be obligated to issue certificates evidencing the shares of Class A Stock issuable upon such conversion unless the certificates evidencing such shares of Class B Stock are either delivered to the Corporation or its transfer agent as provided below, or the holder notifies the Corporation or its transfer agent that such certificates have been lost, stolen or destroyed and executes an agreement satisfactory to the Corporation to indemnify the Corporation from any loss incurred by it in connection with such certificates. Upon the occurrence of such automatic conversion of the Class B Stock, the holders of Class B Stock shall surrender the certificates representing such shares at the office of the Corporation or any transfer agent for the Class B Stock or Class A Stock. Thereupon, there shall be issued and delivered to such holder promptly at such office and in his name as shown on such surrendered certificate or certificates, a certificate or certificates for the number of shares of Class A Stock into which the shares of Class B Stock surrendered were convertible on the date on which such automatic conversion occurred.

(g) (1) In the event of any liquidation, dissolution, or winding up of the Corporation, either voluntary or involuntary, the assets and funds of the Corporation available for distribution to the stockholders of the Corporation shall be distributed as follows:

(i) The holders of Class B Stock shall be entitled to receive, prior and in preference to any distribution of any assets or funds of the Corporation to the holders of Class A Stock, an amount equal to $1.00 per share for each share of Class B Stock then outstanding (subject to adjustment in the event of any stock dividends, subdivisions, or combinations so that the aggregate liquidation preference of all shares of Class B Stock issued and outstanding immediately prior to any such stock dividend, subdivision, or combination shall be and remain the same immediately thereafter), plus an amount equal to any dividends declared but unpaid on the Class B Stock. If the assets and funds of the Corporation available for distribution to the holders of Class B Stock of the Corporation shall be insufficient to permit the payment of the full preferential amount set forth above, then all of the assets and funds of the Corporation available for distribution to the holders of Class B Stock shall be distributed to the holders of Class B Stock pro rata based on their holdings of Class B Stock.

(ii) After distribution to the holders of Class B Stock of the amounts set forth in subparagraph (g)(1)(i) above, the holders of Class A Stock shall be entitled to receive, prior and in preference to any additional distribution of any assets or funds of the Corporation to the holders of Class B Stock and Class A Stock as provided in paragraph (g)(1)(iii) below, an amount equal to $1.00 per share for each share of Class A Stock then outstanding (subject to adjustment in the event of any stock dividends, subdivisions, or combinations so that the aggregate liquidation preference of all shares of Class A Stock issued and outstanding immediately prior to any such stock dividend, subdivision, or combination shall be and remain the same immediately thereafter), plus an amount equal to any dividends declared but unpaid on the Class A Stock. If the assets and funds of the Corporation available for distribution to the holders of the Class A Stock shall be insufficient to permit the full payment of the preferential amount set forth in this subparagraph (g)(1)(ii), then all of the assets and funds available for distribution to the holders of Capital Stock, after payment to the holders of Class B Stock of the preferential payment set forth in subparagraph (g)(1)(i).above, shall be distributed to the holders of Class A Stock pro rata based on their holdings of Class A Stock.

(iii) After distribution of the amounts set forth in subparagraphs(g)(1)(i) and (ii) above, the remaining assets and funds of the Corporation available for distribution to the holders of Class A Stock and Class B Stock shall be distributed to the holders of shares of Class A Stock and Class B Stock pro rata on the basis of the total number of shares of Class A Stock and Class B Stock outstanding with each share of Class A Stock and Class B Stock being treated equally.

(iv) Notwithstanding the provisions of subparagraphs (g)(1)(i) and (ii) above, if at any time there is proposed to be presented to the stockholders of the Corporation for their approval (by vote at a meeting or by written consent) any matter (including without limitation a merger, sale of assets or reorganization involving the Corporation) the approval of which under then applicable law would require the vote or consent of the holders of Class A Stock and Class B Stock as separate classes, but such class vote or consent would not be so required if the liquidation preferences provided for in subparagraphs (g)(1)(i) and (ii) were not applicable, then, in such event and effective on and after the applicable record date for determination of stockholders entitled to vote upon or consent to such matter, the liquidation preferences provided for in subparagraphs (g)(1)(i) and (ii) above shall cease to be applicable and the provisions of subparagraph (g)(1)(iii) shall thereafter govern all distributions to stockholders in the event of any liquidation, dissolution, or winding up; provided, however, that the provisions of this subparagraph (g)(1)(iv) shall not apply to any proposal to amend this Certificate of Incorporation if the amendment would increase or decrease the aggregate number of authorized shares of Class A Stock or Class B Stock, increase or decrease the par value of Class A Stock or Class B Stock, or alter or change the powers, preferences or special rights of Class A Stock or Class B Stock so as to affect them adversely.

(2) A merger, consolidation, or other business reorganization or combination of the Corporation with or into any other corporation or entity in which the Corporation shall not survive or shall become a subsidiary of another corporation or entity, or a sale, exchange, lease, or other transfer or disposition of all or substantially all of the assets of the Corporation, shall not be deemed to be a liquidation, dissolution and winding up for the purpose of this paragraph (g).

(3) If any of the assets of the Corporation are to be distributed other than in cash under this paragraph (g), then the Board of Directors of the Corporation shall promptly engage competent independent appraisers to determine the value of the assets to be distributed to the holders of Stock.

(h) The Board of Directors is authorized, subject to limitations prescribed by law and the provisions of this Article Fourth, to provide for the issuance of the shares of Preferred Stock in one or more series, and by filing a certificate pursuant to the applicable law of the State of Delaware, to establish from time to time the number of shares to be included in each such series, and to fix the voting to be included in each such series, and to fix the voting powers, designations, preferences and relative, participating, optional or other rights, if any, or the qualifications, limitations or restrictions thereof, if any, of the shares of each such series. The authority of the Board of Directors with respect to each series shall include, but not be limited to, determination of the following:

(i) The number of shares constituting that series and the distinctive designation of that series;

(ii) The dividend rate on the shares of that series, whether dividends shall be cumulative and, if so, from which date or dates, and the relative rights of priority, if any, of payment of dividends on shares of that series;

(iii) Whether that series shall have voting rights in addition to the voting rights provided by law and, if so, the terms of such voting rights;

(iv) Whether that series shall have conversion privileges, and, if so, the terms and conditions of such conversion, including provision for adjustment of the conversion rate in such events as the Board of Directors shall determine;

(v) Whether or not the shares of that series shall be redeemable, and, if so, the terms and conditions of such redemption, including the date or dates upon or after which they shall be redeemable, and the amount per share payable in case of redemption, which amount may vary under different redemption dates;

(vi) Whether that series shall have a sinking fund for the redemption or purchase of shares of the series, and, if so, the terms and amount of such sinking fund;

(vii) The rights of the shares of that series in the event of voluntary or involuntary liquidation, dissolution or winding up of the Corporation, and the relative rights of priority, if any, of payment of shares of that series; and

(viii) Any other voting powers, designations, preferences, rights and qualifications, limitations or restrictions of that series, including those dependent upon facts ascertainable outside the resolution or resolutions adopted by the Board of Directors providing for the issue of such series, provided that the manner in which facts shall operate upon the voting powers, designations, preferences, rights and qualifications, limitations or restrictions of such series is clearly and expressly set forth in the resolution or resolutions adopted by the Board of Directors providing for the issue of such series.

The number of authorized shares of Preferred Stock may be increased or decreased (but not below the number of shares thereof then outstanding) by the affirmative vote of the holders of a majority of the outstanding shares of the Corporation entitled to vote thereon.

Fifth: The business and affairs of the Corporation shall be managed by or under the direction of the Board of Directors. The directors need not be elected by ballot unless required by the bylaws of the Corporation.

Sixth: The number of the directors of the Corporation shall be fixed from time to time by, or in the manner provided in, the bylaws and may be increased or decreased as therein provided, but the number thereof shall not be more than twelve or less than nine; provided, however, that at any time the number of stockholders of the Corporation shall be three or less, the number thereof shall not be more than twelve or less than three.

Seventh: In furtherance and not in limitation of the powers conferred by the laws of the State of Delaware, the Board of Directors is expressly authorized to adopt, amend or repeal the bylaws. The bylaws may be adopted, amended or repealed by the stockholders of the Corporation only by the affirmative vote of the holders of not less than 66-2/3% of the combined voting power of the outstanding shares of the Corporation entitled to vote thereon.

Eighth: (a) Except as set forth in paragraph (d) of this Article Eighth, the affirmative vote of the holders of at least 66-2/3% of the combined voting power of the outstanding shares of the Corporation entitled to vote in the election of directors shall be required to effect or validate:

(1) any merger, consolidation or other business reorganization or combination of the Corporation or any of its subsidiaries with or into any other corporation;

(2) any sale, lease, exchange or other disposition of all or any substantial part of the assets of the Corporation or any of its subsidiaries to any other corporation, person or other entity; or

(3) any sale, lease, exchange or other disposition to the Corporation or any of its subsidiaries of any assets, cash securities or other property of any other corporation, person or other entity (except assets, cash, securities or other property having an aggregate fair market value of less than $1,000,000) in exchange for voting securities (or securities convertible into voting securities or options, warrants, or rights to acquire voting securities or securities convertible into voting securities) of the Corporation or any of its subsidiaries, if, as of the record date for the determination of stockholders entitled to notice thereof and to vote thereon, such other corporation, person or entity which is party to such a transaction is the beneficial owner, directly or indirectly of 5% or more of the combined voting power of the outstanding shares of the Corporation entitled to vote in elections of directors. Such affirmative vote shall be in addition to any vote of the holders of the shares of the Corporation otherwise required by law, this Certificate of Incorporation or any agreement between the Corporation and any national securities exchange.

(b) For purposes of Article Fourth, Paragraph (e)(iv) and this Article Eighth, any corporation, person or other entity shall be deemed to be the beneficial owner of any shares of the Corporation which:

(1) it owns directly, whether or not of record;

(2) it has the right to acquire pursuant to any agreement or understanding or upon the exercise of conversion rights, warrants or options or otherwise;

(3) are beneficially owned, directly or indirectly (including shares deemed to be owned through application of clause (2) above), by an “affiliate” or “associate” as those terms are defined in Rule 12b-2 of the General Rules and Regulations under the Securities Exchange Act of 1934 as in effect on January 1, 1985; or

(4) are beneficially owned, directly or indirectly (including shares deemed owned through application of clause (2) above), by any other corporation, person or entity with which it or its “affiliate” or “associate” has any agreement or arrangement or understanding for the purpose of acquiring, holding, voting or disposing of shares of the Corporation. For the purpose of determining whether a corporation, person or entity is the beneficial owner of 5% or more of the combined voting power of the outstanding shares of the Corporation entitled to vote in elections of directors, the outstanding shares of the Corporation shall include shares not in fact outstanding but deemed owned through the application of clauses (b)(2), (3) and (4) above, but shall not include any other shares which may be issuable pursuant to any agreement or upon the exercise of conversion rights, warrants or options or otherwise.

(c) The Board of-Directors shall have the power and duty to determine for the purposes of this Article Eighth, on the basis of information known to the Corporation whether:

(1) Such other corporation, person or other entity beneficially owns more than 5% or more of the combined voting power of the outstanding shares of the Corporation entitled to vote in the election of directors;

(2) A corporation, person or other entity is an “affiliate” or “associate” (as defined in paragraph (b) above) of another; and

(3) The assets, cash, securities or other property being acquired by the Corporation, or any subsidiary thereof, have an aggregate fair market value of less than $1,000,000.

Any such determination shall be conclusive and binding for all purposes of this Article Eighth.

(d) The provisions of this Article Eighth shall not apply to any transaction described in clauses (1), (2) or (3) of paragraph (a) above if:

(1) The Board of Directors of the Corporation has approved such transaction prior to the time that the other party thereto shall have become the beneficial owner of more than 5% of the combined voting power of the. outstanding shares of the Corporation entitled to vote in the election of directors; or

(2) A majority of the outstanding shares of all classes of stock entitled to vote in the election of directors of such other corporation, or a majority of the equity interest in any such other person or entity, is owned of record or beneficially, directly or indirectly, by the Corporation.

Ninth: To the fullest extent permitted by the Delaware General Corporation Law, a director of this Corporation shall not be liable to the Corporation or to its stockholders for monetary damages for breach of fiduciary duty as director.

Tenth: The Corporation reserves the right to amend and repeal any provision contained in this Certificate of Incorporation in the manner prescribed by the laws of the State of Delaware. Notwithstanding any other provision of this Certificate of Incorporation, the affirmative vote of the holders of at least 66-2/3% of the combined voting power of the outstanding shares of the Corporation entitled to vote thereon shall be required to amend or repeal, or to adopt any provision inconsistent with, this Article Tenth, Paragraph (d) of Article Fourth, or Articles Sixth, Seventh, Eighth, or Ninth of this Certificate of Incorporation.

IN WITNESS WHEREOF, the undersigned hereby certify that this Restated Certificate of Incorporation has been approved by the vote of the Directors of the Corporation in accordance with Section 245(b) of the General Corporation Law of the State of Delaware; that the foregoing Restated Certificate of Incorporation restates in its entirety the provisions of the Corporation’s Certificate of Incorporation filed on September 30, 1985, as previously amended; and hereby execute and acknowledge the foregoing Restated Certificate of Incorporation on this 16th day of February, 2006.

/s/ Shawn M. Canaday

Name: Shawn M. Canaday
Title: Assistant Secretary

/s/ Ralph J. Goehring

Name: Ralph J. Goehring
Title: Executive Vice-President and Chief Financial Officer

Exhibit 10.1

DESCRIPTION OF THE SHORT-TERM CASH INVENTIVE PLAN (BONUS)

Annual cash incentive awards, which are designed to provide short-term performance incentives, are made to employees to recognize and reward corporate and individual performance. The plan in effect provides an annual incentive fund of up to 3.5% of the Company's annual net income, with certain adjustments, to potentially any and all employees upon achievement of the Company’s growth and profitability goals.

Annually, Management and the Board will set specific targets to be achieved which will determine the cash payment as a whole and then to each eligible employee based on a formula. There shall be specific targets established for each of the following: net income, production, operating expenditures, reserve additions, and finding and development costs. The Board retains the flexibility to adjust various items to assure compliance with the intent of the cash incentive awards. All annual cash bonuses for executives are approved by the Compensation Committee and the Board of Directors.

Exhibit 10.6

[EXECUTION]

FIRST AMENDMENT TO CREDIT AGREEMENT

THIS FIRST AMENDMENT TO CREDIT AGREEMENT (herein called the “Amendment”) made as of December 15, 2005 by and among BERRY PETROLEUM COMPANY, a Delaware corporation (“Borrower”), WELLS FARGO BANK, NATIONAL ASSOCIATION, individually and as Administrative Agent (“Agent”), and the Lenders party to the Original Agreement defined below (“Lenders”).

W I T N E S S E T H:

WHEREAS, Borrower, Agent and Lenders entered into that certain Credit Agreement dated as of June 27, 2005 (the “Original Agreement”), for the purpose and consideration therein expressed, whereby Lenders became obligated to make loans to Borrower as therein provided; and

WHEREAS, Borrower, Agent and Lenders desire to amend the Original Agreement as set forth herein;

NOW, THEREFORE, in consideration of the premises and the mutual covenants and agreements contained herein and in the Original Agreement, in consideration of the loans which may hereafter be made by Lenders to Borrower, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto do hereby agree as follows:

ARTICLE I.

DEFINITIONS AND REFERENCES

Section 1.1. Terms Defined in the Original Agreement. Unless the context otherwise requires or unless otherwise expressly defined herein, the terms defined in the Original Agreement shall have the same meanings whenever used in this Amendment.

Section 1.2. Other Defined Terms. Unless the context otherwise requires, the following terms when used in this Amendment shall have the meanings assigned to them in this Section 1.2.

“Amendment” means this First Amendment to Credit Agreement.

“Credit Agreement” means the Original Agreement as amended hereby.

“Original Certificate” means the original Omnibus Certificate of Borrower dated as of June 27, 2005.

ARTICLE II.

AMENDMENTS TO ORIGINAL AGREEMENT

Section 2.1. Defined Terms. The definition of “Current Assets” in Section 1.1 of the Original Agreement is hereby amended in its entirety to read as follows:

“'Current Assets' means the sum of the current assets of Borrower and its Consolidated Subsidiaries at such time, plus the Availability at such time in an amount not to exceed $50,000,000, but excluding, for purposes of this definition any non-cash gains for any Hedging Contract resulting from the requirements of SFAS 133 at such time.”

ARTICLE III.

CONDITIONS OF EFFECTIVENESS

Section 3.1. Effective Date. This Amendment shall become effective as of the date first above written when, and only when, (i) Agent shall have received, at Agent's office, a counterpart of this Amendment executed and delivered by Borrower and Majority Lenders and
(ii) Agent shall have additionally received all of the following documents, each document (unless otherwise indicated) being dated the date of receipt thereof by Agent, duly authorized, executed and delivered, and in form and substance satisfactory to Agent:

(a) Officer's Certificate and Supporting Documents. Agent shall have received (i) a certificate of the Secretary and the President or Chief Financial Officer of Borrower certifying (A) that all of the representations and warranties set forth in Article IV hereof are true and correct and no Default exists, (B) that attached to the Original Certificate is a true and complete copy of resolutions adopted by the Board of Directors of Borrower authorizing the execution, delivery and performance of this Amendment and (C) as to the names and true signatures of the officers of Borrower authorized to sign this Amendment, and (ii) such supporting documents as Agent may reasonably request.

(b) Borrower shall have paid, in connection with such Loan Documents, all recording, handling, amendment and other fees required to be paid to Agent pursuant to any Loan Documents.

(c) Borrower shall have paid, in connection with such Loan Documents, all other fees and reimbursements to be paid to Agent pursuant to any Loan Documents, or otherwise due Agent and including fees and disbursements of Agent's attorneys.

ARTICLE IV.

REPRESENTATIONS AND WARRANTIES

Section 4.1. Representations and Warranties of Borrower. In order to induce each Lender to enter into this Amendment, Borrower represents and warrants to each Lender that:

(a) The representations and warranties contained in Article V of the Original Agreement are true and correct at and as of the time of the effectiveness hereof, except to the extent that the facts on which such representations and warranties are based have been changed by the extension of credit under the Credit Agreement except to the extent such representations and warranties specifically refer to an earlier date, in which case they are true and correct as of such earlier date.

(b) Borrower is duly authorized to execute and deliver this Amendment and is and will continue to be duly authorized to borrow monies and to perform its obligations under the Credit Agreement. Borrower has duly taken all corporate action necessary to authorize the execution and delivery of this Amendment and to authorize the performance of the obligations of Borrower hereunder.

(c) The execution and delivery by Borrower of this Amendment, the performance by Borrower of its obligations hereunder and the consummation of the transactions contemplated hereby and thereby do not and will not conflict with any provision of law, statute, rule or regulation or of the certificate of incorporation and bylaws of Borrower, or of any material agreement, judgment, license, order or permit applicable to or binding upon Borrower, or result in the creation of any lien, charge or encumbrance upon any assets or properties of Borrower. Except for those which have been obtained, no consent, approval, authorization or order of any court or governmental authority or third party is required in connection with the execution and delivery by Borrower of this Amendment or to consummate the transactions contemplated hereby and thereby.

(d) When duly executed and delivered, this Amendment and the Credit Agreement will be a legal and binding obligation of Borrower, enforceable in accordance with its terms, except as limited by bankruptcy, insolvency or similar laws of general application relating to the enforcement of creditors' rights and by equitable principles of general application.

(e) The audited annual Consolidated financial statements of Borrower dated as of December 31, 2004 and the unaudited quarterly Consolidated financial statements of Borrower dated as of September 30, 2005 fairly present the Consolidated financial position at such dates and the Consolidated statement of operations and the changes in Consolidated financial position for the periods ending on such dates for Borrower. Copies of such financial statements have heretofore been delivered to each Lender. Since such dates no material adverse change has occurred in the financial condition or businesses or in the Consolidated financial condition or businesses of Borrower.

ARTICLE V.

MISCELLANEOUS

Section 5.1. Ratification of Agreements. The Original Agreement as hereby amended is hereby ratified and confirmed in all respects. The Loan Documents, as they may be amended or affected by this Amendment, are hereby ratified and confirmed in all respects. Any reference to the Credit Agreement in any Loan Document shall be deemed to be a reference to the Original Agreement as hereby amended. The execution, delivery and effectiveness of this Amendment shall not, except as expressly provided herein or therein, operate as a waiver of any right, power or remedy of Lenders under the Credit Agreement, the Notes, or any other Loan Document nor constitute a waiver of any provision of the Credit Agreement, the Notes or any other Loan Document.

Section 5.2. Survival of Agreements. All representations, warranties, covenants and agreements of Borrower herein shall survive the execution and delivery of this Amendment and the performance hereof, including without limitation the making or granting of the Loans, and shall further survive until all of the Obligations are paid in full. All statements and agreements contained in any certificate or instrument delivered by Borrower any Related Person/Restricted Person hereunder or under the Credit Agreement to any Lender shall be deemed to constitute representations and warranties by, and/or agreements and covenants of, Borrower under this Amendment and under the Credit Agreement.

Section 5.3. Loan Documents. This Amendment is a Loan Document, and all provisions in the Credit Agreement pertaining to Loan Documents apply hereto and thereto.

Section 5.4. Governing Law. This Amendment shall be deemed a contract made under the laws of the State of California and shall be construed and enforced in accordance with and governed by the laws of the State of California and the laws of the United States of America, without regard to principles of conflicts of law.

Section 5.5. Counterparts; Fax. This Amendment may be separately executed in counterparts and by the different parties hereto in separate counterparts, each of which when so executed shall be deemed to constitute one and the same Amendment. This Amendment may be validly executed by facsimile or other electronic transmission.

THIS AMENDMENT AND THE OTHER LOAN DOCUMENTS REPRESENT THE FINAL AGREEMENT BETWEEN THE PARTIES AND MAY NOT BE CONTRADICTED BY EVIDENCE OF PRIOR, CONTEMPORANEOUS, OR SUBSEQUENT ORAL AGREEMENTS OF THE PARTIES. THERE ARE NO UNWRITTEN ORAL AGREEMENTS OF THE PARTIES.

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Exhibit 10.6

IN WITNESS WHEREOF, this Amendment is executed as of the date first above written.

BERRY PETROLEUM CORPORATION, as Borrower

By: Ralph J. Goehring Executive
Executive Vice President and Chief Financial Officer

WELLS FARGO BANK, NATIONAL ASSOCIATION, as Administrative Agent, LC Issuer and a Lender

By: Guy C. Evangelista
Vice President

JPMORGAN CHASE BANK, N.A., as a Lender

By: Jo Linda Papadakis
Vice President

BANK OF SCOTLAND, as a Lender

By: Karen Weich
Assistant Vice Preside

BNP PARIBAS, as a Lender

By: Brian M. Malone
Managing Director

By: Polly Schott
Vice President

CITIBANK (WEST), FSB, as a Lender

By: Gai Sherman
VP/Credit Relationship Mgr.

COMERICA BANK, as a Lender

By: Juli Bieser
Vice President

MIDFIRST BANK, as a Lender

By: Shawn D. Brewer
Vice President

SOCIETE GENERALE, as a Lender

By: Josh Rogers
Vice President

UNION BANK OF CALIFORNIA, N.A., as a Lender

By: Dustin Gaspari
Vice President

Exhibit 10.13

BERRY PETROLEUM COMPANY

NON-EMPLOYEE DIRECTOR DEFERRED STOCK AND COMPENSATION PLAN

(as amended effective January 1, 2006)

Section 1. Establishment of Plan; Purpose. The Berry Petroleum Company Non-Employee Director Deferred Stock and Compensation Plan (the "Plan") is hereby established to permit Eligible Directors, in recognition of their contributions to the Company (a) to receive Shares in lieu of Compensation and (b) to defer recognition of their Compensation in the manner described below. The Plan is intended to enable the Company to attract, retain and motivate qualified directors and to enhance the long-term mutuality of interest between Directors and stockholders of the Company.

Section 2. Definitions. When used in this Plan, the following terms shall have the definitions set forth in this Section:

2.1. "Accounts" shall mean an Eligible Director's Stock Unit Account and Interest Account.

2.2. "Board of Directors" shall mean the Board of Directors of the Company.

2.3. "Committee" shall mean the Compensation Committee of the Board of Directors or such other committee of the Board as the Board shall designate from time to time.

2.4. "Company" shall mean Berry Petroleum Company, a Delaware corporation.

2.5. "Compensation" shall mean (a) the fee earned by an Eligible Director for service as a Director; (b) the fee, if any, earned by an Eligible Director for service as a member of a committee of the Board of Directors; and (c) the fee earned by an Eligible Director for (i) attendance at meetings of the Board of Directors and (ii) attendance at meetings of committees. All Compensation earned by an Eligible Director for the services identified in subsections (a), (b) and (c) above, shall be deemed earned by an Eligible Director and credited to the designated Accounts on the last trading day of the fiscal quarter in which such service was provided.

2.6. "Director" shall mean any member of the Board of Directors, whether or not such member is an Eligible Director.

2.7. "Effective Date" shall mean the date on which the Plan is approved by the stockholders of the Company.

2.8. "Eligible Director" shall mean a member of the Board of Directors who is not an employee of the Company.

2.9. "Exchange Act" shall mean the Securities Exchange Act of 1934, as amended.

2.10. "Fair Market Value" shall mean the closing price or the last sale (as reported by the New York Stock Exchange) of a Share on the last trading day of the fiscal quarter as required by Section 5.4(a) or any other reasonable basis using actual transactions of such Shares as reported and as shall be consistently applied by the Committee.

2.11. "Interest Account" shall mean the bookkeeping account established to record the interests of an Eligible Director with respect to deferred Compensation that is not allocated to Units in a Stock Unit Account.

2.12. "Shares" shall mean shares of Stock.

2.13. "Stock" shall mean the Class A Common Stock of the Company.

2.14. "Stock Unit Account" shall mean a bookkeeping account established to record the interests of an Eligible Director who has elected to have deferred Compensation credited as Units in this Account.

2.15. "Unit" shall mean a contractual obligation of the Company to deliver a Share based on the Fair Market Value of a Share to an Eligible Director or the beneficiary or estate of such Eligible Director as provided herein.

Section 3. **Administration**. The Plan shall be administered by the Committee; provided, however, that the Plan shall be administered such that any Director participating in the Plan shall continue to be deemed to be a "disinterested person" under Rule 16b-3 of the Securities and Exchange Commission under the Exchange Act ("Rule 16b-3"), as such Rule is in effect on the Effective Date of the Plan and as it may be subsequently amended, for purposes of such Director's ability to serve on any committee charged with administering any of the Company's stock-based incentive plans for executive officers intended to qualify for the exemptive relief available under Rule 16b-3.

Section 4. **Shares Authorized for Issuance.**

4.1. **Maximum Number of Shares**. The aggregate number of Shares which may be issued to Eligible Directors under the Plan shall not exceed Two Hundred Fifty Thousand (250,000) Shares, subject to adjustment as provided in Section 4.2 below. If any Unit is forfeited without a distribution of Shares, the Shares otherwise subject to such Unit shall again be available hereunder.

4.2. **Adjustment for Corporate Transactions**. If the outstanding Stock is increased, decreased, changed into or exchanged for a different number or kind of shares of the Company through reorganization, recapitalization, reclassification, stock dividend, stock split or reverse stock split, an appropriate and proportionate adjustment shall be made in the number or kind of shares which may be issued in the aggregate under this Plan and the number of Units that have been, or may be, issued under this Plan; provided, however, that no such adjustment need be made if, upon the advice of counsel, the Committee determines that such adjustment may result in the receipt of federally taxable income to holders of Stock or other classes of the Company's equity securities. The nature and extent of such adjustments shall be determined by the Committee in its sole discretion, and any such determination as to what adjustments shall be made, and the extent thereof, shall be final, binding and conclusive. No fractional shares of Stock shall be issued under this Plan pursuant to any such adjustment.

Section 5. **Deferred Compensation Program.**

5.1. **Election to Defer**. On or before December 31 of any calendar year, an Eligible Director may elect to defer receipt of all or any part of any Compensation payable in respect of the calendar year following the year in which such election is made, and to have such amounts credited, in whole or in part, to a Stock Unit Account or an Interest Account. Any person who shall become an Eligible Director during any calendar year may elect, not later than the 30th day after his term as a Director begins, to defer payment of all or any part of his Compensation payable for the portion of such calendar year following such election. In the year in which this Plan is first implemented, any Eligible Director may elect, not later than the 30th day after the Effective Date, to defer payment of all or any part of his Compensation payable for the portion of such calendar year following the Effective Date.

5.2. **Method of Election**. A deferral election shall be made by written notice filed with the Corporate Secretary of the Company. Such election shall continue in effect (including with respect to Compensation payable for subsequent calendar years) unless and until the Eligible Director revokes or modifies such election by written notice filed with the Corporate Secretary. Any such revocation or modification of a deferral election shall become effective as of December 31 of the year in which such notice is given and only with respect to Compensation payable in respect of the calendar year following the year in which such revocation or modification is made; provided however that if the effect of such revocation or modification of a deferral election is to change the amount of deferred Compensation that would otherwise have been credited to the Stock Unit Account, such notice shall in no event become effective earlier than six (6) months after it is received by the Corporate Secretary. This means that notice must be received by the Corporate Secretary by July 1 to be effective for the following year. Amounts credited to the Eligible Director's Stock Unit Account prior to the effective date of any such revocation or modification of a deferral election shall not be affected by such revocation or modification and shall be credited and distributed only in accordance with the deferral election in place prior to such revocation and modification and otherwise in accordance with the applicable terms of the Plan. An Eligible Director who has revoked an election to participate in the Plan may file a new election to defer Compensation with respect to services rendered in the calendar year following the year in which such new election is filed with the Corporate Secretary of the Company.

5.3. **Investment Election**. At the time an Eligible Director elects to defer receipt of Compensation pursuant to Section 5.1, the Eligible Director shall also designate in writing the portion of such Compensation, stated as a whole percentage, to be credited to the Interest Account and the portion to be credited to the Stock Unit Account. If an Eligible Director fails to designate the allocation between the two Accounts, 100% of such Compensation shall be credited to the Interest Account. By written notice to the Corporate Secretary, an Eligible Director may change the investment election and the manner in which Compensation is allocated among the Accounts but only with respect to services to be rendered in the calendar year following the year in which such new investment election is filed with the Corporate Secretary, provided that any such election shall only be effective with respect to Compensation payable six (6) months after such new investment election is received by the Corporate Secretary.

5.4. **Interest Account.**

a. Any Compensation allocated to an Eligible Director's Interest Account shall be deemed earned and credited to the Interest Account as of the last trading day of the fiscal quarter in which the service was provided for which such compensation amount would have been paid to the Eligible Director.

b. Any amounts credited to the Interest Account shall be credited with interest at the annual rate for the 3-month treasury bill as of the last trading day of the fiscal quarter as quoted in the Wall Street Journal, times 3/12.

5.5. Stock Unit Account.

a. Any Compensation allocated to an Eligible Director's Stock Unit Account shall be deemed earned and credited to Units in the Stock Unit Account as of the last trading day of the fiscal quarter in which the service was provided for which such compensation amount would have been paid to the Eligible Director.

b. The number of Units allocated to the Eligible Director's Stock Unit Account pursuant to subsection (a) above shall be equal to the quotient of (i) the aggregate Compensation allocated to the Stock Unit Account as of the last trading day of the fiscal quarter divided by (ii) the Fair Market Value on the last trading day of such quarter. Fractional Units shall be credited, but shall be rounded to the nearest hundredth percentile, with amounts equal to or greater than .005 rounded up and amounts less than .005 rounded down.

5.6. Dividend Equivalents.

a. An Eligible Director who has elected to defer Compensation to a Stock Unit Account shall have no rights as a stockholder of the Company with respect to any Units until Shares are distributed and delivered to the Eligible Director.

b. Notwithstanding the provisions of subsection (a), each Eligible Director who has allocated Compensation to a Stock Unit Account shall have the right to receive an amount equal to the dividend per Share declared by the Company on the applicable dividend payment date (which, in the case of any dividend distributable in property other than Shares, shall be the per Share value of such dividend, as determined by the Company for purposes of income tax reporting) times the number of Units held by such Eligible Director in his Stock Unit Account (a "Dividend Equivalent").

c. Dividend Equivalents shall be treated as reinvested in an additional number of Units and credited to the Eligible Director's Stock Unit Account.

d. The additional number of Units to be credited to the Eligible Director's Stock Unit Account pursuant to (c) (iii) shall be determined by dividing (i) the product of (A) the number of Units in the Eligible Director's Stock Unit Account on the date the dividend is declared, and (B) the amount of any cash dividend declared by the Company on a Share (or, in the case of any dividend distributable in property other than Shares, the per share value of such dividend, as determined by the Company for purposes of income tax reporting), by (ii) the Fair Market Value on the last trading day of the fiscal quarter in which the dividend is declared.

e. Notwithstanding the date used for purposes of determining the number of additional Units as provided in subsection (d) above, the additional Units to be credited for Dividend Equivalents shall be deemed earned and credited to the Eligible Director's Stock Unit Account on the last trading day of the fiscal quarter in which such dividend is declared.

f. In the event of any stock split, stock dividend, recapitalization, reorganization or other corporate transaction affecting the capital structure of the Company, the Committee shall make such adjustments to the number of Units credited to each Eligible Director's Stock Unit Account as the Committee shall deem necessary or appropriate to prevent the dilution or enlargement of such Eligible Director's rights and such adjustment shall be made and effective as of the last day of the fiscal quarter in which such corporate transaction has occurred.

5.7. Distribution Election.

a. At the time an Eligible Director makes a deferral election pursuant to Section 5.1, the Eligible Director shall also file with the Corporate Secretary a written election (a "Distribution Election").

b. The distribution from the Stock Unit Account shall be made in Shares and the distribution from the Interest Account shall be made in cash. The Distribution Election shall specify that such distribution shall commence, at the election of the Eligible Director, as soon as practicable following the first business day of the calendar month following the date the Eligible Director ceases to be a Director or on the first business day following the calendar year in which the Eligible Director ceases to be a Director.

c. Such distribution shall be in one lump sum payment or in such number of annual installments (not to exceed ten (10)) as the Eligible Director may designate on the Distribution Election. The amount of any installment payment shall be determined by multiplying the amount credited to the Accounts of an Eligible Director immediately prior to the distribution by a fraction, the numerator of which is one and the denominator of which is the number of installments (including the current installment) remaining to be paid.

d. An Eligible Director may at any time prior to the time at which the Eligible Director ceases to be a Director, and from time to time, change any Distribution Election applicable to his Accounts, provided that no election to change the timing of any final distribution shall be effective unless (i) it is made in writing and received by the Corporate Secretary at least one (1) year prior to the time at which the Eligible Director ceases to be a director and (ii) the start date of any installment distribution or lump sum payment is delayed at least five years.

5.8. Unforeseeable Emergency Withdrawal

Any Eligible Director may, after submission of a written request to the Corporate Secretary and such written evidence of the Eligible Director's financial condition as the Committee may reasonably request, withdraw from his Interest Account (but not from his Stock Unit Account) up to such amount as the Committee shall determine to be necessary to alleviate the Eligible Director's unforeseeable emergency plus applicable taxes as a result of the distribution. Withdrawals will only be approved for a severe financial hardship to the Eligible Director resulting from an illness or accident of the Eligible Director, his or her spouse or dependent (as defined in IRC § 409A (a) (2) (B) (ii).

5.9. Timing and Form of Distributions.

a. Any distribution to be made hereunder, whether in the form of a lump sum payment or installments, following the termination of an Eligible Director's service as a Director shall commence in accordance with the Distribution Election made by the Eligible Director pursuant to Section 5.7.

b. If an Eligible Director fails to specify in accordance with Section 5.7 a commencement date for a distribution or whether such distribution shall be made in a lump sum payment or a number of installments, such distribution shall be made in a lump sum payment and commence on the first business day of the month immediately following the date on which the Eligible Director ceases to be a Director. In the case of any distribution being made in annual installments, each installment after the first installment shall be paid on the first business day of each subsequent calendar year, or as soon as practical thereafter, until the entire amount subject to such Distribution Election shall have been paid.

Section 6. Unfunded Status. The Company shall be under no obligation to establish a fund or reserve in order to pay the benefits under the Plan. A Unit represents a contractual obligation of the Company to deliver Shares to an Eligible Director as provided herein. The Company has not segregated or earmarked any Shares or any of the Company's assets for the benefit of an Eligible Director or his beneficiary or estate, and the Plan does not, and shall not be construed to, require the Company to do so. The Eligible Director and his beneficiary or estate shall have only an unsecured, contractual right against the Company with respect to any Units granted or amounts credited to an Eligible Director's Accounts hereunder, and such right shall not be deemed superior to the right of any other creditor. Units shall not be deemed to constitute options or rights to purchase Stock.

Section 7. Amendment and Termination. The Plan may be amended at any time by the Committee or the Board of Directors. Any modification of any of the terms and provisions of the Plan, including this Section, shall not be made more than once every six (6) months. The Plan shall terminate on May 31, 2008. Unless the Board otherwise specifies at the time of such termination, the termination of the Plan will not result in the premature distribution of the amounts credited to an Eligible Director's Accounts.

Section 8. General Provisions.

8.1. No Right to Serve as a Director. This Plan shall not impose any obligations on the Company to retain any Eligible Director as a Director nor shall it impose any obligation on the part of any Eligible Director to remain as a Director of the Company.

8.2. Rights of a Terminated Director. Notwithstanding the fact that an Eligible Director ceases to be a director during any fiscal quarter, the Eligible Director's Accounts shall be credited, on the last trading day of the fiscal quarter, with all Compensation and Dividend Equivalents earned as of the last business day he served as an Eligible Director.

8.3. Construction of the Plan. The validity, construction, interpretation, administration and effect of the Plan and the rights relating to the Plan, shall be determined solely in accordance with the laws of the State of Delaware.

8.4. No Right to Particular Assets. Nothing contained in this Plan and no action taken pursuant to this Plan shall create or be construed to create a trust of any kind or any fiduciary relationship between the Company and any Eligible Director, the executor, administrator or other personal representative or designated beneficiary of such Eligible Director, or any other persons. Any reserves that may be established by the Company in connection with Units granted under this Plan shall continue to be treated as the assets of the Company for federal income tax purposes and remain subject to the claims of the Company's creditors. To the extent that any Eligible Director or the executor, administrator, or other personal representative of such Eligible Director, acquires a right to receive any payment from the Company pursuant to this Plan, such right shall be no greater than the right of an unsecured general creditor of the Company.

8.5. Severability of Provisions. If any provision of this Plan shall be held invalid or unenforceable, such invalidity or unenforceability shall not affect any other provisions hereof, and this Plan shall be construed and enforced as if such provision had not been included.

8.6. Incapacity. Any benefit payable to or for the benefit of a minor, an incompetent person or other person incapable of receipting therefore shall be deemed paid when paid to such person's guardian or to the party providing or reasonably appearing to provide for the care of such person, and such payment shall fully discharge any liability or obligation of the Board of Directors, the Company and all other parties with respect thereto.

8.7. Headings and Captions. The headings and captions herein are provided for reference and convenience only, shall not be considered part of this Plan, and shall not be employed in the construction of this Plan.

Exhibit 10.17

AMENDED AND RESTATED PURCHASE AND SALE AGREEMENT

By and Between

Berry Petroleum Company

and

Orion Energy Partners L.P.

February 23, 2006

Exhibit 10.17

TABLE OF CONTENTS

TABLE OF CONTENTS
(continued)

TABLE OF CONTENTS
(continued)

TABLE OF CONTENTS
(continued)

SCHEDULES

EXHIBITS

Exhibit 10.17

AMENDED AND RESTATED PURCHASE AND SALE AGREEMENT

THIS AMENDED AND RESTATED PURCHASE AND SALE AGREEMENT ("**Agreement**") dated as of February 23, 2006 by and between Berry Petroleum Company, a Delaware corporation ("**Buyer**") and Orion Energy Partners L.P., a Delaware limited partnership (the "**Company**"). Unless herein otherwise defined, capitalized terms used in this Agreement are defined in Section 1.

RECITALS

WHEREAS, Buyer, the Company and the holders of equity securities of the Company entered into that certain Purchase and Sale Agreement dated as of January 26, 2006 (the "**Original Agreement**");

WHEREAS, the Original Agreement contemplated that Buyer and the Company would execute this Agreement if the Company was able to obtain the requisite consents and approvals to allow it to transfer and assign the PGR LLC Interests (as defined below) to a newly formed, wholly owned subsidiary of the Company and to sell its interest in such wholly owned subsidiary to Buyer and if the Company elected to proceed in such manner;

WHEREAS, the Company owns 50% of the issued and outstanding limited liability company interests (the "**PGR LLC Interests**") of Piceance Gas Resources, LLC, a Colorado limited liability company ("**PGR**"). PGR owns certain rights and interests in and to the leasehold estates created by the oil and gas leases described on Exhibit A hereto (the "**PGR Leases**") and the oil and gas wells located on the PGR Leases (the "**PGR Wells**") and other real and personal properties described on Exhibit A (collectively, the **"PGR Assets"**);

WHEREAS, the Company has obtained such consents and approvals to transfer and assign its PGR LLC Interests to Piceance Operating Company, LLC, a Colorado limited liability company ("**POC**) formed for the purposes of holding the Company's PGR LLC Interest and the PGR Assets, and elects to sell its 100% interest in POC (the "**POC Units**") to Buyer under this Agreement;

WHEREAS, prior to the Closing Date (as defined herein), the Company will transfer and assign the PGR LLC Interests to POC and cause POC to redeem all of the PGR LLC Interests in consideration of the assignment by PGR to POC of a direct interest in POC's proportionate share of the PGR Assets as reflected on Exhibit A hereto (the "**Direct Assignment**"). After the Direct Assignment, the term "PGR Assets" shall refer to POC's direct percentage interest in the PGR Assets.

WHEREAS, the Company desires to sell to Buyer and Buyer desires to acquire from the Company all of the POC Units.

AGREEMENT

NOW, THEREFORE, in consideration of the mutual representations, warranties, covenants and agreements, and upon the terms and subject to the conditions, herein set forth, the parties hereto agree as follows:

Exhibit 10.17

Section 1. Definitions.

In addition to any terms defined elsewhere in this Agreement, unless otherwise specifically provided herein, the following terms shall have the following meanings for all purposes when used in this Agreement, and in any note, agreement, certificate, report or other document made or delivered in connection with this Agreement:

(a) "Affiliate" means, with respect to any specified Person, any other Person directly or indirectly controlled by or under common control with such specified Person; provided that the Company shall not be considered an Affiliate of any Seller.

(b) "Allocated Value" The term "Allocated Value" shall mean the value allocated to the PGR Leases as set forth in Exhibit A.

(c) "BLM" means the Federal Bureau of Land Management.

(d) "Defect Value" means the amount by which the Allocated Value of a Defective Interest has been reduced by a Title Defect. In determining which portion of a PGR Lease is a Defective Interest, it is the intent of the parties to include, to the extent possible, only that portion of the PGR Lease materially and adversely affected by the defect. The Defect Value shall be determined by the parties in good faith taking into account all relevant factors, including without limitation, the following:

(1) If the Title Defect is a lien or encumbrance on the PGR Lease, the Defect Value shall be the cost of removing such lien or encumbrance.

(2) If the Title Defect is an actual reduction in NRI, the Defect Value shall be the Allocated Value for the particular PGR Lease, proportionately reduced by the ratio of the actual NRI to the represented NRI.

(3) If the Title Defect does not fall into subsection (1) or (2), then the Defect Value shall be determined by the parties in good faith, taking into account all relevant factors, including without limitation, the following:

(A) The Allocated Value of the affected PGR Lease;

(B) The current status of the Defective Interest (*i.e.*, proved developed producing, etc.) and if such interest is producing, the present value of the future cash flow, net of capital expenditures, expected to be generated therefrom;

(C) If the Title Defect represents only a possibility of title failure, the probability that such failure will occur; and

(D) The legal effect of the Title Defect.

(e) "Defective Interest" means a PGR Lease affected by a Title Defect that reduces the Allocated Value of the affected PGR Lease by more than One Hundred Fifty Thousand Dollars ($150,000.00).

(f) "Defensible Title" The term "Defensible Title" with respect to the PGR Wells and PGR Leases means such title to the PGR Wells and PGR Leases, as reflected in the records of the county or counties where the PGR Assets are located as of the Closing, that, subject to and except for Permitted Encumbrances: (i) entitles PGR to receive not less than the net revenue interest for the formations set forth for each PGR Well and PGR Lease on Exhibit A ("**NRI**"); (ii) obligates PGR to bear costs and expenses relating to the maintenance, development, operation and the production of hydrocarbons from the formations from each PGR Well and PGR Lease in an amount not greater than the working interest set forth in Exhibit A ("**WI**"); and (iii) is free and clear of liens, encumbrances and defects.

(g) "Environmental Assessment" has the meaning set forth in Section 5.2(c).

(h) "GAAP" means generally accepted accounting principles in effect in the United States of America from time to time, applied on a consistent basis which are applicable as of the date on which any calculation is to be made under this Agreement or as of the date on which any financial statement is to be prepared under this Agreement.

(i) "General Partner" shall mean Orion Energy Partners, Inc., a Delaware corporation, the general partner of the Company.

(j) "JOA" means the AAPL form Joint Operating Agreement initialed by the members of PGR on February 16 and ratified and adopted by the members of PGR as of February 14, 2005.

(k) "Losses" shall mean losses, damages, claims and costs (including reasonable attorneys' fees and expenses, but excluding consequential, incidental, exemplary and punitive damages).

(l) "Permitted Encumbrances" shall mean:

(1) lessors' royalties, overriding royalties, proceeds interests, net profits interests, production payments, reversionary interests and similar burdens if the net cumulative effect of such burdens does not operate to reduce the NRIs below those set forth on Exhibit A;

(2) statutory liens for Taxes or assessments not yet due and delinquent or, if delinquent, that are being contested in good faith in the normal course of business;

(3) all rights to consent by, required notices to, filings with, or other actions by federal, state or local governmental bodies, in connection with the conveyance of the applicable PGR Leases if the same are customarily sought after such conveyance;

(4) rights of reassignment contained in any PGR Leases providing for reassignment upon the surrender or expiration of any PGR Leases;

(5) easements, rights-of-way, servitudes, permits, surface leases and other rights with respect to surface operations, on, over or in respect of any of the PGR Leases or any restriction on access thereto that do not materially interfere with the operation of the affected PGR Wells or PGR Leases;

(6) such Title Defects as Buyer has waived;

(7) the terms and conditions of the Contracts to the extent such terms and conditions do not cause the NRI to be less than or the WI to be more than as set forth in Exhibit A for the applicable PGR Wells or PGR Leases;

(8) statutory materialmens', mechanics', operators' or other similar liens arising in the ordinary course of business incidental to operation of the PGR Wells or PGR Leases (i) if such liens and charges have not been filed pursuant to law and the time for filing such liens and charges has expired, (ii) if filed, such liens and charges have not yet become due and payable or payment is being withheld as provided by law, or (iii) if the validity of any such lien is being contested in good faith by appropriate action;

(9) rights reserved to or vested in any federal, state or local governmental body, authority or agency to control or regulate any of the PGR Wells or PGR Leases in any manner; and all applicable laws, rules, regulations and orders of general applicability in the area of the PGR Leases;

(10) any required third party consents to assignments of Contracts or property and similar agreements burdening any of the PGR Leases (excluding those covered by the provisions of Section 4.5 which shall be exclusively dealt with pursuant to Section 4.5);

(11) liens arising under operating agreements, unitization and pooling agreements and production sales contracts securing amounts (i) not yet delinquent or, (ii) if delinquent, being contested in good faith in the ordinary course of business;

(12) all matters of record as of the date of this Agreement unless the matter has properly been identified as a Title Defect in a Notice of Defective Interests;

(13) any defects, irregularities or deficiencies in title to easements, rights-of-way or other agreements that, individually or in the aggregate, do not materially adversely affect the ownership, operation, value or use of any of the PGR Wells or PGR Leases;

(14) carried interests described in Section 7 of the Membership Interest Purchase Agreement between the Company and PGR Partners, LLC dated February 16, 2005; and

(15) all other liens, charges, encumbrances, instruments, obligations, defects and irregularities affecting the PGR Wells or PGR Leases that do not (or would not upon foreclosure or other enforcement) reduce the NRI set forth in Exhibit A nor prevent the receipt of proceeds of production therefrom, nor increase the share of costs above the working interest set forth in Exhibit A nor are such, individually or in the aggregate, as materially interfere with or detract from the ownership, operation, value or use of any of the PGR Wells or PGR Leases.

(m) "Person" means any individual, corporation, limited or general partnership, limited liability company, business trust, or other association or business entity created and/or recognized by State statute, or governmental entity.

(n) "PGR LLC Agreement" means the Limited Liability Company Agreement of PGR, dated effective as of February 14, 2005, among the members of PGR.

(o) "POC LLC Agreement" means the Operating Agreement of POC, dated December 12, 2005 between POC and the Company.

(p) "Subsidiary" means any entity of which securities or other ownership interests having ordinary voting power to elect a majority of the board of directors or other persons performing similar functions are at the time directly or indirectly owned by the Company.

(q) "Taxes" means all taxes, charges, fees, levies, or other assessments, including, without limitation, all income, gross income, gross receipts, sales, use ad valorem, transfer, franchise, profits, license, withholding, payroll, employment, social security, unemployment, excise, estimated, production, severance (and similar taxes and assessments based on or measured by the ownership of property or the production of hydrocarbons or the receipt of proceeds therefrom), occupation, property, or other taxes, fees, assessments, or charges of any kind whatsoever, including, without limitation, all interest and penalties thereon, and additions to tax or additional amounts imposed by any taxing authority upon the Company, POC or PGR.

(r) "Tax Returns" means any return, declaration, report, claim for refund or information return or statement relating to Taxes, including any schedule or attachment thereto, and including any amendment thereof.

(s) "Title Defect" means any lien, encumbrance, adverse claim, defect in or objection to real property title, excluding Permitted Encumbrances, that alone or in combination with other defects renders PGR's title to the particular PGR Wells or PGR Leases less than Defensible Title. Notwithstanding the foregoing, the following shall not be considered Title Defects:

(1) defects based solely on an assertion that PGR's files lack information, provided that any missing information material to the evaluation of the PGR Leases can be obtained by the reasonable efforts of Buyer;

(2) defects in the early chain of title consisting of the failure to recite marital status in a document or omissions of successors of heirship or estate proceedings, unless Buyer provides a reasonable basis for the assertion that such failure or omission has resulted in another party's actual and superior claim of title to the relevant PGR Lease;

(3) defects arising out of lack of survey, unless a survey is required by applicable law;

(4) defects arising out of lack of corporate or other entity authorization unless Buyer provides a reasonable basis for the assertion that the action was not authorized and results in another party's actual and superior claim of title to the particular PGR Well or PGR Lease;

(5) defects that are defensible by possession under applicable statutes of limitation for adverse possession or for prescription;

(6) defects asserting a change in WI or NRI based on a change in drilling and spacing units, tract allocation or other changes in pool or unit participation occurring after the date of this Agreement;

(7) title requirements customarily considered as advisory or waivable as a matter of prudent business judgment.

The following terms have the meanings set forth in the Section opposite such term:

Term	**Section**
Adjusted Purchase Price	2.3(a)
Breach	10.2
Buyer Representatives	7.4
Buyer Indemnified Persons	11.3
Closing	2.4
Closing Date	2.4
Closing Statement	2.3(b)
Code	3.13(g)
Contracts	3.14
CPR Rules	11.4
Defect Notice Date	4.1(a)
Defensible Title	1(h)
Deposit	2.2
Direct Assignment	Recitals
Interest Additions	4.2
NRI	1(h)
Original Agreement	Recitals
Permits	3.20(b)
Permitted Encumbrances	1(p)
PGR	Recitals
PGR Assets	Recitals
PGR Financial Statements	3.9
PGR Leases	Recitals
PGR LLC Interests	Recitals

Term	Section
PGR Wells	Recitals
POC	Recitals
POC Units	Recitals
Purchase Price	2.3(a)
Purchase Price Adjustment	2.3(c)
SEC	5.2(b)
Seller Indemnified Persons	11.4
Survival Period	11.2
Termination Date	10.1(b)
Title Defect Adjustment	4.1(b)(1)
Title Threshold Amount	4.1(b)
Value of Interest Addition	4.2
WI	1(h)

Section 2. Transfer of POC Units; Purchase Price.

2.1 Purchase and Sale. Upon the terms and subject to the conditions of this Agreement, the Company agrees to sell to Buyer and Buyer agrees to purchase from the Company, the POC Units.

2.2 Deposit. On the date of the Original Agreement, Buyer paid to the Company the sum of Seven Million Five Hundred Thousand Dollars ($7,500,000) as a deposit (the "**Deposit**") to be credited to the Adjusted Purchase Price at Closing. The Deposit shall be refunded to Buyer if, and only if, this Agreement is terminated pursuant to Section 10.1 so long as such termination is not the result of Buyer's Breach. The Deposit shall not be interest bearing.

2.3 Purchase Price

(a) Purchase Price. The purchase price (the "**Purchase Price**") to be paid by Buyer to the Company for the POC Units shall be One Hundred Fifty Million Dollars ($150,000,000), which as adjusted pursuant to Section 2.3(c) shall be referred to as the "**Adjusted Purchase Price**."

(b) Closing Statement. The Company will prepare and deliver to Buyer at least two business days prior to Closing a closing statement related to the PGR Assets as of the Closing Date (the "**Closing Statement**"). The Closing Statement shall reflect the various adjustments to the Purchase Price provided in Section 2.3(c) based on operational activities with respect to the PGR Assets from October 1, 2005 until the Closing Date and any Title Defect Adjustment or Interest Addition Adjustment. Such Closing Statement shall include the calculations used in determining the Title Defect Adjustment and the Interest Addition Adjustment and shall set forth the Adjusted Purchase Price.

(c) Purchase Price Adjustment. The Purchase Price shall be adjusted as follows:

(i) The Purchase Price shall be increased for the Company's allocable share of costs, expenses and other liabilities with respect to the PGR Assets incurred and paid by the Company after September 30, 2005 and prior to the Closing Date and the Company's allocable share of costs and expenses with respect to the PGR Assets incurred after September 30, 2005 and to be paid by the Company after Closing, including but not limited to, drilling and completion costs, land costs, facilities costs, lease operating costs and geological consulting fees;

(ii) The Purchase Price shall be increased by the cost of the field inventories to be transferred to Buyer at Closing;

(iii) The Purchase Price shall be reduced for the Company's allocable share of revenues with respect to the PGR Assets attributable to production periods subsequent to September 30, 2005 and received by the Company prior to the Closing Date, less the amount of royalties, severance and ad valorem taxes attributable to such revenues;

(iv) The Purchase Price shall be reduced for accrued ad valorem, property, production, severance and similar taxes and assessments based on or measured by the ownership of property or the production of hydrocarbons or the receipt of proceeds therefrom with respect to the PGR Assets to which Buyer is subject or will be liable; and

(v) The Purchase Price will be reduced by any Title Defect Adjustments as calculated pursuant to Section 4.1 and increased by any Interest Addition Adjustment as calculated pursuant to Section 4.2.

2.4 Closing. Subject to the satisfaction or waiver of the closing conditions set forth in Sections 9.1 and 9.2, the closing (the "**Closing**") of the purchase and sale of the POC Units shall take place at the offices of Davis Graham & Stubbs LLP at 10:00 a.m. Mountain time on March 1, 2006 or such earlier or later date as the parties agree (the "**Closing Date**"). Except as otherwise expressly provided in this Agreement or in any document contemplated by this Agreement, all matters at the Closing shall be considered to take place simultaneously and no delivery of any documents shall be deemed complete until all transactions and deliveries of documents are completed.

2.5 Payment. At the Closing, Buyer shall deliver the Adjusted Purchase Price minus the amount of the Deposit and the amount of the Escrow Account, if any, to the Company. The amount of the Escrow Account, if any, shall be paid at Closing to the Escrow Agent.

2.6 Further Assurances. At any time prior to, and from time to time after, the Closing, the parties hereto shall, at the request of the other and without further consideration, execute and deliver further instruments or documents as the other parties hereto may reasonably require to evidence or otherwise facilitate the consummation of the transactions contemplated hereby.

Exhibit 10.17

Section 3. Representations and Warranties of the Company.

3.1 Making of Representations and Warranties. The Company hereby makes to Buyer the representations and warranties contained in this Section 3. The representations and warranties of the Company are hereby qualified by reference to the Disclosure Schedules attached hereto. References to the "knowledge" of the Company shall mean the actual knowledge, after reasonable inquiry, of James D. Lightner, Thomas W. Dyk, Daniel G. Blanchard, Douglas R. Harris or Rodney G. Mellott.

3.2 Authority. The Company has the full right, authority and power to enter into this Agreement and each agreement, document and instrument to be delivered by the Company, pursuant to this Agreement and to carry out the transactions contemplated hereby and thereby.

3.3 Execution, Delivery; Valid and Binding Agreement. The execution, delivery and performance of this Agreement by the Company and the consummation of the transactions contemplated hereby have been duly and validly authorized by all requisite partnership action as may be applicable to the Company, and no other proceedings are necessary to authorize the execution, delivery and performance of this Agreement. This Agreement has been duly executed and delivered by the Company and constitutes the valid and binding obligation of the Company, enforceable in accordance with its terms, except as such enforcement may be limited by applicable bankruptcy, insolvency, reorganization, moratorium or other laws of general application affecting enforcement of creditors' rights or by general principles of equity.

3.4 No Breach. The execution, delivery and performance of this Agreement by the Company and the consummation by the Company of the transactions contemplated hereby (i) do not and will not violate any provision of the organizational documents of the Company, POC or PGR; (ii) do not and will not violate any federal, state or local laws or regulations applicable to the Company, POC or PGR or any of their respective properties or assets; (iii) do not and will not result in the creation of any lien, security interest, charge or encumbrance upon any of the PGR Assets or the POC Units, and (iv) do not and will not result in a material breach of, constitute a material default under, accelerate any material obligation under or give rise to a right of termination under any indenture or loan agreement or any other material agreement or contract to which the Company, POC or PGR is a party.

3.5 Governmental Authorities; Consents. Except as set forth in Schedule 3.5, the Company is not required to submit any notice, report or other filing with any governmental authority in connection with the execution or delivery of this Agreement or the consummation of the transactions contemplated hereby. Except as set forth in Schedule 3.5, no consent, approval or authorization of any governmental or regulatory authority or any other party or person is required to be obtained by the Company in connection with its execution, delivery and performance of this Agreement or the transactions contemplated hereby. Schedule 3.5 shall provide the required timing for obtaining or making application or filing with respect to the scheduled consents, approvals or authorizations.

3.6 Ownership of POC Units. The Company owns all right, title and interest in and to the POC Units free and clear of any security interests, claims, liens, pledges, options, encumbrances, charges, agreements, voting trusts, proxies or other arrangements, restrictions or limitations of any kind (except for security interests that will be released prior to or at the Closing). The POC Units represent all of the outstanding interests in the profits, losses and capital of POC.

3.7 Company Organization; Qualification. The Company is a limited partnership duly formed, validly existing and in good standing under the laws of the State of Delaware and has the requisite power and authority to own and operate its properties and to carry on its business as now conducted. The Company is qualified to do business as a foreign limited partnership in every jurisdiction in which the nature of its business or its ownership of property requires it to be so qualified except for those jurisdictions in which the failure to be so qualified would not, individually or in the aggregate, have a material adverse effect on the Company's business or financial condition. PGR is a limited liability company duly formed, validly existing and in good standing under the laws of the State of Colorado and has the requisite power and authority to own and operate its properties and to carry on its business as now conducted.

3.8 POC. POC is a limited liability company duly formed, validly existing and in good standing under the laws of the State of Colorado. POC was formed on December 12, 2005 as a Colorado limited liability company and as of the date of this Agreement does not own and has never owned any assets and is not subject to any liabilities. The Company and POC have satisfied all conditions and obtained all consents and approvals necessary to enable (i) the transfer and assignment of the PGR LLC Interests by the Company to POC, (ii) POC to act as the Operator under the JOA, and (iii) the redemption of the PGR LLC Interests by POC in consideration for the Direct Assignment, other than as provided in Schedule 3.8, which shall set forth all such consents and approvals obtained or to be obtained, and the transfer of such PGR LLC Interests and the redemption and Direct Assignment will be effected in compliance with applicable law and the terms of all applicable agreements.

3.9 [Intentionally Omitted]

3.10 Absence of Undisclosed Liabilities. Except as set forth on Schedule 3.10, as of the Closing Date, there are no liabilities of POC or related to the PGR Assets, whether contingent, absolute, determined or otherwise, except for accounts payable incurred in the ordinary course of business.

3.11 No Material Adverse Changes. Except as set forth on Schedule 3.11 or as otherwise provided in this Agreement or as related to the transfer and assignment of the PGR LLC Interests to POC and the redemption of the PGR LLC Interests by POC in connection with the Direct Assignment, since September 30, 2005, the Company and PGR have each operated its business only in the ordinary course of business consistent with past practice and:

(a) other than events or circumstances affecting the oil and gas industry or economy as a whole, there has been no change in the business of the Company as it relates to the PGR Assets, POC or PGR (including any damage or casualty loss to the PGR Assets not covered by insurance), nor has the Company or PGR entered into a material transaction or incurred a material expense other than sale expenses, in each case other than in the ordinary course of business consistent with past practice, that would result in a material adverse effect on the PGR Assets, the business or financial condition of the Company as it relates to the PGR Assets, POC or PGR, as applicable;

(b) POC does not have any employment agreements;

(c) there have not been sales or transfers by the Company, POC or PGR of properties or assets which are part of the PGR Assets or cancellation or prepayment of material debts or claims or waiver of material rights by the Company or PGR relating to the PGR Assets;

(d) there has not been an amendment or termination of a material contract related to the PGR Assets or to which PGR or POC is or was a party;

(e) there has not been a regulatory decision by a governmental authority regarding any of PGR Assets that would have a material adverse effect on the PGR Assets; and

(f) there has not been any incurrence, assumption or guarantee by the Company, POC or PGR of any indebtedness.

3.12 Title to Properties.

(a) As of the date of this Agreement, PGR owns the PGR Leases and PGR Wells described on Exhibit A. Exhibit A separately lists the related NRIs and WIs for each such PGR Lease and sets forth the Allocated Value of each PGR Lease. PGR has Defensible Title to the PGR Leases. As of the Closing Date, after the transfer and assignment of the PGR LLC Interests to POC and the redemption by POC of the PGR LLC Interests in connection with the Direct Assignment, POC will own directly the interest reflected in Exhibit A hereto in each of the PGR Leases and PGR Wells, subject to the provisions of the PGR LLC Agreement.

(b) The Company has delivered to Buyer or made available for Buyer's inspection complete and accurate copies of each of the PGR Leases, and none of such PGR Leases has been modified in any respect, except to the extent that such modifications are disclosed by the copies delivered to or made available for inspection by Buyer and except for Direct Assignment. To the knowledge of the Company, PGR is not in default under any of the PGR Leases, and no event has occurred and no circumstances exist which would, either with or without notice or the passage of time or both, result in such default under any of the PGR Leases.

(c) To the knowledge of the Company, the equipment and other tangible assets used by PGR in the conduct of its oil and gas operations are, in all material respects, in good condition and repair, ordinary wear and tear excepted.

3.13 Tax Matters.

(a) Each of the Company, POC and PGR has: (i) timely filed all Tax Returns required to be filed or sent by it in respect of any Taxes or required to be filed or sent by it by any taxing authority having jurisdiction; and (ii) timely and properly paid all Taxes shown to be due and payable on such Tax Returns.

(b) There are no liens for Taxes upon any assets of the Company, POC or PGR, except liens for Taxes not yet due as of the Closing Date, or which are being contested in good faith by all appropriate proceedings.

(c) No deficiency for any Taxes has been asserted or assessed against the Company, POC or PGR that has not been resolved and paid in full. No waiver, extension or comparable consent given by the Company, POC or PGR regarding the application of the statute of limitations with respect to any Taxes or Tax Returns is outstanding, nor is any request for any such waiver or consent pending.

(d) None of the Company, POC or PGR has requested any extension of time within which to file any Tax Return, which Tax Return has not since been filed.

(e) POC is a disregarded entity for federal income tax purposes. PGR has been a partnership for federal and applicable state income tax purposes since the date of its formation, and has never been taxable as a corporation or as an association taxable as a corporation.

(f) Each of the Company and PGR have disclosed in their Tax Returns all positions taken therein that could reasonably be expected to give rise to a substantial understatement of tax within the meaning of Section 6662 of the Internal Revenue Code of 1986, as amended (the "Code") or any corresponding provision of state tax law, including any required filing of Form 8886 and compliance with alternative disclosure procedures utilizing Schedule M-3. There are no outstanding rulings, or requests for rulings, with any income tax authority addressed to either of the Company or PGR that are, or if issued would be, binding upon either of the Company or PGR for any tax period ending after the Closing Date.

(g) Neither the Company nor PGR has (i) executed, become subject to or entered into any closing agreement pursuant to Section 7121 of the Code that would be binding on either of the Company or PGR, (ii) agreed to any extension of time with respect to the payment of any Taxes of either of the Company or PGR or any limitation period regarding the assessment of any such Taxes, or (iii) received approval to make or agreed to a change in any accounting method or has any application pending with any Tax authority requesting permission for any such change.

3.14 Contracts. (a) All operating agreements, production sales contracts, farmout agreements and other contracts or agreements relating to the PGR Leases and PGR Wells can be found either of record in the counties in which the PGR Leases are located or have been made available to Buyer and are listed on Schedule 3.14(a) and all other contracts to which the Company is a party that relate to the PGR Assets and to which PGR is a party that involve the performance of services or delivery of goods or materials by or to, or the expenditure or receipts of, the Company, POC or PGR of an amount or value in excess of $150,000, are listed on Schedule 3.14(a) (all of the foregoing, collectively, the "**Contracts**") and to the knowledge of the Company, the Contracts are currently in full force and effect in accordance with their applicable terms. (b) Schedule 3.14(b) lists all Contracts that will be assigned by the Company to POC and the required timing of such assignments.

3.15 Litigation Against the Company. There are no actions, suits, proceedings, orders or investigations pending against the Company relating to the PGR Assets, POC or PGR or to which the Company (with respect to action relating to the PGR Assets), POC or PGR are a party.

3.16 Employee Matters. POC currently has no employees.

3.17 Insurance. The Company maintains insurance with respect to the PGR Assets and PGR's operations. All of such insurance policies are in full force and effect and will be in full force and effect through the Closing Date. The Company is not in default with respect to its obligations under any of such insurance policies.

3.18 Compliance with Laws; Permits.

(a) The Company, POC and, to the knowledge of the Company, PGR are not in violation of or in default under any law, regulation or order applicable to it, the effect of which, individually or in the aggregate with such other violations and defaults, could reasonably be expected to have a material adverse effect on the PGR Assets or the business or financial condition of the Company as related to the PGR Assets, POC or PGR.

(b) To the knowledge of the Company, PGR has and on the Closing Date, POC will have, in full force and effect, or with respect to the Direct Assignment, will have filed or applied to obtain, all licenses, permits and certificates, from federal, state and local authorities used in and, individually or in the aggregate, material to the business or financial condition of PGR or POC, as applicable (collectively, the "**Permits**"). To the knowledge of the Company, PGR has conducted its business in compliance with all material terms and conditions of the Permits.

3.19 Brokerage. No third party shall be entitled to receive any brokerage commissions, finder's fees, fees for financial advisory services or similar compensation in connection with the transactions contemplated by this Agreement based on any arrangement or agreement made by or on behalf of the Company.

3.20 PGR Leases and PGR Wells. To the knowledge of the Company, all of the PGR Wells have been or are being drilled, completed and operated (i) within the boundaries of the PGR Leases or within the limits otherwise permitted by contract, pooling or unit agreement, and by law and (ii) are in material compliance with all applicable rules, regulations, permits, judgments, orders and decrees of any court or the federal and state regulatory authorities having jurisdiction thereof.

3.21 Marketing. To the knowledge of the Company, no amounts of hydrocarbons produced from the PGR Leases are subject to a sales contract (except for contracts terminable without penalty by PGR on not more than 30 days notice), and no person has any call upon, option to purchase or similar rights under any agreement with respect to the PGR Leases or to the production therefrom. PGR has not in any respect collected any proceeds from the sale of hydrocarbons produced from the PGR Leases that are subject to a material refund. As of the Closing Date, proceeds from the sale of oil, condensate and gas from the PGR Leases were being received in all respects by POC in a timely manner and were not being held in suspense for any reason. PGR has not been nor will POC be obligated by virtue of any prepayment made under any production sales contract or any other contract containing a "take or pay" clause, or under any gas balancing, deferred production or similar arrangement to deliver oil, gas or other minerals produced from or allocated to any of the PGR Leases at some future time without receiving full payment therefor at the time of delivery. There are no material gas imbalances as between PGR or POC and any third party with respect to operations relating to the PGR Leases.

3.22 Change in Property Condition. Since September 30, 2005, there has occurred no physical change in the real property relating to the PGR Leases (other than operations and productions in the ordinary course) or other casualty that adversely affects the value, use or operation of any of such Leases (other than declines due to actual depletion), except ordinary wear and tear and except any changes as would not have a material adverse effect.

3.23 Environmental Protection. To the knowledge of Company, the Company, POC and PGR have obtained all permits, licenses and other authorizations with respect to the PGR Assets which are required under federal, state and local laws relating to pollution or protection of the environment, including laws relating to emissions, discharges, releases or threatened releases of pollutants, contaminants, or hazardous or toxic materials or wastes into ambient air, surface water, ground water, or land, or otherwise relating to the manufacture, processing, distribution, use, treatment, storage, disposal, transport, or handling of pollutants, contaminants or hazardous or toxic materials or wastes and true copies of all such permits, licenses and authorizations have been delivered to or made available for inspection by Buyer. To the knowledge of Company, the Company, POC and PGR are in compliance with all terms and conditions of the required permits, licenses and authorizations, and are also in compliance with all other limitations, restrictions, conditions, standards, prohibitions, requirements, obligations, schedules and timetables applicable to the PGR Assets contained in those laws or contained in any regulation, code, plan, order, decree, judgment, notice or demand letter issued, entered, promulgated or approved thereunder. None of the Company, POC or, to the knowledge of the Company, PGR has received notice of any past, present or future events, conditions, circumstances, activities, practices, incidents, actions or plans with respect to the PGR Assets which have not been remedied and which may interfere with or prevent continued compliance, or which may give rise to any common law or legal liability, or otherwise form the basis of any claim, action, suit, proceeding, hearing or investigation, based on or related to the manufacture, processing, distribution, use, treatment, or threatened release into the environment, of any pollutant, contaminant, or hazardous or toxic material or waste.

3.24 Warranties and Representations. THE PGR ASSETS HAVE BEEN UTILIZED BY THE COMPANY AND PGR FOR THE PURPOSE OF EXPLORATION, DEVELOPMENT, AND/OR PRODUCTION OF OIL AND GAS. THE COMPANY HAS MADE AVAILABLE TO BUYER PHYSICAL ACCESS TO THE PGR ASSETS AND, TO THE COMPANY'S KNOWLEDGE, ALL AVAILABLE INFORMATION REGARDING CRUDE OIL, GAS AND PRODUCED WATER WHICH MAY HAVE BEEN SPILLED OR DISPOSED OF ONSITE AND THE LOCATIONS THEREOF; PIT CLOSURES, BURIAL, LANDFARMING, LANDSPREADING, AND UNDERGROUND INJECTION; AND SOLID WASTE DISPOSAL SITES, IF ANY EXIST, HAVE BEEN MADE AVAILABLE TO BUYER. BUYER ACKNOWLEDGES THAT THERE MAY HAVE BEEN SPILLS OF THESE OR OTHER MATERIALS IN THE PAST ONTO THE PGR ASSETS. IN ADDITION, SOME PRODUCTION EQUIPMENT MAY CONTAIN ASBESTOS AND/OR NATURALLY OCCURRING RADIOACTIVE MATERIAL (HEREINAFTER REFERRED TO AS "NORM"). IN THIS REGARD, BUYER EXPRESSLY UNDERSTANDS THAT NORM MAY AFFIX OR ATTACH ITSELF TO THE INSIDE OF WELLS, MATERIALS AND EQUIPMENT AS SCALE, OR IN OTHER FORMS, AND THAT WELLS, MATERIALS AND EQUIPMENT LOCATED ON THE LANDS MAY CONTAIN NORM AND THE NORM-CONTAINING MATERIAL MAY BE BURIED AND OTHERWISE DISPOSED OF ON THE PGR ASSETS. BUYER ALSO EXPRESSLY UNDERSTANDS THAT SPECIAL PROCEDURES MAY BE REQUIRED FOR THE REMOVAL AND DISPOSAL OF ASBESTOS AND NORM FROM THE EQUIPMENT AND PGR ASSETS WHERE IT MAY BE FOUND AND THAT BUYER ASSUMES ALL LIABILITY FOR ASSESSMENT, REMOVAL AND DISPOSAL OF ANY SUCH MATERIALS AND ASSOCIATED ACTIVITIES.

EXCEPT AS ELSEWHERE PROVIDED IN THIS AGREEMENT, THIS AGREEMENT IS EXECUTED WITHOUT WARRANTY OF TITLE, EITHER EXPRESS OR IMPLIED, WITHOUT ANY EXPRESS OR IMPLIED WARRANTY OR REPRESENTATION AS TO THE MERCHANTABILITY OF ANY OF THE EQUIPMENT OR PERSONAL PROPERTY OR ITS FITNESS FOR ANY PURPOSE AND WITHOUT ANY OTHER EXPRESS OR IMPLIED WARRANTY OR REPRESENTATION WHATSOEVER. BUYER UNDERSTANDS AND AGREES THAT THIS AGREEMENT IS MADE ON AN "AS IS, WHERE IS" BASIS AND BUYER RELEASES THE COMPANY FROM ANY LIABILITY WITH RESPECT THERETO WHETHER OR NOT CAUSED BY OR ATTRIBUTABLE TO COMPANY'S NEGLIGENCE EXCEPT AS OTHERWISE PROVIDED HEREIN. WITHOUT LIMITING THE ABOVE, AND EXCEPT AS EXPRESSLY PROVIDED HEREIN, BUYER WAIVES ITS RIGHT TO RECOVER FROM THE COMPANY AND FOREVER RELEASES, DISCHARGES AND INDEMNIFIES THE COMPANY FROM ANY AND ALL DAMAGES, CLAIMS, LOSSES, LIABILITIES, PENALTIES, FINES, LIENS, JUDGMENTS, COSTS OR EXPENSES WHATSOEVER, (INCLUDING, WITHOUT LIMITATION, ATTORNEYS' FEES AND COSTS), WHETHER DIRECT OR INDIRECT, KNOWN OR UNKNOWN, FORESEEN OR UNFORESEEN, THAT MAY ARISE ON ACCOUNT OF OR IN ANY WAY BE CONNECTED WITH THE PHYSICAL CONDITION OF THE PGR ASSETS OR ANY FEDERAL, STATE OR LOCAL LAW OR REGULATION APPLICABLE THERETO, INCLUDING, WITHOUT LIMITATION, THE COMPREHENSIVE ENVIRONMENTAL RESPONSE, COMPENSATION, AND LIABILITY ACT OF 1980, AS AMENDED (42 U.S.C. §9601 ET. SEQ.), THE RESOURCE CONSERVATION AND RECOVER ACT OF 1976 (42 U.S.C. §6901 ET. SEQ.), THE CLEAN WATER ACT (33 U.S.C. §466 ET. SEQ.), THE SAFE DRINKING WATER ACT (14 U.S.C. §1401-1450), THE HAZARDOUS MATERIALS TRANSPORTATION ACT (49 U.S.C. §1801 ET. SEQ.), AND THE TOXIC SUBSTANCE CONTROL ACT (15 U.S.C. §2601-2629).

THE COMPANY MAKES NO WARRANTY OR REPRESENTATION, EXPRESS, IMPLIED, STATUTORY OR OTHERWISE, AS TO THE ACCURACY OR COMPLETENESS OF ANY DATA, RESERVE OR OTHER REPORTS, RECORDS, PROJECTIONS, INFORMATION OR MATERIALS NOW, HERETOFORE OR HEREAFTER FURNISHED OR MADE AVAILABLE TO BUYER IN CONNECTION WITH THIS AGREEMENT, INCLUDING, WITHOUT LIMITATION, ANY DESCRIPTION OF THE PGR ASSETS, PRICING ASSUMPTIONS, OR QUALITY OR QUANTITY OF HYDROCARBON RESERVES (IF ANY) ATTRIBUTABLE TO THE PGR ASSETS OR THE ABILITY OR POTENTIAL ABILITY OF THE PGR ASSETS TO PRODUCE HYDROCARBONS OR THE ENVIRONMENTAL CONDITION OF THE PGR ASSETS OR ANY OTHER MATTERS CONTAINED IN CONFIDENTIAL INFORMATION OR ANY OTHER MATERIALS FURNISHED OR MADE AVAILABLE TO BUYER BY COMPANY OR ITS AGENTS OR REPRESENTATIVES; ANY AND ALL SUCH DATA, RECORDS, REPORTS, PROJECTIONS, INFORMATION AND OTHER MATERIALS FURNISHED BY THE COMPANY OR BY COMPANY'S AGENTS OR REPRESENTATIVES OR MADE AVAILABLE TO BUYER ARE PROVIDED TO BUYER AS A CONVENIENCE, AND SHALL NOT CREATE OR GIVE RISE TO ANY LIABILITY OF OR AGAINST COMPANY; **AND ANY RELIANCE ON OR USE OF THE SAME SHALL BE AT BUYER'S SOLE RISK**.

Section 4. <u>Title Matters</u>.

4.1 <u>Purchase Price Adjustments for Defective Interests</u>.

(a) <u>Notice of Defective Interest</u>. Buyer shall give the Company written "Notice of Defective Interests" as soon as possible but no later than five (5) business days before the Closing Date, (the "**Defect Notice Date**"). This notice must be in writing and satisfy the following conditions precedent: (i) a description of each Defective Interest; (ii) the basis for each Defective Interest, and, if the basis is derived from any document, a copy of such document (or pertinent part thereof) shall be attached or if the basis is derived from any gap in PGR'S chain of title, the documents preceding and following the gap shall be attached; (iii) the Allocated Value of the affected PGR Lease; and (iv) Buyer's good faith estimate of the Defect Value and the computations upon which Buyer's estimate is based. If a PGR Lease has not been given an Allocated Value or the Allocated Value of PGR Lease is Fifty Thousand Dollars ($50,000) or less, the Company shall be deemed to have Defensible Title to such PGR Lease.

(b) <u>Defect Adjustments</u>.

(1) If a PGR Lease is a Defective Interest, the Purchase Price will be reduced under Section 2.3(c)(ii) by the corresponding Defect Value (which reduction is called a "**Title Defect Adjustment**") unless prior to the Closing Date:

(A) the Company either cures the Title Defect to Buyer's reasonable satisfaction or elects to cure the Title Defect no later than 90 days after Closing; or

(B) Buyer elects to waive the relevant Title Defect.

The Purchase Price shall be adjusted pursuant to Section 2.3 for Defective Interests only if the aggregate of all Defect Values, net of the Value of all Interest Additions, for all of the PGR Leases exceeds 3% of the Purchase Price (the "**Title Threshold Amount**").

(2) If a PGR Lease is a Defective Interest for which an adjustment to the Purchase Price would otherwise be required and the Company elects to cure the defect after Closing, Buyer and the Company shall at Closing in good faith agree to place a portion of the Purchase Price into an escrow account (the "**Escrow Account**") established pursuant to an escrow agreement in substantially the form attached hereto as <u>Exhibit F</u> (the "**Escrow Agreement**") with Wells Fargo Bank or another mutually acceptable financial institution ("**Escrow Agent**") until Buyer's receipt of the Company's curative materials. The amount of the Escrow Account shall be the aggregate of all Defect Values net of the Value of Interest Additions.

(3) If the Company has elected to cure a Title Defect and such Title Defect is cured on or before 90 days after Closing, the Escrow Agent shall distribute to the Company, immediately upon Buyer's receipt of curative materials reasonably satisfactory to Buyer, the amount placed in the Escrow Account with respect to such Title Defect (and any account interest accrued thereon).

(4) If the Company does not cure a Title Defect within the 90 day time period, Buyer shall be entitled to an amount equal to the corresponding Defect Value as provided in Section 4.1(b)(1).

(5) If Buyer disputes the adequacy of the Company's curative material, Buyer must invoke the dispute resolution mechanism set forth in Section 4.3 within 30 days after receipt thereof. If the parties dispute the Defect Value of a Defective Interest which is not timely cured, then the provisions of Section 4.3 shall apply.

4.2 Interest Additions. Promptly on discovery, Buyer or the Company, whichever is the discovering party shall notify the other of any interest that entitles PGR to receive more than the NRI set forth in Exhibit A, or obligates PGR to bear costs and expenses in an amount less than the WI set forth in Exhibit A (collectively, "**Interest Additions**"). The party who discovers Interest Additions must give the other party written notice of Interest Additions as soon as possible, but in no event later than on or before two (2) business days prior to Closing. This notice must be in writing and must include (i) a description of each Interest Addition, (ii) the basis for each Interest Addition, (iii) the Allocated Value of the PGR Lease affected by the Interest Addition, and (iv) the value of the Interest Addition or the amount by which the notifying party believes the Allocated Value of the PGR Lease has been increased by the Interest Addition ("**Value of Interest Addition**") and the computations upon which such party's belief is based. The Value of Interest Addition shall be determined by the parties in good faith taking into account all relevant factors and the Purchase Price will be increased in accordance with Section 2.3 by such an amount ("**Interest Addition Adjustment**") if the aggregate of all Interest Addition Adjustments, net of the aggregate of all Defect Values, exceeds One Hundred Fifty Thousand Dollars ($150,000.00) (the "**Addition Threshold Amount**").

4.3 Title Dispute Resolution. The parties agree to resolve disputes concerning the following matters pursuant to this Section: (i) the existence and scope of a Title Defect, (ii) the Defect Value of that portion of the PGR Lease affected by a Title Defect, (iii) the Value of an Interest Addition, and (iv) the adequacy of the Company's Title Defect curative materials (the "**Title Disputed Matters**"). The parties agree to attempt to initially resolve all disputes through good faith negotiations. If the parties cannot resolve disputes regarding items (i), (ii) or (iii) on or before fifteen (15) days after Closing, the Disputed Matters will be finally determined by binding arbitration pursuant to Section 11.7 with an independent arbitrator mutually acceptable to the parties or, if none, with a panel of three arbitrators appointed pursuant to Section 11.7 who are qualified by education, knowledge and experience with title defects affecting the types of properties which are subject to the disputed Title Defect and have a minimum of ten years experience with such types of defects and properties. The arbitrator(s) shall take into account the factors set forth in the definition of "Defect Value" and employ such independent attorneys, petroleum engineers and/or other consultants as deemed necessary. On or before 60 days after Closing, Buyer and the Company shall present their respective positions in writing to the Arbitrator(s), together with such evidence as each party deems appropriate. The Arbitrator(s) shall be instructed to resolve the dispute through a final decision within 90 days after Closing and the final decision may be reflected in a final settlement statement. If the parties cannot resolve disputes regarding Section 4.3 (iv) within five (5) days after Buyer's receipt of the Company's Title Defect curative materials, the dispute will similarly be finally determined by binding arbitration pursuant to Section 11.7 and this Section 4.3 but the arbitration hearing shall be held no later than fifteen (15) days after Buyer's receipt of the Company's Title Defect curative materials with a final decision no later than twenty-five (25) days after Buyer's receipt of the Company's Title Defect curative materials and the final decision shall similarly be reflected in a final settlement statement.

4.4 Termination. Notwithstanding the foregoing, if the aggregate of all Defect Values, net of the Value of all Interest Additions, for all of the PGR Leases exceeds Ten Percent (10%) of the Purchase Price set forth in Section 2.3, the Company or Buyer may terminate this Agreement upon written notice to the other party delivered no later than 5:00 p.m. on the day before the scheduled Closing Date; provided however that Buyer, at its sole discretion, may elect to waive all or any portion of any Title Defect to reduce the aggregate Title Defect Values below such percentage in which event this Agreement shall remain in full force and effect. If a party has elected to exercise this right of termination and the other party does not agree that the right of termination has been triggered, the objecting party shall notify the other party on or before 5:00 p.m. on the scheduled Closing Date and, thereafter, unless the parties are able to resolve the dispute within three (3) days after the originally scheduled Closing Date, the matter shall be determined by binding arbitration pursuant to Section 11.7, before a panel of arbitrators meeting the qualifications set forth in Section 4.3, and with the arbitrators to be appointed and the arbitration to be conducted within the time frame provided in Section 4.3 for Title Disputed Matters other than those relating to Title Defect curative materials. In the event of an objection over whether the right to terminate has been triggered, the Closing shall be extended until three (3) business days after the dispute is resolved by parties as provided in this Section 4.4 or the parties receive a final decision from the arbitrators, whichever is applicable.

4.5 Preferential Rights. The Company has no knowledge of any preferential rights of third parties applicable to the transaction contemplated by this Agreement. Nonetheless, if prior to Closing, the Company or Buyer becomes aware of any claims asserted by third parties that preferential rights are applicable to this transaction, it shall promptly notify the other party of such fact. In such event, the Company agrees (a) to join in the defense of such claim, (b) to present the best defense possible, (c) to deliver to Buyer copies of such records, documents, files and other data which it possesses pertaining to such claim, and (d) to take such actions or do, or cause to be done, all things necessary, proper or advisable, which Buyer may reasonably and lawfully request in defense against such claims. The Company shall bear its own costs incurred in performing its obligations under this section.

Section 5. Covenants of the Company.

5.1 Conduct of Business. Unless otherwise contemplated by this Agreement or related to the transfer and assignment of the PGR LLC Interest to POC and the redemption by POC of the PGR LLC Interest in connection with the Direct Assignment, or unless otherwise approved by Buyer in writing, from the date hereof until the Closing Date, the Company shall:

(a) conduct its business with respect to the PGR Assets and the business of PGR only in the ordinary course and refrain from changing or introducing any method of management or operations except in the ordinary course of business and consistent with prior practices;

(b) refrain from doing or permitting to occur any of the following: (i) selling, pledging, disposing of or encumbering any of the PGR Assets except (A) pursuant to existing contracts or commitments or (B) in the ordinary course of business; (ii) amending the PGR LLC Agreement, (iii) allowing PGR to incur any indebtedness for borrowed money except accounts payable and other expenditures in the ordinary course of business or issue any debt securities;

(c) (i) use commercially reasonable efforts to preserve intact the Company's business organization and goodwill with respect to the PGR Assets and PGR's business organization and goodwill and maintain its business relationships with suppliers, distributors, customers and others having business relationships with the Company and PGR consistently with past practice; (ii) confer with representatives of Buyer to report operational matters and the general status of ongoing operations; (iii) promptly notify Buyer in writing if the Company shall discover that any representation or warranty made in this Agreement was when made, or has subsequently become, untrue in any respect; and

(d) (i) file any Tax Returns, elections or information statements with respect to any liabilities for Taxes of the Company, POC or PGR or other matters relating to Taxes of the Company, POC or PGR which pursuant to applicable law must be filed prior to the Closing Date; (ii) promptly upon filing provide copies of any such Tax Returns, elections or information statements to Buyer; and (iii) make any new Tax elections or other discretionary positions or change any existing Tax elections or other discretionary positions with respect to Taxes affecting POC, the PGR Assets or PGR only upon prior consultation with Buyer.

5.2 Access to Information; Confidentiality.

(a) From the date hereof until the Closing Date, the Company will (i) give Buyer, its counsel, financial advisors, auditors and other authorized representatives reasonable access to the offices, properties, books and records of the Company that relate to the PGR Assets and PGR, (ii) furnish to Buyer, its counsel, financial advisors, auditors and other authorized representatives such financial and operating data and other information relating to the PGR Assets and PGR as such may be reasonably requested and (iii) instruct the counsel, financial advisors and other authorized representatives of the Company to cooperate with Buyer in its investigation of the PGR Assets and PGR. Any investigation pursuant to this Section shall be conducted in such manner as not to interfere unreasonably with the conduct of the business of the Company or PGR. Notwithstanding the foregoing, Buyer shall not have access to other information which in the Company's good faith opinion is sensitive or the disclosure of which could subject the Company to risk of liability.

(b) On and after the date hereof and through the Closing Date, the Company will afford promptly to Buyer and its agents reasonable access to its books of account, financial statements and other records (including, without limitation, accountant's work papers), information, knowledgeable personnel and auditors to the extent necessary or useful for Buyer in connection with the preparation and audit of segmented and other financial statements and other reports as may be required to be filed by Buyer with the United States Securities and Exchange Commission (the "**SEC**"), any audit, investigation, dispute or litigation or any other reasonable business purpose relating to the Company and PGR; provided that any such access by Buyer shall not unreasonably interfere with the conduct of the business of the Company or PGR. Buyer shall bear all of the costs and expenses (including, without limitation, attorneys' fees) in connection with the foregoing.

(c) The Company hereby consents to Buyer conducting, prior to Closing and upon advance notice to the Company, at Buyer's sole risk and expense, on-site inspections and an ASTM Phase One Environmental Assessment (an "**Environmental Assessment**") of the PGR Wells and PGR Leases; provided that Buyer shall not conduct any sampling activities without prior notice and consent of the Company, which consent shall not be unreasonably withheld. In connection with any such on-site inspections or Environmental Assessment, Buyer agrees not to interfere with the normal operation of the PGR Leases and agrees to comply with all requirements and safety policies of the operator. If Buyer or its agents prepares an Environmental Assessment of any property, Buyer will furnish copies thereof to the Company. The parties shall execute a "common undertaking" letter regarding the confidentiality of environmental assessments where appropriate. In connection with the granting of such access, Buyer represents that it is adequately insured and, waives, releases and agrees to indemnify the Company and its representatives against all claims for injury to, or death of, persons or for damage to property arising in any way from the access afforded to Buyer hereunder or the activities of Buyer. This waiver, release and indemnity by Buyer shall survive termination of this Agreement.

(d) Through the 90^{th} day following the Closing Date, the Company will provide Buyer, its auditors and other Representatives reasonable access to knowledgeable personnel and the Company's auditors to the extent necessary or useful for Buyer in connection with the preparation and audit of segmented and other financial statements and other reports as may be required to be filed by Buyer with the SEC, any audit, investigation, dispute or litigation or any other reasonable business purpose relating to the Company and PGR. Buyer shall bear all of the costs and expenses (including, without limitation, attorneys' fees) in connection with the foregoing.

5.3 Conditions. The Company shall take all commercially reasonable actions necessary to cause the conditions set forth in Section 9.1 to be satisfied and to consummate the transactions contemplated herein as soon as reasonably possible after the satisfaction thereof.

5.4 Exclusive Dealings. The Company will not directly or indirectly, through any representative or otherwise, solicit or entertain offers from, negotiate with or in any manner encourage, discuss, accept, consider or pursue, any proposal of any other person relating to the acquisition of POC, the PGR Assets or PGR, in whole or in part (other than with respect to the Excluded Assets), whether directly or indirectly, through purchase, merger, consolidation or otherwise. The Company will promptly notify Buyer regarding any contact of which it has knowledge between the Company or PGR and any other Person regarding any such offer or proposal or any other related inquiry, including full and complete disclosure of all details regarding such contact.

5.5 Redemption of PGR LLC Interests. The Company shall transfer and assign its PGR LLC Interests to POC and shall cause POC to redeem all of the PGR LLC Interests in connection with the Direct Assignment in accordance with and subject to the provisions of the PGR LLC Agreement. After the Direct Assignment, the term "PGR Assets" shall refer to POC's direct percentage interest in the PGR Assets.

5.6 Deliveries. On the Closing Date, the Company shall execute and deliver to Buyer all of the following:

(a) a certificate signed by the General Partner of the Company dated as of the Closing Date to the effect that the statements set forth in paragraphs (a) and (b) of Section 9.1 are true and correct;

(b) an assignment for transfer of the POC Units in form and substance substantially as set forth in Exhibit B;

(c) an assignment and bill of sale for the Direct Assignment in form and substance substantially as set forth in Exhibit C;

(d) all books, records, files and materials of the Company related to the Company's administration of the PGR Assets, PGR or POC;

(e) the Escrow Agreement, if required;

(f) resignation of any officers of POC;

(g) an opinion of counsel for the Company in substantially the form set forth in Exhibit D;

(h) a nonforeign certificate under Section 1445 of the Code;

(i) a certificate of good standing with respect to the Company, issued not more than ten (10) days prior to the Closing Date by (i) the Secretary of State of the State of Delaware and (ii) by the Secretary of State of Colorado and a certificate of good standing with respect to POC issued not more than ten (10) days prior to the Closing Date by the Secretary of State of Colorado; and

(j) Non-Competition Agreements in the form attached hereto as Exhibit E from each of the Company, Orion Energy Partners, Inc., James D. Lightner, Thomas W. Dyk, Daniel G. Blanchard, Douglas R. Harris and Rodney G. Mellott.

Section 6. Representations and Warranties of Buyer.

6.1 Making of Representations and Warranties. As a material inducement to the Company to enter into this Agreement and consummate the transactions contemplated hereby, Buyer hereby makes the representations and warranties to the Company contained in this Section 6 as of the date hereof and the Closing Date.

6.2 Organization of Buyer. Buyer is a corporation duly organized, validly existing and in good standing under the laws of the State of Delaware with full corporate power to own or lease its properties and to conduct its business in the manner and in the places where such properties are owned or leased or such business is conducted by it.

6.3 Authority of Buyer. Buyer has full right, authority and power to enter into this Agreement and each agreement, document and instrument to be executed and delivered by Buyer pursuant to this Agreement and to carry out the transactions contemplated hereby and thereby.

6.4 Execution, Delivery; Valid and Binding Agreement. The execution, delivery and performance of this Agreement by Buyer and the consummation of the transactions contemplated hereby have been duly and validly authorized by all requisite corporate action of Buyer and no other proceedings are necessary to authorize the execution, delivery and performance of this Agreement. This Agreement has been duly executed and delivered by Buyer and constitutes the valid and binding obligation of Buyer, enforceable in accordance with its terms, except as such enforcement may be limited by applicable bankruptcy, insolvency, reorganization, moratorium or other laws of general application affecting enforcement of creditors’ rights or by general principles of equity.

6.5 No Breach. The execution, delivery and performance of this Agreement by Buyer and the consummation by Buyer of the transactions contemplated hereby (i) do not and will not violate any provisions of the organizational documents of Buyer; (ii) do not and will not violate any federal, state, local or foreign laws or regulations applicable to Buyer; and (iii) do not and will not result in a material breach of, constitute a material default under, accelerate any material obligation under or give rise to a right of termination under any indenture or loan agreement or any other material agreement or contract to which Buyer is party.

6.6 Litigation. There is no litigation pending or, to Buyer’s knowledge, threatened against Buyer which would prevent or hinder the consummation of the transactions contemplated by this Agreement.

6.7 Governmental Authorities; Consents. Other than reports required to be made by Buyer with the SEC, Buyer is not required to submit any notice, report or other filing with any governmental authority in connection with the execution or delivery by it of this Agreement or the consummation of the transactions contemplated hereby. No consent, approval or authorization of any governmental or regulatory authority or any other party or Person is required to be obtained by Buyer in connection with its execution, delivery and performance of this Agreement or the transactions contemplated hereby.

6.8 Financing. Buyer has, or will have prior to the Closing, sufficient cash, available lines of credit or other sources of immediately available funds to enable it to make payment of the Purchase Price and any other amounts to be paid by it hereunder.

6.9 Brokerage. No third party shall be entitled to receive any brokerage commissions, finder's fees, fees for financial advisory services or similar compensation in connection with the transactions contemplated by this Agreement based on any arrangement or agreement made by or on behalf of Buyer.

6.10 Investment Representations.

(a) Buyer is an informed and sophisticated purchaser, and has engaged expert advisors, experienced in the evaluation and purchase of companies such as the company as contemplated hereunder. Buyer has undertaken such investigation and has been provided with and has evaluated such documents and information as it has deemed necessary to enable it to make an informed and intelligent decision with respect to the execution, delivery and performance of this Agreement. Buyer acknowledges that the Company has given Buyer complete and open access to the key employees, documents and facilities of the Company and PGR and which are related to the PGR Leases. Buyer will undertake prior to Closing such further investigation and request such additional documents and information as it deems necessary. Buyer agrees to accept the POC Units and the PGR Assets in the condition they are in on the Closing Date based upon its own inspection, examination and determination with respect thereto as to all matters and without reliance upon any express or implied representations or warranties of any nature made by or on behalf of or imputed to the Company, except as expressly set forth in this Agreement. Without limiting the generality of the foregoing, Buyer acknowledges that the Company makes no representation or warranty with respect to (i) any projections, estimates or budgets delivered to or made available to Buyer of future revenues, future results of operations (or any component thereof), future cash flows or future financial condition (or any component thereof) of the Company or the PGR Assets or the future business and operations of the Company or the PGR Assets or (ii) any other information or documents made available to Buyer or its counsel, accountants or advisors with respect to the PGR Assets or the Company or their respective businesses or operations, except as expressly set forth in this Agreement.

(b) Buyer has such knowledge and expertise in financial, business and oil and gas matters that Buyer is capable of evaluating the merits and risks involved in the purchase of the POC Units and the PGR Assets.

(c) Buyer is acquiring the POC Units for investment purposes only, solely for the account of Buyer (and not as a nominee or agent), and not with a view towards the resale or distribution of any part thereof, and Buyer has no present intention of selling, granting any participation in, or otherwise distributing the same.

(d) Buyer is an "accredited investor," as such term is defined in Rule 501(a) of the Securities Act.

Section 7. Covenants of Buyer.

7.1 Confidentiality. Buyer agrees that, unless and until the Closing has been consummated, Buyer and the Buyer Representatives will hold in strict confidence, and will not use, any confidential or proprietary data or information obtained from the Company with respect to the business or financial condition of the Company, PGR or the PGR Wells and PGR Leases except for the purpose of evaluating, negotiating and completing the transactions contemplated hereby. Information generally known in the industry or which has been disclosed to Buyer by third parties, which have a right to do so shall not be deemed confidential or proprietary information for purposes of this Agreement. If the transactions contemplated by this Agreement are not consummated, Buyer will return to the Company (or certify that it has destroyed) all copies of such data and information, including, but not limited to, financial information, customer lists, business and corporate records, worksheets, test reports, tax returns, lists, memoranda and other documents prepared by or made available to Buyer in connection with the transactions. Notwithstanding the foregoing, Buyer shall be permitted to disclose such information about the Company and PGR and the transactions contemplated hereby as shall be legally required; provided that Buyer shall give prior notice of such disclosure to the Company sufficiently in advance of such disclosure so that the Company may seek to obtain confidential treatment thereof if available.

7.2 Compliance. Buyer shall make all filings with and notifications of governmental authorities, regulatory agencies and other entities required to be made by Buyer in connection with the execution and delivery of this Agreement and the consummation of the transactions contemplated hereby.

7.3 Conditions. Buyer shall take all commercially reasonable actions necessary to cause the conditions set forth in Section 9.2 to be satisfied and to consummate the transactions contemplated herein as soon as reasonably possible after the satisfaction thereof.

7.4 Due Diligence.

(a) Buyer agrees that it shall, and it shall cause its contractors, subcontractors, agents, employees and consultants (collectively “**Buyer Representatives**”) to, conduct and perform Buyer’s due diligence investigation of the Company, PGR and the PGR Wells and PGR Leases in a good and workmanlike manner and Buyer shall be solely responsible for the prompt payment of all costs and expenses incurred in connection therewith, including without limitation, all field and laboratory costs, insurance premiums, consultants’ fees, and attorneys’ and experts’ fees.

(b) Buyer agrees to indemnify, protect, defend and hold harmless the Company and its employees, officers, directors, managers, accountants, agents and advisors and each of them, in all capacities including individually, from any liability, claim, cause of action, damage, cost or other expense of every nature whatsoever including, without limitation, reasonable attorney’s fees, personal injury claims, loss of use of, or damage to, the assets or business of the Company or PGR, incurred as a result of Buyer’s due diligence.

(c) Buyer shall conduct its due diligence in a manner which minimizes interference with the Company, PGR and their business and operations. Upon completion of due diligence, Buyer, at its sole cost and expense, shall remove all materials, equipment, machinery, and other items used by any of Buyer or Buyer Representatives and, with respect to fields, assets, or real property, repair and restore such assets and property to their condition as they existed immediately prior to Buyer's entry upon and performance of its due diligence.

7.5 Notification. Buyer shall promptly notify the Company in writing if Buyer discovers that any representation or warranty made in this Agreement was when made, or has subsequently become, untrue in any respect.

7.6 Payment. On the Closing Date, Buyer shall make the payments required pursuant to Section 2.5.

7.7 Deliveries. On the Closing Date, Buyer shall execute and deliver to the Company all of the following:

(a) a certificate signed by the appropriate officer of Buyer dated as of the Closing Date to the effect that the statements set forth in paragraphs (a) and (b) of Section 9.2 are true and correct;

(b) the Escrow Agreement, if required; and

(c) a certificate of good standing with respect to Buyer, issued not more than ten (10) days prior to the Closing Date by the Secretary of State of the State of Delaware.

Section 8. [Intentionally Omitted].

Section 9. Conditions.

9.1 Conditions to the Obligations of Buyer. The obligation of Buyer to consummate this Agreement and the transactions contemplated hereby are subject to the fulfillment, prior to or at the Closing, of the following conditions precedent:

(a) Representations; Warranties; Covenants. Each of the representations and warranties of the Company contained in this Agreement shall be true and correct as of the Closing Date as though made on and as of the Closing Date, except for such representations and warranties as are made as of a specified date and except for such breaches of representations and warranties as do not, individually or in the aggregate, have a material adverse effect.

(b) No Proceedings. There shall not be instituted or pending any action or proceeding, before any court or governmental authority or agency, domestic or foreign, (i) challenging or seeking to make illegal, or to delay or otherwise directly or indirectly restrain or prohibit, the consummation of the transactions contemplated hereby or seeking to obtain material damages in connection with such transactions, (ii) seeking to prohibit direct or indirect ownership or operation by Buyer of all or a material portion of the PGR Assets, or to compel Buyer or any of its subsidiaries or the Company to dispose of or to hold separately all or a material portion of the business or assets of Buyer and its subsidiaries or of the PGR Assets, as a result of the transactions contemplated hereby, or (iii) seeking to invalidate or render unenforceable any material provision of this Agreement or any of the other agreements attached as exhibits hereto.

(c) Performance. The Company shall have performed in all material respects all of its obligations hereunder required to be performed by it at or prior to the Closing Date.

(d) Consents and Approvals. The Company shall have obtained, or caused to be obtained, and delivered to Buyer each consent and approval in Schedule 3.5 or Schedule 3.8 that is required to be delivered at or prior to Closing. The Company shall have made all filings and applications with respect to consents or approvals for which filings or applications are required at or prior to Closing as provided in Schedule 3.5 or Schedule 3.8.

(e) Contracts. The Company shall deliver assignments for those Contracts listed on Schedule 3.14(b) that are designated as to be assigned to POC at or prior to Closing.

(f) Closing Documents. Buyer shall have received from the Company all of the documents referred to in Section 5.6 above.

9.2 Conditions to Obligations of the Company. The obligations of the Company to consummate this Agreement and the transactions contemplated hereby is subject to the fulfillment, prior to or at the Closing, of the following conditions precedent:

(a) Representations; Warranties; Covenants. Each of the representations and warranties of Buyer contained in this Agreement shall be true and correct as of the Closing Date as though made on and as of the Closing Date except for such representations and warranties as are made as of a specified date and except for such breaches of representations and warranties as do not, individually or in the aggregate, have a material adverse effect.

(b) No Proceedings. There shall not be threatened, instituted or pending any action or proceeding before any court or governmental authority or agency, domestic or foreign, (i) challenging or seeking to make illegal, or to delay or otherwise directly or indirectly restrain or prohibit, the consummation of the transactions contemplated hereby or seeking to obtain material damages in connection with such transactions, (ii) seeking to prohibit direct or indirect ownership or operation by Buyer of all or a material portion of the PGR Assets, or to compel Buyer or any of its subsidiaries or the Company to dispose of or to hold separately all or a material portion of the business or assets of Buyer and its subsidiaries or of the PGR Assets, as a result of the transactions contemplated hereby, and (iii) seeking to invalidate or render unenforceable any material provision of this Agreement or any of the other agreements attached as exhibits hereto.

(c) Performance. Buyer shall have performed in all material respects all of its obligations hereunder required to be performed by it at or prior to the Closing Date.

(d) Payment of Adjusted Purchase Price. Buyer shall have made the payments required pursuant to Section 2.5.

(e) Consents and Approvals. Buyer shall have obtained, or caused to be obtained, each consent and approval required of it in order to complete the transactions contemplated hereby.

(f) Closing Documents. The Company shall have received from Buyer all of the documents referred to in Section 7.7 above.

Section 10. Termination of Agreement; Rights to Proceed.

10.1 Termination. At any time prior to the Closing, this Agreement may be terminated as follows:

(a) by mutual written consent of Buyer and the Company;

(b) by Buyer or the Company, if the Closing has not occurred on or before April 1, 2006 (the "**Termination Date**"); provided that the terminating party is not in material breach of this Agreement;

(c) by Buyer or the Company pursuant to Section 4.4; or

(d) by either the Company or Buyer if consummation of the transactions contemplated hereby would violate a nonappealable final order, decree or judgment of any court or governmental body having competent jurisdiction.

The party desiring to terminate this Agreement pursuant to Section 10.1(b), (c) or (d) shall give notice of such termination to the other party.

10.2 Effect of Termination. If this Agreement is terminated as permitted by Section 10.1, such termination shall be without liability of either party (or any stockholder, member, partner, director, officer, employee, agent, consultant or representative of such party) to the other party to this Agreement and the Deposit shall be returned to Buyer; provided that if a termination under Section 10.1(b) or (d) shall result from the (i) failure of either party to fulfill a condition to the performance of the obligations of the other party, (ii) failure of either party to perform a covenant of this Agreement or (iii) breach by either party hereto of any representation or warranty or agreement contained herein (any of (i), (ii) or (iii), a "**Breach**"), then, in the case of a Breach by Buyer, the Company shall retain the Deposit and the retention of the Deposit by the Company in such circumstances shall in no way limit the amount of damages that may be recovered by the Company from Buyer with respect to Losses suffered as a result of Buyer's Breach (with the Deposit to be applied against any damages awarded against Buyer), and in the case of a Breach by the Company, Buyer shall have the right to pursue all available legal and equitable remedies including, without limitation, specific performance. In the case of a termination by Buyer under Section 10.1(c), the return to Buyer of the Deposit shall be Buyer's sole and exclusive remedy against the Company, and the Company shall have no further liability to Buyer. The provisions of Sections 7.1, 11.1, 11.6 and 11.7 shall survive any termination hereof pursuant to this Section 10.

Section 11. Miscellaneous.

11.1 Fees and Expenses. Each party shall pay its own expenses and costs associated with the preparation and negotiation of this Agreement and the consummation of the transactions contemplated hereby.

11.2 Survival of Representations and Warranties. All representations and warranties made by the Company or Buyer shall survive the Closing until the first anniversary of the Closing Date (the "**Survival Period**"). All covenants made by the Company or Buyer shall survive until June 15, 2009.

11.3 Indemnification by the Company. From and after Closing, and subject to Section 11.5, the Company shall indemnify and hold harmless Buyer and its representatives, stockholders, controlling persons, and Affiliates (the "**Buyer Indemnified Persons**") for, and will pay to the Buyer Indemnified Persons the amount of, any Loss arising, directly or indirectly, from or in connection with: (a) any Breach by the Company of any representation or warranty made by the Company in this Agreement; and (b) any Breach by the Company of any covenant or obligation of the Company in this Agreement.

11.4 Indemnification by Buyer. From and after Closing, and subject to Section 11.5, Buyer shall indemnify and hold harmless each the Company and its Affiliates (the "**Seller Indemnified Persons**") for, and will pay to the Seller Indemnified Persons the amount of, any Loss arising, directly or indirectly, from or in connection with: (a) any Breach by Buyer of any representation or warranty made by Buyer in this Agreement and (b) any Breach by Buyer of any covenant or obligation of Buyer in this Agreement.

11.5 Limitations on Indemnity. Neither party will have any liability under Section 11.3 or 11.4 as the case may be for indemnification with respect to any representation or warranty unless the party seeking indemnification notifies the indemnifying party of a claim in writing specifying the claim in reasonable detail prior to the end of the Survival Period. The Company shall not have any liability for indemnification with respect to matters described in Section 11.3(a) or, to the extent relating to any failure to perform or comply prior to the Closing Date, Section 11.3(b), until the total of all Losses with respect to such matters exceeds $750,000 and then only for the amount by which such Losses exceeds $750,000, provided that the foregoing deductible shall not apply to any Breach of a representation, warranty or covenant relating to income taxes or with respect to Section 5.1(b) and (d), and the first sentence of Section 5.4. The Company shall not have any liability for indemnification with respect to Losses suffered by the Buyer Indemnified Persons, in the aggregate, in excess of $15,000,000, provided that the foregoing limitation shall not apply to any Breach of a representation, warranty or covenant relating to income taxes.

11.6 Governing Law; Consent to Jurisdiction. This Agreement and all disputes, actions or proceedings arising out of or relating to this Agreement or the negotiation, validity or performance hereunder or the transactions contemplated hereby and/or the rights and obligations of the parties to this Agreement shall be governed by and construed in accordance with the internal laws of the State of Delaware, without regard to its conflict of laws provisions. Each of the parties hereto hereby irrevocably and unconditionally consents to the jurisdiction of the Center for Public Resources to resolve any such dispute, action or proceeding (except with respect to any equitable remedy to which a party is entitled), and further consents to the jurisdiction of the courts of the State of Colorado and the United States District Court for the District of Colorado for the purpose of enforcing the arbitration provisions of Section 11.7 and pursuing any equitable remedy. Each of the parties hereto hereby irrevocably and unconditionally waive any objection to the laying of venue of any such dispute, action or proceeding before the Center for Public Resources based on a lack of personal jurisdiction or the laying of venue, and hereby further irrevocably and unconditionally waive and agree not to plead or claim in any court that arbitration before the Center for Public Resources has been brought in an inconvenient forum. Each of the parties hereto further agree that service of process, summons, notice or document by U.S. registered mail to such party's address set forth in Section 11.8 hereof shall be effective service of process for any such dispute, action or proceeding brought against such party in any such court.

11.7 Arbitration. Any dispute arising out of or relating to this Agreement or the breach, termination negotiation, or validity hereof and/or the rights or obligations of the parties arising out of or relating to this agreement or the breach, termination, negotiation, or validity hereof shall be finally settled by binding arbitration conducted expeditiously in accordance with the Center for Public Resources Rules for Nonadministered Arbitration of Business Disputes (the "**CPR Rules**"). The Center for Public Resources shall appoint a neutral advisor from its National CPR Panel. The arbitration shall be governed by the United States Arbitration Act, 9 U.S.C. §§1-16, and judgment upon the award rendered by the arbitrators may be entered by any court having jurisdiction thereof. The place of arbitration shall be Denver, Colorado.

Such proceedings shall be administered by the neutral advisor in accordance with the CPR Rules as he/she deems appropriate, however, such proceedings shall be guided by the following agreed upon procedures:

(a) mandatory exchange of all relevant documents, to be accomplished within forty-five (45) days of the initiation of the procedure;

(b) no other discovery;

(c) hearings before the neutral advisor which shall consist of a summary presentation by each side of not more than three hours; such hearings to take place on one or two days at a maximum; and

(d) decision to be rendered not more than ten (10) days following such hearings.

Notwithstanding anything to the contrary contained herein, the provisions of this Section 11.7 shall not apply with respect to any equitable remedies to which any party may be entitled.

11.8 Notices. Any notice, request, demand or other communication required or permitted hereunder shall be in writing and shall be deemed to have been given (i) if delivered or sent by facsimile transmission, upon acknowledgment of receipt by the recipient, (ii) if sent by a nationally recognized overnight courier, properly addressed with postage prepaid, on the next business day (or Saturday or Sunday if sent for delivery on such days), (iii) or if sent by registered or certified mail, upon the earlier of the date on which receipt is acknowledged or the date which is three (3) days after deposit in United States post office facilities properly addressed with postage prepaid. All notices to a party will be sent to the addresses set forth below or to such other address or person as such party may designate by notice to each other party hereunder:

TO BUYER:

Berry Petroleum Company
5201 Truxtun Avenue, Suite 300
Bakersfield, California 93309-0640
Attn: Land Manager
Fax: (661) 616-3886
Tel: (661) 616-3900

With copies to:

Musick, Peeler & Garrett LLP
200 North Westlake Boulevard, Suite 204
Westlake Village, California 91362
Attn: Laura McAvoy
Fax: (805) 418-3101
Tel: (805) 418-3115

and

Holland & Hart LLP
555 Seventeenth Street, Suite 2700
Denver, Colorado 80201
Attn: Davis O'Connor
Fax: (303) 295-8261
Tel: (303) 295-8000

If to Company:

Orion Energy Partners L.P.
1675 Broadway, Suite 2000
Denver, CO 80202
Attn: General Partner
Fax: (303) 595-3043
Tel: (303) 595-3030

With a copy to:

Davis Graham & Stubbs LLP
1550 Seventeenth Street, Suite 500
Denver, CO 80202
Attn: Chris Richardson
Fax: (303) 893-1379
Tel: (303) 892-9400

Any notice given hereunder may be given on behalf of any party by his counsel or other authorized representatives.

11.9 Entire Agreement. This Agreement, including the Schedules and Exhibits hereto, reflects the entire agreement of Buyer and the Company with respect to its subject matter, and replaces and supersedes the Original Agreement and all previous written or oral negotiations, commitments and writings. The Original Agreement is hereby terminated and all rights and obligations of the parties thereto are hereby terminated and discharged.

11.10 Severability. Whenever possible, each provision of this Agreement will be interpreted in such manner as to be effective and valid and valid under applicable law, but if any provision of this Agreement is held to be prohibited by or invalid under applicable law, such provision will be ineffective only to the extent of such prohibition or invalidity, without invalidating the remainder of such provision or the remaining provisions of this Agreement.

11.11 Assignability; Binding Effect. This Agreement may not be assigned by any party hereto without the prior written consent of the other parties hereto. This Agreement shall be binding upon and enforceable by, and shall inure to the benefit of, the parties hereto and their respective successors and permitted assigns.

11.12 Captions and Gender. The captions in this Agreement are for convenience only and shall not affect the construction or interpretation of any term or provision hereof. The use in this Agreement of the masculine pronoun in reference to a party hereto shall be deemed to include the feminine or neuter, as the context may require.

11.13 Execution in Counterparts/Third Party Beneficiaries. For the convenience of the parties and to facilitate execution, this Agreement may be executed in two or more counterparts, each of which shall be deemed an original, but all of which shall constitute one and the same document. Facsimile signatures shall constitute original signatures. No provision of this Agreement is intended to confer upon any Person other than the parties hereto any rights or remedies hereunder.

11.14 Amendments. This Agreement may not be amended or modified, nor may compliance with any condition or covenant set forth herein be waived, except by a writing duly and validly executed by Buyer and the Company, or in the case of a waiver, the party waiving compliance.

11.15 Publicity and Disclosures. Except as and to the extent required by law, without the prior written consent of Buyer, the Company will not and the Company will direct their representatives not to, make, directly or indirectly, any public comment, statement or communication with respect to, or otherwise to disclose or to permit the disclosure of the existence of discussions regarding a transaction between the parties or any of the terms, conditions, or other aspects of the transaction. If the Company is required by law to make any such disclosure, it must first provide to Buyer the content of the proposed disclosure, the reasons that such disclosure is required by law, and the time and place that the disclosure will be made and afford Buyer a reasonable opportunity to comment upon and request changes in the disclosure. In the period before Closing, prior to Buyer making any press release or public disclosure regarding this Agreement or the transaction between the parties, Buyer will provide the Company with relevant portions of any such disclosure and afford the Company a reasonable opportunity to comment and request changes to such disclosure.

11.16 Disclosure Schedules. The representations and warranties contained in Section 3 are qualified by reference to the Disclosure Schedules attached hereto. The Disclosure Schedules are not intended to constitute, and shall not be construed as constituting, representations or warranties of the Company except as and to the extent provided in this Agreement. The Disclosure Schedules may include items or information which the Company is not required to disclose under this Agreement; disclosure of such items or information shall not affect (directly or indirectly) the interpretation of this Agreement or the scope of the disclosure obligation of the Company under the Agreement. Inclusion of information in the Disclosure Schedules shall not be construed as an admission that such information is material to the Company or the financial position or results of operation of the PGR Assets or the Company.

Cross references that may be contained in certain of the Disclosure Schedules to other Disclosure Schedules should not be regarded as all-inclusive. Information contained in various Disclosure Schedules or sections and subsections of the Disclosure Schedules may be applicable to other Disclosure Schedules or sections and subsections. Every matter, document or item referred to, set forth or described in one Disclosure Schedule shall be deemed to be disclosed under each and every part, category or heading of that Disclosure Schedule and all other Disclosure Schedules and shall be deemed to qualify the representations and warranties of the Company in the Agreement, to the extent such matter, document or item may apply. Headings have been inserted on sections of the Disclosure Schedules for the convenience of reference only and shall to no extent affect the construction or interpretation of any of the provisions of the Agreement or the Disclosure Schedules.

Exhibit 10.17

IN WITNESS WHEREOF the parties hereto have caused this Agreement to be executed as of the date first set forth above.

BUYER

BERRY PETROLEUM COMPANY

By: /s/ Michael Duginski
Name: Michael Duginski
Title: Executive Vice President

COMPANY

ORION ENERGY PARTNERS L.P.

By: Orion Energy Partners, Inc., its General Partner

By: /s/ Daniel G. Blanchard
Name: Daniel G. Blanchard
Title: Executive Vice President

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-8 (Nos. 333-62871, 333-62799, 333-98379 and 333-127018) of Berry Petroleum Company of our report dated March 1, 2006 relating to the financial statements, management's assessment of the effectiveness of internal control over financial reporting and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Los Angeles, California
March 3, 2006

Exhibit 23.2

DeGolyer and MacNaughton

5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

March 1, 2006

Berry Petroleum Company
5201 Truxtun Avenue, Suite 300
Bakersfield, California 93309-0640

Gentlemen:

In connection with the Annual Report on Form 10-K for the fiscal year ended December 31, 2005, (the Annual Report) of Berry Petroleum Company (the Company), we hereby consent to (i) the use of and reference to our “Appraisal Report as of December 31, 2005 on Certain Properties owned by Berry Petroleum Company,” “Appraisal Report as of December 31, 2004 on Certain Properties owned by Berry Petroleum Company,” and “Appraisal Report as of December 31, 2003 on Certain Properties owned by Berry Petroleum Company,” (the “Reports”), under the captions “Business” and “Oil and Gas Properties” in Item 1 of the Annual Report, under the caption “Selected Financial Data” in Item 6 of the Annual Report, and under the caption “Supplemental Information About Oil & Gas Producing Activities (Unaudited)” in Item 8 of the Annual Report; and (ii) the use of and reference to the name DeGolyer and MacNaughton as the independent petroleum engineering firm that prepared the Reports under such items; provided, however, that since the cash-flow calculations in the Annual Report include estimated income taxes not included in the Reports, we are unable to verify the accuracy of the cash-flow values in the Annual Report.

Very truly yours,

/s/ DeGOLYER and MacNAUGHTON

Exhibit 31.1

Certification of Chief Executive Officer

Pursuant to Section 302 of Sarbanes Oxley Act of 2002

I, Robert F. Heinemann, President, Chief Executive Officer, and Director certify that:

1. I have reviewed this report on Form 10-K of Berry Petroleum Company (the Company);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the Company as of, and for, the periods presented in this annual report;

4. The Company’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a - 15(e) and 15d - (e) and internal control over financial reporting (as defined in Exchange Act Rules 13a - 15(f) and 15d - 15(f)) for the Company and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Company is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designated under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the Company’s disclosure controls and procedures and presented in this report our conclusions abut the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the Company’s internal control over financial reporting that occurred during the Company’s most recent fiscal quarter that has materially affected or is reasonably likely to materially affect the Company’s internal control over financial reporting.

5. The Company’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Company’s auditors and the audit committee of the Company’s board of directors:

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Company’s ability to record, process, summarize and report financial information and have identified for the registrant’s auditors any material weaknesses in internal controls; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the Company’s internal controls over financial reporting.

/s/ Robert F. Heinemann

Robert F. Heinemann

March 3, 2006 — President, Chief Executive Officer, and Director

Exhibit 31.2

Certification of Chief Financial Officer

Pursuant to Section 302 of Sarbanes Oxley Act of 2002

I, Ralph J. Goehring, Executive Vice President and Chief Financial Officer, certify that:

1. I have reviewed this report on Form 10-K of Berry Petroleum Company (the Company);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the Company as of, and for, the periods presented in this annual report;

4. The Company’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a - 15(e) and 15d - (e) and internal control over financial reporting (as defined in Exchange Act Rules 13a - 15(f) and 15d - 15(f)) for the Company and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Company is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designated under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the Company’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the Company’s internal control over financial reporting that occurred during the Company’s most recent fiscal quarter that has materially affected or is reasonably likely to materially affect the Company’s internal control over financial reporting;

5. The Company’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting to the Company’s auditors and the audit committee of the Company’s board of directors:

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Company’s ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the Company’s internal controls over financial reporting.

/s/ Ralph J. Goehring

Ralph J. Goehring

March 3, 2006

Executive Vice President and Chief Financial Officer

Exhibit 32.1

Certification of Chief Executive Officer

Pursuant to Section 906 of Sarbanes Oxley Act of 2002

In Connection with the Annual Report of Berry Petroleum Company (the "Company") on Form 10-K for the period ending December 31, 2005 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Robert F. Heinemann, President, Chief Executive Officer and Director of the Company, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to 906 of the Sarbanes-Oxley Act of 2002, that:

1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Robert F. Heinemann

Robert F. Heinemann

March 3, 2006

President, Chief Executive Officer and Director

Exhibit 32.2

Certification of Chief Financial Officer

Pursuant to Section 906 of Sarbanes Oxley Act of 2002

In Connection with the Annual Report of Berry Petroleum Company (the “Company”) on Form 10-K for the period ending December 31, 2005 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Ralph J. Goehring, Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to 906 of the Sarbanes-Oxley Act of 2002, that:

1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Ralph J. Goehring

Ralph J. Goehring

March 3, 2006 — Executive Vice President and Chief Financial Officer