BERRY PETROLEUM CO
Form 10-Q
May 09, 2006

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

FORM 10-Q

x Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the quarterly period ended **March 31, 2006**
Commission file number **1-9735**

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

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

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

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

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 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 April 20, 2006, the registrant had 21,160,513 shares of Class A Common Stock ($.01 par value) outstanding. The registrant also had 898,892 shares of Class B Stock outstanding on April 20, 2006 all of which is held by an affiliate of the registrant.

BERRY PETROLEUM COMPANY AND SUBSIDIARY
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BERRY PETROLEUM COMPANY AND SUBSIDIARY
Unaudited Condensed Consolidated Balance Sheets
(In Thousands, Except Share Information)

	March 31, 2006	December 31, 2005
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,385	$ 1,990
Short-term investments available for sale	661	661
Accounts receivable	59,941	59,672
Deferred income taxes	9,943	4,547
Fair value of derivatives	624	3,618
Prepaid expenses and other	6,066	4,398
Total current assets	78,620	74,886
Oil and gas properties (successful efforts basis), buildings and equipment, net	738,627	552,984
Long-term deferred income taxes	2,329	1,600
Other assets	5,399	5,581
	$ 824,975	$ 635,051
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 55,153	$ 57,783
Revenue and royalties payable	13,862	34,920
Accrued liabilities	8,174	8,805
Line of credit	9,500	11,500
Income taxes payable	5,592	1,237
Fair value of derivatives	26,560	15,398
Total current liabilities	118,841	129,643
Long-term liabilities:		
Deferred income taxes	52,664	55,804
Long-term debt	249,000	75,000
Abandonment obligation	10,724	10,675
Unearned revenue	736	866
Fair value of derivatives	61,349	28,853
	374,473	171,198
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; 21,177,938 shares issued and outstanding (21,099,906 in 2005)	212	211
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	58,225	56,064
Accumulated other comprehensive loss	(49,474)	(24,380)
Retained earnings	322,689	302,306
Total shareholders' equity	331,661	334,210

	$ 824,975	$ 635,051

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

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BERRY PETROLEUM COMPANY AND SUBSIDIARY
Unaudited Condensed Consolidated Statements of Income
Three Month Periods Ended March 31, 2006 and 2005
(In Thousands, Except Per Share Data)

	2006	2005
REVENUES		
Sales of oil and gas	$ 101,932	$ 75,391
Sales of electricity	15,169	12,456
Interest and other income, net	493	148
	117,594	87,995
EXPENSES		
Operating costs - oil and gas production	25,738	20,892
Operating costs - electricity generation	14,332	13,358
Production taxes	3,233	2,515
Exploration costs	2,289	561
Depreciation, depletion & amortization - oil and gas production	13,223	8,527
Depreciation, depletion & amortization - electricity generation	767	772
General and administrative	8,314	4,820
Interest	1,577	1,162
Commodity derivatives	4,828	-
Dry hole, abandonment and impairment	5,209	2,021
	79,510	54,628
Income before income taxes	38,084	33,367
Provision for income taxes	14,833	10,862
Net income	$ 23,251	$ 22,505
Basic net income per share	$ 1.06	$ 1.02
Diluted net income per share	$ 1.03	$ 1.00
Dividends per share	$ .13	$ .12
Weighted average number of shares of capital stock outstanding (used to calculate basic net income per share)	21,994	21,981
Effect of dilutive securities:		
Equity based compensation	459	433
Director deferred compensation	49	56
Weighted average number of shares of capital stock used to calculate diluted net income per share	22,502	22,470

Unaudited Condensed Consolidated Statements of Comprehensive Income
Three Month Periods Ended March 31, 2006 and 2005
(In Thousands)

Net income	$	23,251	$	22,505
Unrealized losses on derivatives, net of income taxes of ($14,184) and ($12,165), respectively		(21,276)		(18,831)
Reclassification of realized (losses) gains included in net income net of income taxes of ($2,545) and ($501), respectively		(3,818)		752
Comprehensive (loss) income	$	(1,843)	$	4,426

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

BERRY PETROLEUM COMPANY AND SUBSIDIARY
Unaudited Condensed Consolidated Statements of Cash Flows
Three Month Periods Ended March 31, 2006 and 2005
(In Thousands)

	2006	2005
Cash flows from operating activities:		
Net income	$ 23,251	$ 22,505
Depreciation, depletion and amortization	13,990	9,299
Dry hole, abandonment and impairment	4,985	(213)
Commodity derivatives	4,828	-
Stock-based compensation expense	1,014	376
Deferred income taxes, net	7,464	5,042
Other, net	52	89
Increase in current assets other than cash, cash equivalents and short-term investments	(1,936)	(10,541)
Increase in current liabilities other than book overdraft, line of credit and fair value of derivatives	(28,331)	(7,305)
Net cash provided by operating activities	25,317	19,252
Cash flows from investing activities:		
Exploration and development of oil and gas properties	(41,345)	(23,075)
Property acquisitions	(159,016)	(101,105)
Additions to vehicles, drilling rigs and other fixed assets	(5,723)	(970)
Net cash used in investing activities	(206,084)	(125,150)
Cash flows from financing activities:		
Proceeds from issuance of line of credit	51,000	-
Payment of line of credit	(53,000)	-
Proceeds from issuance of long-term debt	219,750	116,000
Payment of long-term debt	(45,750)	(6,000)
Dividends paid	(2,867)	(2,642)
Change in book overdraft	9,881	-
Stock option exercises	2,950	-
Repurchase of shares	(1,802)	-
Net cash provided by financing activities	180,162	107,358
Net (decrease) increase in cash and cash equivalents	(605)	1,460
Cash and cash equivalents at beginning of year	1,990	16,690
Cash and cash equivalents at end of period	$ 1,385	$ 18,150
Supplemental non-cash activity:		
Increase (decrease) in fair value of derivatives:		
Current (net of income taxes of $5,468 and $10,756, respectively)	$ (8,203)	$ (16,717)
Non-current (net of income taxes of $11,261 and $908, respectively)	(16,891)	(1,362)
Net decrease to accumulated other comprehensive income	$ (25,094)	$ (18,079)

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

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BERRY PETROLEUM COMPANY AND SUBSIDIARY
Notes to the Unaudited Condensed Consolidated Financial Statements

1. General

All adjustments which are, in the opinion of Management, necessary for a fair statement of Berry Petroleum Company's and subsidiary (collectively, the "Company") financial position at March 31, 2006 and December 31, 2005 and results of operations and cash flows for the three month periods ended March 31, 2006 and 2005 have been included. All such adjustments are of a normal recurring nature. The results of operations and cash flows are not necessarily indicative of the results for a full year.

With the exception of the consolidation of the new subsidiary obtained in our acquisition, Piceance Operating Company LLC (see Note 8), the accompanying unaudited condensed consolidated financial statements have been prepared on a basis consistent with the accounting principles and policies reflected in the December 31, 2005 financial statements. The December 31, 2005 Form 10-K should be read in conjunction herewith. The year-end condensed balance sheet was derived from audited financial statements, but does not include all disclosures required by accounting principles generally accepted in the United States of America.

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 March 31, 2006 and March 31, 2005 is $11.8 million and $1.9 million, respectively, representing outstanding checks in excess of the bank balance (book overdraft).

2. Recent Accounting Developments

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.

3. Share-Based Compensation

In December 2004, SFAS No. 123(R), *Share-Based Payment*, was issued which establishes standards for transactions in which an entity exchanges its equity instruments for goods or services. This standard requires an issuer to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award. In April 2005 the SEC issued a rule that SFAS No. 123(R) will be effective for annual reporting periods beginning on or after June 15, 2005. As a result, the Company adopted this statement beginning January 1, 2006. The Company previously adopted the fair value recognition provisions of SFAS No. 123, *Accounting for Stock-Based Compensation*. Accordingly, the adoption of SFAS No. 123(R) did not have a material impact on our condensed consolidated financial statements for the three months ended March 31, 2006.

Equity Compensation Plans
The 2005 Equity Incentive Plan (the 2005 Plan), approved by shareholders in May 2005, 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 vesting is either at 25% per year for 4 years or 100% after 3 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. The Company uses a broker for issuing new shares upon option exercise.

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. 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. For the three months ended March 31, 2006, the Company repurchased 30,000 shares for approximately $1.8 million. Since June 2005, total shares repurchased through March 31, 2006 is 138,900 for approximately $8.1 million.

3. Share-Based Compensation (Continued)

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.

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. There were no grants made in the first quarter of 2005, therefore no data is shown below for that quarter.

	March 31, 2006
Expected volatility	32% - 33%
Weighted-average volatility	32%
Expected dividends	.79% - .88%
Expected term (in years)	5.27
Risk-free rate	4.5 - 4.7

The following is a summary of stock option activity for the three months ended March 31, 2006 is as follows:

	Options	Weighted Average Exercise Price	Weighted Average Contractual Life Remaining
Balance outstanding, January 1	1,555,413	$ 33.52	
Granted	45,000	69.00	
Exercised	(123,370)	21.03	
Canceled/expired	(107,050)	37.91	
Balance outstanding, March 31	1,369,993	35.46	7.9 years
Balance exercisable at March 31	603,168	25.61	6.8 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 RSU’s granted vest based on either 25% per year over 4 years or 100% after 3 years. At March 31, 2006 all RSUs are unvested and none are exercisable. 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.

3. Share-Based Compensation (Continued)

The following is a summary of RSU activity for the three months ended March 31, 2006 as follows:

	RSUs	Weighted Average Intrinsic Value at Grant Date	Weighted Average Contractual Life Remaining
Balance outstanding, January 1	70,950	$ 61.29	
Granted	8,540	70.62	
Converted	-	-	
Canceled/expired	(6,800)	61.29	
Balance outstanding, March 31	72,690	62.14	3.7 years

Other share-based compensation data

	Stock Options		RSUs	
	Three months ended		Three months ended	
	3/31/06	3/31/05	3/31/06	3/31/05
Weighted-average grant date fair value	$ 23.90	$ -	$ 70.62	$ -
Total intrinsic value of options exercised (in millions)	5.9	9.1	-	-
Total intrinsic value of options/RSUs outstanding (in millions)	45.2	33.1	4.9	-
Total intrinsic value of options exercisable (in millions)	25.9	16.0	-	-
Total compensation cost recognized into income (in millions)	.7	.6	.3	-

The total compensation cost related to nonvested awards not yet recognized for the three months ended March 31, 2006 is $9.5 million and the weighted average period over which this cost is expected to be recognized is 3 years. The tax benefit realized from stock options exercised during the annual period ended March 31, 2006 is $1.8 million.

4. Derivatives

The Company’s derivatives (natural gas swaps and collar contracts) that were put in place on March 1, 2006 do not qualify for hedge accounting under SFAS 133, but are important economic hedges of the Company’s natural gas commodity price exposure. These contracts are recorded at their fair value on the balance sheet. During the first quarter of 2006, the Company recognized all unrealized and realized gains and losses related to these contracts in the amount of $4.8 million on the income statement under the caption “Commodity derivatives.” The related cash flow impact of all of the Company’s derivative activities are reflected as cash flows from operating activities.

At March 31, 2006, the Company’s net fair value of derivatives liability was $87.3 million as compared to $40.6 million at December 31, 2005. Accumulated other comprehensive loss consisted of $49.5 million, net of tax, of unrealized losses from the Company's crude oil and natural gas swaps and collars that qualified for hedge accounting treatment at March 31, 2006. Deferred net losses recorded in Accumulated other comprehensive loss at March 31, 2006 and subsequent marked-to-market changes in the underlying hedging contracts are expected to be reclassified to earnings over the life of these contracts.

5. Revisions to the Classification of Production Taxes

Certain amounts in the condensed consolidated income statements for the three months ended March 31, 2005 have been reclassified to conform to the 2006 presentation. In connection with the preparation of the 2005 financial statements the Company reclassified production taxes out of operating costs-oil and gas into a separate line. This reclassification 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 three months ended March 31, 2005 (in thousands):

		March 31, 2005
Operating costs - oil and gas		
As previously reported		23,407
As revised		20,892
Difference	$	2,515
Production taxes		
As previously reported	$	-
As revised		2,515
Difference	$	(2,515)

6. Dry Hole, Abandonment and Impairment

The $5.2 million reflected on the Company’s income statement under the dry hole, abandonment and impairment line item consists primarily of two Coyote Flats, Utah prospect wells that were drilled, tested and determined non-commercial in 2006.

7. Pro Forma Results (unaudited)

On January 27, 2005, the Company acquired certain interests in the Niobrara field in northeastern Colorado for approximately $105 million. The unaudited pro forma results presented below for the three months ended March 31, 2005 have been prepared to give effect to the acquisition on the Company’s results of operations under the purchase method of accounting as if it had been consummated on January 1, 2005. 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):

		March 31, 2005
Proforma Revenue	$	89,358
Proforma Income from operations		40,016
Proforma Net income		22,809
Proforma Basic earnings per share		1.04
Proforma Diluted earnings per share		1.02

8. Acquisition

On February 28, 2006 the Company closed on 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. The acquisition was funded under the Company's existing credit facility. The Company purchased 100% interests in Piceance Operating

Company LLC (which owns a 50% working interest in the acquired assets). The total purchase price was allocated as follows, $30 million to proved reserves and $129 million to unproved properties. Allocation was made based on fair value. The operating activities of these oil and gas assets are insignificant compared to Berry's historical operations and therefore are omitted from disclosure. Piceance Operating Company LLC is the subsidiary obtained in the acquisition and is consolidated into the financial statements.

9. Income Taxes

The Company's effective tax rate was 39% for the first quarter of 2006 compared to 30% for the fourth quarter of 2005 and 33% for the first quarter of 2005. The effective tax rate was lower in 2005 due to the Company's investment in projects that qualified for the enhanced oil recovery (EOR) tax credits. The federal and state EOR tax credits are fully phased out in 2006 due to the 2005 average U.S. wellhead crude oil price exceeding the allowable EOR tax credit ceiling price of approximately $44.50 per barrel.

10.Subsequent Event

In April 2006, the Company increased its existing credit facility borrowing base from $350 million to $500 million and extended the term by one year to July 2011.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

General. The following discussion provides information on the results of operations for each of the three month periods ended March 31, 2006 and 2005 and the financial condition, liquidity and capital resources as of March 31, 2006. The financial statements and the notes thereto contain detailed information that should be referred to in conjunction with this discussion.

The profitability of our operations in any particular accounting period will be directly related to the realized prices of oil, gas and electricity sold, the type and volume of oil and gas produced and electricity generated and the results of development, exploitation, acquisition, exploration and hedging activities. The realized prices for natural gas and electricity will fluctuate from one period to another due to regional market conditions and other factors, while oil prices will be predominantly influenced by world supply and demand. The aggregate amount of oil and gas produced may fluctuate based on the success of development and exploitation of oil and gas reserves pursuant to current reservoir management. The cost of natural gas used in our steaming operations and electrical generation, production rates, labor, equipment costs, maintenance expenses, and production taxes are expected to be the principal influences on operating costs. Accordingly, our results of operations may fluctuate from period to period based on the foregoing principal factors, among others.

Corporate Strategy. Our mission is to increase shareholder value, primarily through increasing the net asset value and maximizing the cash flow and earnings of our 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, utilize available technologies, reduce our risk and/or improve efficiencies

Key First Quarter Items.

- Achieved production which averaged 23,461 BOE/D, up 6% from the first quarter of 2005
- Announced discovery in Green River formation at Lake Canyon, Utah
- Acquired operatorship and significant working interest in Piceance, Colorado natural gas assets - acquisition cost of $159 million
- Increased our 2006 capital budget by $48 million to $208 million to include development of our Piceance Basin assets
- Placed natural gas hedges (both swaps and collars) on an average of 15,000 MMBtu per day of future production from 2006 through 2008
- Have two wells testing commercial quantities of gas at Coyote Flats, Utah and wrote off two dry holes
- Added J. Frank Keller to the Board of Directors in February 2006
- Purchased drilling rig for Piceance Basin drilling program

Anticipated and Completed Key Second Quarter Items.

- Added financial capacity by increasing our credit facility borrowing base by $150 million to $500 million
- Will take delivery of automated drilling rig in California
- Two-for-one split of Class A Common Stock and Class B Stock to be completed upon shareholder approval in May
- Anticipate adding 240 net acres to our Poso Creek, California enhanced oil recovery project
- Production has increased to 25,000 BOE/D in the first week of May 2006
- Poso Creek, California achieved a 1,000 BOE/D milestone in April 2006
- Secured commitments for three additional rigs to begin drilling on our Piceance Basin property by July 2006

Acquisitions. On February 28, 2006, we completed the acquisition of a 50% working interest in 6,314 acres in the Piceance Basin of western Colorado for approximately $159 million. We estimate our net share of reserves on these properties to be 330 billion cubic feet (Bcf), which are comprised of 26 Bcf of proved reserves and 304 Bcf of probable reserves. Since acquisition, we are drilling our fifth gross well and as of the first week of May 2006 there are 10 wells producing on this acreage. We have budgeted approximately $48 million for the initial development of this asset in 2006 and are projecting to exit 2006 at approximately 10 MMcf per day of production, net to our interest.

Results of Operations. The following companywide results are in thousands (except per share data) for the three months ended:

	March 31, 2006	March 31, 2005	Change	December 31, 2005	Change
Sales of oil	$ 83,280	$ 65,844	26%	$ 74,588	12%
Sales of gas	18,652	9,547	95%	22,467	(17%)
Total sales of oil and gas	$ 101,932	$ 75,391	35%	$ 97,055	5%
Sales of electricity	15,169	12,456	22%	18,328	(17%)
Interest and other income, net	493	148	233%	674	(27%)
Total revenues and other income	$ 117,594	$ 87,995	34%	$ 116,057	1%
Net income	$ 23,251	$ 22,505	3%	$ 30,372	(23%)
Earnings per share (diluted)	$ 1.03	$ 1.00	3%	$ 1.35	(24%)

Our revenues may vary significantly from period to period as a result of changes in commodity prices and/or production volumes. Improvements in production volume are due to acquisitions and sizable capital investments. Improvement in prices during 2006 are due to a tighter supply and demand balance and the nervousness of the market about possible supply disruptions, and in particular Iran and its nuclear aspirations. In 2006, we anticipate production, excluding potential future acquisitions, to average approximately 25,800 BOE/D.

Our production for the quarter ended March 31, 2006 was 23,461 BOE/D, which was up 6% from the first quarter of 2005, but lower by 1% from the fourth quarter of 2005. Our production was lower in this quarter versus our initial expectations primarily as a result of changes at our California South Midway-Sunset field including a modification in our steaming practices, the shut-in of a number of horizontal wells while we drilled a series of infill horizontal wells and weather related outages. In the first quarter we revised our steam injection patterns wherein we intend to improve production and ultimate recovery of our reserves by managing the steam volumes in the entire reservoir instead of managing the steam by decisions based on each well’s individual performance. Our production in early May is increasing from this field as our new steam injection methodology is beginning to respond and the majority of our horizontal wells are back on production.

From the first quarter of 2006 as compared to the fourth quarter 2005, there was an approximate 575 BOE/D decrease in California production and an approximate 360 BOE/D increase in Rockies and Mid-Continent production, for a net 215 BOE/D decrease quarter to quarter. Our Rockies and Mid-Continent production is meeting our expectations and averaged approximately 7,950 BOE/D in the first quarter of 2006.

In the first quarter of 2006, we incurred charges of $2.3 million in exploration costs which consists of our geological and geophysical (G&G) costs, primarily 3D surveys and data accumulation, associated with our Tri-State and Uinta Basin acreage. We project our total exploration expense for 2006 to be between $5 million and $6 million. We also incurred charges of $5.2 million for two dry holes drilled at the Coyote Flats, Utah prospect. One well tested the acreage west of the Scofield reservoir and the other well was our first test of the Emery Coals. As we continue to determine the size of the reservoir at Coyote Flats, we have now drilled two wells that are each testing gas in excess of 900 Mcf per day near the discovery well which was drilled in 2003 with peak rates exceeding 1 MMcf per day. In addition to the two dry holes at Coyote Flats, we also had one non-commercial well in the North Dakota Bakken play and one dry hole on our Tri-State acreage in the first quarter of 2006. The combined dry hole expense for these two wells was less than $.3 million.

In the first quarter ended March 31, 2006, we took a charge for the change in fair market value of our natural gas derivatives we put in place to protect our Piceance Basin acquisition economics. These gas derivatives do not qualify for hedge accounting under SFAS 133, thus, it is necessary to record any mark-to-market gains or losses into the respective accounting period. The pre-tax charge in the first quarter is $4.8 million which represents the change in fair market value over the life of the contract, and is a result of an increase in natural gas prices from the date of the derivative. We expect that we will be recording a non-cash gain or loss related to these derivative instruments in each subsequent quarter until the expiration date of December 31, 2008 (see page 18 for hedge details) as the underlying future commodity price curves increase or decrease.

Operating data. The following table is for the three months ended:

	March 31, 2006	%	March 31, 2005	%	December 31, 2005	%
Oil and Gas						
Heavy Oil Production (Bbl/D)	15,407	66	15,813	72	15,997	68
Light Oil Production (Bbl/D)	3,303	14	3,343	15	3,438	15
Total Oil Production (Bbl/D)	18,710	80	19,156	87	19,435	83
Natural Gas Production (Mcf/D)	28,507	20	17,347	13	25,428	17
Total (BOE/D)	23,461	100	22,047	100	23,673	100
Percentage increase from prior year	6%					
Per BOE:						
Average sales price before hedging	$ 50.04		$ 40.89		$ 51.71	
Average sales price after hedging	48.45		37.81		44.90	
Oil, per Bbl:						
Average WTI price	$ 63.48		$ 49.85		$ 60.05	
Price sensitive royalties	(5.41)		(3.12)		(5.02)	
Gravity differential	(6.36)		(5.22)		(5.38)	
Crude oil hedges	(2.04)		(3.54)		(7.54)	
Average oil sales price after hedging	$ 49.67		$ 37.97		$ 42.11	
Gas, per MMBtu:						
Average Henry Hub price	$ 7.92		$ 6.27		$ 12.48	
Natural gas hedges	(.03)		-		(.55)	
Location and quality differentials	(1.05)		(.79)		(2.92)	
Average gas sales price after hedging	$ 6.84		$ 5.48		$ 9.01	

Oil Contracts. On November 21, 2005, we entered into a new crude oil sales contract for our California production for deliveries beginning February 1, 2006 and ending January 31, 2010 for approximately 15,000 net barrels per day. 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.

Brundage Canyon crude oil production, which is approximately 40 degree API gravity, is currently sold under contract at WTI less a fixed differential approximating $2.00 per barrel. This contract expires on September 30, 2006. The differential of this crude oil to WTI, based on recent postings, has widened to approximately $9.00 per barrel. We are investigating our market opportunities for this crude oil and are in negotiations with several refineries on certain quantities of our production. While the ultimate outcome of future crude oil sales contracts remains uncertain, we are working diligently to place the majority of our Uinta Basin crude production with refiners at prices approximating market. We may also renegotiate our existing crude oil sales contract near current market prices in an effort to secure a longer term contract for our crude.

Hedging. See Note 4 to the unaudited condensed consolidated financial statements and Item 3. Quantitative and Qualitative Disclosures about Market Risk.

Electricity. We consume natural gas as fuel to operate our three cogeneration facilities which are intended to provide an efficient and secure long-term supply of steam necessary for the economic production of heavy oil. Revenue and operating costs in the three months ended March 31, 2006 were up from the three months ended March 31, 2005 due to 25% higher electricity prices and 25% higher natural gas prices, respectively. However, revenue and operating costs in the three months ended March 31, 2006 were down from the three months ended December 31, 2005 due to 16% lower electricity prices and 29% lower natural gas prices, respectively. We purchased approximately 38 MMBtu/D and 39 MMBtu/D, respectively, as fuel for use in our cogeneration facilities in the three months ended March 31, 2006 and 2005. The following table is for the three months ended:

	March 31, 2006	March 31, 2005	December 31, 2005
Electricity			
Revenues (in millions)	$ 15.2	$ 12.5	$ 18.3
Operating costs (in millions)	$ 14.3	$ 13.4	$ 18.5
Increase (decrease) to total oil and gas operating expenses-per barrel	$ .40	$ (.45)	$ (.07)
Electric power produced - MWh/D	2,080	2,117	2,082
Electric power sold - MWh/D	1,884	1,918	1,886
Average sales price/MWh after hedging	$ 85.93	$ 68.87	$ 101.73
Fuel gas cost/MMBtu (excluding transportation)	$ 7.19	$ 5.74	$ 10.07

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 three month periods ended:

	Amount per BOE			Amount (in thousands)		
	March 31, 2006	March 31, 2005	December 31, 2005	March 31, 2006	March 31, 2005	December 31, 2005
Operating costs - oil and gas production	$ 12.19	$ 10.53	$ 13.66	$ 25,738	$ 20,892	$ 29,710
Production taxes	1.53	1.27	1.35	3,233	2,515	2,937
DD&A - oil and gas production	6.26	4.30	5.22	13,223	8,527	11,350
G&A	3.94	2.43	2.49	8,314	4,820	5,408
Interest expense	.75	.59	.71	1,577	1,162	1,548
Total	$ 24.67	$ 19.12	$ 23.43	$ 52,085	$ 37,916	$ 50,953

Our total operating costs, production taxes, G&A and interest expenses for the three months ended March 31, 2006, stated on a unit-of-production basis, increased 29% over the three months ended March 31, 2005 and increased 5% over the three months ended December 31, 2005. The changes were primarily related to the following items:

· Operating costs: Operating costs in the first quarter of 2006 were higher than the first quarter of 2005 due to higher costs of steaming operations, increased well servicing activities and higher cost of goods and services in general. However, operating costs were lower in the first quarter of 2006 as compared to the fourth quarter of 2005, primarily due to the decrease in fuel gas cost. The cost of our steaming operations on our heavy oil properties in California vary depending on the cost of natural gas used as fuel and the volume of steam injected. The following table presents steam information:

	March 31, 2006	March 31, 2005	Change	December 31, 2005	Change
Average volume of steam injected (Bbl/D)	75,138	70,440	7%	73,312	2%
Fuel gas cost/MMBtu	$7.19	$5.74	25%	$10.07	(29%)

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

· Depreciation, depletion and amortization: DD&A increased per BOE in the three months ended March 31, 2006 due to higher acquisition costs of our Rocky Mountain and Mid-Continent region assets as compared to our legacy heavy oil assets in California and higher finding and development costs. As these costs increase, our DD&A rates per BOE will also increase.

· General and administrative: Approximately two-thirds of our G&A is compensation or compensation related costs. To remain competitive in workforce compensation and achieve our growth goals, the Company's compensation costs increased significantly due to additional staffing, higher compensation levels, bonuses, stock compensation and benefit costs. We also incurred higher employee travel and other G&A costs associated with our growth activities.

· Interest expense: We increased our outstanding borrowings to $249 million at March 31, 2006 as compared to $75 million at December 31, 2005. Average borrowings increased as a result of an acquisition of $159 million during February 2006. A certain portion of our interest cost related to our Piceance Basin acquisition has been capitalized into the basis of the asset, and we anticipate more will be capitalized during 2006.

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

		Anticipated range in 2006 per BOE
Operating costs-oil and gas production (1)	$	11.75 to 13.75
Production taxes		1.35 to 1.65
DD&A		6.00 to 6.75
G&A		3.40 to 3.80
Interest expense		.60 to 1.00
Total	$	23.10 to 26.95

(1) Assuming natural gas prices of approximately NYMEX HH $7.50 MMBtu, we plan to inject steam at levels in 2006 comparable to, or slightly higher than 2005 levels.

Income Taxes. See Note 9 to the unaudited condensed consolidated financial statements. Our effective tax rate will be higher in 2006 as compared to 2005 due to the phase-out of the EOR tax credit in 2006. We experienced an effective tax rate in the first quarter of 39%, which is in line with our projections.

Development, Exploitation and Exploration Activity. Berry drilled 95 gross (65 net) wells during the first quarter of 2006, realizing a gross success rate of 97 percent. We expect total expenditures of $208 million, excluding any future acquisitions in 2006. As of March 31, 2006, we have seven rigs drilling on our properties under long term contracts, one of which we own. We have several more rigs scheduled to begin in mid-2006, including the two other rigs we own which are being refurbished.

Uinta Basin

Brundage Canyon: In the first quarter we drilled 20 gross (20 net) wells at Brundage Canyon with 100% success rate. We added a gas plant and significantly upgraded the gas gathering infrastructure, including the addition of 30 miles of pressurized gas line, to handle significantly higher volumes of natural gas. We are meeting all requirements to proceed with drilling in the Ashley National Forest where we anticipate drilling up to 14 wells in 2006.

Lake Canyon - Shallow: In January 2006, we announced commercial success from our first two wells on this acreage which is approximately three miles west of our Brundage Canyon field. These wells contributed 45 net barrels of oil per day in our first quarter. A gas pipeline to the area and to the wells was completed in early May, thus gas production and sales are commencing out of these two wells. We are in the permitting process with another 30 wells which is intended to continue exploratory and development drilling on approximately 20,000 acres on the eastern edge of this 169,000 acre block.

Lake Canyon - Deep: Berry's industry partner is testing and evaluating a formation interval (6,600 foot depth) in the #1 DLB well. Production of 42 degree API crude oil has been established and a sustained production test over several months is needed in order to quantify the magnitude of this discovery. Berry has a 25% working interest in this well.

Coyote Flats: We have two successful appraisal Ferron gas wells on the east side of the Scofield reservoir which have each tested flow rates exceeding 900 Mcf per day. We are planning to construct a 13 mile gas pipeline to transport the gas to a sales point and anticipate sales will begin in the third quarter of 2006. In the first quarter of 2006, we determined that our Emery coalbed methane well and our Ferron gas well, which were drilled west of the Scofield reservoir, were dry holes. To better delineate the areal extent of the Ferron and to improve our drilling success rate, we are designing a 15.5 square mile 3D seismic survey on the more promising acreage. We have now completed five of our nine-well drilling commitment under our drill-to-earn agreement.

Denver-Julesburg Basin
Tri-State Area: In Yuma County, Colorado, we have drilled 43 wells in the first quarter with one dry hole and are upgrading our gas gathering facilities to handle production increases. In the Phillips County, Colorado, Paoli prospect, we have completed the acquisition of 20 square miles of 3D seismic and are planning to begin drilling in the second quarter of 2006. In our Tri-State area, Berry's industry partner has recently completed four 3D seismic surveys covering a total of 62 square miles and we plan to drill exploratory wells in the second and third quarters of 2006 based on the results of those surveys.

Williston Basin
Bakken Play: We continue to be an active participant in several wells in North Dakota. We wrote off one well as non-commercial for approximately $.3 million and the other wells, in which we have an interest, are being tested and/or evaluated. It is our intent to participate with a low working interest in a number of wells in the area over the next year so we can gather data with respect to the potential of our acreage position.

Piceance Basin
Grand Valley: In early May, we had 10 wells completed and producing into a sales line. We are drilling our fifth gross well on the property since our acquisition and have completed seven wells since the acquisition with initial test rates per well between 1.3 and 2 MMcf/D. These results are consistent with our acquisition metrics. Our net production in March averaged 1.1 MMcf/D and in early May it is averaging over 4 MMcf/D. We currently have one drilling rig running and plan to add three more rigs by mid-year 2006. We have made significant progress in gearing up for extensive development of this asset beginning in mid-year 2006. We anticipate drilling a total of 35 gross wells on this asset in 2006 and are planning for approximately 78 wells in 2007. We expect gas production from this project to increase quarter over quarter as we proceed with our development.

Diatomite
The project's current performance is meeting our expectations and our goal of determining commerciality in 2006 is on track. During the first quarter of 2006 we have focused our efforts on integrating the large scale, 25 well expansion to the pilot steam flood project that we drilled in late 2005. Steam injection has increased, per well production performance is improving and we have seen consistent production growth nearing 300 BOE/D. We continue to accumulate data, monitor subsurface temperatures and reservoir response and modify our application of technology and operating practices in ways that we believe will lead to commercial development.

Midway-Sunset
A total of 17 well were drilled (including eight horizontal wells) during the first quarter of 2006. The horizontal wells were drilled at the end of the first quarter with initial steam cycles occurring in the second quarter. The vertical wells were drilled as part of our Ethel D property thermal revitalization efforts where production has increased from approximately 300 BOE/D in December to its current level of over 700 BOE/D.

In an effort to improve production and make better use of our steam, we modified our cyclic steam injection practices. The modifications were made to heat regions of the reservoir to accelerate response as opposed to choosing cyclic candidates based on individual well performance. This decision was made, in part, based on successful results from a targeted application of this approach during our 2005 cyclic steaming program. While this methodology resulted in lower first quarter production, we believe it will ultimately result in improved recoveries.

Poso Creek

During the first quarter of 2006, we continued the successful redevelopment of the Poso Creek field through continued steam flood injection into our pilot area, drilling seven additional infill wells and consolidating operations by acquiring offsetting properties. Production on this property was negligible when Berry acquired it in 2003. Through thermal redevelopment, we have seen production consistently increase to current levels which are currently above 1,000 BOE/D. To build on our position at Poso Creek we added 40 acres to the west of our existing operations in the first quarter and expect to close on an additional 240 acres to the south of our project in the second quarter of 2006.

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

	Gross Wells	Net Wells	Workovers
Midway-Sunset	17	16.8	6
Poso Creek	7	7.0	2
Placerita	-	-	6
Brundage Canyon	20	20.0	14
Coyote Flats *(1)*	2	2.0	-
Tri-State *(2)*	43	16.6	15
Piceance	5	2.5	-
Bakken *(3)*	1	.1	-
Totals	**95**	**65.0**	**43**

(1) Includes 2 gross wells that were dry holes. Acreage ownership is earned upon fulfilling certain drilling obligations.

(2) Includes 1 gross well (.3 net well) that was a dry hole

(3) Includes 1 gross well (.06 net well) that was a dry hole.

California Drilling Rig. In 2005, we entered into a three-year drilling contract for the services of an automated drilling rig. This rig provides a means for us to meet at least half of our 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, we purchased two drilling rigs, one of which is currently drilling while the other is being refurbished. These rigs are leased to a drilling company under a three year contract and carry purchase options available to the drilling company. Owning these rigs allows us to successfully meet a portion of our drilling needs in the Uinta Basin over the next several years. In February 2006, we purchased a third drilling rig, which upon refurbishment, is expected to cost approximately $9 million and will be used in our Piceance Basin development program. We have several more rigs contracted to begin in mid-2006.

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, we plan to invest approximately $147 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. All capital expenditures, excluding acquisitions, are funded out of internally generated cash flow.

Dividends. In 2005, we increased the dividend for the third consecutive year and the current quarterly dividend is $.13 per share.

Stock Split. On March 1, 2006, our Board of Directors approved a two-for-one split of our 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 May 17, 2006 annual meeting. Berry's shareholders are being asked to approve an increase in the 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 on June 5, 2006. Based on shares outstanding on May 1, 2006, Berry would have approximately 42.4 million shares of Common Stock and 1.8 million shares of Class B Stock outstanding following the proposed stock split

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

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

The table below compares financial condition, liquidity and capital resources changes for the three month periods ended as follows (in millions, except for production and average prices):

	March 31, 2006	March 31, 2005	Change	December 31, 2005	Change
Production (BOE/D)	23,461	22,047	6%	23,673	(1%)
Average oil and gas sales prices, per BOE after hedging	$ 48.45	$ 37.81	28%	$ 44.90	8%
Net cash provided by operating activities	$ 25	$ 19	32%	$ 65	(62%)
Working capital	$ (40)	$ (1)	*negligible*	$ (55)	(27%)
Sales of oil and gas	$ 102	$ 75	36%	$ 97	5%
Long-term debt	$ 249	$ 138	80%	$ 75	232%
Capital expenditures, including acquisitions and deposits on acquisitions	$ 206	$ 125	65%	$ 46	348%
Dividends paid	$ 2.9	$ 2.6	12%	$ 2.9	-

Contractual Obligations. Berry's contractual obligations as of March 31, 2006 are as follows (in thousands) for the years ended:

	Total	2006	2007	2008	2009	2010	Thereafter
Long-term debt and interest	$ 265,011	$ 4,003	$ 4,003	$ 4,003	$ 4,002	$ 249,000	$ -
Abandonment obligations	10,724	315	360	539	556	556	8,398
Operating lease obligations	11,521	1,046	1,400	1,370	1,178	955	5,572
Drilling and rig obligations	22,383	14,633	2,400	2,950	2,400	-	-
Firm natural gas transportation contracts	35,625	3,706	4,574	4,398	4,386	4,386	14,175
Total	$ 345,264	$ 23,703	$ 12,737	$ 13,260	$ 12,522	$ 254,897	$ 28,145

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

<u>Operating leases</u> - We lease corporate and field offices in California and Colorado.

Drilling obligation - We intend to participate in the drilling of over 16 gross wells on our Lake Canyon prospect over the next four years, and our minimum obligation under our exploration and development agreement is $9.6 million.

Drilling rig obligation - We are obligated in operating lease agreements for the use of multiple drilling rigs, each for one year or less ending in 2006.

Firm natural gas transportation - We entered into several firm transportation contracts which provide us additional flexibility in securing our natural gas supply and allow us to potentially benefit from lower natural gas prices in the Rocky Mountains compared to natural gas prices in California.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

As discussed in Note 4 to the unaudited condensed consolidated financial statements, to minimize the effect of a downturn in oil and gas prices and protect our profitability and the economics of our development plans, from time to time we enter into crude oil and natural gas hedge contracts. The terms of contracts depend on various factors, including Management's view of future crude oil and natural gas prices, acquisition economics on purchased assets and our future financial commitments. This price hedging program is designed to moderate the effects of a severe crude oil and natural gas price downturn while allowing us to participate in the upside. In California, we benefit from lower natural gas pricing and elsewhere, we benefit from higher natural gas pricing. We have hedged, and may hedge in the future both natural gas purchases and sales as determined appropriate by Management. Management regularly monitors the crude oil and natural gas markets and our financial commitments to determine if, when, and at what level some form of crude oil and/or natural gas hedging or other price protection is appropriate in accordance with Board established policy.

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

The following table summarizes our hedge position as of March 31, 2006:

Term	Average Barrels Per Day	Average Price	Term	Average MMBtu Per Day	Average Price
Crude Oil Sales (NYMEX WTI)			**Natural Gas Purchases (SoCal Border)**		
Swaps			**Swaps**		
2nd Quarter 2006	3,000	$50.20	2nd Quarter 2006	5,000	$4.85
3rd Quarter 2006	3,000	$49.56			
			Natural Gas Sales (NYMEX HH)		
Collars		Floor/Ceiling Prices	**Swaps**		
1st through 3rd Quarter 2006	7,000	$47.50 / $70	2nd Quarter 2006	4,000	$6.96
4th Quarter 2006	10,000	$47.50 / $70	3rd Quarter 2006	6,000	$7.35
Full year 2007	10,000	$47.50 / $70			
Full year 2008	10,000	$47.50 / $70	**Collars**		Floor/Ceiling Prices
Full year 2009	10,000	$47.50 / $70	4th Quarter 2006	8,000	$8.00 / $9.72
			1st Quarter 2007	12,000	$8.00 / $16.70
			2nd Quarter 2007	13,000	$8.00 / $8.82
			3rd Quarter 2007	14,000	$8.00 / $9.10
			4th Quarter 2007	15,000	$8.00 / $11.39
			1st Quarter 2008	16,000	$8.00 / $15.65

	2nd Quarter 2008	17,000	$7.50 / $8.40
	3rd Quarter 2008	19,000	$7.50 / $8.50
	4th Quarter 2008	21,000	$8.00 / $9.50

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

The use of hedging transactions also involves the risk that the counterparties will be unable to meet the financial terms of such transactions. With respect to our hedging activities, we utilize multiple counterparties on our hedges and monitor each counterparty’s credit rating. We also attempt to minimize credit exposure to counterparties through diversification.

Based on NYMEX futures prices as of March 31, 2006, (WTI $68.71; HH $9.09) and due to the backwardated nature of the futures prices as of that date, we would expect to make pre-tax future cash payments or to receive payments over the remaining term of our crude oil and natural gas hedges in place as follows:

	March 31, 2006 NYMEX Futures	Impact of percent change in futures prices on earnings -20%	-10%	+ 10%	+ 20%
Average WTI Price	$ 68.71	$ 54.97	$ 61.84	$ 75.59	$ 82.46
Crude Oil gain/(loss) (in millions)	(10.4)	(2.8)	(6.6)	(87.5)	(181.7)
Average HH Price	9.09	7.27	8.18	10.00	10.91
Natural Gas gain/(loss) (in millions)	(.8)	7.1	.7	(8.4)	(17.4)
Net pre-tax future cash (payments) and receipts by year (in millions):					
2006	$ (10.6)	$ (1.8)	$ (6.1)	$ (28.6)	$ (48.7)
2007	(.2)	2.3	-	(26.8)	(55.5)
2008	(.4)	3.8	.2	(24.7)	(54.4)
2009	-	-	-	(15.8)	(40.5)
Total	$ (11.2)	$ 4.3	$ (5.9)	$ (95.9)	$ (199.1)

Interest Rates. Our exposure to changes in interest rates results primarily from long-term debt. Total long-term debt outstanding at March 31, 2006 was $249 million. Interest on amounts borrowed is charged at LIBOR plus 1.0% to 1.75%. Based on these borrowings, a 1% change in interest rates would have a $2.5 million impact on our financial statements.

Item 4. Controls and Procedures

As of March 31, 2006, we have carried out an evaluation under the supervision of, and with the participation of Management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15 under the Securities and Exchange Act of 1934, as amended.

Based on their evaluation as of March 31, 2006, the Chief Executive Officer and Chief Financial Officer have concluded that our 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 in the reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms.

There was no change in our internal control over financial reporting during the most recently completed calendar quarter that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Forward Looking Statements

“Safe harbor under the Private Securities Litigation Reform Act of 1995:” Any statements in this Form 10-Q that are not historical facts are forward-looking statements that involve risks and uncertainties. Words such as “estimate,” “will,” “intend,” “continue,” “target,” “expect,” “achieve,” “strategy,” “future,” “may,” “goal(s),” or other comparable words or phras 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 Berry's 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."

PART II. OTHER INFORMATION

Item 1. Legal Proceedings
None.

Item 1A. Risk Factors
No material changes from 2005 Form 10-K.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds
None.

Item 3. Defaults Upon Senior Securities
None.

Item 4. Submission of Matters to a Vote of Security Holders
None.

Item 5. Other Information
None.

Item 6. Exhibits

Exhibit No. Description of Exhibit
10.1* Amended and Restated Purchase and Sale Agreement between Registrant and Orion Energy Partners, LP.
10.2 Second Amendment to Credit Agreement, dated as of April 28, 2006 by and between the Registrant and Wells Fargo Bank, N.A. and other financial institutions
31.1 Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2 Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1 Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2 Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Incorporated by reference in the Company's 2005 annual report on Form 10-K filed on March 6, 2006

SIGNATURE

Pursuant to the requirements 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.

BERRY PETROLEUM COMPANY

/s/ Donald A. Dale
Donald A. Dale
Controller
(Principal Accounting Officer)

Date: May 9, 2006