BERRY PETROLEUM CO
Form 10-Q
August 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 **June 30, 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 July 21, 2006, the registrant had 42,062,030 shares of Class A Common Stock ($.01 par value) outstanding. The registrant also had 1,797,784 shares of Class B Stock outstanding on July 21, 2006 all of which is held by an affiliate of the registrant.

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BERRY PETROLEUM COMPANY
SECOND QUARTER 2006 FORM 10-Q
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BERRY PETROLEUM COMPANY
Unaudited Condensed Balance Sheets
(In Thousands, Except Share Information)

	June 30, 2006	December 31, 2005
ASSETS		
Current assets:		
Cash and cash equivalents	$ 626	$ 1,990
Short-term investments available for sale	662	661
Accounts receivable	75,345	59,672
Deferred income taxes	13,006	4,547
Fair value of derivatives	2,780	3,618
Prepaid expenses and other	8,426	4,398
Total current assets	100,845	74,886
Oil and gas properties (successful efforts basis), buildings and equipment, net	784,216	552,984
Long-term deferred income taxes	514	1,600
Fair value of derivatives	1,165	-
Other assets	13,255	5,581
	$ 899,995	$ 635,051
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 59,817	$ 57,783
Revenue and royalties payable	26,542	34,920
Accrued liabilities	14,967	8,805
Line of credit	23,500	11,500
Income taxes payable	1,256	1,237
Fair value of derivatives	35,958	15,398
Total current liabilities	162,040	129,643
Long-term liabilities:		
Deferred income taxes	59,456	55,804
Long-term debt	249,000	75,000
Abandonment obligation	10,812	10,675
Unearned revenue	2,046	866
Fair value of derivatives	80,719	28,853
	402,033	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, 100,000,000 shares authorized; 42,137,030 shares issued and outstanding (21,099,906 on a pre-split basis in 2005)	421	211
Class B Stock, 3,000,000 shares authorized; 1,797,784 shares issued and outstanding (liquidation preference of $1,798) (898,892 on a pre-split basis in 2005)	18	9
Capital in excess of par value	49,812	56,064
Accumulated other comprehensive loss	(68,362)	(24,380)

Retained earnings	354,033	302,306
Total shareholders' equity	335,922	334,210
	$ 899,995	$ 635,051

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

BERRY PETROLEUM COMPANY
Unaudited Condensed Statements of Income
Three Month Periods Ended June 30, 2006 and 2005
(In Thousands, Except Per Share Data)

	Three months ended June 30,	
	2006	2005 (1)
REVENUES		
Sales of oil and gas	$ 110,641	$ 80,825
Sales of electricity	11,715	11,514
Interest and other income, net	803	350
	123,159	92,689
EXPENSES		
Operating costs - oil and gas production	27,074	24,194
Operating costs - electricity generation	10,626	10,923
Production taxes	3,373	2,180
Exploration costs	1,472	225
Depreciation, depletion & amortization - oil and gas production	16,263	9,461
Depreciation, depletion & amortization - electricity generation	807	839
General and administrative	7,877	5,204
Interest	2,460	1,740
Commodity derivatives	(5,563)	-
Dry hole, abandonment and impairment	1,573	601
	65,962	55,367
Income before income taxes	57,197	37,322
Provision for income taxes	22,994	12,062
Net income	$ 34,203	$ 25,260
Basic net income per share	$ .78	$ .57
Diluted net income per share	$ .76	$ .56
Dividends per share	$ .065	$ .060
Weighted average number of shares of capital stock outstanding (used to calculate basic net income per share)	44,053	44,134
Effect of dilutive securities:		
Equity based compensation	785	654
Director deferred compensation	101	114
Weighted average number of shares of capital stock used to calculate diluted net income per share	44,939	44,902

Unaudited Condensed Statements of Comprehensive Income
Three Month Periods Ended June 30, 2006 and 2005

(In Thousands)				
Net income	$	34,203	$	25,260
Unrealized losses on derivatives, net of income taxes of ($11,414) and ($1,237), respectively		(17,121)		(1,855)
Reclassification of realized losses included in net income net of income taxes of ($1,178) and ($271), respectively		(1,767)		(406)
Comprehensive income	$	15,315	$	22,999

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

(1) The 2005 earnings per share amounts have been restated to give retroactive effect to the two-for-one stock split that became effective on May 17, 2006. See Note 2.

BERRY PETROLEUM COMPANY
Unaudited Condensed Statements of Income
Six Month Periods Ended June 30, 2006 and 2005
(In Thousands, Except Per Share Data)

	Six months ended June 30,	
	2006	2005 (1)
REVENUES		
Sales of oil and gas	$ 212,575	$ 156,196
Sales of electricity	26,884	23,970
Interest and other income, net	1,296	518
	240,755	180,684
EXPENSES		
Operating costs - oil and gas production	52,813	45,086
Operating costs - electricity generation	24,958	24,281
Production taxes	6,606	4,695
Exploration costs	3,761	786
Depreciation, depletion & amortization - oil and gas production	29,359	17,988
Depreciation, depletion & amortization - electricity generation	1,701	1,611
General and administrative	16,192	10,023
Interest	4,038	2,902
Commodity derivatives	(736)	-
Dry hole, abandonment and impairment	6,782	2,622
	145,474	109,994
Income before income taxes	95,281	70,690
Provision for income taxes	37,827	22,925
Net income	$ 57,454	$ 47,765
Basic net income per share	$ 1.31	$ 1.08
Diluted net income per share	$ 1.28	$ 1.06
Dividends per share	$ .13	$ .12
Weighted average number of shares of capital stock outstanding (used to calculate basic net income per share)	44,020	44,048
Effect of dilutive securities:		
Equity based compensation	836	766
Director deferred compensation	99	114
Weighted average number of shares of capital stock used to calculate diluted net income per share	44,955	44,928

Unaudited Condensed Statements of Comprehensive Income
Six Month Periods Ended June 30, 2006 and 2005

(In Thousands)				
Net income	$	57,454	$	47,765
Unrealized losses on derivatives, net of income taxes of ($26,965) and ($13,019), respectively		(40,448)		(19,529)
Reclassification of realized (losses) gains included in net income net of income taxes of ($2,356) and ($541), respectively		(3,534)		(811)
Comprehensive income	$	13,472	$	27,425

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

(1) The 2005 earnings per share amounts have been restated to give retroactive effect to the two-for-one stock split that became effective on May 17, 2006. See Note 2.

BERRY PETROLEUM COMPANY
Unaudited Condensed Statements of Cash Flows
Six Month Periods Ended June 30, 2006 and 2005
(In Thousands)

	Six months ended June 30,	
	2006	2005
Cash flows from operating activities:		
Net income	$ 57,454	$ 47,765
Depreciation, depletion and amortization	31,060	19,599
Dry hole, abandonment and impairment	6,375	15
Commodity derivatives	(674)	-
Stock-based compensation expense	2,199	969
Deferred income taxes, net	25,068	10,064
Other, net	(64)	179
Increase in current assets other than cash, cash equivalents and short-term investments	(18,596)	(17,840)
(Decrease) increase in current liabilities other than book overdraft, line of credit and fair value of derivatives	(18,726)	5,440
Net cash provided by operating activities	84,096	66,191
Cash flows from investing activities:		
Exploration and development of oil and gas properties	(103,939)	(57,134)
Property acquisitions	(161,600)	(103,712)
Additions to vehicles, drilling rigs and other fixed assets	(5,892)	(3,375)
Net cash used in investing activities	(271,431)	(164,221)
Cash flows from financing activities:		
Proceeds from issuance of line of credit	155,000	-
Payment of line of credit	(143,000)	-
Proceeds from issuance of long-term debt	235,250	116,000
Payment of long-term debt	(61,250)	(19,000)
Dividends paid	(5,726)	(5,290)
Debt issuance cost	(313)	(809)
Increase in book overdraft	14,242	-
Stock option exercises	4,539	-
Repurchase of shares of common stock	(12,771)	-
Net cash provided by financing activities	185,971	90,901
Net decrease in cash and cash equivalents	(1,364)	(7,129)
Cash and cash equivalents at beginning of year	1,990	16,690
Cash and cash equivalents at end of period	$ 626	$ 9,561
Supplemental non-cash activity:		
(Decrease) increase in fair value of derivatives:		
Current (net of income taxes of $9,015 and ($9,191), respectively)	$ (13,622)	$ 13,786
Non-current (net of income taxes of $19,775 and ($4,369), respectively)	(30,360)	6,554
Net (decrease) increase to accumulated other comprehensive income	$ (43,982)	$ 20,340

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

BERRY PETROLEUM COMPANY
Notes to the Unaudited Condensed Financial Statements

1. General

All adjustments which are, in the opinion of Management, necessary for a fair statement of Berry Petroleum Company's (the "Company") financial position at June 30, 2006 and December 31, 2005 and results of operations for the three and six month periods ended June 30, 2006 and 2005 and cash flows for the six month periods ended June 30, 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.

The accompanying unaudited condensed 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 and the March 31, 2006 Form 10-Q 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. In the second quarter 2006, the Company dissolved its subsidiary, Piceance Operating Company LLC.

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 June 30, 2006 and June 30, 2005 is $16.2 million and $1.5 million, respectively, representing outstanding checks in excess of the bank balance (book overdraft).

2. Stock Split

On March 1, 2006, the Company's Board of Directors approved a two-for-one stock split to shareholders of record on May 17, 2006, subject to obtaining shareholder approval of an increase in the Company's authorized shares. On May 17, 2006 the Company's shareholders approved the authorized share increase and on June 2, 2006 each shareholder received one additional share for each share in the shareholder's possession on May 17, 2006. This did not change the proportionate interest a shareholder maintained in the Company on that date. All shares, equity awards and per share amounts have been adjusted for the two-for-one stock split.

3. Recent Accounting Developments

In June 2006, the Financial Accounting Standards Board (FASB) issued Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109*. FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return, and provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. This Interpretation is effective for fiscal years beginning after December 15, 2006. The Company is currently assessing the potential impact of this Interpretation on its financial statements.

In February 2006, the FASB's Statement of Financial Accounting Standards (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 and while the Company anticipates no impact on its financial statements based on its existing derivatives, the Company may experience a financial impact depending on the nature and extent of any new derivative instruments entered into after the effective date of SFAS No. 155.

4. 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) using the modified prospective method, did not have a material impact on the Company’s condensed financial statements for the three or six months ended June 30, 2006.

4. Share-Based Compensation (Continued)

Equity Compensation Plans
The 2005 Equity Incentive Plan (the 2005 Plan), approved by shareholders in May 2005, provides for granting of equity compensation up to an aggregate of 2,900,000 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 has generally been 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 10,000 options at the market value on the date of grant. The options granted to the non-employee Directors vest immediately. The Company generally uses a broker for issuing new shares upon option exercise.

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 No. 123, *Accounting for Stock-Based Compensation*, which was the predecessor to SFAS No. 123(R). The modified prospective method was selected as described in SFAS No. 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.

	June 30, 2006
Expected volatility	32% - 33%
Weighted-average volatility	32.4%
Expected dividends	0.9%
Expected term (in years)	5.3
Risk-free rate	4.7%

The following is a summary of stock option activity for the six months ended June 30, 2006:

	Options	Weighted Average Exercise Price	Weighted Average Contractual Life Remaining
Balance outstanding, January 1	3,110,826	$ 16.76	
Granted	106,000	34.33	
Exercised	(391,990)	10.24	
Canceled/expired	(304,000)	18.61	
Balance outstanding, June 30	2,520,836	18.29	7.8 years

Balance exercisable at June 30	1,128,585	13.40	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. RSU's granted generally vest at either 25% per year over 4 years or 100% after 3 years. At June 30, 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 pays 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.

4. Share-Based Compensation (Continued)

The following is a summary of RSU activity for the six months ended June 30, 2006 as follows:

	RSUs	Weighted Average Intrinsic Value at Grant Date	Weighted Average Contractual Life Remaining
Balance outstanding, January 1	141,900	$ 30.65	
Granted	214,880	31.50	
Converted	-	-	
Canceled/expired	(19,400)	30.65	
Balance outstanding, June 30	337,380	31.10	3.5 years

Other share-based compensation data

	Stock Options		RSUs	
	Six months ended		Six months ended	
	June 30, 2006	June 30, 2005	June 30, 2006	June 30, 2005
Weighted-average grant date fair value	$ 11.96	$ 5.41	$ 31.50	$ -
Total intrinsic value of options exercised (in millions)	9.1	10.0	-	-
Total intrinsic value of options/RSUs outstanding (in millions)	37.5	71.8	10.5	-
Total intrinsic value of options exercisable (in millions)	22.3	25.6	-	-
Total compensation cost recognized into income (in millions)	.8	1.2	.5	-

The total compensation cost related to nonvested awards not yet recognized on June 30, 2006 is $17.2 million and the weighted average period over which this cost is expected to be recognized is 3.2 years. The tax benefit realized from stock options exercised during the three and six months ended June 30, 2006 is $1.1 million and $3.1 million, respectively.

5. Derivatives

The Company entered into derivative contracts (natural gas swaps and collar contracts) on March 1, 2006 that did not qualify for hedge accounting under SFAS 133 because the price index in the derivative instrument did not correlate closely with the item being hedged. These contracts were recorded in the first quarter of 2006 at their fair value on the balance sheet and the Company recognized an unrealized net loss of approximately $4.8 million on the income statement under the caption “Commodity derivatives.”

On May 31, 2006, the Company entered into basis swaps with natural gas volumes to match the volumes on the Company’s NYMEX Henry Hub collars that were placed on March 1, 2006. The combination of the derivative instruments entered into on March 1, 2006 (described above) and the basis swaps were designated as cash flow hedges in accordance with SFAS 133. Thus, the unrealized net gain of $5.6 million on the income statement in the second quarter of 2006 under the caption “Commodity derivatives” is primarily the change in fair value of the derivative instrument caused by changes in forward price curves prior to designating these instruments as cash flow hedges.

Additionally, on June 8, 2006, the Company entered into an interest rate swap for a fixed rate on $50 million of the Company’s outstanding borrowings under its credit facility for five years. This interest rate swap has been designated as a cash flow hedge.

The related cash flow impact of all of the Company’s derivative activities are reflected as cash flows from operating activities.

At June 30, 2006, the Company’s net fair value of derivatives liability was $116.7 million as compared to $87.3 million at March 31, 2006 and $40.6 million at December 31, 2005. As of June 30, 2006, and based on NYMEX strip pricing on that date, the Company expects to make hedge payments under the existing derivatives of $26.2 million during the next twelve months. Accumulated other comprehensive income consisted of $68.4 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 June 30, 2006. Deferred net losses recorded in Accumulated other comprehensive loss at June 30, 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.

6. Revisions to the Classification of Production Taxes

Certain amounts in the condensed income statements for the three months ended June 30, 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 and six months ended June 30, 2005 (in thousands):

		Three months ended June 30, 2005		Six months ended June 30, 2005
Operating costs - oil and gas				
As previously reported	$	26,374	$	49,781
As revised		24,194		45,086
Difference	$	(2,180)	$	(4,695)
Production taxes				
As previously reported	$	-	$	-
As revised		2,180		4,695
Difference	$	2,180	$	4,695

7. Dry Hole, Abandonment and Impairment

The amount reflected on the Company’s income statement under the dry hole, abandonment and impairment line item consists primarily of the Company’s 25% share in the #1 DLB 12-15-56, an exploration well located in the Lake Canyon project area of the Uinta Basin. This well, which was completed in late April 2006, was tested and determined in the second quarter of 2006 to be commercial in the Wasatch formation and non-commercial in the zones below the Wasatch, thus, approximately $1.6 million net to Berry’s interest was written off.

8. Joint Venture

On June 7, 2006 the Company entered into an agreement with a party to jointly develop the North Parachute Ranch property in the Piceance Basin of western Colorado for approximately $153 million payable by the Company in three installments by May 2007. The Company will fund the drilling of 90 natural gas wells on the party’s acreage with the Company holding a 5% working interest in those wells. Drilling the 90 wells on the party’s acreage will take place through December 1, 2008.

On July 7, 2006, the Company paid $51 million, which was the first installment of the total $153 million and thereby earned 4,300 gross acres elsewhere in the property with a working interest to the Company of 95% and a net revenue interest of approximately 79%. The Company is required to drill 120 wells on this acreage which drilling will take place through 2011. The 2006 budgeted capital expenditure to begin drilling wells on this acreage is approximately $24 million. At the date of the agreement there were no operating activities from these oil and gas assets.

9. Income Taxes

The Company’s effective tax rate was 40% for the second quarter of 2006 compared to 39% for the first quarter of 2006 and 32% for the second quarter of 2005. The effective tax rate was lower in 2005 due to the Company’s investment in projects that qualified for 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 $44.48 per barrel.

10. Credit Facility

In April 2006, the Company completed a new unsecured five-year bank credit agreement (the Agreement) with a banking syndicate and extended the term by one year to July 2011. The Agreement is a revolving credit facility for up to $750 million and replaces the previous $500 million facility. The current borrowing base was established at $500 million, as compared to the previous $350 million. This transaction was accounted for in accordance with Emerging Issues Task Force, (EITF) 98-14, Debtor’s Accounting for Changes in Line-of-Credit or Revolving-Debt Arrangements.

10. Credit Facility (Continued)

The total outstanding debt on the $500 million credit facility and line of credit was $273 million at June 30, 2006, leaving $227 million available. Interest on amounts borrowed is charged at LIBOR plus a margin of 1.00% to 1.75% or the prime rate, 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 a commitment fee of .25% to .38% on the unused portion of the credit facility.

The weighted average interest rate on outstanding borrowings at June 30, 2006 was 6.6%. 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 covenants as of June 30, 2006.

11. Leases Receivable

The Company entered into two separate three year lease agreements on two drilling rigs. Each agreement has a three year purchase option. The agreements were signed in the third and second quarters of 2005 and 2006, respectively. The total net investment in these rigs is approximately $8.8 million at June 30, 2006. Both agreements are accounted for as direct financing leases as defined by SFAS No. 13, *Accounting for Leases*. Net investment in both leases are included in the balance sheet as other assets and as of June 30, 2006 are as follows (in thousands):

Net minimum lease payments receivable	$ 12,191
Unearned income	(3,440)
Net investment in direct financing lease	$ 8,751

As of June 30, 2006, estimated future minimum lease payments, including the purchase option, to be received are as follows (in thousands):

2006	$ 618
2007	1,276
2008	4,545
2009	5,752
Total	$ 12,191

12. 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.

13. 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 was the subsidiary obtained in the acquisition and was subsequently dissolved.

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 and six month periods ended June 30, 2006 and 2005 and the financial condition, liquidity and capital resources as of June 30, 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 Second Quarter Items.

- Achieved production which averaged 24,768 BOE/D, up 9% from the second quarter of 2005 and 6% from the first quarter of 2006
- Entered into an agreement to jointly develop natural gas properties in the North Parachute Ranch property in the Piceance Basin, Colorado to earn a 95% working interest in 4,300 gross acres near our Grand Valley assets - capital commitment of $153 million
- Increased our 2006 capital budget to $232 million to include development of additional Piceance Basin assets
- Began $25 million, 50 well expansion of our diatomite project in California
- Accomplished production of 559 BOE/D in the Grand Valley field in the Piceance Basin
- Added 240 net acres to our Poso Creek, California enhanced oil recovery project and achieved production of 1,000 BOE/D
- Participated in a light oil discovery in the Wasatch formation at Lake Canyon and wrote off the well cost for the Mesaverde formation
- Added financial capacity by increasing our credit facility borrowing base from $350 million to $500 million
- Completed two-for-one split of Class A Common Stock and Class B Stock
- Secured commitments for three additional rigs to begin drilling on our Piceance Basin in the third quarter
- Entered into a new 43-month employment contract with President and CEO, Robert Heinemann

***Key Third Quarter Items*.**

- Earned a 95% working interest in 4,300 gross acres in the North Parachute Ranch property in the Piceance Basin of western Colorado with initial contract payment made in July

- Increasing production from the diatomite expansion and further evaluation of the pilot performance
- Drilling to appraise the Paoli prospect located near our producing areas in the Tri-State area
- Drilling in the Ashley Forest located in the southern portion of our Brundage Canyon property upon receiving approval of environmental review
- Drilling the next six wells to expand the appraisal of our Lake Canyon acreage

Joint Venture. See Note 8 to the unaudited condensed financial statements.

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

	June 30, 2006	June 30, 2005	Change	March 31, 2006	Change
Sales of oil	$ 94,965	$ 67,098	42%	$ 83,280	14%
Sales of gas	15,676	13,727	14%	18,652	(16%)
Total sales of oil and gas	$110,641	$ 80,825	37%	$ 101,932	9%
Sales of electricity	11,715	11,514	2%	15,169	(23%)
Interest and other income, net	803	350	129%	493	63%
Total revenues and other income	$123,159	$ 92,689	33%	$ 117,594	5%
Net income	$ 34,203	$ 25,260	35%	$ 23,251	47%
Earnings per share (diluted)	$ .76	$ .56	36%	$ .52	46%

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.

Our production for the quarter ended June 30, 2006 was 24,768 BOE/D, which was up 9% from the second quarter of 2005, and an increase of 6% from the first quarter of 2006. Our production increased by over 1,300 BOE/D in the second quarter over the first quarter due primarily to additional drilling. Our Rockies and Mid-Continent production is meeting our expectations and averaged just under 9,200 BOE/D in the second quarter of 2006. We are accelerating the development of three new steam floods in California to partially offset the delay in the production response to our steam optimization efforts in our core assets. Our production for the six months ended June 30, 2006 was 24,118 BOE/D, which was up 8% from the same period last year. While production continues to improve, the timing of the increases from our projects is causing us to now forecast average production of between 25,300 BOE/D and 25,800 BOE/D for 2006.

In the second quarter of 2006, we incurred charges of $1.5 million in exploration costs which consists of our geological and geophysical costs, primarily 3D surveys and data accumulation, associated with our Tri-State and Uinta Basin acreage. We project our total exploration expense for 2006 to be between $5 million and $6 million. We also incurred charges for our 25% share of a deep well drilled at Lake Canyon in the Uinta Basin. This well, which was completed in late April was tested and determined, in the second quarter of 2006, to be commercial in the Wasatch formation and non-commercial in the zones below the Wasatch, thus, approximately $1.6 million net to Berry’s interest of the well cost was written off.

In the first quarter ended March 31, 2006, we took a charge for the change in fair market value of our natural gas derivatives put in place to protect our Piceance Basin acquisition future cash flows. These gas derivatives did not qualify for hedge accounting under SFAS 133 because the price index in the derivative instrument did not correlate closely with the item being hedged. The pre-tax charge in the first quarter was $4.8 million which represented the change in fair market value over the life of the contract, which resulted from an increase in natural gas prices from the date of the derivative to March 31, 2006. On May 31, 2006, the Company entered into basis swaps with natural gas volumes to match the volumes on the Company’s NYMEX Henry Hub collars that were placed on March 1, 2006. The combination of the derivative instruments entered into on March 1, 2006 (described above) and the basis swaps were designated as cash flow hedges in accordance with SFAS 133. Thus, the unrealized net gain of $5.6 million on the income statement in the second quarter of 2006 under the caption “Commodity derivatives” is primarily the change in fair value of the derivative instrument caused by changes in forward price curves prior to designating these instruments as cash flow hedges. Post May 31, 2006 changes in the marked-to-market fair values are reflected in

Other Comprehensive Income.

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

	June 30, 2006	%	June 30, 2005	%	March 31, 2006	%
Oil and Gas						
Heavy Oil Production (Bbl/D)	15,532	63	15,733	69	15,407	66
Light Oil Production (Bbl/D)	4,061	16	3,253	14	3,303	14
Total Oil Production (Bbl/D)	19,593	79	18,986	83	18,710	80
Natural Gas Production (Mcf/D)	31,047	21	22,090	17	28,507	20
Total (BOE/D)	24,768	100	22,668	100	23,461	100
Per BOE:						
Average sales price before hedging	$ 52.46		$ 43.67		$ 50.04	
Average sales price after hedging	49.75		39.32		48.45	
Oil, per Bbl:						
Average WTI price	$ 70.72		$ 53.22		$ 63.48	
Price sensitive royalties	(5.66)		(3.76)		(5.41)	
Quality differential	(8.49)		(5.47)		(6.54)	
Crude oil hedges	(3.38)		(5.27)		(2.04)	
Average oil sales price after hedging	$ 53.19		$ 38.72		$ 49.49	
Gas, per MMBtu:						
Average Henry Hub price	$ 6.65		$ 6.71		$ 7.92	
Natural gas hedges	-		.10		(.03)	
Location and quality differentials	(1.06)		(1.02)		(1.05)	
Average gas sales price after hedging	$ 5.59		$ 5.79		$ 6.84	

The following table is for the six months ended:

	June 30, 2006	%	June 30, 2005	%
Oil and Gas				
Heavy Oil Production (Bbl/D)	15,470	64	15,773	71
Light Oil Production (Bbl/D)	3,684	15	3,298	15
Total Oil Production (Bbl/D)	19,154	79	19,071	86
Natural Gas Production (Mcf/D)	29,784	21	19,734	14
Total (BOE/D)	24,118	100	22,359	100
Per BOE:				
Average sales price before hedging	$ 51.08		$ 42.34	
Average sales price after hedging	48.92		38.62	
Oil, per Bbl:				
Average WTI price	$ 67.13		$ 51.53	
Price sensitive royalties	(5.52)		(3.44)	
Quality differential	(7.49)		(5.34)	
Crude oil hedges	(2.72)		(4.41)	
Average oil sales price after hedging	$ 51.40		$ 38.34	
Gas, per MMBtu:				
Average Henry Hub price	$ 7.28		$ 6.57	
Natural gas hedges	(.01)		(.06)	
Location and quality differentials	(1.14)		(.86)	
Average gas sales price after hedging	$ 6.13		$ 5.65	

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 gross crude oil production is approximately 4,900 Bbl/D (4,000 Bbl/D net) of near 40 degree API gravity. It was being sold under contract at WTI less a fixed differential approximating $2.00 per barrel. This contract was set to expire on September 30, 2006. Over the last year the differential of this crude oil to WTI has widened to approximately $9.00 per barrel due to a limited number of refineries that can process this paraffinic-based crude. In May 2006, we revised our contract to a $9.00 per barrel differential beginning with delivery on May 1, 2006 through September 30, 2006. Effective

October 1, 2006, the pricing of the production will be at the refiner's posted price and the production subject to this contract will be limited to 1,500 Bbl/D. This amended contract expires on September 30, 2007. We are pursuing other potential buyers of our remaining volumes of crude for delivery after September 30, 2006.

Hedging. See Note 5 to the unaudited condensed 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 June 30, 2006 were down from the three months ended June 30, 2005 due to 9% lower electricity prices and 10% lower natural gas prices, respectively. Similarly, revenue and operating costs in the three months ended June 30, 2006 were down from the three months ended March 31, 2006 due to 21% lower electricity prices and 23% lower natural gas prices, respectively. The following table is for the three months ended:

	June 30, 2006	June 30, 2005	March 31, 2006
Electricity			
Revenues (in millions)	$ 11.7	$ 11.5	$ 15.2
Operating costs (in millions)	$ 10.6	$ 10.9	$ 14.3
Electric power produced - MWh/D	2,023	1,897	2,080
Electric power sold - MWh/D	1,827	1,702	1,884
Average sales price/MWh after hedging	$ 67.88	$ 74.52	$ 85.93
Fuel gas cost/MMBtu (excluding transportation)	$ 5.55	$ 6.15	$ 7.19

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

	Amount per BOE			Amount (in thousands)		
	June 30, 2006	June 30, 2005	March 31, 2006	June 30, 2006	June 30, 2005	March 31, 2006
Operating costs - oil and gas production	$ 12.01	$ 11.73	$ 12.19	$ 27,074	$ 24,194	$ 25,738
Production taxes	1.50	1.06	1.53	3,373	2,180	3,233
DD&A - oil and gas production	7.22	4.50	6.26	16,263	9,461	13,223
G&A	3.49	2.52	3.94	7,877	5,204	8,314
Interest expense	1.09	.84	.75	2,460	1,740	1,577
Total	$ 25.31	$ 20.65	$ 24.67	$ 57,047	$ 42,779	$ 52,085

Our total operating costs, production taxes, G&A and interest expenses for the three months ended June 30, 2006, stated on a unit-of-production basis, increased 23% over the three months ended June 30, 2005 and increased 3% over the three months ended March 31, 2006. The changes were primarily related to the following items:

- Operating costs: Operating costs in the second quarter of 2006 were 2% higher than the second quarter of 2005 due to the net effect of a 15% higher volume of steam used at 10% lower costs of fuel gas. The first half of 2006 also had increased well servicing activities and higher cost of goods and services in general. However, operating costs were 1% lower in the second quarter of 2006 as compared to the first quarter of 2006, primarily due to the 23% decrease in fuel gas cost in that time period. 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:

	June 30, 2006	June 30, 2005	Change	March 31, 2006	Change
Average volume of steam injected (Bbl/D)	78,322	68,066	15%	75,138	4%
Fuel gas cost/MMBtu	$5.55	$6.15	(10%)	$7.19	(23%)

As commodity prices remain robust, we anticipate that cost pressures within our industry may continue. Natural gas prices impact our cost structure in California by approximately $1.75 per California BOE for each $1.00 change in natural gas price.

- Production taxes: Our production taxes have increased over the last year as the value of our oil and natural gas has increased. Severance taxes, which are prevalent in Utah and Colorado, are directly related to the cost of the field sales price of the commodity and in California, our production is burdened with ad valorem taxes on our total proved reserves. We expect production taxes to track the commodity price generally. If California Proposition 87, "The Clean Energy Initiative" is passed by California voters in November 2006, this initiative can add up to a 6% severance tax on our California production. At $70 WTI, this could add over $3.00 per barrel of new taxes on each of our California barrels produced after December 31, 2006. If this initiative is passed, we may redetermine our allocation of capital to our inventory of projects to optimize the return on our capital investments.

- Depreciation, depletion and amortization: DD&A increased per BOE in the three months ended June 30, 2006 due to several sizable acquisitions, more extensive development in higher cost fields and cost pressures in our labor and capital investments. As these costs increase, our DD&A rates per BOE will also increase.

- General and administrative: Approximately two-thirds of our G&A is compensation or compensation related costs. To remain competitive in workforce compensation and achieve our growth goals, the Company's compensation costs increased significantly in 2006 due to additional staffing, higher compensation levels, bonuses, stock compensation and benefit costs. G&A decreased per BOE in the three months ended June 30, 2006 compared to the three months ended March 31, 2006 due to higher compensation costs in the first quarter, including payroll taxes and bonus accrual.

- Interest expense: Our outstanding borrowings, including our line of credit, was $273 million at June 30, 2006 and $259 million at March 31, 2006. Average borrowings in 2006 increased as a result of a $159 million acquisition during February 2006. A certain portion of our interest cost related to our Piceance Basin acquisition and joint venture has been capitalized into the basis of the assets, and we anticipate a portion will continue to be capitalized during 2006 and 2007 until our probable reserves have been recategorized to proved reserves. In 2006, we expect to capitalize between $8 million and $12 million of interest cost.

Estimated 2006 and Actual Six Months Ended June 30, 2006 Oil and Gas Operating, G&A and Interest Expenses.

	Anticipated range in 2006 per BOE	Six months ended June 30, 2006
Operating costs-oil and gas production (1)	$ 11.75 to 13.25	$ 12.10
Production taxes	1.35 to 1.65	1.51
DD&A	6.50 to 7.50	6.73
G&A	3.40 to 3.80	3.71
Interest expense	.90 to 1.30	.92
Total	$ 23.90 to 27.50	$ 24.97

(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 10 to the unaudited condensed 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 second quarter of 40%, which is in line with our projections.

Development, Exploitation and Exploration Activity. We drilled 155 gross (97.6 net) wells during the second quarter of 2006, realizing a gross success rate of 99 percent. Excluding any future acquisitions, in 2006 our approved capital budget is $232 million, and we are currently evaluating whether we may increase the budget to include additional projects As of June 30, 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 two other rigs we own, which are being refurbished.

Piceance Basin

In the second quarter of 2006, we drilled five wells on the Garden Gulch properties in the Grand Valley field of the Piceance Basin and had 14 wells producing. Our net production in the second quarter 2006 averaged 3,356 Mcf/D (559 BOE/D). We continued to drill with one rig and added two additional rigs to the project in July. We have made significant progress in gearing up for extensive development of this asset, including additional outlets for gas sales. Going forward, production from Garden Gulch will be gathered and processed under an agreement which prorates the system capacity on this pipeline system among our partners and us. This gathering system will be expanded as we progress with our drilling program. Through the third week of July, we were processing our gas under a different, interruptible contract that could curtail our production. We estimate that our second quarter production was negatively impacted by approximately 1,000 Mcf/D by these curtailments. Current production is back over 6,000 Mcf/D from Garden Gulch.

On June 8, 2006, Berry announced an agreement for an additional 4,300 gross acres in the Piceance Basin, immediately east of the Garden Gulch property. This agreement for the North Parachute Ranch property expands upon our reserves and drilling opportunities with an additional 400 locations. We will invest $24 million in this project in the third and fourth quarters of 2006. Production from these wells is expected to be similar to Garden Gulch wells, with initial production rates ranging from 1.3 to 2.0 MMcf/D.

Uinta Basin
Brundage Canyon: In the second quarter we drilled 37 wells with 100% success rate. We continue to develop this field with a three rig drilling program. For the second quarter, daily net production averaged 6,059 barrels of oil equivalent per day. Minor infield gas gathering infrastructure has been upgraded and an additional compressor was set to handle increasing volumes of natural gas. The environmental review process is proceeding to initiate drilling in the Ashley National Forest where we anticipate drilling up to 14 wells in 2006.

Lake Canyon: Production from the two shallow Green River wells drilled in Lake Canyon continues to be favorable. We have a 56.25% working interest in these two wells which contributed 70 net BOE/D in the second quarter. The next six Green River locations are permitted to confirm the previously announced discoveries and drilling is expected to commence in the third quarter of 2006. We are in the permitting process for an additional 26 wells which are intended to continue exploratory and development drilling on the eastern portion of our Lake Canyon acreage. The timing of drilling these wells is uncertain, but we are preparing to begin drilling these wells this year. Our industry partner has finished testing the productivity of the deep Mesaverde sands and has reported this interval non-commercial. The well was plugged back and completed in the Wasatch formation at a depth of 6,600 feet. We have a 25% working interest in this well. Second quarter 2006 production contribution from this well, net to Berry, has been 44 barrels per day of approximately 40 degree API crude oil from Wasatch formation sands. Due to the success of the #1 DLB Wasatch discovery well, the Company's partner plans to drill four Wasatch wells in the fourth quarter of 2006.

Coyote Flats: We have three successful appraisal Ferron gas wells on the east side of the Scofield reservoir which have each tested flow rates exceeding 900 Mcf/D. We are proceeding with plans to construct a 13 mile gas pipeline to transport gas from three wells and project sales to now begin in the fourth quarter of 2006. We are currently negotiating an amendment to the participating agreement with our industry partner to earn our 50% interest in the project without drilling the remaining Emery coalbed methane wells. We determined in the first quarter of 2006 that the Emery coalbed methane well we drilled was a dry hole due to low gas saturation, and its costs were expensed.

Denver-Julesburg Basin
In our Tri-State area, we have drilled 71 wells in the second quarter of 2006 with no dry holes. In the second quarter 2006, net production averaged 13.8 MMcf/D or 2,307 BOE/D. As of the third week in July, net production has increased to 14.9 MMcf/D or 2,476 BOE/D. Gas gathering facility upgrades have been completed, including the setting of additional compression by one of our gas gatherers. On our Paoli prospect (Colorado) and our Kansas acreage we have permitted 24 locations (12 at each) based on the results of the 3D seismic we shot or acquired in the first quarter of 2006. We will begin drilling the vertical wells on these prospects in the third quarter and several horizontal wells will be drilled in 2006 by our industry partner in Kansas.

San Joaquin Valley Basin
Diatomite: The project's current performance is meeting our expectations and our goal of determining commerciality in 2006 is on track. Production has increased consistently to approximately 300 BOE/D with a steam-to-oil ratio (SOR) approximating 14, down from a SOR of approximately 19 in the first quarter. Based on the initial reservoir response to our first 39 wells (21 producers, 15 steam injectors and 3 service wells) we have begun a 50 well expansion (38 producers, 11 steam injectors and 1 service well) of the commercial test of the diatomite resource during the second quarter of 2006. We anticipate that all of these wells will be completed and ready for production in

the second half of 2006. We continue to accumulate data, monitor subsurface temperatures and reservoir response and modify our application of technology and operating practices in ways that we believe are leading toward commercial development.

Midway-Sunset: Production, excluding diatomite, remained basically flat at approximately 11,400 Bbl/D in the second quarter versus the first quarter of 2006. The new horizontal producers drilled in the first quarter have been steamed and are responding as expected. We have steamed a significant number of our horizontal producers during the second quarter using our traditional approach and are expecting to see the response from this concentrated program in the second half of 2006. We are focused on improving our production by optimizing our steam distribution and reservoir temperatures and project that production will average approximately 11,800 Bbl/D in the second half of 2006.

We are accelerating the development of new steam floods on our Ethel D, Pan, (which are included in Midway-Sunset production) and Poso Creek properties. We are drilling approximately 60 producing wells on these properties in 2006 and installing the appropriate steam generators and water processing facilities. Production from these properties at July 2006 approximates 2,000 Bbl/D with continued expansions underway.

Drilling Activity. The following table sets forth certain information regarding drilling activities for the three and six months ended June 30, 2006:

	Three months ended June 30, 2006			Six months ended June 30, 2006		
	Gross Wells	Net Wells	Net Workovers	Gross Wells	Net Wells	Net Workovers
Midway-Sunset *(1)*	27	26.7	8.9	44	43.5	14.9
Poso Creek	11	11.0	-	18	18.0	2.0
Placerita	-	-	-	-	-	6.0
Brundage Canyon	37	37.0	-	57	57.0	14.0
Lake Canyon	1	.3	1.0	1	.3	1.0
Coyote Flats *(2)*	-	-	.5	2	2.0	.5
Tri-State *(3)*	71	19.9	12.7	115	36.8	27.7
Piceance	5	2.5	-	10	5.0	-
Bakken *(4)*	3	.2	-	4	.3	-
Totals	**155**	**97.6**	**23.1**	**251**	**162.9**	**66.1**

(1) Includes 1 gross well (1 net well) that was a dry hole in the second quarter of 2006.

(2) Includes 2 gross wells that were dry holes in first quarter 2006. Acreage ownership is earned upon fulfilling certain drilling obligations.

(3) Includes 1 gross well (.3 net well) that was a dry hole in the first quarter 2006.

(4) Includes 1 gross well (.06 net well) that was a dry hole in the first quarter 2006.

Rocky Mountain and Mid-Continent Region Drilling Rigs. During 2005 and 2006, we purchased three drilling rigs, two of which began drilling in the third quarter of 2006. These rigs are leased to a drilling company under three year contracts and carry purchase options available to the drilling company. Owning these rigs allows us to successfully meet a portion of our drilling needs in both the Uinta and Piceance Basins over the next several years. We have several more rigs we do not own contracted to begin drilling 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. In the second quarter of 2006, we revised our five year unsecured credit facility to increase our maximum credit amount under the facility to $750 million and increased our current borrowing base to $500 million. As of June 30, 2006, we have total borrowings under the facility and line of credit of $273 million.

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

Excluding any future acquisitions, in 2006 our approved capital budget is $232 million, and we are currently evaluating whether we may increase the budget to include additional projects. Additional expenditures would be directed toward developing reserves, thereby increasing oil and gas production and exploration opportunities. For 2006, we plan to invest approximately $171 million, or 74% of the approved capital budget, in our Rocky Mountain and Mid-Continent region assets, and $61 million, or 26%, in our California assets. Approximately half of the capital budget is focused on converting probable and possible reserves into proved reserves and on our appraisal and exploratory projects, while the other half is for the development of our proved reserves and facility costs. 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 $.065 per share.

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 (in millions, except for production and average prices):

	June 30, 2006	June 30, 2005	Change	March 31, 2006	Change
Production (BOE/D)	24,768	22,668	9%	23,461	6%
Average oil and gas sales prices, per BOE after hedging	$ 49.75	$ 39.32	27%	$ 48.45	3%
Net cash provided by operating activities	$ 59	$ 47	26%	$ 25	136%
Working capital, excluding line of credit	$ (38)	$ (9)	(322%)	$ (31)	(23%)
Sales of oil and gas	$ 111	$ 81	37%	$ 102	9%
Long-term debt, including line of credit	$ 273	$ 125	118%	$ 259	5%
Capital expenditures, including acquisitions and deposits on acquisitions	$ 65	$ 39	67%	$ 206	(68%)
Dividends paid	$ 2.9	$ 2.6	12%	$ 2.9	-

Contractual Obligations. Berry's contractual obligations as of June 30, 2006 are due in the years ended December 31, as follows (in thousands):

Contractual Obligations	Total	2006	2007	2008	2009	2010	Thereafter
Long-term debt and interest	$ 257,215	$ 1,643	$ 1,643	$ 1,643	$ 1,643	$ 1,643	$ 249,000
Abandonment obligations	10,812	315	360	539	556	556	8,486
Operating lease obligations	11,060	584	1,400	1,370	1,178	955	5,573
Drilling and rig obligations	116,462	25,661	29,246	24,535	37,020	-	-
Firm natural gas transportation contracts	73,490	2,039	4,574	7,304	8,217	8,379	42,977
Total	$ 469,039	$ 30,242	$ 37,223	$ 35,391	$ 48,614	$ 11,533	$ 306,036

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

Operating leases - We lease corporate and field offices in California and Colorado.

Drilling obligation - We intend to participate in the drilling of over 16 gross wells on our Lake Canyon prospect over the next four years, and our minimum obligation under our exploration and development agreement is $9.6 million. Also included above, our June 2006 joint venture agreement states that we must have 120 wells drilled by December 31, 2009 to avoid penalties of $24 million.

Drilling rig obligation - We are obligated in operating lease agreements for the use of multiple drilling rigs.

Firm natural gas transportation - We have one firm transportation contract which provides us additional flexibility in securing our natural gas supply and allows us to potentially benefit from lower natural gas prices in the Rocky Mountains compared to natural gas prices in California. We also have several long term gas transportation contracts which provide us with physical access to interstate pipelines to move gas from our producing areas to markets.

<u>Item 3. Quantitative and Qualitative Disclosures About Market Risk</u>

As discussed in Note 5 to the unaudited condensed 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 June 30, 2006:

Term	Average Barrels Per Day	Average Price	Term	Average MMBtu Per Day	Average Price
Crude Oil Sales (NYMEX WTI)			**Natural Gas Sales (NYMEX HH TO CIG)**		
Swaps			**Basis Swaps**		
3rd Quarter 2006	3,000	$49.56	2006 Average	8,000	1.45
			2007 Average	13,500	1.65
			2008 Average	18,250	1.50
			Natural Gas Sales (NYMEX HH)		
Collars		Floor/Ceiling Prices	**Swaps**		
1st through 3rd Quarter 2006	7,000	$47.50 / $70	3rd Quarter 2006	6,000	$7.35
4^{th} Quarter 2006	10,000	$47.50 / $70			
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 June 30, 2006, (WTI $74.20; HH $8.82) and due to the backwardated nature of the futures prices as of that date, we would expect to make pre-tax future cash payments or to receive payments over the remaining term of our crude oil and natural gas hedges in place as follows:

	June 30, 2006 NYMEX Futures	Impact of percent change in futures prices on earnings -20%	-10%	+ 10%	+ 20%
Average WTI Price	$ 74.20	$ 59.36	$ 66.78	$ 81.62	$ 89.04
Crude Oil gain/(loss) (in millions)	(59.3)	(2.7)	(4.8)	(154.2)	(249.1)
Average HH Price	8.82	7.05	7.94	9.70	10.58
Natural Gas gain/(loss) (in millions)	(.5)	10.3	3.5	(5.2)	(13.6)
Net pre-tax future cash (payments) and receipts by year (in millions):					
2006	$ (14.5)	$ (1.0)	$ (3.7)	$ (29.1)	$ (43.8)
2007	(22.3)	3.8	1.2	(51.2)	(82.0)
2008	(15.8)	4.8	1.2	(45.5)	(77.1)
2009	(7.2)	-	-	(33.6)	(59.8)
Total	$ (59.8)	$ 7.6	$ (1.3)	$ (159.4)	$ (262.7)

Interest Rates. Our exposure to changes in interest rates results primarily from long-term debt. Total long-term debt outstanding at June 30, 2006 was $249 million. Interest on amounts borrowed is charged at LIBOR plus 1.0% to 1.75%, with the exception of the $50 million of principal for which we have a hedge in place to fix the interest rate at 5.4% plus the credit facility's margin. Based on these borrowings, a 1% change in interest rates would have a $2 million impact on our financial statements.

Item 4. Controls and Procedures

As of June 30, 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 June 30, 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

Material changes from 2005 Form 10-K are as follows:

A widening of commodity differentials may adversely impact our revenues and per barrel economics. Both our produced crude oil and natural gas are subject to pricing in the local markets where the production occurs. It is customary that such products are priced based on local or regional supply and demand factors. California heavy crude sells at a discount to WTI, the U.S. benchmark crude oil, primarily due to the additional cost to refine gasoline or light product out of a barrel of heavy crude. Our Utah light crude also is currently priced at $9.00 below WTI through September 30, 2006. Beginning October 1, 2006 through September 30, 2007, 1,500 Bbl/D of our Utah light crude oil barrels then contracted for sale will be sold at the refiner's posting price. Natural gas field prices are normally priced off of Henry Hub NYMEX price, the benchmark for U.S. natural gas. While we attempt to contract for the best possible price in each of our producing locations, there is no assurance that past price differentials will continue into the future. Numerous factors may influence local pricing, such as refinery capacity, particularly for black wax crude, pipeline capacity and specifications, upsets in the mid-stream or downstream sectors of the industry, trade restrictions and governmental regulations. We may be adversely impacted by a widening differential on the products sold.

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

Factors that can cause price volatility for crude oil and natural gas include:

- availability and capacity of refineries;
- availability of gathering systems with sufficient capacity to handle local production;
- seasonal fluctuations in local demand for production;
- local and national gas storage capacity;
- interstate pipeline capacity; and
- availability and cost of gas transportation facilities.

Currently all Brundage Canyon crude oil production, which is approximately 40 degree API gravity, is sold under a contract at WTI less a fixed differential approximating $9.00 per barrel. However, effective October 1, 2006, the pricing of the production will be at the refiner's posted price and the production subject to this contract will be 1,500 Bbl/D. This contract expires on September 30, 2007. Brundage Canyon gross crude oil production is approximately 4,900 Bbl/D (4,000 Bbl/D net). We are investigating other market opportunities for the remainder of this crude oil. The majority of this crude oil, while light, is a "paraffinic" crude, and can be processed efficiently by only a limited number of refineries. Increasing production of this type crude in this region, as well as increasing Canadian crude exports, is resulting in a downward pricing pressure. If market prices continue to deteriorate, we may allocate capital expenditures to projects which produce natural gas and crude oils with lower paraffinic content and/or a better margin until the refinery constraint is resolved.

Passing of a California proposition may impact the additional taxes placed on hydrocarbon production. Our California production may be burdened with a severance tax in addition to the current ad valorem tax structure if Proposition 87 is passed by California voters in November 2006. This initiative can add up to a 6% severance tax on our California production after December 31, 2006. If this initiative is passed, we may redetermine our allocation of capital to our inventory of projects to optimize the return on our capital investments.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

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. 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. For the three months ended June 30, 2006, the Company repurchased 347,700 shares for approximately $11 million. Since June 2005, total shares repurchased through June 30, 2006 are 625,500 for approximately $19.1 million.

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
First Quarter 2006	60,000	$ 30.04	60,000	$ 41,882,036
April 2006	48,000	34.85	48,000	40,209,043
May 2006	160,000	33.00	160,000	34,929,126
June 2006	139,700	28.75	137,700	30,912,780
Total	407,700	$ 31.33	407,700	$ 30,912,780

Item 3. Defaults Upon Senior Securities

None.

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

At the annual meeting, which was held at the Four Points Sheraton Hotel, Bakersfield, California, on May 17, 2006, nine incumbent directors were re-elected. The results of voting as reported by the inspector of elections are noted below:

1. There were 21,996,180 shares of the Company's capital stock issued, outstanding and generally entitled to vote as of the record date, March 17, 2006.

2. There were present at the meeting, in person or by proxy, the holders of 20,414,583 shares, representing 92.8% of the total number of shares outstanding and entitled to vote at the meeting, such percentage representing a quorum.

PROPOSAL ONE: Election of Nine Directors

NOMINEE	VOTES CAST FOR	PERCENT OF QUORUM VOTES CAST	AUTHORITY WITHHELD
Joseph H. Bryant	20,317,301	99.5%	97,282
Ralph B. Busch, III	19,796,828	96.9%	617,755
William E. Bush, Jr.	19,565,930	95.8%	848,653
Stephen L. Cropper	19,976,165	97.8%	438,418

J. Herbert Gaul, Jr.	20,022,360	98.0%	392,223
Robert F. Heinemann	20,319,393	99.5%	95,190
Thomas J. Jamieson	20,037,795	98.1%	376,788
J. Frank Keller	20,327,368	99.5%	87,215
Martin H. Young, Jr.	20,037,795	98.1%	376,788

Percentages are based on the shares represented and voting at the meeting in person or by proxy.

PROPOSAL TWO: Approval to amend the Company's Restated Certificate of Incorporation increasing from 50,000,000 to 100,000,000 the number of authorized shares of Class A Common stock and increasing from 1,500,000 to 3,000,000 the number of authorized shares of Class B Stock.

	For	Against	Abstentions	Broker Non-Votes
Shares	19,976,035	428,792	9,726	30

Item 5. Other Information

None.

Item 6. Exhibits

Exhibit No. Description of Exhibit

3.1 Registrant's Restated Certificate of Incorporation.

10.1* Amended and Restated Employment Agreement with Robert F. Heinemann (filed as Exhibit 99.1 on Form 8-K filed on June 26, 2006, File No. 1-9735).

10.2* Stock Award Agreement with Robert F. Heinemann (filed as Exhibit 99.2 on Form 8-K filed on June 26, 2006, File No. 1-9735).

10.3* Amendment to the Company's 1994 Stock Option Plan (filed as Exhibit 99.3 on Form 8-K filed on June 26, 2006, File No. 1-9735).

10.4* Berry Petroleum Company Form of Stock Award Agreement (filed as Exhibit 99.4 on Form 8-K filed on June 26, 2006, File No. 1-9735).

10.5* Carry and Earning Agreement, Dated June 7, 2006, between Registrant and EnCana Oil & Gas (USA), Inc. (filed as Exhibit 99.2 on Form 8-K/A filed on June 19, 2006, File No. 1-9735).

10.6* 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 (filed as Exhibit 10.2 to the Registrant's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2006, File No. 1-09735).

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

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: August 9, 2006

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