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, 2003
Commission file number 1-9735

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

DELAWARE	77-0079387
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

5201 Truxtun Avenue, Suite 300, Bakersfield, California	93309-0640
(Address of principal executive offices)	(Zip Code)

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

Former name, Former Address and Former Fiscal Year, if Changed Since Last Report:
NONE

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or 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 ( )

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act). YES (X) NO ( )

The number of shares of each of the registrant's classes of capital stock outstanding as of June 30, 2003, was 20,872,964 shares of Class A Common Stock ($.01 par value) and 898,892 shares of Class B Stock ($.01 par value). All of the Class B Stock is held by a shareholder who owns in excess of 5% of the outstanding stock of the registrant.

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BERRY PETROLEUM COMPANY
Part I. Financial Information
Item 1. Financial Statements
Condensed Balance Sheets
(In Thousands, Except Share Information)

	June 30, 2003 (Unaudited)	December 31, 2002
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 6,928	$ 9,866
Short-term investments available for sale	661	660
Accounts receivable	18,408	15,582
Prepaid expenses and other	3,922	2,597
Total current assets	29,919	28,705
Oil and gas properties (successful efforts basis), buildings and equipment, net	237,137	228,475
Other assets	955	893
	$ 268,011	$ 258,073
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 20,034	$ 19,189
Accrued liabilities	3,140	6,470
Federal and state income taxes payable	3,447	2,612
Fair value of derivatives	4,561	4,123
Total current liabilities	31,182	32,394
Long-term liabilities:		
Deferred income taxes	34,317	33,866
Long-term debt	15,000	15,000
Abandonment obligation	5,113	4,596
Fair value of derivatives	522	159
Total long-term liabilities	54,952	53,621
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; 20,872,964 shares issued and outstanding at June 30, 2003 (20,852,695 at December 31, 2002)	209	209
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	49,105	49,052
Accumulated other comprehensive loss	(3,050)	(2,569)
Retained earnings	135,604	125,357
Total shareholders' equity	181,877	172,058
	$ 268,011	$ 258,073

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

BERRY PETROLEUM COMPANY
Part I. Financial Information
Item 1. Financial Statements
Condensed Income Statements
Three Month Periods Ended June 30, 2003 and 2002
(In Thousands, Except Per Share Information)
(Unaudited)

	2003	2002
Revenues:		
Sales of oil and gas	$ 29,466	$ 25,568
Sales of electricity	10,386	6,477
Interest and other income, net	228	1,167
	40,080	33,212
Expenses:		
Operating costs - oil and gas production	15,626	10,893
Operating costs - electricity generation	10,386	6,477
Depreciation, depletion and amortization	4,729	4,278
General and administrative	2,404	2,032
Interest	268	261
	33,413	23,941
Income before income taxes	6,667	9,271
Provision for income taxes	157	2,444
Net income	$ 6,510	$ 6,827
Basic net income per share	$ .30	$ .31
Diluted net income per share	$ .30	$ .31
Cash dividends per share	$ .15	$ .10
Weighted average number of shares of capital stock outstanding (used to calculate basic net income per share)	21,764	21,735
Effect of dilutive securities:		
Stock options	145	198
Other	45	41
Weighted average number of shares of capital stock used to calculate diluted net income per share	21,954	21,974

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

BERRY PETROLEUM COMPANY
Part I. Financial Information
Item 1. Financial Statements
Condensed Income Statements
Six Month Periods Ended June 30, 2003 and 2002
(In Thousands, Except Per Share Information)
(Unaudited)

	2003	2002
Revenues:		
Sales of oil and gas	$ 63,820	$ 45,246
Sales of electricity	23,265	13,791
Interest and other income, net	248	1,545
	87,333	60,582
Expenses:		
Operating costs - oil and gas production	28,810	18,979
Operating costs - electricity generation	23,265	13,460
Depreciation, depletion and amortization	9,183	8,270
General and administrative	4,661	3,894
Recovery of electricity receivables	-	(3,631)
Dry hole and abandonment	2,487	-
Interest	477	684
	68,883	41,656
Income before income taxes	18,450	18,926
Provision for income taxes	2,763	3,479
Net income	$ 15,687	$ 15,447
Basic net income per share	$ .72	$ .71
Diluted net income per share	$ .72	$ .70
Cash dividends per share	$ .25	$ .20
Weighted average number of shares of capital stock outstanding (used to calculate basic net income per share)	21,761	21,734
Effect of dilutive securities:		
Stock options	130	140
Other	43	41
Weighted average number of shares of capital stock used to calculate diluted net income per share	21,934	21,915

Condensed Statements of Comprehensive Income
Six Month Periods Ended June 30, 2003 and 2002
(in Thousands)
(Unaudited)

	2003	2002
Net income	$ 15,687	$ 15,447
Unrealized losses on derivatives, (net of income taxes of $320 and $1,084, respectively)	(481)	(1,626)
Comprehensive income	$ 15,206	$ 13,821

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

BERRY PETROLEUM COMPANY
Part I. Financial Information
Item 1. Financial Statements
Condensed Statements of Cash Flows
Six Month Periods Ended June 30, 2003 and 2002
(In Thousands)
(Unaudited)

	2003	2002
Cash flows from operating activities:		
Net income	$ 15,687	$ 15,447
Depreciation, depletion and amortization	9,183	8,270
Dry hole and abandonment	2,432	(224)
Deferred income tax liability	451	1,140
Other, net	277	161
Net working capital provided by operating activities	28,030	24,794
Decrease (increase) in accounts receivable, prepaid expenses and other	(3,975)	4,000
Decrease in current liabilities	(1,650)	(3,422)
Net cash provided by operating activities	22,405	25,372
Cash flows from investing activities:		
Capital expenditures	(12,636)	(11,738)
Property acquisitions	(7,447)	-
Other, net	181	(44)
Net cash used in investing activities	(19,902)	(11,782)
Cash flows from financing activities:		
Payment of long-term debt	-	(10,000)
Dividends paid	(5,441)	(4,347)
Other, net	-	(172)
Net cash used in financing activities	(5,441)	(14,519)
Decrease in cash and cash equivalents	(2,938)	(929)
Cash and cash equivalents at beginning of year	9,866	7,238
Cash and cash equivalents at end of period	$ 6,928	$ 6,309
Supplemental non-cash activity:		
Decrease in fair value of derivatives:		
Current (net of income taxes of $175 and $1,084 in 2003 and 2002, respectively)	$ 263	$ 1,626
Non-current (net of income taxes of $145 and $0 in 2003 and 2002, respectively)	218	-
Net decrease to accumulated other comprehensive income	$ 481	$ 1,626

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

BERRY PETROLEUM COMPANY
Part I. Financial Information
Item 1. Financial Statements
Notes to Condensed Financial Statements
June 30, 2003
(Unaudited)

1. All adjustments which are, in the opinion of management, necessary for a fair presentation of the Company's financial position at June 30, 2003 and December 31, 2002 and results of operations for the three and six month periods ended June 30, 2003 and 2002 and cash flows for the six month periods ended June 30, 2003 and 2002 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.

2. The accompanying unaudited financial statements have been prepared on a basis consistent with the accounting principles and policies reflected in the December 31, 2002 financial statements. The December 31, 2002 Form 10-K and the March 31, 2003 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.

3. The Company has leased approximately 208,000 acres in Wabaunsee, Jackson and Osage counties in Kansas and 55,000 acres in Illinois for the purpose of exploring for economic concentrations of coalbed methane for a total lease cost of approximately $6.0 million. The Company drilled a five-well pilot on the Illinois acreage in the fourth quarter of 2002 which, as anticipated, continues to dewater. The results of this pilot are not yet conclusive and are not expected to be known until the latter half of 2003. An additional five-well pilot was drilled in the Wabaunsee County portion of the Kansas acreage late in the fourth quarter of 2002. On this pilot, initial water production was less than expected with no resulting gas pressure buildup and the gas content of the coals was significantly lower than anticipated. Consequently, in the first quarter of 2003, the Company wrote off the cost to drill the five-well pilot and the associated leased acreage for a total charge of $2.5 million. The Company is still evaluating the location and method of drilling test wells in Osage County which the Company anticipates drilling towards the end of 2003. The Company entered into a definitive agreement in July 2003 to sell its approximately 43,000 acreage position in Jackson County, for an undisclosed amount which covers the Company's cost in this acreage, while retaining an overriding royalty interest in the property. The transaction is subject to certain conditions and, if all conditions are satisfied, the Company anticipates the sale to close in the third quarter of 2003.

4. As allowed in Statement of Financial Accounting Standards (SFAS) No. 123, "Accounting for Stock-Based Compensation," as amended, the Company continues to apply Accounting Principles Board Opinion (APB) No. 25, "Accounting for Stock Issued to Employees," and related interpretations in recording compensation related to its plan.

BERRY PETROLEUM COMPANY
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4. (cont'd) Under SFAS No. 123, as amended, compensation cost would be recognized for the fair value of the employee's option rights. Had compensation cost for the Company's stock based compensation plan been based upon the fair value at the grant dates for awards under the plan consistent with the method of SFAS No. 123, as amended, using the Black Scholes Method, the Company's compensation cost, net of related tax effects, net income and earnings per share would have been recorded as the proforma amounts indicated below for the three and six months ended June 30, 2003 and 2002 (in thousands, except per share data):

	Three Months Ended June 30		Six Months Ended June 30	
	2003	2002	2003	2002
Compensation cost, net of income taxes				
As reported	$ 35	$ 21	$ 55	$ 26
Pro forma	164	201	315	362
Net income:				
As reported	6,510	6,827	15,687	15,447
Pro forma	6,381	6,647	15,427	15,111
Basic net income per share:				
As reported	.30	.31	.72	.71
Pro forma	.29	.31	.71	.70
Diluted net income per share:				
As reported	.30	.31	.72	.70
Pro forma	.29	.30	.71	.69

5. In April 2003, the Company entered into a purchase and sale agreement with Williams Production RMT Company to acquire its oil and gas properties located in Brundage Canyon, Utah in the Uinta Basin for approximately $48.6 million. The properties, located in northeastern Utah, consist of approximately 43,500 net acres, and are currently producing approximately 2,000 net BOE/day of light crude oil and natural gas and the Company estimates the proved reserves at 8.6 million BOE (75% light oil and 25% natural gas) as of April 1, 2003. The Company paid a deposit of $4.9 million in May (recorded in oil and gas properties) from cash generated from operations and anticipates funding the remainder from borrowings on its credit facility. The closing is expected to occur in the third quarter of 2003, although, the completion of the transaction is subject to certain conditions and there is no assurance that all conditions will be satisfied.

BERRY PETROLEUM COMPANY
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6. The Company successfully completed a new $200 million unsecured three year bank credit facility in July. Participants included several large banks based in the United States as well as international banking institutions. The facility replaces the previous $150 million facility which was due to mature in January 2004. The new facility recognizes the Company's strong financial position and should provide significant low-cost capital for the Company to grow, primarily through acquisitions. Initial borrowings were $15 million which represented an amount equal to the borrowings outstanding under the previous credit facility.

7. In April 2003, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities." This statement is effective for contracts entered into or modified after June 30, 2003 and is also effective for hedging relationships designated after June 30, 2003. Implementation of this standard is not expected to have a material impact on the Company's financial position or results of operations.

BERRY PETROLEUM COMPANY
Part I. Financial Information
Item 2. Management's Discussion and Analysis of
Financial Condition and Results of Operations

Results of Operations

The Company earned net income of $6.5 million, or $.30 per share, on revenues of $40.1 million in the second quarter of 2003, down 4% from net income of $6.8 million, or $.31 per share, on revenues of $33.2 million in the second quarter of 2002, and down 29% from net income of $9.2 million, or $.42 per share, on revenues of $47.3 million in the first quarter of 2003. Net income for the six months ended June 30, 2003 was $15.7 million, or $.72 per share, on revenues of $87.3 million, up 2% from $15.4 million, or $.71 per share, on revenues of $60.6 million for the six months ended June 30, 2002. Results in the first quarter of 2003 include a pre-tax write off of $2.5 million, representing the cost of a pilot project and associated leasehold acquisition costs in Kansas. The results in the first six months of 2002 include a pre-tax gain from the recovery of a $3.6 million receivable for electricity sales which was written off in 2001.

	Three Months Ended			Six Months Ended	
	June 30, 2003	March 31, 2003	June 30, 2002	June 30, 2003	June 30, 2002
Oil and gas:					
Net Production - BOE per day day	15,397	15,736	14,060	15,566	13,930
Per BOE:					
Realized sales price(1)	$21.07	$24.23	$19.99	$22.66	$17.96
Operating costs (2)	10.63	8.78	7.96	9.71	6.98
Production taxes	.52	.53	.55	.52	.55
Total operating costs	11.15	9.31	8.51	10.23	7.53
Depreciation/Depletion (DD&A)	3.38	3.15	3.34	3.26	3.28
General & administrative expenses (G&A)	1.72	1.59	1.59	1.65	1.54
Interest expense	.19	.15	.20	.17	.27
Electricity:					
Production - Mwh per day	2,036	2,137	1,935	2,086	1,992
Sales - Mwh per day	1,847	1,951	1,748	1,899	1,819
Average sales price - $/Mwh	62.59	73.39	39.46	68.11	36.79
Fuel gas cost - $/Mmbtu	5.04	5.40	2.97	5.21	2.73

(1) Includes realized hedge losses of $1.42, $2.62 and $.51 for the three months ended June 30, 2003, March 31, 2003 and June 30, 2002, respectively, and losses of $2.02 and $.26 for the six months ended June 30, 2003 and 2002, respectively.

(2) Includes monthly expenses in excess of monthly revenues from cogeneration operations of $2.79, $1.72 and $1.73 for the second quarter of 2003, the first quarter of 2003 and the second quarter of 2002, respectively. For the first six months of 2003 and 2002, respectively, these expenses represent $2.25 and $1.03.

Operating income from oil and gas operations for the second quarter of 2003 was $9.2 million, down from $14.3 million and $10.5 million in the first quarter of 2003 and the second quarter of 2002, respectively. Operating income from oil and gas operations for the first six months of 2003 was $23.5 million, up from $18.2 million for the first six months of 2002.

Oil and gas production (BOE/day) was 15,397 in the second quarter of 2003, up 10% from 14,060 in the second quarter of 2002, but down 2% from 15,736 in the first quarter of 2003. A significant portion of the Company's 2003 drilling program was completed during the second quarter. As of July 15, 2003, the Company has drilled and completed 46 (including 13 horizontal wells) of the 99 new wells originally budgeted to be drilled in 2003. Because of the close proximity between wells, a number of existing wells had to be shut-in temporarily while certain of the new wells were drilled in the second quarter which contributed to the decline in production from the first quarter. However, the majority of these wells are now back on production. The Company is making a concerted effort to increase production during 2003. During the second quarter, the Company increased its steam injection volumes to an average of over 64,000 B/D and plans to average between 68,000 and 70,000 B/D for the remainder of the year, assuming stable crude oil and natural gas prices. Crude oil production has averaged 15,600 BOE/day for the first half of 2003 and is averaging approximately 16,000 BOE/day as of July 31, 2003. With the 2003 development program and the increased steaming activity, the Company anticipates production to average approximately 16,000 BOE/day from its existing properties for all of 2003 which would represent a 14% increase over 2002 production. In addition, we still expect to close our Brundage Canyon acquisition in the third quarter of 2003. If that closing should occur, the Company's production would increase by Brundage Canyon's current production of approximately 2,000 BOE/day.

The average price received for the Company's heavy crude oil in the second quarter of 2003 was $21.07 per barrel, up 5% from $19.99 received in the second quarter of 2002, but down 13% from $24.23 received in the first quarter of 2003. This price decline resulted in a $4.4 million reduction in revenues from sales of oil and gas in the second quarter of 2003 compared to the first quarter of 2003. The posted price for the Company's crude oil has rebounded to $26.50 per barrel as of August 4, 2003 which is 15% higher than the average posted price of $23.07 for the second quarter of 2003.

The Company primarily is at risk to sharp reductions in operating income as a result of declines in crude oil and electricity prices and increases in natural gas prices. To mitigate these risks, the Company periodically enters into various types of commodity hedges. See "Item 3. Quantitative and Qualitative Disclosure About Market Risk" for detail of market risk and existing hedges for the Company at June 30, 2003.

In January 2003, Standard Offer contract terms were reinstated on the power produced from one of two turbines at the Company's cogeneration facility located in the Placerita oilfield in Los Angeles County and on both the 38 megawatt and 18 megawatt facilities located on the Company's Midway-Sunset properties in Kern County, California. Under the terms of these agreements, the Company received an average of $58.89 per Mwh in the second quarter of 2003 and $65.13 for the first six months of 2003. The primary benefit of these contracts is that the Company's electricity revenues are based on the cost of natural gas. Therefore, these contracts help to mitigate the Company's exposure to higher operating costs based on higher natural gas costs. The Company consumes approximately 37,000 MMBtu of natural gas per day for use in generating steam and of this total, approximately 72% is consumed in the Company's cogeneration operations.

Operating costs from oil and gas operations in the second quarter were $15.6 million, or $11.15 per BOE, up from $13.2 million, or $9.31 per BOE, in the first quarter of 2003 and $10.9 million, or $8.51 per BOE, in the second quarter of 2002. The two major components of operating costs are costs associated with steam generation and non-steam related costs.

Non-steam operating costs, the component which is the more controllable factor, has been effectively managed by the Company. Total non-steam operating costs for the second quarter of 2003 were $6.5 million, or $4.66 per BOE, compared to $6.0 million, or $4.69 per BOE, in the second quarter of 2002 and $6.2 million, or $4.37 per BOE, in the first quarter of 2003.

Steam costs, however, increased substantially in the second quarter of 2003 due to high natural gas prices, lower electricity revenue, scheduled turnarounds at the Company's cogeneration facilities and higher steam injection volumes from the Company's higher cost conventional sources. The price per MMBtu the Company paid for natural gas was $5.04 in the second quarter of 2003, compared to $5.40 in the first quarter of 2003 but up 70% from $2.97 in the second quarter of 2002. The Company's electricity revenue is based on the price of natural gas at the Northern California border (Malin), however, the majority of the Company's gas purchases is based on the price of gas at the Southern California border (SoCal). In the first quarter of 2003, the price of Malin gas was an average of $.15 per MMBtu higher than the price at SoCal resulting in high electricity prices relative to the Company's cost of fuel. In the second quarter of 2003, the cost of gas at Malin was an average of $.30 per MMBtu lower than the cost of gas at SoCal resulting in relatively low electricity prices and lower electricity revenues. Lower natural gas prices in the second quarter and, to a lesser extent, this $.45 per MMBtu swing were the principal reasons why electricity revenues declined $2.5 million, or 19%, in the second quarter of 2003 compared to the first quarter of 2003. Also contributing to higher steam costs in the second quarter were increased steam volumes from conventional generators. Injection from these sources averaged 26,973 B/D, up 15% and 26% from 23,539 B/D in the second quarter of 2002 and 21,363 B/D in the first quarter of 2003, respectively.

To protect the Company's cash flow from future increases in natural gas prices on the fixed electricity price contract on Unit 1 of the Company's Placerita cogeneration facility, the Company entered into natural gas swaps on a total volume of 5,000 MMBtu per day at a fixed price of $4.85 per MMBtu for the period June 2003 through June 2006, thereby helping to control steam costs. The Company also entered into a 1,000 MMBtu per day swap at a fixed price of $4.55 for November 2003 through March 2004.

DD&A for the second quarter of 2003 was $4.7 million, or $3.38/BOE, up from $4.3 million, or $3.34/BOE, in the second quarter of 2002 and $4.5 million, or $3.15/BOE, in the first quarter of 2003, respectively. The Company anticipates that, assuming stable crude oil and natural gas prices, the rate per BOE will trend lower during the latter half of the year.

G&A for the second quarter of 2003 was $2.4 million, or $1.72/BOE, up 20% from $2.0 million, or $1.59/BOE, in the second quarter of 2002 and up 4% from $2.3 million, or $1.59/BOE, in the first quarter of 2003. The increases in the 2003 periods compared to the second quarter of 2002 were primarily related to the Company's efforts to expand into a new core area outside of California. To that end, the Company opened a Denver office in February 2003 and incurred higher property evaluation costs in the 2003 periods compared to the 2002 period. On a per BOE basis, the Company anticipates G&A to trend lower in the latter half of 2003 as production levels are expected to increase through the remainder of the year.

The Company has leased approximately 208,000 acres in Wabaunsee, Jackson and Osage counties, Kansas and 55,000 acres in Illinois for the purpose of exploring for economic concentrations of coalbed methane for a total lease cost of approximately $6.0 million. The Company drilled a five-well pilot on the Illinois acreage in the fourth quarter of 2002 which, as anticipated, continues to dewater. The results of this pilot are not yet conclusive and are not expected to be known until the latter half of 2003. An additional five-well pilot was drilled in the Wabaunsee County portion of the Kansas acreage late in the fourth quarter of 2002. On this pilot, initial water production was less than expected with no resulting gas pressure buildup and the gas content of the coals was significantly lower than anticipated. Consequently, in the first quarter of 2003 the Company wrote off the cost to drill the five-well pilot and the associated leased acreage for a total charge of $2.5 million . The Company is still evaluating the location and method of drilling test wells in Osage County which the Company anticipates drilling towards the end of 2003. The Company entered into a definitive agreement in July 2003 to sell approximately 43,000 acres in Jackson County, for an undisclosed amount which covers the Company's cost in this acreage, while retaining an overriding royalty interest in the property. The transaction is subject to certain conditions and, if all conditions are satisfied, the Company anticipates the sale to close in the third quarter of 2003.

The Company's effective tax rate was 2% in the second quarter of 2003, down from 22% in the first quarter of 2003 and down from 26% in the second quarter of 2002. The primary reasons for the significantly lower income taxes in the second quarter of 2003 versus the first quarter was significantly lower pre-tax income (due to lower crude oil prices, higher operating costs and lower production volumes) and anticipated higher EOR credits due to higher natural gas prices which increased steam cost per BOE used in the EOR calculation.

Liquidity and Capital Resources

Working capital at June 30, 2003 was ($1.3) million, up from ($3.7) million at December 31, 2002. Net cash provided by operations was $22.4 million for the first six months of 2003, down from $25.4 million for the first six months of 2002. Cash was used in the first half of 2003 to pay dividends of $5.4 million, capital expenditures of $12.6 million, property acquisitions of $7.4 million and to pay an annual revenue sharing royalty on 2002 production of $5.5 million.

In April 2003, the Company entered into a purchase and sale agreement with Williams Production RMT Company to acquire its oil and gas properties located in Brundage Canyon, Utah in the Uinta Basin for $48.6 million. The properties, located in northeastern Utah, consist of approximately 43,500 net acres, and are currently producing approximately 2,000 BOE/day of light crude oil and natural gas and the Company estimates the proved reserves at 8.6 million BOE (75% light oil and 25% natural gas) as of April 1, 2003. The Company paid a deposit of $4.9 million (recorded in oil and gas properties) in May from cash generated from operations and anticipates funding the remainder from borrowings on its credit facility. The closing is expected to occur in the third quarter of 2003 although the completion of the transaction is subject to certain conditions and there is no assurance that all conditions will be satisfied.

During the second quarter of 2003, the Company aggressively pursued the implementation of its 2003 capital development budget. As of July 15, 2003, 46 wells, including all 13 of the planned horizontal wells, have been drilled. For the remainder of 2003, the Company plans to drill an additional 53 wells on its existing properties and up to an additional 26 development wells at Brundage Canyon in Utah, assuming the purchase closes in the third quarter. The number of wells that may actually be drilled at Brundage Canyon will depend on whether or not and when the actual closing occurs. This planned activity would bring the total estimated development (drilling and facility) spending for 2003 to approximately $44 million.

The Company successfully completed a new $200 million unsecured three year bank credit facility in July 2003. Participants included several large banks based in the United States as well as international banking institutions. The facility replaces the previous $150 million facility which was due to mature in January 2004. The new facility recognizes the Company's strong financial position and should provide significant low-cost capital for the Company to grow, primarily through acquisitions. Initial borrowings were $15 million which represented an amount equal to the borrowings outstanding under the previous credit facility.

Forward Looking Statements

"Safe harbor under the Private Securities Litigation Reform Act of 1995:" With the exception of historical information, the matters discussed in this Form 10-Q are forward-looking statements that involve risks and uncertainties. Although the Company believes that its expectations are based on reasonable assumptions, it can give no assurance that its goals will be achieved. Important factors that could cause actual results to differ materially from those in the forward-looking statements herein include, but are not limited to, the timing and extent of changes in commodity prices for oil, gas and electricity, a limited marketplace for electricity sales within California, counterparty risk, competition, environmental risks, litigation uncertainties, drilling, development and operating risks, the availability of drilling rigs and other support services, legislative and/or judicial decisions and other government regulations.

BERRY PETROLEUM COMPANY
Part I. Financial Information
Item 3. Quantitative and Qualitative Disclosures About Market Risk

The Company has significant market risk exposure related to the prices received for the sale of its crude oil. A $1 change in oil price per barrel equates to an approximate $5.8 million change in annual revenues. The Company primarily uses zero-cost bracketed collars based on WTI crude oil prices to protect cash flow from a severe crude oil price decline. At June 30, 2003, the Company has hedged 6,500 barrels per day for the remainder of 2003 whereby the Company could capture an average of $3.88 below a WTI price of $22.31 per barrel and may give up to an average of $4.48 above $25.79 per barrel. The Company has also hedged 5,000 barrels per day in the first quarter of 2004 and 4,000 barrels per day for the second through fourth quarters of 2004. In 2004, the Company could capture up to an average of $3.64 per barrel below approximately $22.39 per barrel and may give up to an average of $4.24 per barrel above $25.65 per barrel. In addition to these collars, the Company entered into a series of crude oil swaps based on WTI pricing on 1,500 barrels per day at prices ranging from $25.68 to $27.17 covering the six month period from May 1, 2003 to October 31, 2003 and 1,000 barrels per day for the six months beginning November 2003 for an average price of $25.00. The Company utilizes more than one counterparty on these hedges and monitors each counterparty's credit rating.

The Company is also at risk for a widening of the differential between the WTI crude oil price and the posted price of the Company's heavy crude oil. To mitigate this risk, the Company has a sales contract in place through 2005 where more than 90% of its crude oil production from its California properties is priced at the higher of local field posting plus a bonus, or WTI minus a fixed differential.

The Company also has market risk exposure related to the price received for the sale of its electricity production and the cost paid by the Company for the natural gas used in its cogeneration operations. The Company's three cogeneration facilities, when combined, have electricity production capacity of 98 Mw of electricity. Of this total, the Company sells approximately 92 Mw and the remaining 6 Mw is consumed in the Company's operations. The Company's goal is to control its "spark spread" (the difference between the sales price received for its electricity and the cost to purchase natural gas used as fuel in the cogeneration operations).

The Company consumes approximately 27,000 MMBtu/day of natural gas as fuel in these facilities. A change of $.25/MMBtu in the cost of natural gas used in the cogeneration facilities equates to a change of approximately $1.1 million in annual operating costs. To protect cash flow from future increases in natural gas prices, thereby helping to reduce steam costs, the Company entered into natural gas swaps on a total volume of 5,000 MMBtu per day at a fixed price of $4.85 per MMBtu for the period June 2003 through June 2006 and an additional gas swap on 1,000 MMBtu per day at a fixed price of $4.55 per MMBtu for the period November 2003 through March 2004. The Company has a long-term electricity sales contract in place, with a major utility, through July 31, 2006 at a fixed price of $53.70/Mwh plus capacity on approximately 19 Mw of electricity production. A change of $1.50/Mwh in the price received for electricity on the remaining 73 Mw equates to approximately $1 million in annual revenues. During 2002, the majority of the remaining electricity was sold on the open market to a creditworthy customer. In January 2003, the Company entered into three reformed or reinstated Standard Offer contracts with the utilities which resulted in improved electrical pricing in the first half of 2003 and should also result in improved electrical pricing for the remainder of 2003. These contracts will expire no later than December 31, 2003. The Company is pursuing longer-term arrangements on the sale of electricity and may enter into additional hedges on its natural gas purchases to seek to improve the spark spread in 2003 and beyond.

The Company also consumes up to an additional 10,000 MMBtu/day of additional natural gas as fuel in its conventional generators, which are used to supplement the Company's steam requirements. A change of $.25 in the cost of this natural gas requirement equates to a change of approximately $.9 million in annual operating costs. The Company may enter into hedges on natural gas purchases to help control this cost.

Related to its natural gas purchases, the Company is also exposed to the volatility in the differential between gas prices at the Southern California border and Henry Hub delivery points. To help minimize this risk, the Company entered into a 12,000 MMBtu/day firm transportation agreement on the Kern River pipeline expansion for gas deliveries which commenced in May 2003. This agreement provides the Company additional flexibility in securing its natural gas supply and allows the Company to potentially benefit from discounted natural gas prices in the Rockies. This is a 10 year use-or-pay contract at approximately $.71/MMBtu and the Company is currently transporting volumes under the terms of the agreement. This 10-year use-or-pay commitment totals approximately $31 million over the life of the contract and for 2003 is approximately $2.1 million.

Item 4. Controls and Procedures

The Company's Chief Executive Officer and its Chief Financial Officer have evaluated the Company's disclosure controls and procedures within 90 days of the filing of this report pursuant to Rule 13a-14 of the Securities and Exchange Act of 1934 and have concluded that there are no significant changes in the Company's internal controls or in other factors that could significantly affect these controls.

BERRY PETROLEUM COMPANY
Part II. Other Information

Item 5. Submission of Matters to a Vote of Security Holders

At the annual meeting, which was held at the Stockdale Towers on May 19, 2003, ten incumbent directors were re-elected. The results of voting as reported by the inspector of elections are noted below:

1. There were 21,758,962 shares of the Company's common stock issued, outstanding and entitled to vote as of the record date, March 12, 2003.

2. There were present at the meeting, in person or by proxy, the holders of 19,177,252 shares, representing 88.13% of the total number of shares outstanding and entitled to vote at the meeting, such percentage representing a quorum.

PROPOSAL ONE: Election of Directors

NOMINEE	FOR VOTES	PERCENT OF QUORUM VOTES CAST	WITHHOLD AUTHORITY
William F. Berry	18,952,361	98.83%	224,891
Ralph B. Busch, III	19,007,167	99.11%	170,085
William E. Bush, Jr.	19,006,312	99.11%	170,940
Stephen L. Cropper	19,006,945	99.11%	170,307
J. Herbert Gaul, Jr.	19,006,945	99.11%	170,307
John A. Hagg	19,006,725	99.11%	170,527
Robert F. Heinemann	16,574,232	86.43%	2,603,020
Jerry V. Hoffman	17,716,453	92.38%	1,460,799
Thomas J. Jamieson	18,988,648	99.02%	188,604
Martin H. Young, Jr.	19,006,945	99.11%	170,307

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

Item 6. Exhibits and Reports on Form 8-K

Exhibit No.	Description
31.1	Rule 13a-14(a) Certification of Chief Executive Officer
31.2	Rule 13a-14(a) Certification of Chief Financial Officer
32.1	Rule 1350 Certification of Chief Executive Officer
32.2	Rule 1350 Certification of Chief Financial Officer

PART II OTHER INFORMATION

Item 6. Exhibits and Reports on Form 8-K (cont'd)

On April 8, 2003, the Company filed a Form 8-K reporting an Item 5 - Other Event to furnish the Securities and Exchange Commission a copy of the Company's press release announcing a dividend increase.

On April 24, 2003, the Company filed a Form 8-K reporting an Item 5 - Other Event to furnish the Securities and Exchange Commission a copy of the Company's press release announcing the Company's intent to acquire certain Uinta Basin properties in Utah.

On May 8, 2003, the Company filed a Form 8-K reporting an Item 5 - Other Event to furnish the Securities and Exchange Commission a copy of the Company's press release announcing the first quarter results for 2003.

On July 15, 2003, the Company filed a Form 8-K reporting an Item 9 - Regulation FD Disclosure to furnish the Securities and Exchange Commission a copy of the Company's press release announcing the completion of a new $200 million unsecured credit facility.

On July 22, 2003, the Company filed a Form 8-K reporting an Item 9 - Regulation FD Disclosure to furnish the Securities and Exchange Commission a copy of the Company's press release announcing entering into a definitive agreement to sell its interest in 43,000 acres of non-producing coal bed methane acreage in eastern Kansas.

SIGNATURES

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 thereunto duly authorized.

BERRY PETROLEUM COMPANY

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

Date: August 6, 2003

CERTIFICATION OF CHIEF EXECUTIVE OFFICER

I, Jerry V. Hoffman, certify that:

1. I have reviewed this report on Form 10-Q of Berry Petroleum Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and we have:

a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision to ensure that material information relating to the registrant is made known to us by others within the registrant, particularly during the period in which this report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report on such evaluation; and

c) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

a) all significant deficiencies and material weaknesses in the design or operation of internal controls over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls over financial reporting.

Date: August 6, 2003

/s/ Jerry V. Hoffman
Jerry V. Hoffman
Chairman, President and
Chief Executive Officer

Exhibit 31.1

CERTIFICATION OF CHIEF FINANCIAL OFFICER

I, Ralph J. Goehring, certify that:

1. I have reviewed this report on Form 10-Q of Berry Petroleum Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and we have:

a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision to ensure that material information relating to the registrant is made known to us by others within the registrant, particularly during the period in which this report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report on such evaluation; and

c) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

a) all significant deficiencies and material weaknesses in the design or operation of internal controls over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls over financial reporting

Date: August 6, 2003 /s/ Ralph J. Goehring
Ralph J. Goehring
Senior Vice President and
Chief Financial Officer

Exhibit 31.2

Certification Pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002

I, Jerry V. Hoffman, as Chairman, President and Chief Executive Officer of Berry Petroleum Company (the "Company"), hereby certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Quarterly Report on Form 10-Q of the Company for the period ended June 30, 2003 (the "Report") which this certification accompanies, fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Jerry V. Hoffman
Jerry V. Hoffman
Chairman, President and Chief Executive Officer
August 6, 2003

Certification Pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002

I, Ralph J. Goehring, Senior Vice President and Chief Financial Officer of Berry Petroleum Company (the "Company"), hereby certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Quarterly Report on Form 10-Q of the Company for the period ended June 30, 2003 (the "Report") which this certification accompanies, fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Ralph J. Goehring
Ralph J. Goehring
Senior Vice President and Chief Financial Officer
August 6, 2003

Exhibit 32.2