BERRY PETROLEUM CO
Form 10-Q
October 26, 2004

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 September 30, 2004

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 September 30, 2004, was 21,043,911 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.

BERRY PETROLEUM COMPANY
September 30, 2004

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

	September 30, 2004 (Unaudited)	December 31, 2003 (Restated)
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 8,208	$ 10,658
Short-term investments available for sale	662	663
Accounts receivable	33,713	23,506

Deferred income taxes	10,122	6,410
Prepaid expenses and other	2,035	2,049
Total current assets	54,740	43,286
Oil and gas properties (successful efforts basis), buildings and equipment, net	323,475	295,151
Other assets	7,189	1,940
	$ 385,404	$ 340,377
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 39,236	$ 32,490
Accrued liabilities	6,126	4,214
Income taxes payable	5,130	4,412
Fair value of derivatives	16,055	5,710
Total current liabilities	66,547	46,826
Long-term liabilities:		
Deferred income taxes	46,702	38,559
Long-term debt	33,000	50,000
Abandonment obligation	7,471	7,311
Fair value of derivatives	893	343
Total long-term liabilities	88,066	96,213
Shareholders' equity:		
Preferred stock, $.01 par value; 2,000,000 shares authorized; no shares outstanding	-	-
Capital stock, $.01 par value:		
Class A Common Stock, 50,000,000 shares authorized; 21,043,911 shares issued and outstanding at September 30, 2004 (20,904,372 at December 31, 2003)	210	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	59,801	56,475
Deferred stock option compensation	-	(1,108)
Accumulated other comprehensive loss	(9,726)	(3,632)
Retained earnings	180,497	145,385
Total shareholders' equity	230,791	197,338
	$ 385,404	$ 340,377

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 September 30, 2004 and 2003
(In Thousands, Except Per Share Information)
(Unaudited)

	2004	2003 (Restated)
Revenues:		
Sales of oil and gas	$ 61,560	$ 33,466
Sales of electricity	11,344	10,642
Interest and other income, net	45	350
	72,949	44,458
Expenses:		
Operating costs - oil and gas production	22,107	16,534
Operating costs - electricity generation	11,344	10,642
Depreciation, depletion and amortization	8,323	5,167
General and administrative	4,228	2,349
Interest	512	368
	46,514	35,060
Income before income taxes	26,435	9,398
Provision for income taxes	8,206	1,571
Net income	$ 18,229	$ 7,827
Basic net income per share	$ .83	$ .36
Diluted net income per share	$ .82	$ .35
Cash dividends per share	$ .18	$ .11
Weighted average number of shares of capital stock outstanding (used to calculate basic net income per share)	21,934	21,776
Effect of dilutive securities:		
Stock options	375	242
Other	56	47
Weighted average number of shares of capital stock used to calculate diluted net income per share	22,365	22,065

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

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BERRY PETROLEUM COMPANY
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Condensed Income Statements
Nine Month Periods Ended September 30, 2004 and 2003
(In Thousands, Except Per Share Information)

(Unaudited)

	2004	2003 (Restated)
Revenues:		
Sales of oil and gas	$ 159,520	$ 97,286
Sales of electricity	34,569	32,959
Interest and other income, net	338	598
	194,427	130,843
Expenses:		
Operating costs - oil and gas production	59,321	45,344
Operating costs - electricity generation	34,569	32,959
Depreciation, depletion and amortization	24,036	14,350
General and administrative	15,202	7,855
Dry hole, abandonment and impairment	-	2,487
Interest	1,577	845
	134,705	103,840
Income before income taxes	59,722	27,003
Provision for income taxes	15,850	3,996
Net income	$ 43,872	$ 23,007
Basic net income per share	$ 2.01	$ 1.06
Diluted net income per share	$ 1.97	$ 1.05
Cash dividends per share	$ .40	$ .36
Weighted average number of shares of capital stock outstanding (used to calculate basic net income per share)	21,875	21,766
Effect of dilutive securities:		
Stock options	366	107
Other	54	44
Weighted average number of shares of capital stock used to calculate diluted net income per share	22,295	21,917

Condensed Statements of Comprehensive Income
Nine Month Periods Ended September 30, 2004 and 2003
(in Thousands)
(Unaudited)

	2004	2003 (Restated)
Net income	$ 43,872	$ 23,007
Unrealized losses on derivatives, (net of income taxes of $4,063 and $407, respectively)	(6,094)	(610)
Comprehensive income	$ 37,778	$ 22,397

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
Nine Month Periods Ended September 30, 2004 and 2003

(In Thousands)
(Unaudited)

	2004	2003 (Restated)
Cash flows from operating activities:		
Net income	$ 43,872	$ 23,007
Depreciation, depletion and amortization	24,036	14,350
Dry hole, abandonment and impairment	(364)	2,517
Deferred income taxes	6,846	3,387
Deferred stock compensation	4,520	917
Other, net	569	(290)
Increase in current assets other than cash, cash equivalents and short-term investments	(12,448)	(6,780)
Increase in current liabilities	11,451	2,881
Net cash provided by operating activities	78,482	39,989
Cash flows from investing activities:		
Capital expenditures	(51,856)	(24,620)
Property acquisitions	-	(47,519)
Other, net	(3,320)	1,764
Net cash used in investing activities	(55,172)	(70,375)
Cash flows from financing activities:		
(Payment of) proceeds from long-term debt	(17,000)	40,000
Dividends paid	(8,760)	(7,836)
Other, net	-	(1,076)
Net cash (used in) provided by financing activities	(25,760)	31,088
Net (decrease) increase in cash and cash equivalents	(2,450)	702
Cash and cash equivalents at beginning of year	10,658	9,866
Cash and cash equivalents at end of period	$ 8,208	$ 10,568
Supplemental non-cash activity:		
Increase(decrease)in fair value of derivatives:		

Current (net of income taxes of $4,138 and $(43) in 2004 and 2003, respectively)	$ 6,207	$ (65)
Non-current (net of income taxes of ($75) and $450 in 2004 and 2003, respectively)	(113)	675
Net increase (decrease) to accumulated other comprehensive loss	$ 6,094	$ 610

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

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Part I. Financial Information
Item 1. Financial Statements
Notes to Condensed Financial Statements
September 30, 2004
(Unaudited)

1. All adjustments which are, in the opinion of management, necessary for a fair presentation of the Company's financial position at September 30, 2004 and December 31, 2003 and results of operations for the three and nine month periods ended September 30, 2004 and 2003 and cash flows for the nine month periods ended September 30, 2004 and 2003 have been included. All such adjustments are of a normal recurring nature, except as indicated in Notes 3 and 4. The results of operations and cash flows are not necessarily indicative of the results for a full year.

2. The accompanying unaudited condensed financial statements have been prepared on a basis consistent with the accounting principles and policies reflected in the December 31, 2003 financial statements, except as noted in Notes 3 and 4. The December 31, 2003 Form 10-K/A, March 31, 2004 Form 10-Q/A and June 30, 2004 Form 10-Q should be read in conjunction herewith. The year-end condensed balance sheet, as restated, 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. Restatement of Prior Financial Information for Variable Accounting for Stock Options - The accompanying condensed financial statements reflect certain unaudited restated financial information for the three months and nine months ended September 30, 2003. The original Form 10-Q for the quarter ended September 30, 2003 was filed with the Securities and Exchange Commission on November 7, 2003. The Company has restated its financial information as of September 30, 2003, and results of operations and cash flows for the three months and nine months ended September 30, 2003, to account for the Company's stock option plan using variable plan accounting, insofar as the Company had permitted option holders to exercise options by surrendering underlying unexercised options in payment of the exercise price of the options and related taxes. While the Company had accounted for options issued under the plan as fixed awards with compensation expense recorded for certain option exercises, it was determined that variable plan accounting is required under generally accepted accounting principles in the United States. The use of variable plan accounting requires a charge to compensation expense, commencing at the grant date, in an amount by which the market price of the Company's stock covered by the grant exceeds the option price. This accounting has been changed and subsequent changes in the market price of the Company's stock from the date of grant to the date of exercise or forfeiture does not result in a change in the measure of compensation cost for the award being recognized. Amounts in the ensuing discussion have been adjusted for these restatements where applicable.

Accordingly, the income statements for the three and nine months ended September 30, 2003 reflect stock compensation using variable plan accounting. As described in Note 4, the Company adopted the fair value method of accounting for its stock options effective January 1, 2004 using the modified prospective method which does not require restatement of periods prior to the effective date.

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The effect of the restatement for variable plan accounting is as follows:

Condensed Income Statements

	Three Months Ended September 30, 2003		
	As Previously Reported	Adjustments	Restated
REVENUES	$ 44,458	$ -	$ 44,458
EXPENSES			
Operating costs	27,176	-	27,176
Depreciation, depletion & amortization	5,167	-	5,167
General & administrative	2,002	347	2,349
Interest	368	-	368
	34,713	347	35,060
Income before income taxes	9,745	(347)	9,398
Provision for income taxes	1,710	(139)	1,571
Net income	$ 8,035	$ (208)	$ 7,827
Basic net income per share	$ 0.37	$ (0.01)	$ 0.36
Diluted net income per share	$ 0.36	$ (0.01)	$ 0.35
Weighted average shares of capital stock outstanding (used to calculate basic net income per share)	21,776	-	21,776
Effect of dilutive securities			
Stock options	242	-	242
Other	47	-	47

Weighted average shares of capital stock outstanding (used to calculate diluted net income per share)	22,065	-	22,065

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	Nine Months Ended September 30, 2003		
	As Previously Reported	Adjustments	Restated
REVENUES	$ 130,843	$ -	$ 130,843
EXPENSES			
Operating costs	78,303	-	78,303
Depreciation, depletion & amortization	14,350	-	14,350
General & administrative	6,663	1,192	7,855
Interest	845	-	845
Dry hole, abandonment and impairment	2,487	-	2,487
	102,648	1,192	103,840
Income before income taxes	28,195	(1,192)	27,003
Provision for income taxes	4,473	(477)	3,996
Net income	$ 23,722	$ (715)	$ 23,007
Basic net income per share	$ 1.09	$ (0.03)	$ 1.06
Diluted net income per share	$ 1.08	$ (0.03)	$ 1.05
Weighted average shares of capital stock outstanding (used to calculate basic net income per share)	21,766	-	21,766
Effect of dilutive securities			
Stock options	107	-	107

Other	44	-	44
Weighted average shares of capital stock outstanding (used to calculate diluted net income per share)	21,917	-	21,917

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(Unaudited)

	Nine Months Ended September 30, 2003		
	As Previously Reported	Adjustments	Restated
Cash flows from operating activities:			
Net income	$ 23,722	$ (715)	$ 22,799
Adjustments to reconcile net income to net cash provided in operating activities	16,267	715	17,190
Net cash provided by operating activities	39,989	-	39,989
Cash flows from investing activities:			
Net cash used in investing activities	(70,375)	-	(70,375)
Cash flows from financing activities:			
Net cash provided by financing activities	31,088	-	31,088
Net increase in cash and cash equivalents	702	-	702
Cash and cash equivalents at beginning of year	9,866	-	9,866
Cash and cash equivalents at end of period	$ 10,568	$ -	$ 10,568

4. Effective January 1, 2004, the Company voluntarily adopted the fair value method of accounting for its stock option plan as prescribed by SFAS 123, "Accounting for Stock-based Compensation." The modified prospective method was selected as described in SFAS 148, "Accounting for Stock-Based Compensation - Transition and Disclosure." Under this method, the Company recognizes stock option compensation expense as if it had applied the fair value method to account for unvested stock options from its original effective date. Stock option compensation expense is recognized from the date of grant to the vesting date. During the quarters ended September 30, 2004 and 2003, the Company recorded stock option compensation expense of $.4 million and $.5 million, respectively, which is included in General and administrative expenses. For the nine months ended September 30, 2004, stock option compensation expense was $5.0 million, up from $1.5 million recognized during the nine months ended September 30, 2003.

From January 1, 2004 to July 29, 2004, the Company had determined that a portion of its stock option compensation under SFAS 123 is required to be calculated under variable plan accounting; however, the majority of stock option compensation is accounted for under the fair value method. In accordance with variable plan accounting, the Company recognized a corresponding liability determined by a mark-to-market valuation of the Company's stock at each financial

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(Unaudited)

reporting date. On July 29, 2004, the Company revised certain stock option exercise provisions of the plan and, subsequent to July 29, 2004, variable plan accounting is no longer required. Accordingly, as of July 29, 2004, $3.3 million and $.9 million of current and non-current liabilities, respectively, were reclassified to Capital in excess of par value.

If the fair value method under SFAS 123 had been used to record stock option expense for the three and nine months ended September 30, 2003, the following would have been recorded (in thousands, except per share data):

	Three Months Ended September 30, 2003 (Restated)	Nine Months Ended September 30, 2003 (Restated)
Compensation expense, net of income taxes:		
As reported	$ 304	$ 918
Pro forma	193	580
Net income:		
As reported	7,827	23,007
Pro forma	7,938	23,345
Basic net income per share:		
As reported	0.36	1.06
Pro forma	0.36	1.07
Diluted net income per share:		
As reported	0.35	1.05
Pro forma	0.36	1.07

5. Property Acquisitions/Agreements

Lake Canyon

During July 2004, the Company and Bill Barrett Corporation (BBC) entered into a joint Exploration and Development Agreement (Agreement) with the Ute Indian Tribe (Tribe) to explore and develop approximately 125,000 prospective acres of tribal lands in the Uinta Basin in Utah. On October 5, 2004, the Bureau of Indian Affairs approved the Agreement as amended, which now includes the Ute Distribution Corporation as an additional party. The Company will operate the shallow horizons down to approximately 6,500 feet. The Company's ownership will be up to 75% in these shallow zones. For the Company and BBC to earn their respective interests in the 125,000 acres pursuant to the Agreement, they are required to participate in drilling 13 deep wells and 21 shallow wells prior to December 31, 2009, including one deep well and two shallow wells by December 31, 2005. The Company plans to commence drilling shallow wells in the first quarter

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of 2005. BBC intends to drill the first deep well beginning in January 2005. The Company estimates its share of the drilling cost of these 34 wells over the term of the Agreement to be approximately $21 million. This estimate is subject to changes in drilling and completion costs. The Tribe has an option to participate for a 25% working interest in wells drilled pursuant to the Agreement. This right terminates as to all wells in a lease block if the Tribe does not participate in the first two wells drilled in that lease block. If the Tribe exercises its right to participate, Berry's interest would be reduced to 56.25% in the shallow zones and 18.75% in the deep zones in the wells in which the Tribe participates.

Separately, in the third quarter of 2004, the Company signed a Purchase and Sale Agreement to purchase from BBC an interest in 46,000 acres of fee lands adjacent to or near the tribal acreage. The Company's working interest on this acreage is 75% in the shallow horizons and 25% in the deep horizons. The Company is not required to fulfill a drilling commitment on this acreage.

The aggregate 171,000 acre block (over 265 square miles), covered by the above agreements, is located immediately west of the Company's Brundage Canyon field. The Company and BBC will develop a plan to test the 171,000 acres. Natural gas potential will be the focus of the deeper horizons, primarily in the Wasatch and Mesaverde formations, and the Company will participate up to 25% in the development of these deeper zones. The Company will pay approximately $2 million for this acreage and related costs in the fourth quarter.

Duschesne and Uintah Counties

In September 2004, the Company and an industry partner were high bidders on certain leases offered by the Bureau of Land Management (BLM). These leases, representing approximately 17,000 gross acres (8,500 net acres to the Company), are located southeast of the Company's Brundage Canyon field. The final issuance of leases for this acreage is pending due to various court challenges by special interest groups. The Company paid approximately $3.3 million for its interest in this acreage, which is included as a deposit in the Company's Condensed Balance Sheet as of September 30, 2004.

Brundage Canyon

In September 2004, the Company and BBC entered into a Farmout Agreement to explore and develop the deeper horizons of the Company's Brundage Canyon field. While the initial test well will be funded by BBC, the Company will retain a 25% working interest at payout. BBC is required to drill to a minimum depth of 14,000 feet. Upon completion of the drilling of this well, BBC will earn a 75% working interest in the deeper horizons of the Company's Brundage Canyon field.

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

Results of Operations

The Company earned a record net income of $18.2 million, or $.82 per share (diluted), on revenues of $72.9 million in the third quarter of 2004, up 133% from net income of $7.8 million, or $.35 per share, on revenues of $44.5 million in the third quarter of 2003, and up 19% from net income of $15.3 million, or $.68 per share, on revenues of $64.1 million in the second quarter of 2004. Net income for the nine months ended September 30, 2004 was $43.9 million, or $1.97 per share (diluted), on revenues of $194.4 million, up 91% from $23.0 million, or $1.05 per share, on revenues of $130.8 million for the nine months ended September 30, 2003. Results in the nine months ended September 30, 2003 include an after-tax write off of $1.4 million, representing the cost of a coalbed methane pilot project.

	Three Months Ended			Nine Months Ended	
	Sept 30, 2004	June 30, 2004	Sept 30, 2003	Sept 30, 2004	Sept 30, 2003
Oil and gas:					
Net Production - BOE per day	20,825	20,315	16,482	20,243	15,874
Per BOE:					
Average sales price, net of hedges(1)	$32.28	$28.55	$22.07	$28.81	$22.45
Operating costs (2)	10.32	9.21	10.21	9.57	9.88
Production taxes	1.22	1.17	.69	1.12	.58
Total operating costs	11.54	10.38	10.90	10.69	10.46
Depreciation, depletion and amortization (DD&A)	4.34	4.60	3.41	4.33	3.31
General & administrative expenses (G&A)	2.21	2.38	1.55	2.74	1.81
Interest expense	.27	.29	.24	.28	.19
Electricity:					
Production - MWh/day	2,122	2,045	2,127	2,112	2,100
Sales - MWh/day	1,916	1,843	1,937	1,905	1,912
Average sales price, net of hedges - $/Mwh	75.96	67.51	60.12	70.25	65.38
Fuel gas cost - $/Mmbtu	5.27	5.44	4.75	5.27	5.06
(1) Comparative average West Texas Intermediate (WTI) price:	$43.89	$38.28	$30.21	$39.21	$30.94
(2) Includes monthly expenses in excess of monthly revenues from cogeneration operations of:	$ 2.09	$ 1.81	$ 2.34	$ 1.91	$ 2.28

The Company achieved another production record in the third quarter of 2004. Production (BOE/day) for the quarter averaged 20,825, up 26% from 16,482 in the third quarter of 2003 and 3% from 20,315 in the second quarter of 2004. The increase from the third quarter of 2003 was due primarily to production from our Brundage Canyon field which was purchased in late August 2003. Production from that field, which averaged less than 1,000 BOE/day for the third quarter of 2003, averaged 4,950 BOE/day in the third quarter of 2004. The Company drilled 42 wells in the Brundage Canyon field during the nine months ended September 30, 2004. A total of 55 wells are planned for the property in 2004.

Production (BOE/day) from the Company's California properties averaged 15,689, 15,971 and 15,522 for the third quarter of 2004, the second quarter of 2004 and the third quarter of 2003, respectively. The Company has plans to drill approximately 20 new wells and work over approximately 24 wells in the fourth quarter of 2004, which is expected to improve California production to approximately 16,000 BOE/day. Additionally, the Company has launched three new enhanced (thermal) recovery projects in California (Poso Creek field, Ethel D property and a diatomite pilot) which all show promise to increase production in future periods. On a Companywide basis, management believes the Company will achieve its average production target of 20,500 BOE/day in 2004.

While preliminary, the Company is targeting production growth from existing assets of approximately 10% to average in excess of 22,500 BOE/day in 2005. This expectation is based on crude oil prices exceeding WTI $35 per barrel and maintaining a historic natural gas to oil pricing ratio of six to one. The Company is anticipating a capital budget for 2005 of at least $80 million with the majority of funds allocated for Rocky Mountain activity.

World crude oil prices reached an all time high during the third quarter of 2004, with Nymex WTI prices averaging $43.89 per barrel. In the third quarter, the Company's average price received per BOE was $32.28, up 13% from $28.55 in the second quarter of 2004 and 46% from $22.07 per BOE in the third quarter of 2003. The difference of $11.61 between the price received by the Company and Nymex WTI average price for the quarter is derived from 1) the quality differential between WTI crude oil and the heavier crude oils produced by the Company, which was a reduction of approximately $5.39 per BOE, 2) hedge losses on produced and sold quantities in the quarter had an impact of $3.32 per BOE, and 3) a price based royalty paid on production from a California property that lowered the price by $2.90 per BOE. The average differential per barrel between Nymex WTI and the average posting for the Company's 13 degree heavy crude oil in California, which averaged $5.72 in 2003, has expanded to an average of $8.68 in the third quarter of 2004, and was $11.38 on September 30, 2004. The Company believes that this widening differential is due to the WTI price being well above $40 per barrel and a general increase in supply of heavier crude oil on a worldwide basis.

The Company has a sales contract in California under which it sells 97% of its California production with a price mechanism equating to WTI less approximately $6.00 per barrel. This contract expires December 31, 2005 and while the Company believes there is a sufficient market for its crude oil, it can make no assurances as to the terms it can negotiate within a new sales contract. The Company anticipates crude oil prices to remain strong for the foreseeable future. However, since crude oil prices are impacted by world supply and demand and other factors, actual prices may vary significantly from current levels. Please refer to Part 1, Item 3 of this report for more detail concerning the

Company's current hedge strategy and the impact of these agreements on current and future revenues. For the nine months ended September 30, 2004, the Company's average price received, net of hedges, was $28.81, up 28% from $22.45 received in the same period of 2003.

Sales of oil and gas of $61.6 million in the third quarter of 2004 was up 84% from $33.5 million generated in the third quarter of 2003. On a year-to-date basis, sales of oil and gas increased 64% to $159.5 million in the 2004 nine-month period from $97.3 million in the first nine months of 2003. In 2004, approximately 93% of the Company's oil and gas sales is crude oil, with 79% being heavy crude oil produced in California.

The Company has continued its practice of hedging a portion of its production to protect cash flows from a severe crude oil price decline. See "Item 3. Quantitative and Qualitative Disclosures About Market Risk" for information related to these agreements and their impact on future revenues. The Company nets its oil hedging realized gains or losses into its revenues from the sales of oil and gas. For the third quarter of 2004, the effect of these agreements was to reduce the net realized price per barrel of crude oil by $3.32 compared to a reduction of $2.28 in the second quarter of 2004 and $1.90 in the third quarter of 2003.

The Company sells approximately 79 MW of the 88 MW of electricity it generates from its cogeneration facilities. The Company consumes 9 MW, or 10%, of its generation in its field operations. The Company estimates that this consumption practice reduces California oil and gas operating costs by $.20 per BOE. Approximately 59 MW is sold to utilities under Standard Offer (SO) contracts that are scheduled to terminate on December 31, 2004. In January 2004, the California Public Utilities Commission (CPUC) issued a decision that orders the utilities to continue to purchase energy and capacity from Qualified Facilities (QFs), such as Berry, under 5-year SO contracts. The CPUC has not yet determined the price that will be paid under these SO contracts. The Company is currently reviewing draft agreements to accomplish this CPUC order, and expects to sign final agreements in the fourth quarter of 2004. The remaining 20 MW of electricity continues to be sold to a utility under a long-term SO contract that is scheduled to terminate in March 2009. The outlook for electricity volume appears to be relatively stable in 2005. However, revenues will be impacted by volatile fuel (natural gas) costs.

Oil and gas operating expenses per BOE for the third quarter of 2004 were $11.54, up 6% from $10.90 in the third quarter of 2003 and, up 11% from $10.38 in the second quarter of 2004. The primary factor contributing to higher operating costs is steam cost, which increased as a result of a 10% increase in injection volumes into California heavy oil properties during the third quarter of 2004 compared to injection volumes in both the third quarter of 2003 and the second quarter of 2004. Overall, the Company injected approximately 6.7 million barrels of steam during the third quarter of 2004. In addition to higher injection volumes, the operating costs increased in the third quarter of 2004 from the third quarter of 2003 because the cost of natural gas used as fuel in the Company's steam generating operations increased 11% between the two periods. Oil and gas operating expenses for the third quarter of 2004 were $22.1 million, up from $16.5 million, in the third quarter of 2003 and, up from $19.2 million in the second quarter of 2004, which is consistent with production growth.

For the nine months ended September 30, 2004, operating costs per BOE were $10.69, up 2% from $10.46 for the first nine months of 2003. Contributing to the increase in costs per BOE was an 8%, or 1.3 million increase in steam injection volume (in barrels) to 18.6 million in the 2004 nine month period. The cost of natural gas used in steam operations was fairly flat in the two nine-month periods averaging slightly over $5.00 per Mmbtu. Although the Company incurred higher operating costs of $59.3 million for the nine months ended September 30, 2004, up from $45.3 million for the first nine months of 2003, the cost per BOE remained fairly flat because the operating cost per BOE at the Brundage Canyon properties is lower than California since steam is not required in the Utah operations. The Company anticipates that operating costs will average between $10.50 and $11.25 per BOE during the full year of 2004 based on increasing natural gas prices. The Company is targeting operating costs per BOE in 2005 of between $11.00 and $12.00, which is higher than 2004 due to anticipated higher steam volumes and higher average prices for natural gas used to produce steam.

DD&A per BOE for the third quarter of 2004 was $4.34, down by 6% from $4.60 in the second quarter of 2004, however, up 27% from $3.41 in the third quarter of 2003. DD&A per BOE for the first nine months of 2004 was $4.33, up 31% from $3.31 in the first nine months of 2003. The decrease in DD&A per BOE in the third quarter of 2004 compared to the second quarter of 2004 is due to a revision in the reserve estimates for Brundage Canyon that lowered the DD&A rate per BOE as a result of drilling production volumes exceeding previous expectations considered in prior DD&A rates. Consistent with expectations, the DD&A per BOE between the third quarter of 2004 and third quarter of 2003 is trending higher and is expected to continue to increase over the next few years due to the Utah acquisitions, continued development of its Utah and California properties and the shorter reserve life of the Utah assets compared to the California assets. DD&A for the third quarter of 2004 was $8.3 million, up from $5.2 million in the third quarter of 2003 and DD&A for the first nine months of 2004 was $24.0 million, up from $14.4 million in the first nine months of 2003. DD&A increase in total dollars is consistent with the Company's production growth. The Company anticipates its DD&A to approximate $32 million or range from an average of between $4.10 and $4.50 per BOE for all of 2004. For 2005, the Company expects DD&A to approximate $4.40 to $4.70 per BOE, or $36 million to $38 million.

G&A per BOE for the third quarter of 2004 was $2.21, or $4.2 million, down 7% from $2.38, or $4.4 million in the second quarter of 2004 and up 43% from $1.55, or $2.4 million in the third quarter of 2003. For the first nine months of 2004, G&A per BOE was $2.74, or $15.2 million compared to $1.81, or $7.9 million in the first nine months of 2003. Stock option compensation was $5.0 million for the nine months ended September 30, 2004, up $3.5 million from $1.5 million incurred in the first nine months of 2003. G&A expenses also increased in 2004 due to $.8 million in costs associated with the change in the chief executive officer of the Company in the second quarter of 2004, increases in payroll costs of $1.9 million resulting from additional staffing to accommodate Company growth, a change in the treatment of stock compensation, higher accounting and legal fees related to Sarbanes-Oxley compliance and higher oil and gas property evaluation expenses. The Company anticipates G&A costs for all of 2004 to be between $18.0 and $19.0 million and average between $2.40 and $2.55 per BOE. The Company expects its G&A costs to be much lower in 2005 than 2004, primarily due to lower charges related to its stock option accounting. The Company anticipates its G&A costs for 2005 will approximate $1.55 to $1.75 per BOE, or $13 million to $14 million.

The Company experienced an effective tax rate of 31% for the third quarter of 2004, up from 17% for the same period last year. The significant improvement in pre-tax income had the effect of lowering in percentage terms the benefit of enhanced oil recovery (EOR) credit. For the nine months ending September 30, 2004, the Company's effective tax rate was 27%, up from 15% in the same period last year. This increase is also directly related to improved earnings. The Company's investment in qualifying EOR projects in California allows for an effective rate well below the statutory rate of 40%. Based on current oil prices, the Company anticipates an effective tax rate for 2004 of between 24% and 28%. With the likelihood that WTI will average over $42 per barrel in 2004, the Company believes the EOR tax credit will be reduced in 2005 due to the phase-out under its pricing mechanism. Thus, the Company expects to earn less EOR credit in 2005. Generally, the Company expects that its effective tax rate will trend higher as it dedicates an increasing percentage of it capital investments to non-EOR projects. The American Jobs Creation Act, signed by the President on October 22, 2004, is expected to reduce the Company's effective tax rate by approximately one percentage point. Given the above and the outlook for crude oil pricing next year, the Company expects its effective tax rate to average between 34% and 38%.

Liquidity and Capital Resources

Net cash provided by operating activities was $78.5 million in the first nine months of 2004, up $38.5 million or 96% from $40.0 million in the first nine months of 2003. The increase in cash provided is the direct result of increases in crude oil prices and higher production levels in the nine months ended September 30, 2004 compared to the nine months ended September 30, 2003. Sales of oil and gas increased $62.2 million during the period ended September 30, 2004 compared to the same period in 2003 due to a 28% increase in crude oil prices, net of hedges, and a 28% increase in production between the respective periods. Cash flows from operations were affected by an $11.5 million increase in current liabilities, primarily due to a higher level of operating activities in the 2004 nine month period. Cash flows from operations were also impacted by a $10.2 million increase in receivables due primarily to higher crude oil prices and production levels during the nine months ended September 30, 2004.

Excluding 2004 acquisitions, the Company's revised capital budget for 2004 is approximately $70 million, up 32% from its initial capital budget of approximately $53 million. The Company expects to drill a total of approximately 120 wells, perform approximately 90 workovers and complete various facility improvements. The Company intends to fund 100% of its capital program out of internally generated cash flow. During the first 9 months of 2004, cash was used to fund $51.9 million in capital expenditures, which included drilling 93 new wells and completing 76 workovers. Of these totals, 51 new wells were drilled and 41 workovers were performed in California and 42 new wells were drilled and 35 workovers were performed on the Brundage Canyon property.

In August 2004, the Company increased its annual dividend by 9% to $.12 per share per quarter ($.48 per share per annum) and announced a special dividend of $.06 per share. The Company paid dividends of $4.1 million during the third quarter of 2004, which is included in dividends paid of $8.8 million in the first nine months of 2004.

In the third quarter of 2004, the Company paid down $17 million of long-term debt. As of September 30, 2004, the Company had $167 million available under its $200 million unsecured credit facility. Cash provided by operating activities

will be targeted to acquisitions, additional development and debt reduction. As of September 30, 2004, the Company had not closed on the acreage in Lake Canyon. The Company will pay approximately $2 million for this acreage and related costs in the fourth quarter of 2004. The Company estimates its share of the drilling cost associated with its 34 well drilling commitment with the Ute Indian Tribe and Ute Distribution Corporation through December 31, 2009 is approximately $21 million. This estimate is subject to changes in drilling and completion costs. The Company anticipates that it will participate in the first deep test well on this acreage which is targeted to spud in January 2005. The Company is also planning to drill at least two shallow wells on this acreage in the first quarter of 2005.

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 news release 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, drilling, development and operating risks, a limited marketplace for electricity sales within California, counterparty risk, competition, environmental risks, litigation uncertainties, the availability of drilling rigs and other support services, legislative and/or judicial decisions and other government or Tribal regulations.

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

The Company enters into various financial contracts to hedge its exposure to commodity price risk associated with its crude oil production, electricity production and natural gas volumes purchased for its steaming operations. These contracts have historically been in the form of zero-cost collars and swaps. The Company typically hedged between 25% and 50% of its anticipated crude oil production each year and up to 30% of its anticipated net natural gas purchased each year. Going forward, the Company anticipates that it will implement its hedges in the form of swaps with a target of approximately 50% of its production to capture the benefit of favorable crude pricing. The Company may, at times, exceed the 50% target, but in no circumstances foresees exceeding 75% of its production. All of these hedges have historically been deemed to be cash flow hedges with the mark-to-market valuations of the collars and swaps provided by external sources, based on prices that are actually quoted. The Company reviews the effectiveness of these hedges on a regular basis. The Company may not have the benefit of a sales contract that links heavy crude oil prices to Nymex WTI crude prices after 2005, thus, any hedges placed on volumes in 2006 or beyond may not be deemed to be cash flow hedges. Therefore, the accounting treatment under SFAS 133, Accounting for Derivative Instruments and Hedging Activities, may require mark-to-market valuations which would impact the income statement before the cash settlement of the hedge.

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Based on NYMEX futures prices as of September 30, 2004, the Company would expect to make pre-tax future cash receipts (cash payments) over the remaining term of its crude oil (through December 31, 2005) and natural gas (through June 30, 2006) hedges in place as follows:

		Impact of percent change in futures prices on pre-tax earnings (in thousands)			
	NYMEX Futures	-20%	-10%	+10%	+20%
Average WTI Price for Outstanding Contracts	$ 45.67	$ 36.54	$ 41.10	$ 50.24	$ 54.80
Crude Oil gain (loss)/cash receipt (cash payment)	(21,606)	6,504	(7,551)	(35,661)	(49,716)
Average Henry Hub (HH) Price for Outstanding Contracts	6.78	5.43	6.11	7.46	8.14
Natural Gas gain (loss)/cash receipt (cash payment)	4,821	(1,143)	1,839	7,803	10,785

The Company sells approximately 79 MW of the 88 MW of electricity it generates from its cogeneration facilities. The Company consumes 9 MW, or 10%, of its generation in its field operations. The Company estimates that this consumption practice reduces California oil and gas operating costs by $.20 per BOE. Approximately 59 MW is sold to utilities under Standard Offer (SO) contracts that are scheduled to terminate on December 31, 2004. In January 2004, the California Public Utilities Commission (CPUC) issued a decision that orders the utilities to continue to purchase energy and capacity from Qualified Facilities (QFs), such as Berry, under 5-year SO contracts. The CPUC has not yet determined the price that will be paid under these SO contracts. The Company is currently reviewing draft agreements to accomplish this CPUC order, and expects to sign final agreements in the fourth quarter of 2004. The remaining 20 MW of electricity continues to be sold to a utility under a long-term SO contract that is scheduled to terminate in March 2009. The outlook for electricity volume appears to be relatively stable in 2005. However, revenues will be impacted by volatile fuel (natural gas) costs.

The Company attempts to minimize credit exposure to counterparties through monitoring procedures and diversification. The Company's exposure to changes in interest rates results primarily from long-term debt. Total debt outstanding at September 30, 2004 and December 31, 2003 was $33 million and $50 million, respectively. Interest on amounts borrowed is charged at LIBOR plus 1.25% to 2.0%. Based on these borrowings, a 1% change in interest rates would not have a material impact on the Company's condensed financial statements.

BERRY PETROLEUM COMPANY
Part I. Financial Information
Item 4. Controls and Procedures

Based on an evaluation by the Company's management as of the end of the period covered by this Quarterly Report on Form 10-Q, subject to and except for the discussion below, the Company's Chief Executive Officer and Chief Financial Officer have concluded that the Company's disclosure controls and procedures, as defined by regulations of the Securities Exchange Act of 1934 as amended (the "Exchange Act"), are effective to ensure that information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission's rules and forms.

In July, 2004, the Company became aware of a material weakness relating to the Company's internal controls and procedures over its financial reporting for stock based compensation relating to its stock option plan. As a result, the Company performed a review of the method of stock option exercises by employees and directors since the plan's inception in 1994. Based on this review, the Company determined that variable plan accounting was required to comply with generally accepted accounting principles in the United States. In response to this matter, the Company, during the third quarter 2004, revised its procedures related to stock option exercising to remove the option holder's election to surrender options in payment of any portion of taxes above the minimum statutory withholding. Furthermore, the Company, during the third quarter 2004, has remediated the ineffective internal controls through the implementation of enhanced controls to assure that financial reporting is in compliance with generally accepted accounting principles in the United States.

The Company has identified no changes in the internal control over financial reporting that occurred during the fiscal quarter ended September 30, 2004, and that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting, except as described above.

BERRY PETROLEUM COMPANY
Part II. Other Information

Item 6. Exhibits and Reports on Form 8-K

(a) Reports on Form 8-K

On July 19, 2004 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 acquisition of additional Uinta Basin acreage and a joint exploration and development program.

On July 26, 2004 the Company filed a Form 8-K reporting an Item 12 - Disclosure of results of operations and financial condition to furnish the Securities and Exchange Commission a copy of the Company's Press Release announcing a rescheduling of the release of the Company's financial results for the three months ended June 30, 2004 and the revision of accounting treatment for stock options.

On August 9, 2004, the Company filed a Form 8-K reporting an Item 9 - Regulation FD Disclosure and Item 12 - Disclosure of results of operations and financial condition to furnish the Securities and Exchange Commission a copy of the Company's Press Release announcing financial results for the three and six months ended June 30, 2004.

On August 31, 2004, the Company filed a Form 8-K reporting an Item 7.01 - Regulation FD announcing the increase in the annual dividend and capital budget.

(b) Exhibits

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

BERRY PETROLEUM COMPANY
Part II. Other Information

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: October 26, 2004