BERRY PETROLEUM CO
Form 10-Q
August 09, 2005

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

For the quarterly period ended June 30, 2005
Commission file number 1-9735

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

DELAWARE (State or other jurisdiction of incorporation or organization)	77-0079387 (I.R.S. Employer Identification No.)
5201 Truxtun Avenue, Suite 300, Bakersfield, California (Address of principal executive offices)	93309-0640 (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 o

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

The number of shares of each of the registrant’s classes of capital stock outstanding as of June 30, 2005, was 21,181,208 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
JUNE 30, 2005
INDEX

2

Table of Contents

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

	June 30, 2005	December 31, 2004
ASSETS		
Current assets:		
Cash and cash equivalents	$ 9,561	$ 16,690
Short-term investments available for sale	655	659
Accounts receivable	46,928	34,621
Deferred income taxes	12,678	3,558
Fair value of derivatives	4,447	3,243
Prepaid expenses and other	7,768	2,230
Total current assets	82,037	61,001
Oil and gas properties (successful efforts basis), buildings and equipment, net	487,220	338,706
Deposit on potential property acquisitions	3,322	10,221
Other assets	2,730	2,176
	$ 575,309	$ 412,104
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 35,043	$ 27,750
Revenue and royalties payable	20,151	23,945
Accrued liabilities	5,925	6,132
Income taxes payable	-	1,067
Fair value of derivatives	30,127	5,947
Total current liabilities	91,246	64,841
Long-term liabilities:		
Deferred income taxes	53,588	47,963
Long-term debt	125,000	28,000
Abandonment obligations	9,420	8,214
Fair value of derivatives	9,865	-
	197,873	84,177
Shareholders' equity:		
Preferred stock, $.01 par value; 2,000,000 shares authorized; 0 outstanding	-	-
Capital stock, $.01 par value;		
Class A Common Stock, 50,000,000 shares authorized; 21,181,208 shares issued and outstanding (21,060,420 in 2004)	211	210
Class B Stock, 1,500,000 shares authorized;898,892 shares issued and outstanding (liquidation preference of $899)	9	9
Capital in excess of par value	61,644	60,676
Accumulated other comprehensive loss	(21,327)	(987)

Retained earnings		245,653		203,178
Total shareholders' equity		286,190		263,086
	$	575,309	$	412,104

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

Table of Contents

BERRY PETROLEUM COMPANY
Part I. Financial Information
Item 1. Financial Statements
Condensed Consolidated Income Statements
Three Month Periods Ended June 30, 2005 and 2004
(In Thousands, Except Per Share Information)
(Unaudited)

	Three months ended June 30,			
	2005		2004	
Revenues:				
Sales of oil and gas	$	80,825	$	52,755
Sales of electricity		11,514		11,291
Interest and other income, net		350		90
		92,689		64,136
Expenses:				
Operating costs - oil and gas production		26,374		19,451
Operating costs - electricity generation		10,923		10,590
Exploration costs		225		-
Depreciation, depletion and amortization - oil and gas production		9,461		7,643
Depreciation, depletion and amortization - electricity generation		839		861
General and administrative		5,204		4,844
Dry hole, abandonment and impairment		601		-
Interest		1,740		534
		55,367		43,923
Income before income taxes		37,322		20,213
Provision for income taxes		12,062		4,935
Net income	$	25,260	$	15,278
Basic net income per share	$	1.14	$	.70
Diluted net income per share	$	1.13	$	.68
Cash dividends per share	$	.12	$	.11
Weighted average number of shares of capital stock outstanding used to calculate basic net income per share		22,067		21,873
Effect of dilutive securities:				
Stock options		327		488
Other		57		55
Weighted average number of shares of capital stock used to calculate diluted net income per share		22,451		22,416

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

4

Table of Contents

BERRY PETROLEUM COMPANY
Part I. Financial Information
Item 1. Financial Statements
Condensed Consolidated Income Statements
Six Month Periods Ended June 30, 2005 and 2004
(In Thousands, Except Per Share Information)
(Unaudited)

	Six months ended June 30, 2005	2004
Revenues:		
Sales of oil and gas	$ 156,196	$ 97,960
Sales of electricity	23,970	23,225
Interest and other income, net	518	293
	180,684	121,478
Expenses:		
Operating costs - oil and gas production	49,781	36,677
Operating costs - electricity generation	24,281	22,993
Exploration costs	786	-
Depreciation, depletion and amortization - oil and gas production	17,988	13,997
Depreciation, depletion and amortization - electricity generation	1,611	1,716
General and administrative	10,023	11,744
Dry hole, abandonment and impairment	2,622	-
Interest	2,902	1,064
	109,994	88,191
Income before income taxes	70,690	33,287
Provision for income taxes	22,925	7,644
Net income	$ 47,765	$ 25,643
Basic net income per share	$ 2.17	$ 1.17
Diluted net income per share	$ 2.13	$ 1.15
Cash dividends per share	$ .24	$ .22
Weighted average number of shares of capital stock outstanding used to calculate basic net income per share	22,024	21,845
Effect of dilutive securities:		
Stock options	383	439
Other	57	53
Weighted average number of shares of capital stock used to calculate diluted net income per share	22,464	22,337

Condensed Consolidated Statements of Comprehensive Income
Six Month Periods Ended June 30, 2005 and 2004
(In Thousands)
(Unaudited)

Net income	$ 47,765	$ 25,643
Unrealized gains (losses) on derivatives, (net of income taxes of $13,560		

and $1,032 in 2005 and 2004, respectively)		(20,340)		1,548
Comprehensive income	$	27,425	$	27,191

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

Table of Contents

BERRY PETROLEUM COMPANY
Part I. Financial Information
Item 1. Financial Statements
Condensed Consolidated Statements of Cash Flows
Six Month Periods Ended June 30, 2005 and 2004
(In Thousands)
(Unaudited)

	Six months ended June 30, 2005	2004
Cash flows from operating activities:		
Net income	$ 47,765	$ 25,643
Depreciation, depletion and amortization	19,599	15,713
Deferred income taxes, net	10,064	6,142
Stock-based compensation expense	969	2,808
Other, net	194	528
Increase in current assets other than cash, cash equivalents and short-term investments	(17,840)	(6,877)
Increase (decrease) in current liabilities	5,440	(6,324)
Net cash provided by operating activities	66,191	37,633
Cash flows from investing activities:		
Capital expenditures, excluding property acquisitions	(48,159)	(31,838)
Property acquisitions	(116,062)	-
Net cash used in investing activities	(164,221)	(31,838)
Cash flows from financing activities:		
Proceeds from issuance of long-term debt	116,000	-
Payment of long-term debt	(19,000)	-
Debt issuance cost	(809)	-
Dividends paid	(5,290)	(4,646)
Net cash provided by (used in) financing activities	90,901	(4,646)
Net (decrease) increase in cash and cash equivalents	(7,129)	1,149
Cash and cash equivalents at beginning of year	16,690	10,658
Cash and cash equivalents at end of period	$ 9,561	$ 11,807
Supplemental non-cash activity:		
Increase (decrease) in fair value of derivatives:		
Current (net of income taxes of $9,191 and ($322) in 2005 and 2004, respectively)	$ 13,786	$ (484)
Non-current (net of income taxes of $4,369 and ($710) in 2005 and 2004, respectively)	6,554	(1,064)

Net increase (decrease) to accumulated other comprehensive loss	$	20,340	$	(1,548)

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

Table of Contents

BERRY PETROLEUM COMPANY
Part I. Financial Information
Item 1. Financial Statements
Notes to Condensed Consolidated Financial Statements
June 30, 2005
(Unaudited)

1. General. All adjustments which are, in the opinion of Management, necessary for a fair statement of Berry Petroleum Company's and subsidiary (collectively, the "Company") financial position at June 30, 2005 and December 31, 2004 and results of operations and cash flows for the six month periods ended June 30, 2005 and 2004 have been included. All such adjustments are of a normal recurring nature. The results of operations and cash flows are not necessarily indicative of the results for a full year.

The accompanying unaudited condensed consolidated financial statements have been prepared on a basis consistent with the accounting principles and policies reflected in the December 31, 2004 financial statements. The December 31, 2004 Form 10-K and the March 31, 2005 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. Refer to Note 8 for discussion on the new subsidiary, Canyon Drilling.

2. Fair Value of Derivatives. Refer to Note 10 for discussion on new hedges. Due to the increase in NYMEX future strip crude oil prices at June 30, 2005 from December 31, 2004 and the addition of new derivative instruments, the Company's fair value of derivatives liability increased to $40.0 million at June 30, 2005 from $5.9 million at December 31, 2004. The unrealized loss, net of income taxes, of $20.3 million, is recorded in accumulated other comprehensive loss on the Company's balance sheet at June 30, 2005. The deferred tax benefit of the unrealized loss is reflected as an addition to the deferred income tax asset on the Company's balance sheet.

3. Asset Retirement Obligations. The Company follows Statement of Financial Accounting Standard, (SFAS) No. 143, *Accounting for Asset Retirement Obligations,* for recording future site restoration and abandonment costs related to its oil and gas properties. Under SFAS No. 143, the following table summarizes the change in abandonment obligation for the six months ended June 30, 2005 and 2004, respectively, (in thousands):

	2005	2004
Beginning balance at January 1	$ 8,214	$ 7,311
Liabilities incurred	1,165	-
Liabilities settled	(384)	(235)
Accretion expense	425	349
Ending balance at June 30	$ 9,420	$ 7,425

4. Reclassification. Certain amounts in the condensed consolidated income statements for the three and six months ended June 30, 2004 have been reclassified to conform to the 2005 presentation. In the fourth quarter of 2004, the Company concluded that it was appropriate to revise its allocation of cogeneration costs to oil and gas operations. The revised allocation is based on the thermal efficiency (of fuel to electricity and steam) of the Company's cogeneration facilities. In addition, in 2005 the Company is reclassifying technical labor between general and administrative expenses and operating costs - oil and gas. Accordingly, the Company has revised prior classifications for the three and six months ended June 30, 2004 as follows (in thousands):

7

Table of Contents

	Three Months Ended 6/30/04	Six Months Ended 6/30/04
Operating costs - oil and gas		
As previously reported	$ 19,194	$ 37,214
As revised	19,451	36,677
Difference	$ (257)	$ 537
Operating costs - electricity generation		
As previously reported	$ 11,291	$ 23,225
As revised	10,590	22,993
Difference	$ 701	$ 232
G&A expenses		
As previously reported	$ 4,400	$ 10,974
As revised	4,844	11,744
Difference	$ (444)	$ (769)
DD&A - oil and gas		
As previously reported	$ 8,504	$ 15,713
As revised	7,643	13,997
Difference	$ 861	$ 1,716
DD&A - electricity generation		
As previously reported	$ -	$ -
As revised	861	1,716
Difference	$ (861)	$ (1,716)

5. Credit Facility. In June 2005, the Company completed a new unsecured five year bank credit agreement (the Agreement) with a banking syndicate. The Agreement is a revolving credit facility for up to $500 million with nine banks and replaces the previous $200 million facility which was due to mature in 2006. Initial borrowings were $125 million which represented an amount equal to the borrowings outstanding under the previous credit facility and the initial borrowing base was established as $350 million. This transaction is considered a modification of a debt instrument due to modification of terms in accordance with Emerging Issues Task Force, (EITF) 96-19, *Debtor's Accounting for Modification or Exchange of Debt Instruments*.

The credit available under the Agreement is $225 million at June 30, 2005 without any increase to the borrowing base. The maximum amount available is subject to an annual redetermination of the borrowing base in accordance with the lender's customary procedures and practices. Both the Company and the banks have bilateral rights to one additional redetermination each year. The Agreement matures on July 1, 2010. Interest on amounts borrowed is charged at LIBOR plus a margin of 1.00% to 1.75%, or the higher of the lead bank's prime rate or the federal funds rate plus 50 basis points plus a margin of 0% to .50%, with margins on the various rate options based on the ratio of credit outstanding to the borrowing base. The Company is required under the Agreement to pay a commitment fee of 25 to 38 basis points on the unused portion of the credit facility.

The weighted average interest rate on outstanding borrowings at June 2005 was 4.6%. The Agreement contains restrictive covenants which, among other things, require the Company to maintain a certain debt to EBITDA ratio and a minimum current ratio, as defined. The Company was in compliance with all such covenants as of June 30, 2005.

6. Dry hole, abandonment and impairment. At December 31, 2004, the Company was in the process of drilling one exploratory well on its Midway-Sunset property in California and one exploratory well on its Coyote Flats, Utah prospect. These two wells were determined non-commercial in February 2005. Costs of $.5 million which were incurred as of December 31, 2004 were charged to expense in 2004. The remaining costs totaling approximately $2 million were charged to expense during 2005. Also, based on a market assessment, the Company determined that the carrying value of its Illinois properties was impaired and a charge of $.5 million was recorded in the second quarter of 2005. These costs are reflected on the Company's income statement under dry hole, abandonment and impairment.

Table of Contents

7. Pro Forma Results. On January 27, 2005, the Company acquired certain interests (J-W Acquisition) in the Niobrara field in northeastern Colorado for approximately $105 million. The properties consist of approximately 127,000 gross (69,500 net) acres. The acquisition also includes approximately 200 miles of a pipeline gathering system and gas compression facilities for delivery into interstate gas lines. The Company borrowed $105 million under its credit facility to fund this acquisition.

The unaudited pro forma results presented below for the six months ended June 30, 2005 and 2004 have been prepared to give effect to the J-W Acquisition on the Company's results of operations under the purchase method of accounting as if it had been consummated on January 1, 2004. The unaudited pro forma results do not purport to represent the results of operations that actually would have occurred on such date or to project the Company's results of operations for any future date or period:

	Six Months Ended June 30,			
	2005		2004	
Pro forma:	(in thousands, except per share data)			
Revenue	$	182,047	$	130,890
Income from operations		84,282		50,285
Net income		48,069		26,811
Basic earnings per share		2.18		1.23
Diluted earnings per share		2.14		1.20

8. Canyon Drilling. Canyon Drilling ("Canyon") is a Colorado LLC formed by the Company in the second quarter of 2005. The Company purchased a drilling rig at auction and refurbished it for a total of approximately $2.8 million as of June 30, 2005. The Company has 100% membership interest of Canyon and contributed the drilling rig to Canyon. Canyon is consolidated, accounted for and disclosed in accordance with SFAS No. 94, *Consolidation of All Majority-Owned Subsidiaries*. Canyon's drilling rig is leased to a drilling company under a contract and is accounted for as a direct financing lease as defined by SFAS No. 13, *Accounting for Leases*, therefore, Canyon's balance sheet assets of $2.8 million are lease receivables.

Future minimum lease payments to be received as of June 30, 2005 are as follows:

2005	$	702,625
2006		702,625
Total	$	1,405,250

9. Recent Accounting Pronouncements. In May 2005, SFAS No. 154, *Accounting Changes and Error Corrections, a replacement of APB Opinion No. 20 and FASB Statement No. 3* was issued. SFAS No. 154 requires retrospective application to prior period financial statements for changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. SFAS No. 154 also requires that retrospective application of a change in accounting principle be limited to the direct effects of the change. Indirect effects of a change in accounting principle should be recognized in the period of the accounting change. SFAS No. 154 will become effective for the Company's fiscal year beginning January 1, 2006. The impact of SFAS No. 154 will depend on the nature and extent of any voluntary accounting changes and correction of errors after the effective date, but Management does not currently expect SFAS No. 154 to have a material impact on the Company's consolidated financial position, results of operations or cash flows.

Table of Contents

In December 2004, SFAS No. 123 (revised 2004) or SFAS No. 123(R), *Share-Based Payment* was issued. This statement requires the cost resulting from all share-based payment transactions be recognized in the financial statements at their fair value on the grant date. SFAS No. 123(R) is effective as of the beginning of the first annual reporting period that begins after June 15, 2005. As a result, the Company expects to adopt this statement on January 1, 2006. The adoption of this statement is not expected to have a material impact on the Company’s consolidated financial position, results of operations or cash flows.

In December 2004, the Financial Accounting Standards Board (FASB) issued Staff Position (FSP) FAS 109-1, *Application of FASB Statement No. 109, Accounting for Income Taxes, for the Tax Deduction Provided to U.S. Based Manufacturers by the American Jobs Creation Act of 2004*. FSP 109-1 became effective for the Company's fiscal year beginning January 1, 2005. This position clarifies how to apply SFAS No. 109 to the new law's tax deduction for income attributable to "domestic production activities." The implementation of this position did not have a material impact on the Company's financial position, net income or cash flows.

10. Hedging. In June 2005, the Company entered into derivative instruments (zero-cost collars) for approximately 10,000 Bbl/D for the period January 1, 2006 through December 31, 2009. Based on WTI pricing, the floor is $47.50 and the ceiling is $70 per barrel. The use of hedging transactions also involves the risk that the counterparties will be unable to meet the financial terms of such transactions. With respect to the Company’s hedging activities, the Company utilizes multiple counterparties on its hedges and monitors each counterparty’s credit rating. After the June hedge transaction, a significant credit risk concentration existed in one broker. In July 2005, the Company reduced the concentration as the hedges were transferred to multiple counterparties. The Company does not require collateral on these hedging transactions.

11. Taxes. The Company experienced an effective tax rate of 32% for the second quarter of 2005 compared to 33% for the first quarter of 2005 and 24% for the second quarter of 2004. The Company benefits from enhanced oil recovery (EOR) credits on development activities on its heavy oil properties. However, with higher crude oil prices and the increasing investment in its light crude oil and natural gas properties, the Company’s effective income tax rate is trending higher compared to prior years.

Table of Contents

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

Overview

The following discussion provides information on the results of operations for each of the three and six month periods ended June 30, 2005 and 2004 and the financial condition, liquidity and capital resources as of June 30, 2005. The financial statements and the notes thereto contain detailed information that should be referred to in conjunction with this discussion.

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

Results of Operations

The Company earned net income of $25.3 million, or $1.13 per share (diluted), on revenues of $92.7 million in the second quarter of 2005, up 12% from net income of $22.5 million, or $1.00 per share (diluted), on revenues of $88.0 million in the first quarter of 2005, and up 65% from net income of $15.3 million, or $.68 per share (diluted), on revenues of $64.1 million in the second quarter of 2004.

Table of Contents

The following table presents certain operating data for the periods ending:

	Three Months Ended						Six Months Ended	
	Jun 30 2005	%	Mar 31 2005	%	Jun 30 2004	%	Jun 30 2005	Jun 30 2004
Oil and Gas								
Oil Production (Bbl/D)	18,986	84	19,156	87	19,182	94	19,070	18,880
Natural Gas Production (Mcf/D)	22,090	16	17,347	13	6,796	6	19,732	6,409
Total (BOE/D)	22,668	100	22,047	100	20,315	100	22,359	19,949
Per BOE:								
Average sales price before hedging	$ 43.41		$ 40.89		$ 30.83		$ 42.21	$ 29.46
Average sales price after hedging	39.09		37.81		28.55		38.50	27.00
Oil, per Bbl:								
Average WTI price	$ 53.22		$ 49.85		$ 38.28		$ 51.66	$ 36.78
Less:								
Price sensitive royalties	3.76		3.12		2.59		3.44	2.48
Gravity differential	5.47		5.22		4.95		5.47	4.99
Crude oil hedges	5.27		3.54		2.41		4.40	2.60
Average sales price	$ 38.72		$ 37.97		$ 28.33		$ 38.35	$ 26.71
Gas, per Mmbtu:								
Average Henry Hub price	$ 7.05		$ 6.27		$ 6.00		$ 6.66	$ 5.84
Less:								
Location and quality differentials	(0.91)		(0.79)		(0.63)		(0.85)	(0.50)
Average sales price	$ 6.14		$ 5.48		$ 5.37		$ 5.81	$ 5.34
Electricity								
Electric power produced - MWh/D	1,897		2,117		2,045		2,006	2,118
Electric power sold – MWh/D	1,702		1,918		1,843		1,810	1,900
Average sales price/MWh	$ 74.52		$ 68.87		$ 67.51		$ 71.55	$ 67.34
Fuel gas cost/MMBtu (excluding transportation)	$ 6.15		$ 5.74		$ 5.44		$ 5.94	$ 5.26

Bbl One stock tank barrel, or 42 U.S. gallons liquid volume, used herein in reference to crude oil or condensate.
BOE Barrel of oil equivalent, measured as 6 thousand cubic feet of natural gas equal to 1 barrel of crude oil.

MMBtu	Million British thermal units. A British thermal unit represents the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.
Mcf	One thousand cubic feet.
MWh	One million watt-hour.
/D	per day.

Oil and Gas Sales and Production. The Company's revenues may vary significantly from period to period as a result of changes in commodity prices and/or production volumes. Sales of oil and gas were $80.8 million in the second quarter of 2005, up 7% from $75.4 million in the first quarter of 2005 and up 53% from $52.8 million in the second quarter of 2004. This improvement was due to increases in both oil and gas prices and production levels. The average sales price per BOE, net of hedging, of the Company's oil and gas was $39.09 in the second quarter of 2005, up 3% from $37.81 in the first quarter of 2005 and up 37% from $28.55 in the second quarter of 2004. Oil and gas production volumes in the second quarter of 2005 averaged 22,668 BOE/D, up 3% from 22,047 BOE/D in the first quarter of 2005 and up 12% from 20,315 BOE/D in the second quarter of 2004 due primarily to the acquisition of the Niobrara field in January 2005 and continuing development activities on the Company's core assets. For all of 2005, the Company anticipates production to average approximately 23,000 BOE/D.

Table of Contents

In 2004, approximately 94% of the Company's oil and gas sales volumes were crude oil. In the second quarter of 2005, crude oil represented 84% and natural gas represented 16% of the Company's oil and gas production. The Company's objective is to diversify its predominantly heavy crude oil base with light crude oil and natural gas. With the Company's continued development of its Brundage Canyon and Niobrara assets, the Company anticipates natural gas production in 2005 to average in excess of 20,000 Mcf/D.

The Company sells the majority of its California heavy crude oil under a favorable contract which expires on December 31, 2005. The contract pricing is based upon the higher of the average of the local field posted prices plus a fixed premium, or WTI minus a fixed differential approximating $6 per barrel. The Company is confident it will be able to secure a contract for its California heavy crude oil in future periods, however the Company does not anticipate that it will be able to obtain terms similar to the current contract pricing. The Company expects that its oil revenues will be negatively impacted after 2005 due to the widening of the crude price differential between WTI and California heavy crude. The differential, which over the last several years approximated $6 per barrel, increased dramatically in the second half of 2004 to approximately $14 per barrel. In the first seven months of 2005 the differential has narrowed to approximately $11 per barrel.

In the second quarter of 2005, the Company estimates that its revenues benefited from this contract by approximately $10.1 million, and at a differential of approximately $11 per barrel for the second half of 2005, the Company estimates that its revenues in 2005 will benefit from the contract by approximately $37 million. While Management believes that the differential will narrow and move closer toward its historical norms over time, there are no assurances that this will occur. If the differential were to change significantly, it is possible that the Company's hedges, when marked-to-market, could have a material impact on earnings in any given quarter and, thus, add increased volatility to the Company's net income. The marked-to-market values reflect the liquidation values of such hedges and not necessarily the values of the hedges if they are held to maturity. Additionally, the ultimate impact to net income over the life of the hedges will reflect the actual settlement values.

As a result of hedging activities, the Company's oil and gas sales, on a per BOE basis, were reduced by $4.32 in the second quarter of 2005, $3.08 in the first quarter of 2005 and $2.28 in the second quarter of 2004. The Company has hedged approximately 7,500 Bbl/D of its crude oil production at prices averaging $40.75 per barrel for 2005. For the first nine months of 2006 the Company has hedged 3,000 Bbl/D of crude oil at approximately $50.22 per barrel and has a collar of 7,000 Bbl/D with a floor of $47.50 and a ceiling of $70. These same collar terms exist for approximately 10,000 Bbl/D from January 1, 2006 through December 31, 2009. See "Item 3. Quantitative and Qualitative Disclosure About Market Risk."

Electricity Generation. Total electricity revenues were $11.5 million in the second quarter of 2005, comparable to $12.5 million in the first quarter of 2005 and $11.3 million in the second quarter of 2004. The Company produced 1,897 MWh/D of electricity in the second quarter of 2005, down from 2,117 MWh/D in the first quarter of 2005 and 2,045 MWh/D in the second quarter of 2004. Electricity production, revenue and operating costs in the second quarter of 2005 were down from the first quarter of 2005 due to the scheduled turnaround which included a turbine refurbishment in April 2005 on the 38 MW cogeneration facility. The Company received an average sales price per MWh of $74.52 in the second quarter of 2005, compared to $68.87 in the first quarter of 2005 and $67.51 in the second quarter of 2004.

The Company consumes natural gas as fuel to operate its cogeneration facilities. The Company sells its electricity to utilities under Standard Offer contracts, under which its revenues are linked to the cost of natural gas. Natural gas index prices are the primary determinant of the Company's electricity sales price. The correlation between electricity sales and natural gas prices allows the Company to more effectively manage its cost of producing steam for use in heavy oil production.

Table of Contents

Oil and Gas, G&A and Interest Expenses. The following table presents information comparing the Company's oil and gas operating expenses for each of the quarters ended June 30, 2005 and June 30, 2004:

	Amount Per BOE			Amount (in thousands)		
	Jun 30, 2005	Jun 30, 2004	% Change	Jun 30, 2005	Jun 30, 2004	% Change
Operating costs	$ 12.79	$ 10.52	22%	$ 26,374	$ 19,451	36%
DD&A	4.59	4.13	11%	9,461	7,643	24%
G&A	2.52	2.62	(4)%	5,204	4,844	7%
Interest expense	.84	.29	190%	1,740	534	226%

- With the Company's increased drilling activity as competition for goods and services has increased, operating costs for the second quarter of 2005, on a per BOE basis, increased 22% to $12.79 in the second quarter of 2005 from $10.52 in the second quarter of 2004. Operations have experienced price increases in many of its goods and services in the last 12 months as crude oil and natural gas prices have increased. The cost of the Company's steaming operations on its heavy oil properties represents a significant portion of the Company's operating costs and will vary depending on the cost of natural gas used as fuel and the volume of steam injected during the period. Steam costs were higher in the second quarter of 2005 compared to the second quarter of 2004 because the cost of natural gas increased 13% to $6.15 per MMBtu in the second quarter of 2005 from $5.44 per MMBtu in the second quarter of 2004 and the volume of steam injected increased to 68,066 Bbl/D in the second quarter of 2005 from 66,998 Bbl/D in the second quarter of 2004.

- DD&A increased 11% to $4.59 per BOE in the second quarter of 2005 from $4.13 per BOE in the second quarter of 2004 due to higher acquisition and finding and development costs. Competition for drilling rigs has increased dramatically over the last year and, thus, rig rates are continuing to increase which is contributing to higher development costs.

- G&A expense decreased 4% to $2.52 per BOE in the second quarter of 2005 from $2.62 per BOE in the second quarter of 2004. On a total dollar basis, G&A was higher in 2005 primarily due to higher compensation resulting from the hiring of additional technical and administrative personnel to accommodate growth and higher compensation costs to remain competitive in the industry.

- Interest expense in the second quarter of 2005 was $.84 per BOE, up from $.29 per BOE in the second quarter of 2004. The Company's borrowings at June 30, 2004 were $50 million compared to $125 million at June 30, 2005 which caused an increase in interest expense. The increase in debt was primarily due to acquisitions of $116 million in the first half of 2005. The Company's debt at June 30, 2005 of $125 million was reduced from $138 million at March 31, 2005.

Table of Contents

The following table presents information comparing the Company's operating expenses for the six months ended June 30, 2005 and June 30, 2004:

	Amount Per BOE			Amount (in thousands)		
	Jun 30, 2005	Jun 30, 2004	% Change	Jun 30, 2005	Jun 30, 2004	% Change
Operating costs	$ 12.30	$ 10.10	22%	$ 49,781	$ 36,677	36%
DD&A	4.44	3.86	15%	17,988	13,997	29%
G&A	2.48	3.23	(23)%	10,023	11,744	(15)%
Interest expense	.72	.29	148%	2,902	1,064	172%

- With the Company's increased drilling activity as competition for goods and services has increased, operating costs for the six months of 2005 of $12.30 per BOE increased 22% from $10.10 per BOE in the six months ended June 30, 2004. Operations have experienced price increases in many of its goods and services in the last 12 months as crude oil and natural gas prices have increased. This increase was also related to higher steam costs resulting from higher natural gas prices. The Company anticipates operating costs to average between $11.75 and $13.00 per BOE for all of 2005.

- DD&A in the first six months of 2005 of $4.44 per BOE increased from $3.86 per BOE in the first six months of 2004 due primarily to higher acquisition and finding and development costs. The Company anticipates DD&A to average between $4.25 and $4.75 per BOE for all of 2005.

- G&A expenses of $2.48 per BOE in the first half of 2005 decreased 23% from $3.23 incurred in the first half of 2004 due to the charge on stock options that was part of the earnings restatement in 2004. G&A is affected by higher compensation resulting from the hiring of additional technical and administrative personnel to accommodate growth and higher compensation costs to remain competitive in the industry in 2005. The Company expects G&A to average between $2.15 and $2.50 per BOE for all of 2005.

- Interest expense of $.72 per BOE in the first six months of 2005 increased from $.29 per BOE in the first six months of 2004. The Company's borrowings at June 30, 2004 were $50 million compared to $125 million at June 30, 2005 which caused an increase in interest expense. The increase in debt was primarily due to acquisitions of $116 million in the first half of 2005. The Company's debt at June 30, 2005 of $125 million was reduced from $138 million at March 31, 2005. The Company anticipates interest expense to be between $.50 to $.70 per BOE for all of 2005.

Electricity Operating Costs. Operating costs from electricity generation were $10.9 million in the second quarter of 2005, down 19% from $13.4 million in the first quarter of 2005 and up 3% from $10.6 million in the second quarter of 2004. Electricity production, revenue and operating costs in the second quarter of 2005 were down from the first quarter of 2005 due to the scheduled turnaround in April 2005 on the 38 MW cogeneration facility.

Income Taxes. The Company experienced an effective tax rate of 32% for the second quarter of 2005 compared to 33% for the first quarter of 2005 and 24% for the second quarter of 2004. The Company benefits from enhanced oil recovery (EOR) credits on development activities on its heavy oil properties. However, with higher crude oil prices and the increasing investment in its light crude oil and natural gas properties, the Company's effective income tax rate is trending higher compared to prior years. Based on current forecasted oil prices, the Company anticipates an effective tax rate for all of 2005 between 30% and 35%. The Company estimates that the average U.S. wellhead price for crude oil will exceed $43 in 2005, thus triggering a full phase-out of the EOR credit for 2006. Without any EOR credit in 2006, the Company anticipates its effective tax rate to be between 37% and 39%. If the U.S. wellhead price of crude oil declines below the triggering point, the Company will be able to claim the EOR credit on qualifying expenditures and the Company’s effective tax rate should decline.

Table of Contents

Dry Hole, Abandonment and Impairment. At December 31, 2004, the Company was in the process of drilling one exploratory well on its Midway-Sunset property in California and one exploratory well on its Coyote Flats, Utah prospect. These two wells were determined non-commercial in February 2005. Costs of $.5 million which were incurred as of December 31, 2004 were charged to expense in 2004. The remaining costs totaling approximately $2 million were charged to expense during 2005. Also, based on a market assessment, the Company determined that the carrying value of its Illinois properties was impaired and a charge of $.5 million was recorded in the second quarter of 2005. These costs are reflected on the Company's income statement under dry hole, abandonment and impairment.

Acquisitions. In June 2005, the Company acquired interests in approximately 20,000 gross acres located in the Williston Basin in North Dakota and is in the process of purchasing additional interests in another 100,000 gross acres in the area. These acquisitions, totaling approximately $9 million, provide the Company an entry into the emerging Bakken oil play in the Williston Basin. The acreage covers several contiguous blocks located primarily on the eastern flank of the Nesson Anticline. Development activity in the Middle Bakken play is expanding to the area surrounding the Nesson Anticline. The Company expects to close on the additional acreage in the third quarter of 2005.

On January 27, 2005, the Company acquired certain interests in the Niobrara field in northeastern Colorado for approximately $105 million. The properties consist of approximately 127,000 gross (69,500 net) acres. Production at acquisition was approximately 9 MMcf of natural gas per day, with estimated proved reserves of 87 Bcf. The acquisition also included approximately 200 miles of a pipeline gathering system and gas compression facilities for delivery into interstate gas lines. The Company has drilled 13 new wells on this property in the first half of 2005 and plans to drill a total of approximately 60 wells and complete 23 workovers as part of the development of this asset in the full year of 2005.

In January 2005, the Company acquired a working interest in approximately 390,000 gross (172,250 net) prospective acres, located in eastern Colorado, western Kansas and southwestern Nebraska for approximately $5 million, from Bill Barrett Corporation (BBC). The Company and BBC will jointly explore and develop shallow Niobrara biogenic natural gas, Sharon Springs Shale gas and deeper Pennsylvanian formation oil assets on the acreage. The Company believes the potential of the Tri-State area can be exploited by using new drilling techniques and 3-D seismic technology to assess structural complexity, estimate potentially recoverable oil and gas, and determine drilling locations. In the second quarter of 2005, the Company incurred its net share of the expense for 530 miles of 2-D seismic data on this acreage. Additionally, the Company and BBC drilled two exploratory wells in the second quarter of 2005 on this acreage, and based on encouraging results and the seismic data, intend to drill another five wells in 2005.

Other Exploration and Development Activities. In the Coyote Flats prospect, the Company is drilling the second of three test wells in the Ferron sands with the third well expected to be drilled by year end 2005. The Company will drill its six well coal bed methane program on this prospect in 2005 and 2006.

In Brundage Canyon, Utah the Company has budgeted development costs of $45 million, including the drilling of 59 new wells and performing 20 workovers in 2005. In the first six months of 2005, the Company drilled 27 new wells and completed 14 workovers. Due to the high competition for drilling rigs in the Rockies, the Company purchased a drilling rig which began drilling at Brundage Canyon in early July 2005. The Company has, as of June 30, 2005, invested approximately $2.8 million in the rig which is rated to a depth of approximately 7,000 feet. The Company anticipates that this rig will be dedicated to its shallow drilling program in the Uinta Basin.

The Company has two shallow Green River oil and gas wells scheduled for drilling on its Lake Canyon acreage before year end. These initial drill sites will be approximately three miles west of the Company’s Brundage Canyon field. The Company is also participating in the acquisition of a 57 square mile 3-D seismic survey at Lake Canyon. The Company, and its partner, will use the results to drill a deep Mesaverde well that is expected to spud before year end.

16

Table of Contents

In North Dakota, the Company anticipates that it will participate in one well which will test the productivity of the Bakken formation.

In California, the Company has budgeted $38 million in capital development projects. The Company continues to monitor its diatomite exploitation project in the Midway-Sunset field. Production from this project has been gradually improving and averaged approximately 150 Bbl/D of crude oil in the second quarter, and as of August 1, 2005 production exceeds 250 Bbl/D. The Company is expanding this pilot as its production is on track to determine commerciality. On the Company's other California properties, in the first half of 2005 the Company has drilled 32 new wells, of which 8 were horizontal wells, and completed 40 workovers of a planned 70 new wells and 61 workover program in 2005.

Financial Condition, Liquidity and Capital Resources

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

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

Working Capital and Cash Flows. Cash flow from operations is dependent upon the Company's ability to increase production through development, acquisitions and exploration activities and the price of crude oil and natural gas. The Company's working capital balance fluctuates as a result of the timing and amount of borrowings or repayments under its credit arrangements. Generally, the Company uses excess cash to pay down borrowings under its credit arrangement. As a result, the Company often has a working capital deficit or a relatively small amount of positive working capital. Working capital as of June 30, 2005 was a negative ($9.2) million, compared to a negative ($3.8) million at December 31, 2004.

Sales of oil and gas increased $28.1 million during the second quarter 2005 compared to the second quarter 2004, with average oil and gas sales prices, net of hedges, increasing 37% and production increasing 12% in 2005 compared to the second quarter of 2004. Net cash provided by operating activities for the first six months of 2005 was $66.2 million, up 76% from $37.6 million in the first six months of 2005. The increase in 2005 was a direct result of an approximate 43% increase in average oil and gas sales prices and a 12% increase in production volumes. The Company increased its borrowing on its credit line by a net $97 million during the first half of 2005. Cash was used to fund approximately $116 million in property acquisitions, $48.2 million of capital expenditures (of the total $107 million 2005 capital budget), and to pay dividends of $5.3 million.

The Company is re-evaluating its current capital budget of $107 million for a possible increase for the remainder of 2005 in light of current crude oil and natural gas prices and the Company's significant opportunities. All capital expenditures, excluding acquisitions, will be funded out of internally generated cash flow.

Table of Contents

In June 2005 a share repurchase program was authorized for up to an aggregate of $50 million of the Company's outstanding Class A Common Stock. No shares have been repurchased as of June 30, 2005.

Hedging. In June 2005, the Company entered into derivative instruments (zero-cost collars) for approximately 10,000 Bbl/D for the period January 1, 2006 through December 31, 2009. Based on WTI pricing, the floor is $47.50 and the ceiling is $70 per barrel. These strike prices will allow the Company to protect a significant portion of its future cash flow if oil prices decline below $47.50 per barrel while still participating in any oil price increase up to $70 per barrel on these volumes. This hedge improves the Company’s financial flexibility by locking in significant revenues and cash flow upon a substantial decline in crude oil prices. It also allows the Company to develop its long-lived assets and pursue exploitation opportunities with greater confidence in the projected economic outcomes.

The Company’s California oil production is heavy crude that, for the remainder of 2005, is sold to a refiner under a favorable sales contract to Berry. As of August 1, 2005, California heavy crude oil sold at a discount of approximately $11 per barrel to WTI and at this time the Company is retaining the risk of movement in this price differential on its production beginning in 2006. While the Company has designated its hedges as cash flow hedges in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, it is possible that a portion of the hedge related to the movement in the WTI to California heavy oil price differential may be determined to be ineffective. If this occurs, the ineffective portion will directly impact net income rather than being reported as Other Comprehensive Income. While Management believes that the differential will narrow and move closer toward its historical norms over time, there are no assurances as to the movement in the differential. If the differential were to change significantly, it is possible that the Company’s hedges, when marked-to-market, could have a material impact on earnings in any given quarter and, thus, add increased volatility to the Company's net income. The marked-to-market values reflect the liquidation values of such hedges and not necessarily the values of the hedges if they are held to maturity. Additionally, the ultimate impact to net income over the life of the hedges will reflect the actual settlement values.

Contractual Obligations. The Company's contractual obligations as of June 30, 2005 are as follows (in thousands):

	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-term debt	$ 125,000			$ 125,000	
Abandonment obligations	9,420	304	922	1,166	7,028
Operating lease obligations	1,369	621	676	72	
Drilling obligation	14,650	5,050	4,250	5,350	
Firm natural gas transportation contract	22,042	2,814	5,628	5,628	7,972
Total	$ 172,481	$ 8,789	$ 11,476	$ 137,216	$ 15,000

Credit Facility. In June 2005 the Company completed a new unsecured five-year bank credit agreement (the Agreement) with a banking syndicate. The Agreement is a revolving credit facility for up to $500 million with nine banks and replaces the previous $200 million facility which was due to mature in 2006. Initial borrowings were $125 million which represented an amount equal to the borrowings outstanding under the previous credit facility. The new credit facility, which has an initial borrowing base of $350 million, is an integral part of the Company’s financing structure that provides it with improved access to capital and the flexibility to support its growth plans.

The credit available under the Agreement is $225 million at June 30, 2005 without any increase to the borrowing base. The maximum amount available is subject to an annual redetermination of the borrowing base in accordance with the lender's customary procedures and practices. Both the Company and the banks have bilateral rights to one additional redetermination each year. The agreement matures on July 1, 2010. Interest on amounts borrowed is charged at LIBOR plus a margin of 1.00% to 1.75%, or the higher of the lead bank's prime rate or the federal funds rate plus 50 basis points plus a margin of 0% to .50%, with margins on the various rate options based on the ratio of credit outstanding to the borrowing base. The Company is required under the Agreement to pay a commitment fee of 25 to 38 basis points on the unused portion of the credit facility.

The weighted average interest rate on outstanding borrowings at June 2005 was 4.6%. The Agreement contains restrictive covenants which, among other things, require the Company to maintain a certain debt to EBITDA ratio and a minimum current ratio, as defined. The Company was in compliance with all such covenants as of June 30, 2005.

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

The Company has made significant property acquisitions in the last few years and plans significant development of these newly acquired and existing properties. To minimize the effect of a downturn in oil and gas prices and protect the profitability of the Company and the economics of the Company's development plans, from time to time the Company enters into crude oil and natural gas hedge contracts. The terms of contracts depend on various factors, including Management's view of future crude oil and natural gas prices and the Company's future financial commitments. This price hedging program is designed to moderate the effects of a severe crude oil price downturn while allowing Berry to participate in the upside. Management regularly monitors the crude oil and natural gas markets and the Company's financial commitments to determine if, when, and at what level some form of crude oil and/or natural gas hedging or other price protection is appropriate in accordance with Board established policy.

Currently, the hedges are in the form of swaps and collars. However, the Company may use a variety of hedge instruments in the future to hedge WTI or the index gas price.

Currently, the Company has crude oil sales contracts in place, which are priced based on a correlation to WTI index price. Natural gas (for cogeneration and conventional steaming operations) is purchased at the Socal border price and the Company sells its produced gas in Colorado and Utah at the Colorado Interstate Gas (CIG) and Questar index prices, respectively.

The use of hedging transactions may involve basis risk. The Company's oil hedges are based on reported settlement prices on the NYMEX. The basis risk between NYMEX and the Company's California heavy crude oil is mitigated by the Company's crude oil sales contracts. Pricing in the existing California agreement is based upon the higher of the average of the local field posted prices plus a fixed premium of approximately $6 per barrel. This contract expires on December 31, 2005. After contract expiration, prices will be negotiated based on the market. Pricing in the existing crude oil sales agreement at Brundage Canyon is based upon average weekly WTI minus a fixed differential of approximately $2 per barrel through September 30, 2006. After contract expiration, prices will be negotiated based on the market. Upon the expiration of these crude oil contracts, the Company will be exposed to fluctuations in the basis differentials between WTI and the posted price for its crude oil at its various producing locations until new contracts which lock in such differential can be obtained.

It is possible that a portion of the Company's hedge related to the movement in the WTI to the Company's posting oil differentials may be determined to be an ineffective hedge under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities, as amended*. If this occurs the ineffective portion will directly impact net income rather than being reported as Other Comprehensive Income. There are no assurances as to the movement in the differential. If the differential were to change significantly, it is possible that these hedges, when marked-to-market, could have a material impact on earnings in any given quarter and, thus, add increased volatility to the Company's net income. The marked-to-market values reflect the liquidation values of such hedges and not necessarily the values of the hedges if they are held to maturity. Additionally, the ultimate impact to net income over the life of the hedges will reflect the actual settlement values.

19

Table of Contents

The use of hedging transactions also involves the risk that the counterparties will be unable to meet the financial terms of such transactions. With respect to the Company's hedging activities, the Company utilizes multiple counterparties on its hedges and monitors each counterparty's credit rating. After the June hedge transaction, a significant credit risk concentration existed in one broker. In July 2005, the Company successfully reduced the concentration as the hedges were transferred to multiple counterparties. The Company does not require collateral on these hedging transactions.

At June 30, 2005, Accumulated Other Comprehensive Loss, net of income taxes, consisted of $21.3 million of unrealized losses from the Company's crude oil and natural gas hedges. Deferred net losses recorded in Accumulated Other Comprehensive Loss at June 30, 2005 are expected to be reclassified to earnings during 2005 and 2006.

Based on NYMEX futures prices as of June 30, 2005, (WTI $57.65; Henry Hub (HH) $7.74) the Company would expect to make pre-tax future cash payments or to receive payments over the remaining term of its crude oil and natural gas hedges in place as follows:

	June 30, 2005 NYMEX Futures	Impact of percent change in futures prices on earnings			
		-20%	-10%	+10%	+20%
Average WTI Price	$ 57.65	$ 46.12	$ 51.89	$ 63.42	$ 69.18
Crude oil gain/(loss) (in millions)	(31.7)	15.3	(18.8)	(44.6)	(59.2)
Average HH Price	7.74	6.19	6.96	8.51	9.29
Natural gas gain/(loss) (in millions)	4.8	3.4	4.0	5.4	6.1
Net pre-tax future cash receipts (payments) (in millions)	(27.0)	18.7	(14.7)	(39.2)	(53.1)

As a result of hedging activities the Company's revenue was reduced by $15.1 million and $8.9 million at June 30, 2005 and 2004, respectively, which was reported in Sales of oil and gas in the Company's financial statements. These hedging activities resulted in a net reduction in revenue per BOE to the Company of $4.32 in the second quarter of 2005, $3.08 in the first quarter of 2005 and $2.28 in the second quarter of 2004. As of June 30, 2005, contracts had settlement dates through the end of 2009 and no ineffectiveness was realized.

The Company sells the majority of its California heavy crude oil under a favorable contract which expires on December 31, 2005. The contract pricing is based upon the higher of the average of the local field posted prices plus a fixed premium, or WTI minus a fixed differential approximating $6 per barrel. The Company is confident it will be able to secure a contract for its California heavy crude oil in future periods, however the Company does not anticipate that it will be able to obtain terms similar to the current contract pricing. The Company expects that its oil revenues will be negatively impacted after 2005 due to the widening of the crude price differential between WTI and California heavy crude. The differential, which over the last several years approximated $6 per barrel, increased dramatically in the second half of 2004 to approximately $14 per barrel. In the first seven months of 2005 the differential has narrowed to approximately $11 per barrel.

Table of Contents

In the second quarter of 2005, the Company estimates that its revenues benefited from this contract by approximately $10.1 million, and at a differential of approximately $11 per barrel for the second half of 2005, the Company estimates that its revenues in 2005 will benefit from the contract by approximately $37 million. While Management believes that the differential will narrow and move closer toward its historical norms over time, there are no assurances that this will occur. If the differential were to change significantly, it is possible that the Company’s hedges, when marked-to-market, could have a material impact on earnings in any given quarter and, thus, add increased volatility to the Company's net income. The marked-to-market values reflect the liquidation values of such hedges and not necessarily the values of the hedges if they are held to maturity. Additionally, the ultimate impact to net income over the life of the hedges will reflect the actual settlement values.

The Company’s exposure to changes in interest rates results primarily from long-term debt. Total debt outstanding at June 30, 2005 and June 30, 2004 was $125 million and $50 million, respectively. Interest on amounts borrowed is charged at LIBOR plus 1.00% to 1.75%, or the higher of the lead bank’s prime rate or the federal funds rate plus 50 basis points plus a margin of 0% to .50%, with margins on the various rate options based on the ratio of credit outstanding to the borrowing base. Based on these borrowings, a 1% change in interest rates would not have a material impact on the Company’s financial statements.

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

As of June 30, 2005, the Company has carried out an evaluation under the supervision of, and with the participation of, the Company’s Management, including the Company’s Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of the Company’s disclosure controls and procedures pursuant to Rule 13a-15 under the Securities and Exchange Act of 1934, as amended.

Based on their evaluation as of June 30, 2005, the Chief Executive Officer and Chief Financial Officer of the Company have concluded that the Company’s disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e)) under the Securities Exchange Act of 1934) are effective to ensure that the information required to be disclosed by the Company in the reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms.

During the second quarter of 2005, the Company implemented new integrated accounting and production data applications software. The implementation has involved changes in systems that included internal controls, and accordingly, these changes have required modifications to the system of internal controls. Management has reviewed the controls affected by the implementation of the new software and made appropriate changes to affected internal controls during the implementation. Management has concluded that the Company’s controls as modified are appropriate and functioning effectively.

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; exploration, exploitation, drilling, development and operating risks; a limited marketplace for electricity sales within California; counterparty risk; acquisition risks; competition; environmental

risks; litigation uncertainties; the availability of drilling rigs and other support services; pipeline capacity constraints; legislative and/or judicial decisions and other government or Tribal regulations.

Table of Contents

BERRY PETROLEUM COMPANY
Part II. Other Information

Item 1. Legal proceedings
None
Item 2. Unregistered Sales of Equity Securities and Use of Proceeds
None
Item 3. Defaults Upon Senior Securities
None
Item 4. Submission of Matters to a Vote of Security Holders

At the annual meeting, which was held at the Doubletree Hotel, Bakersfield, CA, on May 11, 2005, nine incumbent directors were re-elected. The results of voting as reported by the inspector of elections are noted below:

1. There were 22,018,012 shares of the Company's capital stock issued, outstanding and generally entitled to vote as of the record date, March 14, 2005.

2. There were present at the meeting, in person or by proxy, the holders of 20,359,703 shares, representing 92.47% 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	VOTES CAST FOR	PERCENT OF QUORUM VOTES CAST	AUTHORITY WITHHELD
William F. Berry	19,149,823	94.06%	1,209,880
Ralph B. Busch, III	19,146,095	94.04%	1,213,608
William E. Bush, Jr.	19,197,518	94.29%	1,162,185
Stephen L. Cropper	19,814,820	97.32%	544,883
J. Herbert Gaul, Jr.	19,941,200	97.94%	418,503
John A. Hagg	19,668,497	96.61%	691,206
Robert F. Heinemann	19,962,921	98.05%	396,782
Thomas J. Jamieson	19,533,137	95.94%	826,566
Martin H. Young, Jr.	19,945,869	97.97%	413,834

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

Table of Contents

PROPOSAL TWO:	For	Against	Abstentions	Broker Non-Votes
Approval of 2005 Equity Incentive Plan	11,133,725	5,797,626	411,335	3,017,017

Item 5. Other Information
None

Item 6. Exhibits

Exhibit No.	Description of Exhibit
3.1	Bylaws, as amended, dated July 1, 2005.*
10.1	Credit Agreement, dated as of June 27, 2005, by and between the Registrant and Wells Fargo Bank, N.A. and other financial institutions.*
31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. *
31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. *
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. *
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. *

* Filed herewith

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereto duly authorized.

BERRY PETROLEUM COMPANY

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

Date: August 9, 2005