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, 2007**
oTransition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from __to ___
Commission file number **1-9735**

BERRY PETROLEUM COMPANY

(Exact name of registrant as specified in its charter)

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. YES x NO o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):
Large accelerated filerx Accelerated filero Non-accelerated filero

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). YES o NO x

As of October 15, 2007, the registrant had 42,336,198 shares of Class A Common Stock ($.01 par value) outstanding. The registrant also had 1,797,784 shares of Class B Stock ($.01 par value) outstanding on October 15, 2007 all of which is held by an affiliate of the registrant.

BERRY PETROLEUM COMPANY
THIRD QUARTER 2007 FORM 10-Q
TABLE OF CONTENTS

PART I. FINANCIAL INFORMATION

PART II. OTHER INFORMATION

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

		September 30, 2007		December 31, 2006
ASSETS				
Current assets:				
Cash and cash equivalents	$	191	$	416
Short-term investments		660		665
Accounts receivable		77,320		67,905
Deferred income taxes		14,989		-
Fair value of derivatives		6,703		7,349
Assets held for sale		662		8,870
Prepaid expenses and other		13,581		13,604
Total current assets		114,106		98,809
Oil and gas properties (successful efforts basis), buildings and equipment, net		1,237,921		1,080,631
Fair value of derivatives		1,048		2,356
Other assets		15,526		17,201
	$	1,368,601	$	1,198,997
LIABILITIES AND SHAREHOLDERS' EQUITY				
Current liabilities:				
Accounts payable	$	94,287	$	69,914
Property acquisition payable		-		54,400
Revenue and royalties payable		36,103		45,845
Accrued liabilities		26,051		20,415
Line of credit		4,500		16,000
Fair value of derivatives		42,799		8,084
Other current liabilities		1,335		745
Total current liabilities		205,075		215,403
Long-term liabilities:				
Deferred income taxes		143,320		103,515
Long-term debt		435,000		390,000
Abandonment obligation		32,386		26,135
Other long-term liabilities		9,371		1,437
Fair value of derivatives		46,329		34,807
		666,406		555,894
Shareholders' equity:				
Preferred stock, $.01 par value, 2,000,000 shares authorized; no shares outstanding		-		-
Capital stock, $.01 par value:				
Class A Common Stock, 100,000,000 shares authorized; 42,329,886 shares issued and outstanding (42,098,551 in 2006)		423		421
Class B Stock, 3,000,000 shares authorized; 1,797,784 shares issued and outstanding (liquidation preference of $899)		18		18
Capital in excess of par value		60,449		50,166
Accumulated other comprehensive loss		(48,410)		(19,977)
Retained earnings		484,640		397,072
Total shareholders' equity		497,120		427,700
	$	1,368,601	$	1,198,997

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

BERRY PETROLEUM COMPANY
Unaudited Condensed Statements of Income
Three Month Periods Ended September 30, 2007 and 2006
(In Thousands, Except Per Share Data)

	Three months ended September 30, 2007	2006
REVENUES AND OTHER INCOME ITEMS		
Sales of oil and gas	$ 118,733	$ 116,168
Sales of electricity	12,241	12,592
Gain on sale of assets	1,418	-
Interest and other income, net	1,108	603
	133,500	129,363
EXPENSES		
Operating costs – oil and gas production	33,995	30,950
Operating costs – electricity generation	9,760	11,198
Production taxes	4,344	5,286
Depreciation, depletion & amortization - oil and gas production	23,356	17,974
Depreciation, depletion & amortization - electricity generation	938	825
General and administrative	9,333	9,419
Interest	4,326	2,707
Dry hole, abandonment, impairment and exploration	5,175	527
	91,227	78,886
Income before income taxes	42,273	50,477
Provision for income taxes	15,418	19,103
Net income	$ 26,855	$ 31,374
Basic net income per share	$ .61	$ .71
Diluted net income per share	$ .60	$ .70
Dividends per share	$ .075	$ .095
Weighted average number of shares of capital stock outstanding used to calculate basic net income per share	44,112	43,907
Effect of dilutive securities:		
Equity based compensation	772	654
Director deferred compensation	118	104
Weighted average number of shares of capital stock used to calculate diluted net income per share	45,002	44,665

Unaudited Condensed Statements of Comprehensive Income
Three Month Periods Ended September 30, 2007 and 2006
(In Thousands)

	2007	2006
Net income	$ 26,855	$ 31,374
Unrealized gains (losses) on derivatives, net of income taxes of ($7,027) and $28,188, respectively	(10,541)	42,282
Reclassification of realized (gains) losses included in net income, net of income taxes of $1,411 and ($1,178), respectively	2,116	(1,767)
Comprehensive income	$ 18,430	$ 71,889

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

BERRY PETROLEUM COMPANY
Unaudited Condensed Statements of Income
Nine Month Periods Ended September 30, 2007 and 2006
(In Thousands, Except Per Share Data)

	Nine months ended September 30, 2007	2006
REVENUES AND OTHER INCOME ITEMS		
Sales of oil and gas	$ 333,933	$ 328,742
Sales of electricity	40,704	39,476
Gain on sale of assets	51,816	-
Interest and other income, net	3,754	1,898
	430,207	370,116
EXPENSES		
Operating costs – oil and gas production	103,330	83,763
Operating costs – electricity generation	35,014	36,155
Production taxes	12,297	11,891
Depreciation, depletion & amortization - oil and gas production	65,478	47,333
Depreciation, depletion & amortization - electricity generation	2,661	2,526
General and administrative	29,291	25,610
Interest	13,593	6,745
Commodity derivatives	-	(736)
Dry hole, abandonment, impairment and exploration	9,342	11,070
	271,006	224,357
Income before income taxes	159,201	145,759
Provision for income taxes	61,534	56,930
Net income	$ 97,667	$ 88,829
Basic net income per share	$ 2.22	$ 2.02
Diluted net income per share	$ 2.18	$ 1.98
Dividends per share	$ .225	$ .225
Weighted average number of shares of capital stock outstanding used to calculate basic net income per share	44,020	43,982
Effect of dilutive securities:		
Equity based compensation	701	792
Director deferred compensation	115	101
Weighted average number of shares of capital stock used to calculate diluted net income per share	44,836	44,875

Unaudited Condensed Statements of Comprehensive Income
Nine Month Periods Ended September 30, 2007 and 2006
(In Thousands)

	2007	2006
Net income	$ 97,667	$ 88,829
Unrealized gains (losses) on derivatives, net of income taxes of ($19,484) and $1,223, respectively	(29,226)	1,834
Reclassification of realized (gains) losses included in net income, net of income taxes of $529 and ($3,534), respectively	793	(5,301)
Comprehensive income	$ 69,234	$ 85,362

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

BERRY PETROLEUM COMPANY
Unaudited Condensed Statements of Cash Flows
Nine Month Periods Ended September 30, 2007 and 2006
(In Thousands)

	Nine months ended September 30, 2007	2006
Cash flows from operating activities:		
Net income	$ 97,667	$ 88,829
Depreciation, depletion and amortization	68,139	49,858
Dry hole and impairment	8,725	6,965
Commodity derivatives	804	(264)
Stock-based compensation expense	5,437	3,563
Deferred income taxes	53,162	44,410
Gain on sale of oil and gas properties	(51,816)	-
Other, net	750	1,749
Cash paid for abandonment	(660)	(569)
Increase in current assets other than cash, cash equivalents and short-term investments	(10,785)	(17,996)
Increase in current liabilities other than book overdraft, line of credit, property acquisition payable and fair value of derivatives	13,116	8,600
Net cash provided by operating activities	184,539	185,145
Cash flows from investing activities:		
Exploration and development of oil and gas properties	(206,240)	(185,773)
Property acquisitions	(56,167)	(210,126)
Additions to vehicles, drilling rigs and other fixed assets	(2,944)	(18,302)
Proceeds from sale of asset	68,432	-
Capitalized interest and other	(13,160)	(5,600)
Net cash used in investing activities	(210,079)	(419,801)
Cash flows from financing activities:		
Proceeds from issuance of line of credit	285,150	241,750
Payment of line of credit	(296,650)	(232,750)
Proceeds from issuance of long-term debt	179,300	324,700
Payment of long-term debt	(134,300)	(90,700)
Dividends paid	(10,036)	(9,889)
Change in book overdraft	(2,995)	10,196
Repurchase of shares of common stock	-	(15,766)
Proceeds from stock option exercises	3,051	2,559
Excess tax benefit and other	1,795	2,918
Net cash provided by financing activities	25,315	233,018
Net decrease in cash and cash equivalents	(225)	(1,638)
Cash and cash equivalents at beginning of year	416	1,990
Cash and cash equivalents at end of period	$ 191	$ 352
Supplemental non-cash activity:		
Increase (decrease) in fair value of derivatives:		
Current (net of income taxes of ($13,820) and $1,491, respectively)	$ (20,731)	$ 2,237
Non-current (net of income taxes of ($5,135) and ($3,803), respectively)	(7,702)	(5,704)
Net decrease to accumulated other comprehensive income	$ (28,433)	$ (3,467)

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

1. General

All adjustments which are, in the opinion of Management, necessary for a fair statement of Berry Petroleum Company's (the "Company") financial position at September 30, 2007 and December 31, 2006 and results of operations for the three and nine month periods ended September 30, 2007 and 2006 and cash flows for the nine month periods ended September 30, 2007 and 2006 have been included. All such adjustments are of a normal recurring nature. The results of operations and cash flows are not necessarily indicative of the results for a full year.

The accompanying unaudited condensed financial statements have been prepared on a basis consistent with the accounting principles and policies reflected in the December 31, 2006 financial statements. The December 31, 2006 Form 10-K and the March 31, 2007 and June 30, 2007 Form 10-Qs 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.

Our cash management process provides for the daily funding of checks as they are presented to the bank. Included in accounts payable at September 30, 2007 and December 31, 2006 is $14.2 million and $17.2 million, respectively, representing outstanding checks in excess of the bank balance (book overdraft).

In December 2004, Statement of Financial Accounting Standards (SFAS) No. 123(R), *Share-Based Payment*, was issued which establishes standards for transactions in which an entity exchanges its equity instruments for goods or services. We adopted this statement beginning January 1, 2006. This standard requires us to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award. The adoption of SFAS No. 123(R) using the modified prospective method did not have a material impact on our condensed financial statements for the year ended December 31, 2006. We previously adopted the fair value recognition provisions of SFAS No. 123, *Accounting for Stock-Based Compensation* effective January 1, 2004. The modified prospective method was selected as described in SFAS No. 148, *Accounting for Stock-Based Compensation - Transition and Disclosure*. The adoption of SFAS No. 123(R) did not have a material impact on our condensed financial statements as we previously applied the provisions of SFAS No. 123.

2. Recent Accounting Developments

In June 2006, the Financial Accounting Standards Board (FASB) issued Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109*, *Accounting for Income Taxes*. This interpretation requires that realization of an uncertain income tax position must be "more likely than not" (i.e. greater than 50% likelihood of receiving a benefit) before it can be recognized in the financial statements. Further, this interpretation prescribes the benefit to be recorded in the financial statements as the amount most likely to be realized assuming a review by tax authorities having all relevant information and applying current conventions. This interpretation also clarifies the financial statement classification of tax-related penalties and interest and sets forth new disclosures regarding unrecognized tax benefits. This interpretation is effective for fiscal years beginning after December 15, 2006, and we adopted this interpretation in the first quarter of 2007. See Note 5.

In September 2006, SFAS No. 157, *Fair Value Measurements* was issued by the FASB. This statement defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. SFAS No. 157 will become effective for our fiscal year beginning January 1, 2008, and should not have a material effect on our financial statements.

In September 2006, Staff Accounting Bulletin ("SAB") No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements* was issued by the Securities and Exchange Commission. Registrants must quantify the impact on current period financial statements of correcting all misstatements, including both those occurring in the current period and the effect of reversing those that have accumulated from prior periods. This SAB was adopted at December 31, 2006. The adoption of SAB No. 108 had no effect on our financial position or on the results of our operations.

In April 2007, the FASB issued a FASB Staff Position to amend FASB Interpretation 39, *Offsetting Amount Related to Certain Contracts*. FIN 39-1 states that a reporting entity that is party to a master netting arrangement can offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) against fair value amounts recognized for derivative instruments that have been offset under the same master netting arrangement in accordance with paragraph 10 of Interpretation 39. FIN 39-1 will become effective for our fiscal year beginning January 1, 2008 and will have no effect on our financial statements as we do not post collateral under our hedging agreements.

2. Recent Accounting Developments (Cont'd)

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities*, which permits an entity to measure certain financial assets and financial liabilities at fair value. The objective of SFAS No. 159 is to improve financial reporting by allowing entities to mitigate volatility in reported earnings caused by the measurement of related assets and liabilities using different attributes, without having to apply complex hedge accounting provisions. Under SFAS No. 159, entities that elect the fair value option (by instrument) will report unrealized gains and losses in earnings at each subsequent reporting date. The fair value option election is irrevocable, unless a new election date occurs. SFAS No. 159 establishes presentation and disclosure requirements to help financial statement users understand the effect of the entity's election on its earnings, but does not eliminate disclosure requirements of other accounting standards. Assets and liabilities that are measured at fair value must be displayed on the face of the balance sheet. This statement is effective beginning January 1, 2008 and should not have a material effect on our financial statements.

3. Hedging

The related cash flow impact of all of our hedges is reflected in cash flows from operating activities. At September 30, 2007, our net fair value of derivatives liability was $81.4 million as compared to $33.2 million at December 31, 2006 which reflects increases in commodity prices in the period. At September 30, 2007, Accumulated Other Comprehensive Loss consisted of $48.4 million, net of tax, of unrealized losses from our crude oil and natural gas swaps and collars that qualified for hedge accounting treatment at September 30, 2007. Deferred net losses recorded in Accumulated Other Comprehensive Loss at September 30, 2007 and subsequent marked-to-market changes in the underlying hedging contracts are expected to be reclassified to earnings over the life of these contracts. Our liability is primarily related to the time value of the underlying instruments and based on current prices the amount expected to be reclassified to earnings over the next 12 months is approximately $30 million before tax.

In February 2007, we converted 2,000 Bbl/D of our 2007 oil collars beginning on March 1, 2007 to a swap with a strike price of $60 West Texas Intermediate (WTI). Additionally, we entered into the following oil swaps and oil collars during the nine months ended September 30, 2007:

- oil swaps for 1,000 Bbl/D at $64.55 from July 2007 through December 2007
- oil swaps for 260 Bbl/D at $74 for calendar year 2008
- oil swaps for 240 Bbl/D at $71.50 for calendar year 2009
- oil collars for 1,000 Bbl/D at $60 floor and $75 ceiling prices for calendar year 2010
- oil collars for 1,000 Bbl/D at $65.15 floor and $75 ceiling prices for calendar year 2010
- oil collars for 1,000 Bbl/D at $65.50 floor and $78.50 ceiling prices for calendar year 2010
- oil collars for 1,000 Bbl/D at $70 floor and $75.85 ceiling prices from July to December 2007
- oil collars for 1,000 Bbl/D at $70 floor and $76.70 ceiling prices for calendar year 2008

These hedges have been designated as cash flow hedges in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.*

4. Asset Retirement Obligations

Inherent in the fair value calculation of the asset retirement obligation (ARO) are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the oil and gas property balance. In March 2007, we revised our estimate of future abandonment costs due to demand for related services.

4. Asset Retirement Obligations (Cont'd)

Under SFAS 143, the following table summarizes the change in abandonment obligation for the nine months ended September 30, 2007 (in thousands):

Beginning balance at January 1	$	26,135
Liabilities incurred		2,769
Liabilities settled		(1,601)
Revisions in estimated liabilities		3,272
Accretion expense		1,811
Ending balance at September 30	$	32,386

5. Income Taxes

The effective tax rate was 36% for the third quarter of 2007 compared to 39% for the second quarter of 2007 and 38% for the third quarter of 2006. The effective tax rate was 39% for the nine months ending September 30, 2006 and 2007. Our rate differs from a statutory rate, primarily due to state income taxes.

In June 2006, the FASB issued FIN No. 48, *Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109, Accounting for Income Taxes*. The Interpretation addresses the determination of whether tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under FIN No. 48, we may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. FIN No. 48 also provides guidance on derecognition, classification, interest and penalties on income taxes, accounting in interim periods and requires increased disclosures.

We adopted the provisions of FIN No. 48 on January 1, 2007 and recognized no material adjustment to retained earnings. As of the date of adoption, we had a gross liability for uncertain tax benefits of $14.6 million of which $10.8 million, if recognized, would affect the effective tax rate. We recognize potential accrued interest and penalties related to unrecognized tax benefits in income tax expense, which is consistent with the recognition of these items in prior reporting periods. As of January 1, 2007, we had accrued approximately $.9 million of interest related to our uncertain tax positions.

As of January 1, 2007, we remain subject to examination in the following major tax jurisdictions for the tax years indicated below:

Jurisdiction:	Tax Years Subject to Exam:
Federal	2003 – 2006
California	2002 – 2006
Colorado	2002 – 2006
Utah	2003 – 2006

For the nine months ending September 30, we recognized a net benefit of approximately $.7 million to the statement of income due to the closure of the 2003 federal tax year and additional FIN 48 accruals including interest.

6. Long-term and Short-term Obligations

Short-term debt

In November 2005, we completed an unsecured uncommitted money market line of credit (Line of Credit). Borrowings under the Line of Credit may be up to $30 million for a maximum of 30 days. The Line of Credit may be terminated at any time upon written notice by either us or the lender. At September 30, 2007 the outstanding balance under this Line of Credit was $5 million. Interest on amounts borrowed is charged at LIBOR plus a margin of approximately 1%. The weighted average interest rate on outstanding borrowings on the Line of Credit at September 30, 2007 was 6%.

6. Long-term and Short-term Obligations (Cont'd)

Long-term debt

In October 2006, we issued in a public offering $200 million of 8.25% senior subordinated notes due 2016 (the Notes). The deferred costs of approximately $5 million associated with the issuance of this debt are being amortized over the ten year life of the Notes.

In April 2006, we completed a new unsecured five year bank credit facility agreement (the Agreement) with a banking syndicate and extended the term by one year to July 2011. The Agreement is a revolving credit facility for up to $750 million and replaces the previous $500 million facility. The borrowing base was established at $500 million, as compared to the previous $350 million. This transaction was accounted for in accordance with Emerging Issues Task Force, (EITF) 98-14, *Debtor's Accounting for Changes in Line-of-Credit or Revolving-Debt Arrangements*. Effective May 2007 and in accordance with the existing Agreement, the bank syndicate agreed to increase the borrowing base by $50 million to $550 million. The outstanding Line of Credit reduces our borrowing capacity available under the Agreement.

The total outstanding debt at September 30, 2007 under the credit facility and the short-term Line of Credit was $235 million and $5 million, respectively, leaving $310 million in borrowing capacity available. Interest on amounts borrowed under this debt is charged at LIBOR plus a margin of 1.00% to 1.75% or the prime rate, with margins on the various rate options based on the ratio of credit outstanding to the borrowing base. We are required under the Agreement to pay an annual commitment fee of .25% to .375% on the unused portion of the credit facility.

The Agreement contains restrictive covenants which, among other things, require us to maintain a certain debt to EBITDA ratio and a minimum current ratio, as defined. The $200 million Notes are subordinated to our credit facility indebtedness. Covenants of our Notes limit debt to the greater of $750 million or 40% of Adjusted Consolidated Net Tangible Assets (as defined). Additionally, as long as the interest coverage ratio (as defined) is met, we may incur additional debt. We were in compliance with all such covenants as of September 30, 2007. The weighted average interest rate on the long-term outstanding credit facility borrowings at September 30, 2007 was 6.5%.

7. Contingencies and Commitments

We have no accrued environmental liabilities for our sites, including sites in which governmental agencies have designated us as a potentially responsible party, because it is not probable that a loss will be incurred. However, because of the uncertainties associated with environmental assessment and remediation activities, future expense to remediate the currently identified sites, and sites identified in the future, if any, could be incurred. Management believes, based upon current site assessments, that the ultimate resolution of any matters will not result in substantial costs incurred. We are involved in various other lawsuits, claims and inquiries, most of which are routine to the nature of our business. In the opinion of management, the resolution of these matters will not have a material effect on our financial position, or on the results of operations or liquidity.

On February 27, 2007, we entered into a six year multi-staged crude oil sales contract with a subsidiary of Holly Corporation (Holly) for a portion of our Uinta basin crude oil. Under the agreement, Holly began purchasing 3,200 Bbl/D beginning July 1, 2007. Upon completion of their Woods Cross refinery expansion in Salt Lake City, which is expected in late 2008, Holly will increase total purchased volumes to 5,000 Bbl/D through June 30, 2013. During the term of the contract, the minimum number of delivered units ("base daily volume") is 3,200 Bbl/D increasing to 5,000 Bbl/D upon the certified completion of the refinery upgrade. Holly may, but is not obligated to, purchase volumes in excess of the base daily volumes. Pricing under the contract, which includes transportation, is a fixed percentage of WTI.

8. Asset Sales and Impairment

On May 11, 2007, we sold our non-core West Montalvo assets in Ventura County, California. The sale proceeds were approximately $61 million and we recognized approximately $52 million pretax gain on the sale, including post closing adjustments.

8. Asset Sales and Impairment (Cont'd)

During the second quarter of 2007, we recorded a $2.9 million pretax charge to reduce our carrying value of the Bakken asset in the Williston Basin, North Dakota from $9.9 million to $7 million. This asset was sold during the third quarter of 2007 for approximately its carrying value. In the third quarter of 2007, we also recorded a $4.6 million pretax charge to reduce the carrying value of our Tri-State unproved properties from $5.9 million to $1.3 million which we believe approximates fair value as of September 30, 2007 based on available information. We plan to sell a portion of our Tri-State acreage during the fourth quarter of 2007 and have classified $.7 million as held for sale at September 30, 2007 in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. Total impairment expense for the nine months ended September 30, 2007 was $7.6 million.

9. Subsequent Event

On October 22, 2007, we announced plans to form a master limited partnership (MLP) and intend to proceed with an initial public offering of common units representing limited partner interests in the MLP during the first half of 2008. Approximately $125 million to $175 million of common units are expected to be offered to the public. We will own the general partner of the MLP and expect to retain a significant interest in the MLP at the close of the initial public offering.

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

General. The following discussion provides information on the results of operations for the three and nine month periods ended September 30, 2007 and 2006 and our financial condition, liquidity and capital resources as of September 30, 2007. The financial statements and the notes thereto contain detailed information that should be referred to in conjunction with this discussion.

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

Overview. Our mission is to increase shareholder value through consistent growth in our production and reserves, both through the drill bit and acquisitions. We strive to operate our properties in an efficient manner to maximize the cash flow and earnings of our assets. The strategies to accomplish these goals include:

- Developing our existing resource base
- Acquiring additional assets with significant growth potential
- Utilizing joint ventures with respected partners to enter new basins
- Accumulating significant acreage positions near our producing operations
- Investing our capital in a disciplined manner and maintaining a strong financial position

Notable Third Quarter Items.

- Increased production at North Midway-Sunset diatomite to an average 1,100 Bbl/D in the quarter through modification of our steam cycling practices and well fracturing techniques
- Achieved a record production at Poso Creek to an average 2,400 Bbl/D in the quarter
- Drilled 14 infill horizontal wells at South Midway-Sunset targeting oil pays closer to the oil-water contact; performance is meeting expectations
- Accelerated Pan Fee and Ethel D development by drilling 15 additional infill wells
- Accomplished a 15 day drilling record on a Piceance mesa well as we are realizing our goal of reducing our drilling costs; we drilled 21 gross (7 net) Piceance wells
- Completed and tied into gathering systems 15 gross (8 net) Piceance basin operated wells which increased Piceance net production to 11.5 MMcf/D, up 40% from the second quarter 2007

Notable Items and Expectations for the Remainder of 2007.

- Companywide production is projected to approximate 28,000 BOE/D in the fourth quarter of 2007 with a projected 2007 year end exit rate of 28,200 BOE/D
- Drilling the next 50 well expansion on our North Midway-Sunset diatomite asset; this activity will continue into early 2008 and the projected 2007 year end exit rate is 1,250 Bbl/D
- Accelerating Poso Creek infill drilling by an additional 13 wells and expected 2007 year end exit rate is 2,600 Bbl/D
- Continuing to focus on reducing drilling costs of our operated Piceance mesa wells and we expect to complete 12 gross (6 net) Piceance wells while targeting fourth quarter average net production in Piceance of 15 MMcf/D
- Proceeding with plans as announced on forming a master limited partnership

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

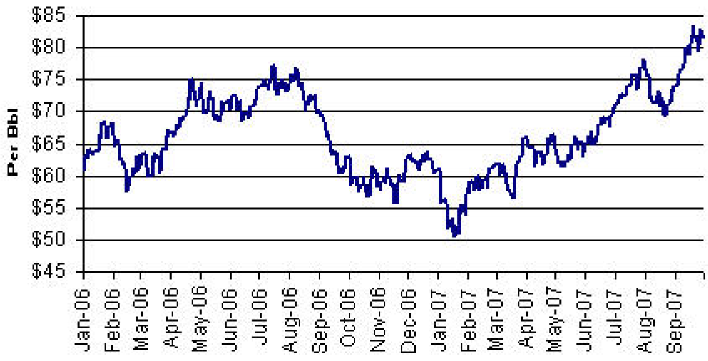
	September 30, 2007 (3Q07)	September 30, 2006 (3Q06)	3Q07 to 3Q06 Change	June 30, 2007 (2Q07)	3Q07 to 2Q07 Change
Sales of oil	$ 100.1	$ 97.9	2%	$ 94.4	6%
Sales of gas	18.6	18.3	2%	19.0	(2%)
Total sales of oil and gas	$ 118.7	$ 116.2	2%	$ 113.4	5%
Sales of electricity	12.3	12.6	(2%)	13.9	(12%)
Gain on sale of assets	1.4	-	n/a	50.4	(97%)
Interest and other income, net	1.1	.6	83%	1.5	(27%)
Total revenues and other income	$ 133.5	$ 129.4	3%	$ 179.2	(26%)
Net income	$ 26.9	$ 31.4	(14%)	$ 52.0	(48%)
Net income per share (diluted)	$ .60	$ .70	(14%)	$ 1.16	(48%)

Our revenues may vary significantly from period to period as a result of changes in commodity prices and/or production volumes. Our production for the third quarter of 2007 averaged 26,873 BOE/D, which was up 2% from the third quarter of 2006, and decreased 1% from the second quarter of 2007. Our average production for the nine months ended September 30, 2007 was 26,525 BOE/D, which was up 7% from the same period last year. Excluding the production impact of the West Montalvo assets sold in the second quarter, production in the third quarter of 2007 increased slightly as compared to the second quarter of 2007. Based on the timing of actual production from our projects we are forecasting average production of between 26,700 BOE/D and 27,000 BOE/D for the full year of 2007.

Crude oil sales in the three months ended September 30, 2007 were 6% higher than the three months ended June 30, 2007 resulting from price increases of 9%, offset by production decreases of 3%. Gas sales in the three months ended September 30, 2007 were 2% lower than the three months ended June 30, 2007 resulting from production increases of 6% partially offset by a price decline of 8%. Similarly, crude oil sales and gas sales were 2% and 3% higher, respectively, in the nine months ended September 30, 2007 as compared to the nine months ended September 30, 2006. Management estimates that for 2008, a $1.00 per MMBtu change in NYMEX Henry Hub natural gas prices would result in a $3 million change in annual net income, demonstrating our relative insensitivity to natural gas prices companywide.

On May 11, 2007, we sold our non-core West Montalvo assets in Ventura County, California. The sale proceeds were approximately $61 million and we recognized approximately $52 million pretax gain on the sale, including post closing adjustments. During the second quarter of 2007, we recorded a $2.9 million pretax charge to reduce our carrying value of the Bakken asset in the Williston Basin, North Dakota from $9.9 million to $7 million. This asset was sold during the third quarter of 2007 for approximately its carrying value. In the third quarter of 2007, we also recorded a $4.6 million charge to reduce the carrying value of our Tri-State unproved properties from $5.9 million to $1.3 million which we believe approximates fair value as of September 30, 2007 based on available information. We plan to sell a portion of our Tri-State acreage during the fourth quarter of 2007 and have classified $.7 million as held for sale at September 30, 2007 in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. Total impairment expense for the nine months ended September 30, 2007 was $7.6 million. In addition, during the second quarter we paid the third and final installment of approximately $54 million for the North Parachute Ranch property located in the Piceance basin.

WTI NYMEX Crude Oil Price



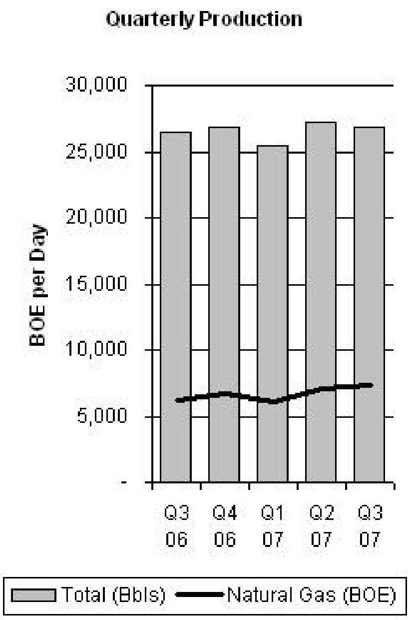
HH NYMEX Natural Gas Price

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

	September 30, 2007	%	September 30, 2006	%	June 30, 2007	%
Oil and Gas						
Heavy Oil Production (Bbl/D)	15,806	59	16,076	61	16,129	59
Light Oil Production (Bbl/D)	3,675	14	4,118	16	4,034	15
Total Oil Production (Bbl/D)	19,481	73	20,194	76	20,163	74
Natural Gas Production (Mcf/D)	44,346	27	37,374	24	42,193	26
Total (BOE/D)	26,873	100	26,423	100	27,195	100
Per BOE:						
Average sales price before hedging	$ 49.35		$ 50.33		$ 44.72	
Average sales price after hedging	47.93		47.28		45.43	
Oil, per Bbl:						
Average WTI price	$ 75.15		$ 70.54		$ 65.02	
Price sensitive royalties	(5.50)		(5.21)		(4.20)	
Quality differential and other	(9.56)		(8.76)		(9.24)	
Crude oil hedges	(4.37)		(3.99)		(.52)	
Average oil sales price after hedging	$ 55.72		$ 52.58		$ 51.06	
Natural gas price:						
Average Henry Hub price per MMBtu	$ 6.24		$ 6.18		$ 7.65	
Conversion to Mcf	.31		.31		.39	
Natural gas hedges	1.07		(.02)		.71	
Location, quality differentials and other	(3.06)		(1.36)		(3.89)	
Average gas sales price after hedging	$ 4.56		$ 5.11		$ 4.86	

The following table is for the nine months ended:

	September 30, 2007	%	September 30, 2006	%
Oil and Gas				
Heavy Oil Production (Bbl/D)	16,019	60	15,681	63
Light Oil Production (Bbl/D)	3,655	14	3,823	15
Total Oil Production (Bbl/D)	19,674	74	19,504	78
Natural Gas Production (Mcf/D)	41,109	26	32,348	22
Total (BOE/D)	26,525	100	24,896	100
Per BOE:				
Average sales price before hedging	$ 45.98		$ 50.81	
Average sales price after hedging	45.82		48.33	
Oil, per Bbl:				
Average WTI price	$ 66.22		$ 68.26	
Price sensitive royalties	(4.48)		(5.41)	
Quality differential and other	(9.26)		(7.87)	
Crude oil hedges	(1.61)		(3.17)	
Average oil sales price after hedging	$ 50.87		$ 51.81	
Natural gas price:				
Average Henry Hub price per MMBtu	$ 7.02		$ 6.89	
Conversion to Mcf	.36		.34	
Natural gas hedges	.67		-	
Location, quality differentials and other	(2.85)		(1.28)	
Average gas sales price after hedging	$ 5.20		$ 5.95	



Gas Basis Differential. Natural gas prices in the Rockies continue to be volatile due to various factors, including takeaway pipeline capacity, supply volumes, and regional demand issues. We expect the basis differential between Henry Hub (HH) and Colorado Interstate Gas (CIG) to narrow upon the startup of the Rockies Express Pipeline (REX) which is anticipated in early 2008. We have contracted 10,000 MMBtu/D on this pipeline to provide firm transport for a portion of our Piceance gas production. The CIG basis differential per MMBtu, based upon first-of-month values, averaged $3.55 below HH and ranged from $2.68 to $4.37 below HH in the third quarter. Although related to CIG, the actual basin price varies. Gas from the Piceance basin was slightly below the CIG price while Uinta basin gas sold for approximately $.40 below CIG pricing. DJ Basin gas is priced using one of two indices. Approximately two-thirds of the pricing of our DJ natural gas is tied to the Panhandle Eastern Pipeline (PEPL) index and the remaining volumes to the CIG. For that portion of the production with firm transportation on either the Cheyenne Plains Pipeline or the KMIGT pipeline, pricing is based upon the PEPL index which averaged approximately $.86 below the HH index before the cost of transportation is considered. The remainder of the DJ Basin gas is sold slightly above the CIG index price.

Oil Contracts. Utah –Our Utah crude oil is paraffinic crude and can be transported only a short distance before solidifying thus limiting the number of refineries for processing. We are currently able to secure short-term contracts which, along with long-term contracts, allows us to produce at full capacity. As of September 30, 2007, our Utah light crude oil is sold under multiple long-term and short-term contracts with different purchasers for varying prices. In some cases the price is tied to field postings and in other contracts the price is based upon a percentage of the average NYMEX WTI prices. As operator we deliver all produced volumes pursuant to these contracts.

On February 27, 2007, we entered into a six year multi-staged crude oil sales contract with a subsidiary of Holly for a portion of our Uinta basin crude oil. Under the agreement, Holly began purchasing 3,200 Bbl/D beginning July 1, 2007. Holly took delivery of approximately 1,000 Bbl/D and 1,500 Bbl/D in the first and second quarters of 2007, respectively, which stabilized our realized sales price and reduced our transportation costs. Upon completion of their Woods Cross refinery expansion in Salt Lake City, which is expected in late 2008, Holly will increase total purchased volumes to 5,000 Bbl/D through June 30, 2013. Pricing under the contract, which includes transportation, is a fixed percentage of WTI. This contract provides the pricing assurance we need to proceed with the long-term development of our Uinta basin assets. We may adjust our capital expenditures in the Uinta basin due to various factors, including the timing of refinery demand for the Uinta basin barrels and the actual or expected change in our realized price.

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

Electricity. We consume natural gas as fuel to operate our three cogeneration facilities which are intended to provide an efficient and secure long-term supply of steam necessary for the economic production of heavy oil in California. Revenue and operating costs for the three months ended September 30, 2007 were down from the three months ended September 30, 2006 and June 30, 2007 due to the decrease in electricity prices and the decrease in fuel gas cost. On September 20, 2007, the California Public Utilities Commission (CPUC) issued a decision (SRAC Decision) that changes SRAC energy and capacity prices paid under Standard Offer (SO) contracts prospectively, and authorizes California utilities to offer new short-term and long-term SO contracts. This decision has been appealed at the CPUC and may be subject to additional challenges and further clarification. We do not believe that the proposed changes will materially effect us in 2007.

The following table is for the three months ended:

	September 30, 2007	September 30, 2006	June 30, 2007
Electricity			
Revenues (in millions)	$ 12.3	$ 12.6	$ 13.9
Operating costs (in millions)	$ 9.8	$ 11.2	$ 11.1
Electric power produced - MWh/D	2,257	2,100	2,060
Electric power sold - MWh/D	2,077	1,895	1,819
Average sales price/MWh	$ 71.28	$ 79.42	$ 84.13
Fuel gas cost/MMBtu (including transportation)	$ 4.84	$ 6.14	$ 6.46

Oil and Gas Operating, Production Taxes, G&A and Interest Expenses. The following table presents information about our operating expenses for each of the three month periods ended:

	Amount per BOE			Amount (in thousands)		
	September 30, 2007	September 30, 2006	June 30, 2007	September 30, 2007	September 30, 2006	June 30, 2007
Operating costs – oil and gas production	$ 13.75	$ 12.73	$ 14.44	$ 33,995	$ 30,950	$ 35,725
Production taxes	1.76	2.17	1.67	4,344	5,286	4,139
DD&A – oil and gas production	9.45	7.39	9.45	23,356	17,974	23,397
G&A	3.78	3.87	3.90	9,333	9,419	9,651
Interest expense	1.75	1.11	2.01	4,326	2,707	4,976
Total	$ 30.49	$ 27.27	$ 31.47	$ 75,354	$ 66,336	$ 77,888

Our total operating costs, production taxes, DD&A, G&A and interest expenses for the three months ended September 30, 2007, stated on a unit-of-production basis, increased 12% over the three months ended September 30, 2006 and decreased 3% as compared to the three months ended June 30, 2007. The changes were primarily related to the following items:

- Operating costs: Operating costs per BOE in the third quarter of 2007 were 8% higher than the third quarter of 2006 primarily due to increases in contract labor, well servicing, chemicals and compression and gathering costs, partially offset by lower steam costs and used on-lease electricity costs. Operating costs per BOE were 5% lower in the third quarter of 2007 as compared to the second quarter of 2007 due to lower steam costs and used on-lease electricity costs. The cost of our steam and electricity used on-lease on our heavy oil properties in California has decreased in the third quarter of 2007 due to lower cost of natural gas used as fuel, partially offset by a higher volume of steam injected. The following table presents steam information:

	September 30, 2007 (3Q07)	September 30, 2006 (3Q06)	3Q07 to 3Q06 Change	June 30, 2007 (2Q07)	3Q07 to 2Q07 Change
Average volume of steam injected (Bbl/D)	88,711	86,556	2%	84,032	3%
Fuel gas cost/MMBtu (including transportation)	$ 4.84	$ 6.14	(21%)	$ 6.46	(25%)

Based on current plans, we are targeting average steam injection of approximately 96,000 barrels of steam per day (BSPD) during the last quarter of 2007.

- Production taxes: Overall, our production taxes have decreased compared to 2006 due to lower tax rates and lower assessed values for some of our oil and natural gas assets. Severance taxes, which are prevalent in Utah and Colorado, are directly related to the cost of the field sales price of the commodity. In California and Utah, our production is burdened with ad valorem taxes on proved reserves. Colorado has an ad valorem tax which is based on field commodity prices. We expect production taxes, in general, to correlate with the underlying commodity price.

· Depreciation, depletion and amortization: DD&A per BOE were 28% higher in the three months ended September 30, 2007 compared to the same period in the prior year due to an increase in capital spending over the last year and particularly more extensive development in fields with higher drilling costs and leasehold acquisition costs.

· General and administrative: G&A per BOE decreased by 2% in the third quarter of 2007 compared to the third quarter of 2006 due to higher production in 2007. G&A per BOE was 3% lower in the third quarter of 2007 as compared to the second quarter of 2007 due to lower compensation related costs and consulting expenses, partially offset by higher legal and accounting expenses related to business development activities.

· Interest expense: Our outstanding borrowings, including our senior unsecured money market line of credit and senior subordinated notes, was approximately $440 million at September 30, 2007 compared to approximately $330 million and $475 million at September 30, 2006 and June 30, 2007, respectively. Our average borrowings increased since September 30, 2006 as a result of our capital expenditure program and due to payments of $153 million to purchase the North Parachute Ranch property located in the Piceance basin. Beginning in 2006, a certain portion of our interest cost related to our Piceance basin acquisition and joint venture has been capitalized into the basis of the assets, and we anticipate a portion will continue to be capitalized until the remainder of our probable reserves has been recategorized to proved developed reserves. For the quarter ended September 30, 2007, $4.8 million has been capitalized and we expect to capitalize approximately $18 million of interest cost during the full year of 2007.

Estimated 2007 and Actual Nine Months Ended September 30, 2007 and 2006 Oil and Gas Operating, G&A and Interest Expenses.

	Anticipated range In 2007 per BOE	Nine months ended September 30, 2007	Nine months ended September 30, 2006
Operating costs-oil and gas production *(1)*	$ 14.00 to 15.00	$ 14.27	$ 12.32
Production taxes	1.50 to 2.00	1.70	1.75
DD&A – oil and gas production	8.50 to 9.50	9.04	6.96
G&A	3.75 to 4.25	4.05	3.77
Interest expense	1.50 to 2.00	1.88	.99
Total	$ 29.25 to 32.75	$ 30.94	$ 25.79

(1) Assuming natural gas prices of approximately NYMEX HH $7.50 MMBtu, we plan to inject approximately 15% greater steam levels in 2007 compared to 2006 levels.

Our total operating costs, production taxes, DD&A, G&A and interest expenses for the nine months ended September 30, 2007, stated on a unit-of-production basis, increased 20% over the nine months ended September 30, 2006. The changes were primarily related to the following items:

· Operating costs: Operating costs per BOE in the nine months ended September 30, 2007 were 16% higher than the comparable period in 2006 primarily due to approximately 15% greater steam levels in 2007 compared to 2006 levels.

· Production taxes: Overall, our production taxes have decreased slightly compared to 2006 due to lower tax rates and lower assessed values for some of our oil and natural gas assets.

· Depreciation, depletion and amortization: DD&A per BOE were 30% higher in the nine months ended September 30, 2007 compared to the same period in the prior year due to an increase in capital spending over the last year and particularly more extensive development in fields with higher drilling costs and leasehold acquisition costs.

· General and administrative: G&A per BOE increased by 7% in the nine months ended September 30, 2007 compared to the same period in the prior year due to additional staffing and higher overall compensation costs associated with our growth activities.

· Interest expense: Our outstanding borrowings, including our senior unsecured money market line of credit and senior subordinated notes, was approximately $440 million at September 30, 2007 compared to approximately $330 million at September 30, 2006, respectively. Our average borrowings increased since September 30, 2006 primarily due to acquisitions.

Estimated 2008 Capital Budget, Production Volume, and Oil and Gas Operating, G&A and Interest Expenses. We are in the process of determining our 2008 capital budget. Excluding any changes that may be impacted by ongoing business development activities and ultimate realized commodity prices, we are targeting our capital expenditures between $250 million and $300 million. Our goal is to maintain our total capital expenditures (excluding acquisitions) within our cash flow from operations, which is primarily determined by our realized commodity sales prices and production volume. With the implementation of this capital budget, we estimate our 2008 production volume will range between 29,500 BOE/D and 31,000 BOE/D. Based on WTI of $60 and NYMEX HH of $7.50 MMBtu, we expect our expenses to be within the following ranges:

		Anticipated range in 2008 per BOE
Operating costs-oil and gas production *(1)*	$	15.50 to 16.50
Production taxes		1.50 to 2.00
DD&A		9.00 to 10.00
G&A		3.75 to 4.25
Interest expense		1.50 to 2.00
Total	$	31.25 to 34.75

(1) We expect operating costs to increase in 2008 as compared to 2007 due to higher projected natural gas costs.

Income Taxes. See Note 5 to the unaudited condensed financial statements. We estimate our effective tax rate of 38% to 39% will be similar in 2007 as compared to 2006, and anticipate a similar effective tax rate in 2008. We experienced an effective tax rate in the three months ended September 30, 2007 of 36%, which is in line with our projections. The decrease in the effective tax rate for the third quarter 2007 was principally due to the closure of certain tax issues for prior years. The effective tax rate was 39% for the nine months ending September 30, 2006 and 2007. Our rate differs from a statutory rate, primarily due to state income taxes. For the nine months ending September 30, we recognized a net benefit of approximately $.7 million to the statement of income due to the closure of the 2003 federal tax year and additional FIN 48 accruals including interest.

Development, Exploitation and Exploration Activity. We drilled 99 gross (83 net) wells during the third quarter of 2007, realizing a success rate of 97 percent. Management is closely monitoring the capital development program in relation to estimated cash flows and expects to expend capital of approximately $275 million to $285 million, excluding acquisitions, during 2007. As of September 30, 2007, we have five rigs drilling on our properties under long-term contracts and have one more rig scheduled to begin in the fourth quarter of 2007.

Drilling Activity. The following table sets forth certain information regarding drilling activities (including operated and non-operated wells):

	Three months ended September 30, 2007		Nine months ended September 30, 2007	
	Gross Wells	Net Wells	Gross Wells	Net Wells
South Midway-Sunset	22	22	46	46
North Midway-Sunset (including diatomite)	5	5	16	16
Socal	11	11	78	78
Piceance	21	7	70	20
Uinta	8	8	36	34
DJ	32	30	100	65
Totals	**99**	**83**	**346**	**259**

The table above includes 3 gross wells (2.5 net wells) and 7 gross wells (4.6 net wells) dry holes drilled in the three months and nine months ended September 30, 2007, respectively.

Production

We have six asset teams as follows: South Midway-Sunset, North Midway-Sunset (including diatomite), Socal (including Poso Creek and Placerita), Piceance, Uinta and DJ.

South Midway-Sunset– During the three months ended September 30, 2007, production averaged approximately 9,300 Bbl/D compared to approximately 10,900 Bbl/D and 9,700 Bbl/D during the three month periods ended September 30, 2006 and June 30, 2007, respectively. We completed ten horizontal infill wells during the three months ended September 30, 2007 and we plan to drill one more horizontal infill well in the fourth quarter. Increased production from these activities is expected to slow the natural decline of these assets.

North Midway-Sunset (including diatomite)– Our North Midway-Sunset properties, including our diatomite project, are performing as expected. During the three months ended September 30, 2007, production from the area averaged approximately 2,100 Bbl/D up from approximately 1,100 Bbl/D and 2,100 Bbl/D during the three month periods ended September 30, 2006 and June 30, 2007, respectively.

Production from the diatomite project has now improved to over 1,100 Bbl/D through implementation of a modified steam injection plan and new well fracturing techniques. We expect production to continue to increase as we have begun the next 50-well development program in the fairway of the asset in the latter part of the third quarter. We will also begin installation of the necessary infrastructure, including steam generation equipment and fluid processing facilities.

Socal– During the three months ended September 30, 2007, production averaged approximately 4,300 Bbl/D up from approximately 3,400 Bbl/D and 4,000 Bbl/D during the three month periods ended September 30, 2006 and June 30, 2007, respectively.

Poso Creek continues to respond favorably to steam flood injection and our accelerated infill drilling program is performing solidly above plan. Production has increased to over 2,400 Bbl/D from less than 1,000 Bbl/D in the same period last year. This year we accelerated development of the asset by drilling over 70 wells to expand our thermally enhanced project and installed a third steam generator. We expect continued production improvement as these wells are cyclically steamed, the additional steam flood patterns are brought on line and the balance of the infill wells are drilled and completed.

Piceance – During the third quarter, production from the Piceance averaged 11.5 MMcf/D, an increase of 40% over the second quarter. On the Berry operated wells, we completed 15 gross wells (8 net). An additional 12 wells (6 net) are forecasted to be drilled and connected by the end of the fourth quarter, and we anticipate production will approximate 15 MMcf/D for the fourth quarter of 2007.

We are currently running a three rig program and we expect to return to a four rig program as we high grade our rig fleet with the addition of another “fit for purpose” Piceance drilling rig. Significant progress was made in the third quarter in lowering the days required to drill wells on our Piceance asset. During the quarter our mesa wells drilled in the Piceance averaged 21 days from spud date to rig release with our most efficient well drilled at 15 days. We are targeting drilling days for our mesa locations at Garden Gulch to be 17 days and 25 days at North Parachute Ranch. We are confident that we can maintain this efficiency and expect improved economics as a result. We continue to expand the infrastructure needed to support our operations. We are pursuing opportunities to acquire additional firm transportation for future sales out of this region.

Uinta – Our 2007 capital is directed at additional Brundage Canyon 40-acre development wells, drilling the Ashley Forest extension to the south of Brundage Canyon, continued Lake Canyon assessment and drilling 20-acre infill wells in Brundage Canyon. During the third quarter, we drilled eight net wells in Brundage Canyon. Average daily production during the third quarter from all Uinta basin assets was approximately 5,900 net BOE/D. We continue to have one drilling rig operating in the basin. Our current oil marketing arrangements provide us the ability to sell all of our crude oil production in the Uinta basin.

Our fourth quarter drilling activity will focus on continued efforts to extend Brundage Canyon success south into the Ashley Forest and continue our assessment of Lake Canyon potential to the west of Brundage. In support of our plans, we have 15 approved drilling permits and a four well drilling commitment in Lake Canyon along with six approved permits in the Ashley Forest. Two Ashley Forest wells that were drilled in the second quarter of 2007 and five wells drilled in the third quarter of 2007 are providing encouraging initial oil production results.

DJ– Our third quarter activity in the DJ basin has focused on drilling 30 successful Niobrara development wells in Yuma County, Colorado. Average daily production in the DJ for the third quarter was 18.9 net MMcf/D. Berry’s Yuma County Niobrara projects provide sustainable and steady cash flow resulting from low capital development costs, modest production declines and long-life reserves.

Financial Condition, Liquidity and Capital Resources. Substantial capital is required to replace and grow reserves. We achieve reserve replacement and growth primarily through successful development and exploitation drilling and the acquisition of properties. Fluctuations in commodity prices have been the primary reason for short-term changes in our cash flow from operating activities. The net long-term growth in our cash flow from operating activities is the result of growth in production as affected by period to period fluctuations in commodity prices. In the second quarter of 2006, we revised our senior unsecured revolving credit facility to increase our maximum credit amount under the facility to $750 million and increased our current borrowing base to $500 million. In the second quarter of 2007, we increased our current borrowing base to $550 million. On October 24, 2006, we completed the sale of $200 million of ten year 8.25% senior subordinated notes and paid down our borrowings under our facility by $145 million.

As of September 30, 2007, we had total borrowings under the senior unsecured revolving credit facility and senior unsecured money market line of credit of $240 million and $200 million under our senior subordinated ten year notes.

Capital Expenditures. We establish a capital budget for each calendar year based on our development opportunities and the expected cash flow from operations for that year. Acquisitions are typically debt financed. We may revise our capital budget during the year as a result of acquisitions, drilling outcomes and/or changes in commodity prices that influence our decision to change capital expenditures to closely match operating cash flows. Excess cash generated from operations is expected to be applied toward capital expenditures, debt reduction or other corporate purposes.

Management is closely monitoring the capital development program in relation to estimated cash flows and expects to expend capital of approximately $275 million to $285 million, excluding acquisitions, during 2007. The capital development program may be revised due to realized commodity prices and price expectations, equipment availability, permitting and/or changes in our internal development plans. Our 2007 expenditures are directed toward developing reserves, increasing oil and gas production and exploitation opportunities. For 2007, we plan to invest up to approximately 66% in our Rocky Mountain assets and 34% in our California assets. Capital expenditures, excluding property acquisitions, totaled $58.6 million and $209.2 million during the three months and the nine months ended September 30, 2007, respectively.

On May 11, 2007, we sold our non-core West Montalvo assets in Ventura County, California. The sale proceeds were approximately $61 million and we recognized approximately $52 million pretax gain on the sale, including post closing adjustments and we transferred the properties in the second quarter of 2007. Production from the property was approximately 700 BOE/D, which is less than 3% of current production and, as of December 31, 2006, the property had 7 million BOE of proved reserves which is less than 5% of the 2006 year end total of 150 million BOE. In addition, during the second quarter we paid the third and final installment of approximately $54 million for the North Parachute Ranch property located in the Piceance basin.

Working Capital and Cash Flows. Cash flow from operations is dependent upon the price of crude oil and natural gas and our ability to increase production and manage costs. Crude oil and gas sales in the three months ended September 30, 2007 were 5% higher than the three months ended June 30, 2007 resulting from an 9% increase in oil price (see graphs on page 13) and an 8% decrease in gas price (see graphs on page 13), partially offset by production declines in both oil and gas.

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

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

	September 30, 2007 (3Q07)	September 30, 2006 (3Q06)	3Q07 to 3Q06 Change	June 30, 2007 (2Q07)	3Q07 to 2Q07 Change
Average production (BOE/D)	26,873	26,423	2%	27,195	(1%)
Average oil and gas sales prices, per BOE after hedging	$ 47.93	$ 47.28	1%	$ 45.43	5%
Net cash provided by operating activities	$ 93	$ 101	(8%)	$ 80	16%
Working capital	$ (91)	$ (175)	(48%)	$ (49)	86%
Sales of oil and gas	$ 119	$ 116	3%	$ 113	5%
Total debt	$ 440	$ 330	32%	$ 475	(8%)
Capital expenditures, including acquisitions and deposits on acquisitions	$ 63	$ 148	(60%)	$ 131	(55%)
Dividends paid	$ 3.4	$ 4.2	(19%)	$ 3.4	-%

Contractual Obligations. Our contractual obligations as of September 30, 2007 are as follows (in millions):

		Total	2007	2008	2009	2010	2011	Thereafter
Total debt and interest	$	673.5 $	36.6 $	31.8 $	31.8 $	31.8 $	259.1 $	282.4
Abandonment obligations		32.3	.7	.9	1.0	1.0	1.0	27.7
Operating lease obligations		12.8	.4	1.7	1.4	1.4	1.4	6.5
Drilling and rig obligations		89.9	9.6	30.6	42.8	6.9	-	-
Firm natural gas transportation contracts		70.2	1.2	7.6	8.5	8.7	8.7	35.5
Total	$	878.7 $	48.5 $	72.6 $	85.5 $	49.8 $	270.2 $	352.1

Total debt and interest - Our credit facility borrowings and related interest of approximately 6.5% can be paid before its maturity date without significant penalty. Our 8.25% senior subordinated notes mature in November 2016, but are not redeemable until November 1, 2011 and are not redeemable without any premium until November 1, 2014. Our Line of Credit has related interest of 6%.

Operating leases - We lease corporate and field offices in California, Colorado and Texas. We lease an airplane for business travel under a ten year operating lease beginning December 2006.

Drilling obligation - We intend to participate in the drilling of over 16 wells on our Lake Canyon prospect over the four year contract, which began in 2006. Our minimum expenditure obligation under our exploration and development agreement is $9.6 million. Also included above, under our June 2006 joint venture agreement in the Piceance basin, we must drill 120 wells by 2010 to avoid penalties of $.2 million per well or a maximum of $24 million.

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

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

On February 27, 2007, we entered into a six year multi-staged crude oil sales contract with a subsidiary of Holly for a portion of our Uinta basin crude oil. Under the agreement, Holly began purchasing 3,200 Bbl/D beginning July 1, 2007. Upon completion of their Woods Cross refinery expansion in Salt Lake City, which is expected in late 2008, Holly will increase their total purchased volumes to 5,000 Bbl/D through June 30, 2013. During the term of the contract, the minimum number of delivered units (“base daily volume”) is 3,200 Bbl/D increasing to 5,000 Bbl/D upon the certified completion of the refinery upgrade. Holly may, but is not obligated to, purchase volumes in excess of the base daily volumes upon proper notification by us.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

As discussed in Note 3 to the unaudited condensed financial statements, to minimize the effect of a downturn in oil and gas prices and protect our profitability and the economics of our development plans, from time to time we enter into crude oil and natural gas hedge contracts. The terms of contracts depend on various factors, including management's view of future crude oil and natural gas prices, acquisition economics on purchased assets and our future financial commitments. This price hedging program is designed to moderate the effects of a severe crude oil and natural gas price downturn while allowing us to participate in any commodity price increases. In California, we benefit from lower natural gas pricing as we are a consumer of natural gas in our operations and elsewhere, we benefit from higher natural gas pricing. We have hedged, and may hedge in the future, both natural gas purchases and sales as determined appropriate by management. Management regularly monitors the crude oil and natural gas markets and our financial commitments to determine if, when, and at what level some form of crude oil and/or natural gas hedging and/or basis adjustments or other price protection is appropriate in accordance with policy established by our board of directors.

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

The following table summarizes our hedge position as of September 30, 2007:

Term	Average Barrels Per Day	Floor/Ceiling Prices	Term	Average MMBtu Per Day	Floor/Ceiling Prices
Crude Oil Sales (NYMEX WTI) Collars			**Natural Gas Sales (NYMEX HH) Collars**		
4th Quarter 2007	1,000	\$70.00 / \$75.85	4th Quarter 2007	15,000	\$8.00 / \$11.39
4th Quarter 2007	8,000	\$47.50 / \$70.00	1st Quarter 2008	16,000	\$8.00 / \$15.65
Full year 2008	10,000	\$47.50 / \$70.00	2nd Quarter 2008	17,000	\$7.50 / \$8.40
Full year 2008	1,000	\$70.00 / \$76.70	3rd Quarter 2008	19,000	\$7.50 / \$8.50
Full year 2009	10,000	\$47.50 / \$70.00	4th Quarter 2008	21,000	\$8.00 / \$9.50
Full year 2010	1,000	\$60.00 / \$80.00			
Full year 2010	1,000	\$55.00 / \$76.20			
Full year 2010	1,000	\$55.00 / \$77.75			
Full year 2010	1,000	\$55.00 / \$77.70			
Full year 2010	1,000	\$55.00 / \$83.10			
Full year 2010	1,000	\$60.00 / \$75.00			
Full year 2010	1,000	\$65.15 / \$75.00			
Full year 2010	1,000	\$65.50 / \$78.50			
			Natural Gas Sales (NYMEX HH TO CIG)		
Swaps		Price	**Basis Swaps**		Price
4th Quarter 2007	1,000	\$64.55	October 2007	15,000	\$1.63
4th Quarter 2007	2,000	\$60.00	November & December 2007	15,000	\$1.71
Full year 2008	260	\$74.00	1st Quarter 2008	16,000	\$1.74
Full year 2009	240	\$71.50	2nd Quarter 2008	17,000	\$1.43
			3rd Quarter 2008	19,000	\$1.40
			4th Quarter 2008	21,000	\$1.46

The collar strike prices will allow us to protect a significant portion of our future cash flow if 1) oil prices decline below our floor prices which range from $47.50 to $70.00 per barrel while still participating in any oil price increase up to the ceiling prices which range from $70.00 to $83.10 per barrel on the volumes indicated above, and if 2) gas prices, including our basis swaps, decline below our floor prices which range from $6.07 to $6.26 per MMBtu while still participating in any gas price increase, including our basis differentials, up to the ceiling prices, which range from $6.97 to $13.91 per MMBtu on the respective volumes. These hedges improve our financial flexibility by locking in significant revenues and cash flow upon a substantial decline in crude oil or natural gas prices, including certain basis differentials. It also allows us to develop our long-lived assets and pursue exploitation opportunities with greater confidence in the projected economic outcomes and allows us to borrow a higher amount under our senior unsecured revolving credit facility.

While we have designated our 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 crude oil price differential may be determined to be ineffective. Likewise, we may have some ineffectiveness in our natural gas hedges due to the movement of HH pricing as compared to actual sales points. If this occurs, the ineffective portion will directly impact net income rather than being reported as Other Comprehensive Income (Loss). If the differential were to change significantly, it is possible that our hedges, when marked-to-market, could have a material impact on earnings in any given quarter and, thus, add increased volatility to our 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.

We entered into derivative contracts (natural gas swaps and collar contracts) on March 1, 2006 that did not qualify for hedge accounting under SFAS 133 because the price index for the location in the derivative instrument did not correlate closely with the item being hedged. These contracts were recorded in the first quarter of 2006 at their fair value on the balance sheet and we recognized an unrealized net loss of approximately $4.8 million on the income statement under the caption “Commodity derivatives.” We entered into natural gas basis swaps on the same volumes and maturity dates as the previous hedges in May 2006 which allowed for these derivatives to be designated as cash flow hedges going forward, causing an unrealized net gain of $5.6 million to be recognized in the second quarter of 2006. The difference of $.8 million was recorded in other comprehensive income at the date the hedges were designated.

The related cash flow impact of all of our derivative activities are reflected as cash flows from operating activities. Irrespective of the unrealized gains reflected in Other Comprehensive Income (Loss), the ultimate impact to net income over the life of the hedges will reflect the actual settlement values. All of these hedges have historically been deemed to be cash flow hedges with the marked-to-market valuations provided by external sources, based on prices that are actually quoted.

Based on average NYMEX futures prices as of September 30, 2007, (WTI $74.79; HH $7.76) for the term of our hedges we would expect to make pretax future cash payments or to receive payments over the remaining term of our crude oil and natural gas hedges in place as follows:

	September 30, 2007 NYMEX Futures	Impact of percent change in futures prices on pretax future cash (payments) and receipts			
		-20%	-10%	+ 10%	+ 20%
Average WTI Futures Price (2007 – 2010)	$ 74.79	$ 59.83	$ 67.31	$ 82.27	$ 89.74
Average HH Futures Price (2007 – 2008)	7.76	6.21	6.99	8.54	9.32
Crude Oil gain/(loss) (in millions)	$ (53.2)	$ 12.2	$ (4.3)	$ (127.1)	$ (214.7)
Natural Gas gain/(loss) (in millions)	4.4	15.4	9.2	3.3	(.5)
Total	$ (48.8)	$ 27.6	$ 4.9	$ (123.8)	$ (215.2)
Net pretax future cash (payments) and receipts by year (in millions) based on average price in each year:					
2007 (WTI $80.59; HH $7.00)	$ (9.1)	$ 6.0	$ .4	$ (18.8)	$ (28.2)
2008 (WTI $76.94; HH $7.95)	(25.8)	13.4	3.7	(57.5)	(92.5)
2009 (WTI $73.75)	(13.9)	1.1	.4	(41.4)	(69.0)
2010 (WTI $72.23)	-	7.1	.4	(6.1)	(25.5)
Total	$ (48.8)	$ 27.6	$ 4.9	$ (123.8)	$ (215.2)

Interest Rates. Our exposure to changes in interest rates results primarily from long-term debt. On October 24, 2006, we issued $200 million of 8.25% senior subordinated notes due 2016 in a public offering. Total long-term debt outstanding including our short-term Line of Credit, at September 30, 2007 was $440 million. Interest on amounts borrowed under our revolving credit facility is charged at LIBOR plus 1.0% to 1.75%, with the exception of the $100 million of principal for which we have hedged the interest rate at approximately 5.5% plus the senior unsecured revolving credit facility's margin through June 30, 2011. Based on September 30, 2007 credit facility borrowings, a 1% change in interest rates would have an annual $.9 million after tax impact on our financial statements.

Item 4. Controls and Procedures

As of September 30, 2007, we have carried out an evaluation under the supervision of, and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15 under the Securities Exchange Act of 1934, as amended.

Based on their evaluation as of September 30, 2007, our Chief Executive Officer and Chief Financial Officer have concluded that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e)) under the Securities Exchange Act of 1934) are effective to ensure that the information required to be disclosed in the reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms.

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

Forward Looking Statements

"Safe harbor under the Private Securities Litigation Reform Act of 1995:" Any statements in this Form 10-Q that are not historical facts are forward-looking statements that involve risks and uncertainties. Words such as "plan," "will," "intend," "continue," "target(s)," "expect," "achieve," "future," "may," "could," "goal(s),", "forecast," "anticipate," or other comparable words or phrases, or the negative of those words, and other words of similar meaning indicate forward-looking statements and important factors which could affect actual results including that the master limited partnership will not be formed, will not complete an offering of securities and will not complete such actions on the timetable indicated. Forward-looking statements are made based on management's current expectations and beliefs concerning future developments and their potential effects upon Berry Petroleum Company. These items are discussed at length in Part I, Item 1A on page 15 of our Form 10-K filed with the Securities and Exchange Commission, under the heading "Risk Factors" and all material changes are updated in Part II, Item 1A within this 10-Q.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

None.

Item 1A. Risk Factors

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

None.

Item 5. Other Information

None.

Item 6. Exhibits

Exhibit No.	Description of Exhibit
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.

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/ Shawn M. Canaday
Shawn M. Canaday
Controller
(Principal Accounting Officer)

Date: October 31, 2007

Exhibit 31.1

Certification of Chief Executive Officer

Pursuant to Section 302 of Sarbanes Oxley Act of 2002

I, Robert F. Heinemann, President, Chief Executive Officer, and Director certify that:

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

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

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

4. The Company's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a - 15(e) and 15d - (e) and internal control over financial reporting (as defined in Exchange Act Rules 13a - 15(f) and 15d - 15(f)) for the Company and have:

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

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designated under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the Company's disclosure controls and procedures and presented in this report our conclusions abut the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the Company's internal control over financial reporting that occurred during the Company's most recent fiscal quarter that has materially affected or is reasonably likely to materially affect the Company's internal control over financial reporting.

5. The Company's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Company's auditors and the audit committee of the Company's board of directors:

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

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

/s/ Robert F. Heinemann

Robert F. Heinemann

October 31, 2007

President, Chief Executive Officer, and Director

Exhibit 31.2

Certification of Chief Financial Officer

Pursuant to Section 302 of Sarbanes Oxley Act of 2002

I, Ralph J. Goehring, Executive Vice President and Chief Financial Officer, certify that:

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

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

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

4. The Company’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a - 15(e) and 15d - (e) and internal control over financial reporting (as defined in Exchange Act Rules 13a - 15(f) and 15d - 15(f)) for the Company and have:

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

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designated under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the Company’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the Company’s internal control over financial reporting that occurred during the Company’s most recent fiscal quarter that has materially affected or is reasonably likely to materially affect the Company’s internal control over financial reporting;

5. The Company’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting to the Company’s auditors and the audit committee of the Company’s board of directors:

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

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

/s/ Ralph J. Goehring

Ralph J. Goehring
Executive Vice President and Chief Financial Officer

October 31, 2007

Exhibit 32.1

Certification of Chief Executive Officer

Pursuant to Section 906 of Sarbanes Oxley Act of 2002

In Connection with the Quarterly Report of Berry Petroleum Company (the “Company”) on Form 10-Q for the period ending September 30, 2007 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Robert F. Heinemann, President, Chief Executive Officer and Director of the Company, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to 906 of the Sarbanes-Oxley Act of 2002, that:

1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

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

/s/ Robert F. Heinemann

Robert F. Heinemann
President, Chief Executive Officer and Director

October 31, 2007

<u>Exhibit 32.2</u>

Certification of Chief Financial Officer

Pursuant to Section 906 of Sarbanes Oxley Act of 2002

In Connection with the Quarterly Report of Berry Petroleum Company (the "Company") on Form 10-Q for the period ending September 30, 2007 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Ralph J. Goehring, Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to 906 of the Sarbanes-Oxley Act of 2002, that:

1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

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

/s/ Ralph J. Goehring

Ralph J. Goehring

October 31, 2007

Executive Vice President and Chief Financial Officer