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, 2009**
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)

1999 Broadway, Suite 3700
Denver, Colorado 80202
(Address of principal executive offices, including zip code)

Registrant's telephone number, including area code: **(303) 999-4400**

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 has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). YES o NO o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.
Large accelerated filerx Accelerated filero Non-accelerated filero Smaller reporting companyo

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 19, 2009, the registrant had 42,860,540 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 19, 2009 all of which is held by an affiliate of the registrant.

BERRY PETROLEUM COMPANY
THIRD QUARTER 2009 FORM 10-Q
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BERRY PETROLEUM COMPANY
Unaudited Condensed Balance Sheets
(In Thousands, Except Share Information)

	September 30, 2009	December 31, 2008
ASSETS		
Current assets:		
Cash and cash equivalents	$ 975	$ 240
Short-term investments	67	66
Accounts receivable, net of allowance for doubtful accounts of $38,508 and $38,511	67,726	65,873
Fair value of derivatives	30,460	111,886
Crude oil inventory	1,393	-
Prepaid expenses and other	8,780	11,015
Total current assets	109,401	189,080
Oil and gas properties (successful efforts basis), buildings and equipment, net	2,096,897	2,254,425
Fair value of derivatives	1,002	79,696
Other assets	33,245	19,182
	$ 2,240,545	$ 2,542,383
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 53,755	$ 119,221
Revenue and royalties payable	14,325	34,416
Accrued liabilities	45,630	34,566
Line of credit	12,500	25,300
Income taxes payable	498	187
Fair value of derivatives	21,441	1,445
Deferred income taxes	892	45,490
Total current liabilities	149,041	260,625
Long-term liabilities:		
Deferred income taxes	250,045	270,323
Senior secured revolving credit facility	365,000	931,800
8 ¼ % Senior subordinated notes due 2016	200,000	200,000
10 ¼ % Senior notes due 2014, net of unamortized discount of $14,075 and $0, respectively	435,925	-
Abandonment obligation	43,229	41,967
Other long-term liabilities	20,828	5,921
Fair value of derivatives	41,316	4,203
Total long-term liabilities	1,356,343	1,454,214
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; 42,855,902 shares issued and outstanding (42,782,365 in 2008)	427	427
Class B Stock, 3,000,000 shares authorized; 1,797,784 shares issued and outstanding in 2009 and 2008 (liquidation preference of $899)	18	18
Capital in excess of par value	87,398	79,653
Accumulated other comprehensive (loss) income	(17,210)	113,697
Retained earnings	664,528	633,749
Total shareholders' equity	735,161	827,544
	$ 2,240,545	$ 2,542,383

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

BERRY PETROLEUM COMPANY
Unaudited Condensed Statements of Operations
Three Months Ended September 30, 2009 and 2008
(In Thousands, Except Per Share Data)

	Three months ended September 30, 2009	2008
REVENUES AND OTHER INCOME ITEMS		
Sales of oil and gas	$ 127,455	$ 193,890
Sales of electricity	9,137	18,317
Gas marketing	5,217	13,284
Gain on derivatives	531	701
Gain on sale of assets	828	95
Interest and other income, net	287	747
	143,455	227,034
EXPENSES		
Operating costs - oil and gas production	39,195	52,486
Operating costs - electricity generation	6,892	13,706
Production taxes	3,874	8,912
Depreciation, depletion & amortization - oil and gas production	33,502	37,354
Depreciation, depletion & amortization - electricity generation	951	646
Gas marketing	4,633	12,034
General and administrative	10,686	14,251
Interest expense	14,562	8,031
Extinguishment of debt	329	-
Dry hole, abandonment, impairment and exploration	69	1,488
	114,693	148,908
Income before income taxes	28,762	78,126
Provision for income taxes	10,423	28,511
Income from continuing operations	18,339	49,615
Income from discontinued operations, net of taxes	668	3,733
Net income	$ 19,007	$ 53,348
Basic net income from continuing operations per share	$ 0.41	$ 1.10
Basic net income from discontinued operations per share	$ 0.01	$ 0.08
Basic net income per share	$ 0.42	$ 1.18
Diluted net income from continuing operations per share	$ 0.40	$ 1.08
Diluted netincome from discontinued operations per share	$ 0.01	$ 0.08
Diluted net income per share	$ 0.41	$ 1.16
Dividends per share	$ 0.075	$ 0.075

Unaudited Condensed Statements of Comprehensive Income
Three Months Ended September 30, 2009 and 2008
(In Thousands)

Net income	$ 19,007	$ 53,348
Unrealized gains (losses) on derivatives, net of income taxes (benefits) of ($345) and $144,881, respectively	(563)	225,693
Reclassification of realized (losses) gains on derivatives included in net income, net of income taxes (benefits) of ($279) and $18,745, respectively	(454)	30,584
Comprehensive income	$ 17,990	$ 309,625

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

BERRY PETROLEUM COMPANY
Unaudited Condensed Statements of Operations
Nine Months Ended September 30, 2009 and 2008
(In Thousands, Except Per Share Data)

	Nine months ended September 30, 2009	2008
REVENUES AND OTHER INCOME ITEMS		
Sales of oil and gas	$ 374,117	$ 514,578
Sales of electricity	26,032	51,223
Gas marketing	17,646	28,046
Gain (loss) on derivatives	6,565	(27)
Gain on sale of assets	828	510
Interest and other income, net	1,375	2,509
	426,563	596,839
EXPENSES		
Operating costs - oil and gas production	111,317	144,158
Operating costs - electricity generation	22,071	45,620
Production taxes	14,411	20,663
Depreciation, depletion & amortization - oil and gas production	104,271	87,462
Depreciation, depletion & amortization - electricity generation	2,938	1,991
Gas marketing	16,149	26,087
General and administrative	37,143	36,312
Interest expense	35,201	14,910
Extinguishment of debt	10,823	-
Dry hole, abandonment, impairment and exploration	209	7,396
	354,533	384,599
Income before income taxes	72,030	212,240
Provision for income taxes	24,681	79,377
Income from continuing operations	47,349	132,863
(Loss) income from discontinued operations, net of taxes	(6,323)	12,657
Net income	$ 41,026	$ 145,520
Basic net income from continuing operations per share	$ 1.04	$ 2.95
Basic net (loss) income from discontinued operations per share	$ (0.14)	$ 0.28
Basic net income per share	$ 0.90	$ 3.23
Diluted net income from continuing operations per share	$ 1.03	$ 2.90
Diluted net (loss) income from discontinued operations per share	$ (0.14)	$ 0.28
Diluted net income per share	$ 0.89	$ 3.18
Dividends per share	$ 0.225	$ 0.225

Unaudited Condensed Statements of Comprehensive Income
Nine Months Ended September 30, 2009 and 2008
(In Thousands)

	2009	2008
Net income	$ 41,026	$ 145,520
Unrealized gains (losses) on derivatives, net of income taxes (benefits) of $104,173 and $58,260, respectively	169,966	(95,055)
Reclassification of realized (losses)gains on derivatives included in net income, net of income taxes (benefits) of ($23,940) and $52,341, respectively	(39,059)	85,399
Comprehensive income	$ 171,933	$ 135,864

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

BERRY PETROLEUM COMPANY
Unaudited Condensed Statements of Cash Flows
Nine Months Ended September 30, 2009 and 2008
(In Thousands)

	Nine months ended September 30, 2009	2008
Cash flows from operating activities:		
Net income	$ 41,026	$ 145,520
Depreciation, depletion and amortization	109,397	98,579
Extinguishment of debt	10,823	-
Dry hole and impairment	9,643	6,858
Commodity derivatives	4,796	(8)
Stock-based compensation expense	7,054	6,653
Deferred income taxes	13,546	76,502
Loss (gain) on sale of oil and gas properties	79	(510)
Other, net	(362)	(1,500)
Cash paid for abandonment	(293)	(3,957)
Change in book overdraft	(20,199)	3,935
Increase in current assets other than cash and cash equivalents	(9,828)	(35,361)
(Decrease) increase in current liabilities other than book overdraft, line of credit and fair value of derivatives	(17,303)	34,537
Net cash provided by operating activities	148,379	331,248
Cash flows from investing activities:		
Exploration and development of oil and gas properties	(93,592)	(302,266)
Property acquisitions	(11,904)	(667,030)
Additions to vehicles, drilling rigs and other fixed assets	(1,044)	(4,146)
Proceeds from sale of assets	139,796	2,038
Capitalized interest	(21,145)	(15,461)
Net cash provided by (used in) investing activities	12,111	(986,865)
Cash flows from financing activities:		
Proceeds from line of credit	323,100	308,000
Payments on line of credit	(335,900)	(303,000)
Proceeds from issuance of long-term debt	1,099,238	1,481,300
Payments on long-term debt	(1,231,076)	(817,000)
Debt issuance cost	(23,857)	(8,353)
Proceeds from financing obligation	18,295	-
Dividends paid	(10,247)	(10,084)
Proceeds from stock option exercises	601	2,834
Excess tax benefit and other	91	1,663
Net cash (used in) provided by financing activities	(159,755)	655,360
Net increase (decrease) in cash and cash equivalents	735	(257)
Cash and cash equivalents at beginning of year	240	316
Cash and cash equivalents at end of period	$ 975	$ 59

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

Berry Petroleum Company
Notes to the Unaudited Condensed Financial Statements

1. General

All adjustments which are, in the opinion of management, necessary for a fair statement of Berry Petroleum Company's (the Company) financial position at September 30, 2009 and December 31, 2008 and results of operations and other comprehensive income for the three and nine months ended September 30, 2009 and 2008, and its cash flows for the nine months ended September 30, 2009 and 2008 have been included. All such adjustments, except as described below, 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, 2008 financial statements, except that the DJ basin operations are now accounted for as discontinued operations as a result of the 2009 sale. The audited financial statements for the three years ended December 31, 2008 and at December 31, 2007 and 2008 included in our Form 8-K filed on August 11, 2009, which give effect to the classification of the DJ Basin assets as discontinued operations, 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, 2009 and December 31, 2008 is $11.6 million and $31.8 million, respectively, representing outstanding checks in excess of the bank balance (book overdraft).

2. Recent Accounting Developments

In December 2007, the Financial Accounting Standards Board (FASB) issued authoritative guidance to establish accounting and reporting standards for the noncontrolling interests in a subsidiary (formerly called minority interests) and for the deconsolidation of a subsidiary. The adoption of this authoritative guidance did not have a material impact on our financial statements.

In March 2008, the FASB issued authoritative guidance, which changes the disclosure requirements for derivative instruments and hedging activities. Expanded disclosures are required to provide information about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. The adoption of this authoritative guidance did not have a material impact on our financial statements. We have expanded our disclosures accordingly. See Note 4 to the unaudited financial statements.

In June 2008, the FASB issued authoritative guidance, which clarifies that share-based payment awards that entitle their holders to receive nonforfeitable dividends before vesting should be considered participating securities. As participating securities, these instruments should be included in the earnings allocation in computing basic earnings per share under the two-class method described in authoritative guidance. All prior period earnings per share data presented shall be adjusted retrospectively to conform with the provisions of this guidance. This guidance is effective for financial statements issued for fiscal years beginning after December 15, 2008 and interim periods within those years. The adoption of this authoritative guidance did not have a material impact on our financial statements. See Note 12 to the unaudited financial statements.

In December 2008, the Securities and Exchange Commission adopted revisions to its oil and gas disclosure requirements that are intended to align them with current practices and changes in technology. Among other things, the amendments will: replace the single-day year-end pricing assumption with a twelve-month average pricing assumption; permit the disclosure of probable and possible reserves; allow the use of certain technologies to establish reserves; require the disclosure of the qualifications of the technical person primarily responsible for preparing the reserves estimates or conducting a reserves audit; require the filing of the independent reserve engineers' summary report; and permit the disclosure of a reserves sensitivity analysis table to illustrate the impact of different price and/or cost assumptions on reserves. These amendments are effective for registration statements filed on or after January 1, 2010, and for annual reports on Form 10-K for fiscal years ending on December 31, 2009, with early adoption prohibited. The Company is currently evaluating the impact that the adoption of this pronouncement will have on the Company's financial position, results of operations, and disclosures.

In April 2009, the FASB issued authoritative guidance which requires disclosures about the fair value of financial instruments for interim reporting periods as well as in annual financial statements. The adoption of this authoritative guidance did not have a material impact on our financial statements. We have expanded our disclosures accordingly. See Note 3 to the unaudited financial statements.

Berry Petroleum Company
Notes to the Unaudited Condensed Financial Statements

In May 2009, the FASB issued authoritative guidance, which establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. We implemented this guidance during the second quarter of 2009 and we expanded our disclosures accordingly. See Note 15 to the unaudited financial statements.

In June 2009, the FASB approved the FASB Accounting Standards Codification (ASC), which after its effective date of July 1, 2009 is the single source of authoritative, nongovernmental U.S. Generally Accepted Accounting Principles (GAAP). The Codification reorganizes all previous U.S. GAAP pronouncements into roughly 90 accounting topics and displays all topics using a consistent structure. All existing standards that were used to create the Codification are now superseded, replacing the previous references to specific Statements of Financial Accounting Standards (SFAS) with numbers used in the Codification's structural organization. The adoption of this authoritative guidance did not have a material impact on our financial statements. We have updated our disclosures accordingly.

3. Fair Value Measurements

In September 2006, the Financial Accounting Standards Board (FASB) issued authoritative guidance that clarifies the definition of fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements. We adopted the authoritative guidance as of January 1, 2008 for all financial and nonfinancial assets and liabilities recognized or disclosed at fair value on a recurring basis. We have also adopted the authoritative guidance as it relates to all nonfinancial assets and liabilities that are not recognized or disclosed on a recurring basis as of January 1, 2009 pursuant to the authoritative guidance issued by the FASB in February 2008. The adoption of the authoritative guidance did not have a material impact on our financial statements.

The authoritative guidance establishes a three-tier fair value hierarchy, which prioritizes the inputs used to measure fair value. These tiers include: Level 1, defined as unadjusted quoted prices in active markets for identical assets or liabilities; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs for use when little or no market data exists, therefore requiring an entity to develop its own assumptions.

A financial instrument's categorization within the valuation hierarchy is based upon the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the classification of assets and liabilities within the fair value hierarchy. Our oil swaps, natural gas swaps and interest rate swaps are valued using internal models which are based on active market data and are classified within Level 2 of the valuation hierarchy. The observable inputs include underlying commodity and interest rate levels and quoted prices of these instruments on actively traded markets. Derivatives that are valued based upon models with significant unobservable market inputs (primarily volatility), and that are normally traded less actively are classified within Level 3 of the valuation hierarchy. Level 3 derivatives include oil collars, natural gas collars and natural gas basis swaps.

The following tables sets forth by level within the fair value hierarchy the Company's assets and liabilities that were measured at fair value on a recurring basis as of September 30, 2009 and December 31, 2008.

September 30, 2009 (in millions)	Total carrying value on the condensed Balance Sheet	Level 2	Level 3
Commodity derivative asset (liability)	$ (21.5)	$ (54.1)	$ 32.6
Interest rate swap asset (liability)	(9.8)	(9.8)	-
Total fair value asset (liability)	$ (31.3)	$ (63.9)	$ 32.6

December 31, 2008 (in millions)	Total carrying value on the condensed Balance Sheet	Level 2	Level 3
Commodity derivative asset (liability)	$ 198.4	$ 25.9	$ 172.5
Interest rate swap asset (liability)	(12.5)	(12.5)	-
Total fair value asset (liability)	$ 185.9	$ 13.4	$ 172.5

Berry Petroleum Company
Notes to the Unaudited Condensed Financial Statements

Changes in Level 3 fair value measurements

The following table sets forth a reconciliation of changes in the fair value of financial instruments classified as Level 3 in the fair value hierarchy:

	Three months ended September 30,		Nine months ended September 30,	
(in millions)	2009	2008	2009	2008
Fair value of Level 3 derivative assets, beginning of period	$ 43.1	$ 569.6	$ 172.5	$ 194.3
Total realized and unrealized losses included in Gain (loss) on derivatives	(1.0)	(0.6)	(1.7)	0.2
Purchases, sales and settlements, net	(9.5)	(360.1)	(141.6)	14.4
Transfers in and/or out of Level 3	-	-	3.4	-
Fair value of Level 3 derivative assets, September 30, 2009	$ 32.6	$ 208.9	$ 32.6	$ 208.9
Total unrealized gains (losses) included in income related to financial assets and liabilities on the condensed balance sheet at September 30, 2009	$ (0.7)	$ -	$ (1.3)	$ -

The $3.4 million of transfers into Level 3 for the nine months ended September 30, 2009 represent crude oil collars that were converted to crude oil swaps during the first quarter of 2009.

Fair Market Value of Financial Instruments

The Company used various assumptions and methods in estimating the fair values of its financial instruments. The carrying amounts of cash and cash equivalents and accounts receivable approximated their fair value due to the short-term maturity of these instruments. The carrying amount of the Company's credit facilities approximated fair value, because the interest rates on the credit facilities are variable. The fair values of our 8 ¼ % senior subordinated notes due 2016 and our 10 ¼ % senior notes due 2014 were estimated based on quoted market prices. The fair values of the Company's derivative instruments and other investments are discussed above.

(in millions)	Carrying Amount	Estimated Fair Value
Line of credit	$ 13	$ 13
Senior secured revolving credit facility	365	365
8 ¼ % Senior subordinated notes due 2016	200	191
10 ¼ % Senior notes due 2014	436	479
	$ 1,014	$ 1,048

4. Hedging

To minimize the effect of a downturn in oil and gas prices and protect our profitability and the economics of our development plans, we enter into crude oil and natural gas hedge contracts from time to time. 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 some commodity price increases. We benefit from lower natural gas pricing as we are a consumer of natural gas in our California operations. In the Rocky Mountains and East Texas 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 also utilize interest rate derivatives to protect against changes in interest rates on our floating rate debt.

Berry Petroleum Company
Notes to the Unaudited Condensed Financial Statements

The related cash flow impact of all of our hedges is reflected in cash flows from operating activities. At September 30, 2009, our net fair value derivative liability was $31.3 million as compared to a net fair value asset of $185.9 million at December 31, 2008 which reflects changes in commodity prices and interest rates. Based on NYMEX strip pricing as of September 30, 2009, we expect to receive hedge payments under the existing derivatives of $14.7 million during the next twelve months. At September 30, 2009, "Accumulated Other Comprehensive Income (Loss)" ("AOCL") consisted of $17.2 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, 2009. Deferred net losses recorded in AOCL at September 30, 2009 and subsequent mark-to-market changes in the underlying hedging contracts are expected to be reclassified to earnings in the same period that the forecasted transaction impacts earnings.

We present our derivative assets and liabilities on our Condensed Balance Sheets on a net basis. We net derivative assets and liabilities whenever we have a legally enforceable master netting agreement with a counterparty to a derivative contract. We use these agreements to manage and reduce our potential counterparty credit risk.

The following table disaggregates our net derivative assets and liabilities into gross components on a contract-by-contract basis before giving effect to master netting arrangements. Finally, we identify the line items on our Condensed Balance Sheets in which these fair value amounts are included. The gross asset and liability values in the table below are segregated between those derivatives designated in qualifying hedge accounting relationships and those not designated in hedge accounting relationships. We use the end of period accounting designation to determine the classification for each derivative position.

	As of September 30, 2009			
	Derivative Assets		Derivative Liabilities	
(in millions)	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Commodity – Oil	Current assets	$ 31.7	Current liability	$ 14.5
Commodity – Natural Gas	Current assets	1.4		
Commodity – Oil	Long term assets	1.0	Long term liabilities	37.3
Commodity – Natural Gas			Long term liabilities	0.3
Commodity – Natural Gas	Current liability	0.7		
Interest rate contracts			Current assets	2.7
Interest rate contracts			Current liabilities	3.6
Interest rate contracts			Long term liabilities	3.4
Total derivatives designated as hedging instruments under authoritative guidance		34.8		61.8
Commodity – Oil		-	Current liabilities	3.1
Commodity – Natural Gas		-	Current liabilities	0.9
Commodity – Natural Gas		-	Long term liabilities	0.3
Total derivatives not designated as hedging instruments under authoritative guidance		-		4.3
Total Derivatives		$ 34.8		$ 66.1

Berry Petroleum Company
Notes to the Unaudited Condensed Financial Statements

The tables below summarize the Statement of Operations impacts of our derivative instruments for the three and nine months ending September 30,2009 (in millions):

Derivatives cash flow hedging relationships	Amount of gain (loss) Recognized in AOCI on Derivative (Effective portion)	Location of Gain (Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Gain (Loss) Reclassified from AOCI into Income (Effective Portion)	Location of Gain (loss) Recognized in Income of Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)	Amount of Gain (loss) Recognized in Income of Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)
	Three Months Ended September 30, 2009		Three Months Ended September 30, 2009		Three Months Ended September 30, 2009
Commodity - Oil	$ (2.5)	Sales of oil and gas	$ 1.0	Sales of oil and gas	$ -
Commodity - Natural Gas	1.8	Sales of oil and gas	0.6	Gain (loss) on derivatives	(0.6)
Interest rate	0.7	Interest expense	(1.1)	Gain (loss) on derivatives	0.1
Total	$ -		$ 0.5		$ (0.5)

Derivatives cash flow hedging relationships	Amount of gain (loss) Recognized in AOCI on Derivative (Effective portion)	Location of Gain (Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Gain (Loss) Reclassified from AOCI into Income (Effective Portion)	Location of Gain (loss) Recognized in Income of Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)	Amount of Gain (loss) Recognized in Income of Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)
	Nine Months Ended September 30, 2009		Nine Months Ended September 30, 2009		Nine Months Ended September 30, 2009
Commodity - Oil	$ 161.4	Sales of oil and gas	$ 36.4	Sales of oil and gas	$ -
Commodity - Natural Gas	13.1	Sales of oil and gas	5.4	Gain (loss) on derivatives	14.0
Interest rate	(3.9)	Interest expense	(2.7)	Gain (loss) on derivatives	(0.2)
Total	$ 170.6		$ 39.1		$ 13.8

Amount of Gain or (Loss) Recognized in Income on Derivatives not designated as Hedging Instruments under authoritative guidance:

Derivatives not designated as Hedging Instruments under authoritative guidance	Location of Gain (Loss) Recognized in Income on Derivative	Amount of Gain (Loss) Recognized in Income on Derivatives not designated as Hedging Instruments under authoritative guidance	Amount of Gain (Loss) Recognized in Income on Derivatives not designated as Hedging Instruments under authoritative guidance
		Three months ended September 30, 2009	Nine months ended September 30, 2009
Commodity – Oil	Gain (loss) on derivatives	$ 1.6	(5.7)
Commodity - Natural Gas	Gain (loss) on derivatives	(0.5)	(1.5)
Commodity - Natural Gas	(Loss) income from discontinued operations, net of taxes	-	(0.5)
Total Derivatives		$ 1.1	(7.7)

We did not enter into any crude oil or natural gas hedges during the three months ended September 30, 2009.

During the first quarter of 2009, we converted oil collars for 6,000 Bbl/D for the full year 2010 into swaps for the same volumes with swap prices ranging from $61.00 to $64.80.

We generally utilize NYMEX WTI based derivatives to hedge cash flows from our California oil sales. Our oil sales contracts with multiple refiners are primarily based on the field posting prices. There is a high correlation between WTI and the field posting prices which allows us to utilize hedge accounting. As there is a ready market for our crude oil in California, we do not believe the loss of any particular contract impacts the probability that our hedged forecasted transactions will occur. We generally hedge our natural gas at the basis location that corresponds to the forecasted sale.

While we designate the majority of our hedges as cash flow hedges, we have not elected hedge accounting on certain of our crude oil and natural gas hedges. During the three and nine months ended September 30, 2009, we recorded $0.5 million and $6.6 million under the caption “Gain (loss) on derivatives” related to hedges for which we either did not elect hedge accounting or which no longer qualified for hedge accounting. In conjunction with the sale of the DJ basin assets, during the first quarter of 2009, we concluded that the forecasted transaction in certain of our hedging relationships was not probable of occurring. As such, we reclassified a gain of $14.3 million from accumulated other comprehensive income (loss) to the statement of operations under the caption “Gain (loss) on derivative.” Additionally, a portion of the change in fair value for hedges that we have designated as cash flow hedges may impact our income as our sales price is not perfectly correlated with our hedges. We recognized an unrealized net loss of $0.5 million and $0.4 million on the statement of operations under the caption “Gain (loss) on derivatives” for the three and nine months ended September 30, 2009, respectively, as a result of ineffectiveness. During the first quarter of 2009, we entered into natural gas derivatives on behalf of the purchaser of our DJ assets. We did not elect hedge accounting for these hedges and recorded an unrealized net loss of $0.5 million on the statement of operations under the caption “(Loss) income from discontinued operations, net of taxes.”

Our hedge contracts have been executed only with counterparties that are party to our senior secured revolving credit facility.

Neither we nor our counterparties are required to post collateral in connection with our derivative positions and netting agreements are in place with each of our counterparties allowing us to offset our commodity derivative asset and liability positions. The credit rating of each of these counterparties was AA-/Aa2, or better as of September 30, 2009. Our derivatives are held with a small number of counterparties and as of September 30, 2009, our largest four counterparties accounted for 90% of the value of our total derivative positions.

As of September 30, 2009, we had the following commodity hedges:

	2009	2010	2011	2012
Oil Bbl/D:	17,535	14,930	9,020	3,000
Natural Gas MMBtu/D:	14,000	14,000	5,000	5,000

5. Crude Oil Inventory

In May 2009, we entered into a sales agreement with a refiner for 1,500 barrels per day of production from our Poso Creek property for the months of May and June 2009. Under this agreement, we delivered approximately 100,000 barrels of oil to the refiner and received inventory of a slightly higher quality crude oil at the refinery. This transaction was accounted for as a non-monetary exchange and the amount was recorded in crude oil inventory. The refiner purchased 50,000 barrels from us during the third quarter of 2009 and the remaining balance in “Crude Oil Inventory” at September 30, 2009 reflects the cost of production, transportation costs and quality differentials for the remaining 50,000 barrels of inventory volume.

6. Asset Retirement Obligations

The following table summarizes the change in abandonment obligation for the nine months ended September 30, 2009 (in thousands):

Beginning balance at January 1, 2009	$ 41,967
Liabilities incurred	1,407
Liabilities settled	(3,044)
Revisions in estimated liabilities	-
Accretion expense	2,899
Ending balance at September 30, 2009	$ 43,229

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The asset retirement obligation ("ARO") reflects the estimated present value of the amount of dismantlement, removal, site reclamation and similar activities associated with our oil and gas properties. Inherent in the fair value calculation of the 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.

7. Acquisitions

During the nine months ended September 30, 2009, we completed acquisitions totaling $11.9 million. In June 2009, we acquired property near McKittrick, California, the deep rights to one of the leases in our Darco property in East Texas, and additional interests in our Piceance Garden Gulch assets.

8. Dispositions and Discontinued Operations

On July 17, 2009, we completed the financing of our East Texas gas gathering system for $18.4 million in cash. We entered into concurrent long-term gas gathering agreements for the East Texas production which contained an embedded lease. The transaction was treated as a financing obligation. Accordingly, the net book value of the property of $16.7 million will be depreciated over the remaining useful life of the asset and the cash received of $18.4 million was recorded as a financing obligation. A portion of future payments will be recorded as gathering expense, a portion as interest expense and the balance as a reduction in the financing obligation. There is no minimum payment required under these agreements.

On March 3, 2009, we entered into an agreement to sell our DJ basin assets and related hedges for $154 million before customary closing adjustments. The closing date of the sale of the assets was April 1, 2009. We recorded a pre-tax impairment loss of $9.6 million related to the sale, which is aggregated within the $6.3 million "(Loss) income from discontinued operations, net of taxes" on our statement of operations for the nine months ended September 30, 2009.

(Loss) income from discontinued operations, net of tax on our accompanying statements of operations is comprised of the following (in thousands):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
Oil and gas revenue	$ -	$ 13,972	$ 5,396	$ 43,111
Loss on sale of asset	(578)	-	(908)	-
Other revenue	-	350	623	1,441
Total Revenue	(578)	14,322	5,111	44,552
Operating expenses	-	3,552	2,576	8,694
Production taxes	-	761	195	2,458
DD&A	-	3,086	2,188	9,126
General and administrative	-	273	388	755
Interest expense	-	724	815	1,534
Commodity derivatives	-	-	484	-
Dry hole, abandonment, impairment and exploration	-	84	9,637	1,766
Total Expenses	-	8,480	16,283	24,333
(Loss) income from discontinued operations, before income taxes	(578)	5,842	(11,172)	20,219
Income tax benefit (expense)	1,246	(2,109)	4,849	(7,562)
Income (Loss) from discontinued operations	$ 668	$ 3,733	$ (6,323)	$ 12,657

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9. Dry Hole, Abandonment and Impairment

During the nine months ended September 30, 2009 and 2008, we recorded dry hole, abandonment, impairment and exploration expense of $0.2 million and $7.4 million, respectively. Charges of $2.7 million, $2.6 million and $1.5 million were recorded during the first, second and third quarters of 2008, respectively for technical difficulties that were encountered on five wells in the Piceance basin before reaching total depth. These holes were abandoned in favor of drilling to the same bottom hole location by drilling new wells. In addition, $0.5 million of exploration expense was recorded during the nine months ended September 30, 2008 for exploration activities which were primarily 3-D seismic in nature.

10. Pro Forma Results

On July 15, 2008, the Company acquired certain interests in natural gas producing properties on 4,500 net acres in Limestone and Harrison Counties in East Texas for $668 million cash (East Texas Acquisition) including an initial purchase price of $622 million, and normal post closing adjustments of $46 million.

The unaudited pro forma results presented below for the three and nine months ended September 30, 2008 have been prepared to give effect to the East Texas Acquisition on the Company's results of continuing operations under the purchase method of accounting as if it had been consummated at January 1, 2008. The unaudited pro forma results (in millions) do not purport to represent the results of continuing operations that actually would have occurred on such date or to project the Company's results of operations for any future date or period:

	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2008
Pro forma revenue	$ 233,236	$ 643,396
Pro forma income from operations	$ 83,575	$ 217,351
Pro forma net income	$ 52,977	$ 136,016
Pro forma basic earnings per share	$ 1.17	$ 3.02
Pro forma diluted earnings per share	$ 1.16	$ 2.97

11. Income Taxes

The effective income tax rate was 36.2% for the third quarter of 2009 compared to 36.1% for the second quarter of 2009 and 36.5% for the third quarter of 2008. The effective tax rate was 34.3% and 37.4% for the nine months ended September 30, 2009 and 2008, respectively. The change for the nine month period ended September 30, 2009 when compared to the same period in 2008 was primarily due to reduced state tax rates and the reduction in our liability related to uncertain tax positions. Our estimated annual effective tax rate varies from the 35% federal statutory rate due to the effects of state income taxes and estimated permanent differences.

As of September 30, 2009, we had a gross liability for uncertain tax benefits of $7.4 million of which $6.2 million, if recognized, would affect the effective tax rate. The liability related to uncertain tax positions was reduced during the nine months ended September 30, 2009 due to the resolution of our IRS examination for 2005.

Due to the uncertainty about the future periods in which other examinations will be completed and limited information related to current audits, we are not able to make reasonably reliable estimates of the periods in which cash settlements will occur with taxing authorities for the noncurrent liabilities.

12. Earnings per Share

In June 2008, the FASB issued authoritative guidance, which clarifies that share-based payment awards that entitle their holders to receive nonforfeitable dividends before vesting should be considered participating securities. As participating securities, these instruments should be included in the earnings allocation in computing basic earnings per share under the two-class method. All prior period earnings per share data presented were adjusted retrospectively to conform with the provisions of the guidance which is effective for financial statements issued for fiscal years beginning after December 15, 2008 and interim periods within those years.

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The following table shows the computation of basic and diluted net (loss) income per share from continuing and discontinued operations for the three and nine months ended September 30, 2009 and 2008 (in thousands):

	Three months ended September 30,		Nine months ended September 30,	
	2009	2008	2009	2008
Net income from continuing operations	$ 18,339	$ 49,615	$ 47,349	$ 132,863
Less: Income allocable to participating securities	445	691	1,153	1,841
Income available for shareholders	17,894	48,924	46,196	131,022
Net income (loss) from discontinued operations	668	3,733	(6,323)	12,657
Less: Income allocable to participating securities	17	53	-	178
Income (loss) from discontinued operations available for shareholders	651	3,680	(6,323)	12,479
Basic earnings per share from continuing operations	0.41	1.10	1.04	2.95
Basic earnings (loss) per share from discontinued operations	0.01	0.08	(0.14)	0.28
Basic earnings per share	0.42	1.18	0.90	3.23
Diluted earnings per share from continuing operations	0.40	1.08	1.03	2.90
Diluted earnings (loss) per share from discontinued operations	0.01	0.08	(0.14)	0.28
Diluted earnings per share	$ 0.41	$ 1.16	$ 0.89	$ 3.18
Weighted average shares outstanding – basic	44,633	44,527	44,607	44,466
Add: dilutive effects of stock options	303	651	189	702
Weighted average shares outstanding – dilutive	44,936	45,178	44,796	45,168

Options to purchase 1.2 million and 1.6 million shares were not included in the diluted (loss) earnings per share calculation for the three and nine months ended September 30, 2009, respectively, because their effect would have been anti-dilutive. Options to purchase 0.2 million and 0.1 million shares were not included in the diluted (loss) earnings per share calculation for the three and nine months ended September 30, 2008, respectively, because their effect would have been anti-dilutive.

The adoption of the guidance issued by the FASB decreased basic earnings per share from continuing operations by $0.02 and $0.04 for the three and nine months ended September 30, 2008, respectively, and dilutive earnings per share from continuing operations by $0.01 and $0.02 for the three and nine months ended September 30, 2008, respectively. Basic and dilutive (loss) earnings per share from discontinued operations remained unchanged for the three and nine months ended September 30, 2008.

13. Debt Obligations

Short-term lines of credit

In 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. In conjunction with the amendment to our senior secured credit facility, on July 15, 2008, the Line of Credit was secured by our assets. At September 30, 2009 and December 31, 2008, the outstanding balance under this Line of Credit was $12.5 million and $25.3 million, respectively. Interest on amounts borrowed is charged at LIBOR plus a margin of approximately 1.6%.

Senior Secured Revolving Credit Facility

Our Senior Secured Revolving Credit Facility (the Agreement) has a current borrowing base and lender commitments of $938 million. The LIBOR and prime rate margins are between 2.25% and 3.0% based on the ratio of credit outstanding to the borrowing base and the annual commitment fee on the unused portion of the credit facility is 0.50%.

Covenants under the Agreement are as follows:

Total funded debt to EBITDAX ratio not greater than:		
2009	2010	Thereafter
4.75	4.50	4.00

Senior secured debt to EBITDAX ratio not greater than:			
to Sep 2010	Mar 2011	Sep 2011	Thereafter
3.75	3.50	3.25	3.0

The write off of $38.5 million to bad debt expense associated with the bankruptcy of Big West Oil of California (‘Big West”) is excluded from the calculation of EBITDAX, per the Agreement.

The Agreement contains a current ratio covenant which, as defined, must be at least 1.0. During the third quarter of 2009 our borrowing base decreased from $969 billion to $938 million as a result of the add-on of our senior unsecured notes. The total outstanding debt at September 30, 2009 under the Agreement, as amended, and the Line of Credit was $365 million and $13 million, respectively, and $4 million in letters of credit have been issued under the facility, leaving $556 million in borrowing capacity available. The maximum amount available is subject to semi-annual redeterminations of the borrowing base, based on the value of our proved oil and gas reserves, in April and October of each year in accordance with the lenders’ customary procedures and practices. Both we and the banks have the bilateral right to one additional redetermination each year.

Second Lien Term Loan

On April 27, 2009 we completed a $140 million second lien credit facility, with lenders from among our current lending group, with a maturity of January 16, 2013. We paid off the second lien term loan on May 29, 2009 from the proceeds of our senior unsecured notes issuance and wrote off $7.2 million in deferred loan fees for the nine months ended September 30, 2009.

Senior Unsecured 10.25% notes due 2014

On May 27, 2009, we issued in a public offering $325 million of 10.25% senior unsecured notes due 2014 ($325 million Notes). Interest on the $325 million Notes is paid semiannually in June and December of each year. The $325 million Notes were issued at a discount to par value of 93.546%, and are carried on the balance sheet at their amortized cost. The deferred costs of approximately $9.5 million associated with the issuance of this debt are being amortized over the five year life of the $325 million Notes. Pursuant to the terms of our senior secured credit facility, the issuance of the $325 million Notes automatically reduced our borrowing base by 25 cents per dollar of Notes issued, or approximately $81 million. We wrote off $3.3 million of deferred loan fees during the second quarter of 2009 as a result of the decrease in our borrowing base.

On August 13, 2009, we issued in a public offering a $125 million add-on to our 10.25% senior unsecured notes due 2014 ($125 million Notes). The $125 million Notes were issued at a premium to par value of 104.75%, and are carried on the balance sheet at their amortized cost. The deferred costs of approximately $1.9 million associated with the issuance of this debt are being amortized over the five year life of the Notes. Pursuant to the terms of our senior secured credit facility, the issuance of the $125 million Notes automatically reduced our borrowing base by 25 cents per dollar of notes issued, or approximately $31 million. We wrote off $0.3 million of deferred loan fees during the third quarter of 2009 as a result of the decrease in our borrowing base.

The $125 million Notes and the previously issued $325 million Notes will be treated as a single series of debt securities under the indenture and are carried on the balance sheet at their combined amortized cost in which the $325 million Notes discount and the $125 million Notes premium net to a discount.

Senior Subordinated 8.25% notes due 2016

In 2006, we issued in a public offering $200 million of 8.25% senior subordinated notes due 2016 (the Sub notes). Interest on the Sub notes is paid semiannually in May and November of each year. The deferred costs of approximately $5.2 million associated with the issuance of this debt are being amortized over the ten year life of the Sub notes.

Financial Covenants

The senior secured revolving credit facility contains restrictive covenants as described above. Under our senior subordinated and senior unsecured notes as long as the interest coverage ratio (as defined) is greater than 2.5 times, we may incur additional debt. We were in compliance with all of these covenants as of September 30, 2009.

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	As of September 30, 2009
Current Ratio (Not less than 1.0)	5.1
EBITDAX To Total Funded Debt Ratio (Not greater than 4.75)	3.3
Interest Coverage Ratio (Not less than 2.5)	4.0
EBITDAX To Senior Secured Debt Ratio (Not greater than 3.75)	1.2

The weighted average interest rate on total outstanding borrowings at September 30, 2009 was 7.0%.

14. Contingencies and Commitments

Our contractual obligations as of September 30, 2009 are as follows (in millions):

	Total	2009	2010	2011	2012	2013	Thereafter
Total debt and interest	$ 1,385.1	$ 30.5	$ 71.8	$ 71.8	$ 430.3	$ 62.6	$ 718.1
Abandonment obligations	43.2	1.3	2.9	2.9	2.8	2.8	30.5
Operating lease obligations	16.6	0.6	2.4	2.4	2.5	2.5	6.2
Drilling and rig obligations	38.6	4.4	8.0	8.0	18.2	-	-
Firm natural gas transportation contracts	140.1	4.6	19.1	19.1	17.8	15.7	63.8
Total	$ 1,623.6	$ 41.4	$ 104.2	$ 104.2	$ 471.6	$ 83.6	$ 818.6

On July 17, 2009, we closed on the financing of our East Texas gas gathering system for $18.4 million in cash. We entered into concurrent long-term gas gathering agreements for the East Texas production which contained an embedded lease. There is no minimum payment required under these agreements. For the first nine months of 2009, we have incurred $1.0 million under the agreements.

On June 17, 2009, we amended our natural gas firm transportation agreement with Enbridge Pipelines providing for transportation of our gas from Tex-OK to Orange County, Florida (Zone 1). The agreement provides for minimum volume of 25,000 MMBtu/d and a maximum volume of 55,000 MMBtu/D.

We have two long-term firm transportation contracts that total 35,000 MMBtu/D on the Rockies Express (REX) pipeline for gas production in the Piceance basin. We pay a demand charge for this capacity and our own production did not completely fill that capacity. To maximize the utilization of our firm transportation, we bought our partners' share of the gas produced in the Piceance basin at the market rate for that area and used our excess transportation to move this gas to the sales point. The pre-tax net of our gas marketing revenue and our gas marketing expense in the Statements of Operations is $0.6 million and $1.5 million for the three and nine month periods ended September 30, 2009, respectively.

In addition, Berry has signed a binding precedent agreement with El Paso Corporation for an average of 35,000 MMBtu/D of firm transportation on the proposed Ruby Pipeline from Opal, WY to Malin, OR. While it is not certain that this new line will be constructed, the expectation is that the project will proceed and be in service by 2011. As part of this agreement and in order to access the Ruby pipeline, we also secured firm transportation from the Piceance basin to Opal.

In February 2007, we entered into a multi-staged crude oil sales contract with a refiner for our Uinta basin light crude oil. Under the agreement, the refiner began purchasing 3,200 Bbl/D in July 2007. The refiner has increased its total capacity to 5,000 Bbl/D as provided in our contract. As operator we deliver all produced volumes under our sales contracts, although our working interest partners or royalty owners may take their respective volumes in kind and market their own volumes. Gross oil production averaged approximately 3,100 BOE/D in the quarter ended September 30, 2009.

On August 13, 2009, we issued in a public offering a $125 million add-on to our 10.25% senior notes due 2014.

On May 27, 2009, we issued in a public offering $325 million of 10.25% senior notes due 2014. Interest on the $325 million Notes is paid semiannually in June and December of each year.

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In December 2008, Flying J, Inc., and its wholly owned subsidiary Big West Oil and its wholly owned subsidiary BWOC filed for bankruptcy protection under Chapter 11 of the United States Bankruptcy Code. Also in December 2008, BWOC informed the Company that it was unable to receive the Company's California production. Included in our allowance for doubtful accounts is $38.5 million due from BWOC. Of the $38.5 million due from BWOC, $11.8 million represents 20 days of our December crude oil sales, an administrative claim under the bankruptcy proceedings, and $26.7 million represents November and the balance of December crude oil sales which would have the same priority as other general unsecured claims. BWOC will also be liable to us for damages under this contract. We have guarantees from Big West Oil and from Flying J, Inc. in the amount of $75 million each, in the event that our claim is not fully collectible from BWOC. While we believe that we may recover some or all of the amounts due from BWOC, the data received from the bankruptcy proceedings to date has not provided us with adequate data from which to make a conclusion that any amounts will be collected.

We have no material 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 and the minimum cost and/or amount of loss cannot be reasonably estimated. However, because of the uncertainties associated with environmental assessment and remediation activities, future expense to remediate the currently identified sites, and sites identified in the future, if any, could be 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.

Certain of our royalty payment calculations are being disputed. We believe that our royalty calculations are in accordance with applicable leases and other agreements. However, the disputed amounts that we may be required to pay are up to approximately $6 million.

In July 2009, we received a notice of proposed civil penalty from the Bureau of Land Management (BLM) related to the Company's alleged non-compliance during 2007 with regulations relating to the operation and position of certain valves in our Uinta Basin operations. The proposed civil penalty was $69.6 million and reflects the theoretical maximum penalty amount under applicable regulations, absent mitigating factors. In 2007 we immediately remediated the instances of non-compliance, cooperated fully with the BLM's investigation and we believe no production was lost, all royalties were paid and there was no harm to the environment. Due to the above mitigating factors, among others, we believe this matter will be resolved by the payment of a penalty that will not exceed $2.1 million and accrued such amount in the second quarter of 2009.

During the California energy crisis in 2000 and 2001, we had electricity sales contracts with various utilities and a portion of the electricity prices paid to us under such contracts from December 2000 to March 27, 2001 has been under a degree of legal challenge since that time. It is possible that we may have a liability pending the final outcome of the CPUC proceedings on the matter. There are ongoing proceedings before the CPUC in which Edison and PG&E are seeking credit against future payments they are to make for electricity purchases based on retroactive adjustments to pricing under contracts with us. Whether or not retroactive adjustments will be ordered, how such adjustments would be calculated and what period they would cover are too uncertain to estimate at this time.

15. Subsequent Events

The Company evaluates subsequent events through the date the financial statements are issued, which for the quarterly period ended September 30, 2009, is October 30, 2009. No subsequent events requiring disclosure were identifited by the Company.

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 months ended September 30, 2009 and 2008 and our financial condition, liquidity and capital resources as of September 30, 2009. The unaudited 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 global 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. We seek 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:

- Maximize production from our base oil assets
- Grow oil production from our inventory of organic development projects
- Increase natural gas production that will meet the growing demand for steam generation
- Acquire additional resources with an emphasis on crude oil

Notable Third Quarter Items.

- Achieved production averaging 28,417 BOE/D, of which 68% is crude oil production, with $22 million of capital investment
- Increased Diatomite net production to an average of 3,119 BOE/D, up 49% from the third quarter of 2008
- Secured twelve month contracts for approximately 90% of our California crude oil
- Issued a $125 million add-on to our 10.25% senior unsecured notes due in 2014 with a yield of 9%
- Paid down $78 million of additional debt and increased liquidity to approximately $550 million
- Completed the sale of our East Texas midstream assets for $18 million
- Tested our new completion method in the Piceance basin, delivering a 25% improvement compared to our historical field average
- Received category exemption allowing 25 wells to be drilled in the Uinta basin in Ashley Forest

Notable Items and Expectations for the Fourth Quarter and Full Year 2009.

- Completed our credit facility borrowing base redetermination and reconfirmed our $938 million borrowing base
- Initiate a steam flood pilot on the McKittrick, California property
- Expect to drill our first East Texas Haynesville well during the fourth quarter of 2009
- Expect production to average approximately 30,000 BOED for the full year 2009

Overview of the Third Quarter of 2009. We had net income from continuing operations of $18 million, or $0.40 per diluted share, and cash provided from operations was $89 million in the third quarter of 2009. Net income includes $1 million from the sale of crude oil inventory. We drilled 32 gross wells, and capital expenditures excluding property acquisitions totaled $22 million. We achieved average production of 28,417 BOE/D in the third quarter of 2009.

Acquisitions. In June 2009, we acquired the Section 21Z property in McKittrick, California. We believe this acquisition provides us with another opportunity to increase our crude oil production and reserves with potential similar to our Poso Creek asset. We also acquired deep rights to one of the leases in our Darco property in East Texas, providing us with an additional 13 Haynesville horizontal locations, and increased our interest at Garden Gulch in the Piceance.

Asset Dispositions.

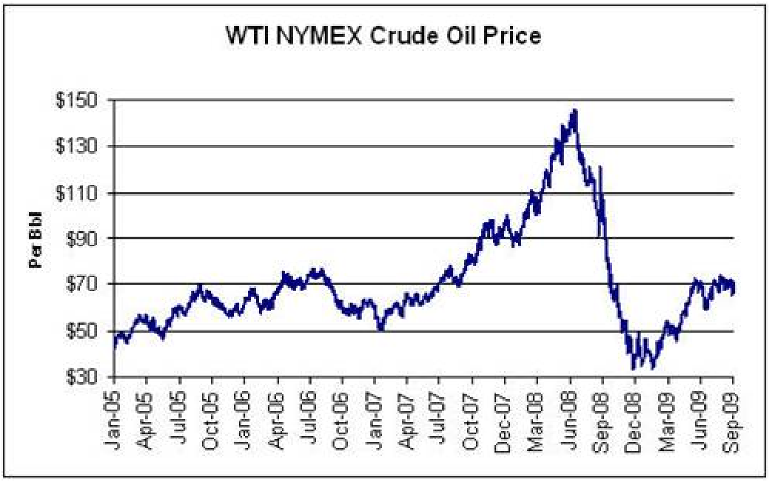
On July 17, 2009, we completed the sale of our East Texas gas gathering system for $18.4 million in cash. See Note 8 to the unaudited financial statements.

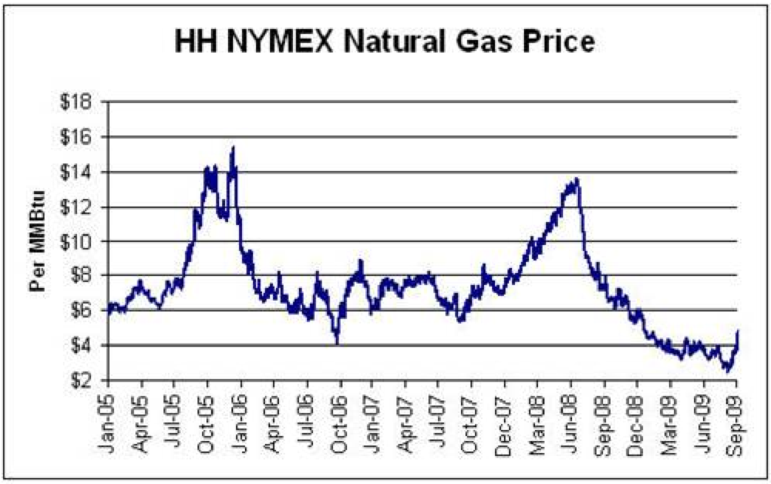
On March 3, 2009, we entered into an agreement to sell our DJ basin assets and related hedges for $154 million before customary closing adjustments. The closing date of the sale of our DJ basin assets was April 1, 2009. We recorded an impairment charge associated with the sale of $9.6 million during the first quarter of 2009. Post closing adjustments recorded in the second and third quarters of 2009 totaled $0.5 million income, net of tax. The total loss on sale was recorded within "(Loss) income from discontinued operations, net of tax," on the condensed statements of operations for the nine months ended September 30, 2009.

Results of Operations. The following results from continuing operations are in millions (except per share data) for the three and nine month periods ended:

	Three months ended,			Nine months ended,	
	Sept 30, 2009	Sept 30, 2008	June 30, 2009	Sept 30, 2009	Sept 30, 2008
Sales of oil	$ 109	$ 146	$ 103	$ 311	$ 423
Sales of gas	18	48	16	63	92
Total sales of oil and gas	$ 127	$ 194	$ 119	$ 374	$ 515
Sales of electricity	9	18	6	26	51
Gas Marketing	5	13	5	18	28
Gain (loss) on derivative	1	1	(31)	7	-
Interest and other income, net	1	1	1	2	3
Total revenues and other income	$ 143	$ 227	$ 100	$ 427	$ 597
Net income (loss) from continuing operations	$ 18	$ 50	$ (13)	$ 47	$ 133
Diluted earnings (loss) per share from continuing operations	$ 0.40	$ 1.08	$ (0.28)	$ 1.03	$ 2.90

Our revenues may vary significantly from period to period as a result of changes in commodity prices and/or production volumes. Crude oil sales in the three months ended September 30, 2009 were higher compared to the three months ended June 30, 2009 resulting from realized price increases of 1%, sales volume increases of 6% and we recognized revenue of $2.7 million resulting from the sale of 50,000 barrels of crude oil inventory. The decrease in crude oil revenue when compared to the third quarter of 2008 is primarily the result of a 24% decrease in realized prices. Natural gas revenues increased from the quarter ended June 30, 2009 as a result of a 12% increase in realized prices and a 2% decrease in volumes from our Piceance and Uinta properties where no capital activity occurred during the quarter. Natural gas revenues were lower in the third quarter of 2009 compared to the third quarter of 2008 primarily due to a 58% decrease in realized prices.





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

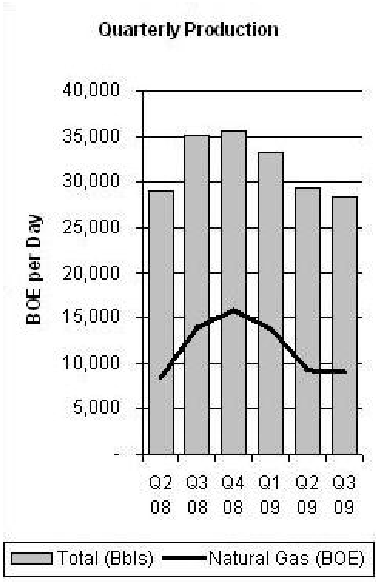
	September 30, 2009	%	September 30, 2008	%	June 30, 2009	%
Heavy Oil Production (Bbl/D)	16,780	59	17,264	49	16,822	57
Light Oil Production (Bbl/D)	2,530	9	3,898	11	3,085	11
Total Oil Production (Bbl/D)	19,310	68	21,162	60	19,907	68
Natural Gas Production (Mcf/D)	54,637	32	83,928	40	56,174	32
Total operations (BOE/D)	28,417	100	35,150	100	29,270	100
DJ Basin Production (BOE/D)	-		3,337		-	
Production - Continuing Operations (BOE/D)	28,417		31,813		29,270	
Oil and gas, per BOE for continuing operations						
Average sales price before hedging	$ 45.41		$ 83.90		$ 39.34	
Average sales price after hedging	46.39		67.04		45.74	
Oil, per Bbl, for continuing operations:						
Average WTI price	$ 68.24		$ 118.22		$ 59.79	
Price sensitive royalties	(2.36)		(5.30)		(2.08)	
Quality differential and other	(8.78)		(10.80)		(7.86)	
Crude oil hedges reported with Sales of oil and gas	2.28		(26.12)		8.91	
Crude oil hedges reported with Gain on derivatives (a)	(1.41)		-		-	
Average oil sales price after hedging	$ 57.97		$ 76.00		$ 58.76	
Natural gas price for continuing operations:						
Average Henry Hub (HH) price per MMBtu	$ 3.39		$ 10.24		$ 3.51	
Conversion to Mcf	0.17		0.51		0.18	
Natural gas hedges reported with Sales of oil and gas	0.27		0.20		0.21	
Natural gas hedges reported with Gain (loss) on derivatives (a)	(0.07)		-		-	
Location, quality differentials and other	(0.28)		(2.69)		(0.72)	
Average gas sales price after hedging per Mcf	$ 3.48		$ 8.26		$ 3.18	

(a) Includes cash settlements on hedges for which the Company has not elected hedge accounting that are recorded in ‘Gain (Loss) on hedges.”

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

	September 30, 2009	%	September 30, 2008	%
Heavy Oil Production (Bbl/D)	16,691	55	16,845	54
Light Oil Production (Bbl/D)	2,892	10	3,710	12
Total Oil Production (Bbl/D)	19,583	65	20,555	66
Natural Gas Production (Mcf/D)	64,493	35	61,201	34
Total operations (BOE/D)	30,332	100	30,755	100
DJ Basin Production (BOE/D)	1,020		3,255	
Production - Continuing Operations (BOE/D)	29,312		27,500	
Oil and gas, per BOE for continuing operations				
Average sales price before hedging	$ 37.99		$ 86.63	
Average sales price after hedging	46.43		68.50	
Oil, per Bbl, for continuing operations:				
Average WTI price	$ 57.22		$ 113.52	
Price sensitive royalties	(1.83)		(3.36)	
Quality differential and other	(8.65)		(12.90)	
Crude oil hedges reported with Sales of oil and gas	11.49		(23.83)	
Crude oil hedges reported with Gain on derivatives (a)	(0.49)		-	
Correction to royalties payable	-		1.88	
Average oil sales price after hedging	$ 57.74		$ 75.31	
Natural gas price for continuing operations:				
Average HH price per MMBtu	$ 3.94		$ 9.74	
Conversion to Mcf	0.20		0.49	
Natural gas hedges reported with Sales of oil and gas	0.56		(0.22)	
Natural gas hedges reported with Gain (loss) on derivatives (a)	(0.02)		-	
Location, quality differentials and other	(0.74)		(1.93)	
Average gas sales price after hedging per Mcf	$ 3.94		$ 8.08	

(a) Includes cash settlements on hedges for which the Company has not elected hedge accounting that are recorded in ‘Gain (Loss) on hedges.”



Gas Basis Differential. We have two contracts with the Rockies Express pipeline providing for 35,000 MMBtu/d of firm transport. Unlike the first and second quarters of 2009 in which the Piceance gas was sold based upon a mid-continent index such as PEPL, third quarter gas was sold based an eastern price such as the Gas Daily Lebanon, Ohio index. For the third quarter of 2009, this index was approximately equal to HH based on daily averages. Our Uinta basin gas is sold based upon a Questar index which averaged $0.77 below HH during the third quarter of 2009 using first of month averages. In East Texas, the majority of the gas was sold based on the Florida Gas Transmission Zone 1 index which averaged $0.03 below HH.

Gas Marketing. We have two long-term firm transportation contracts for our Piceance natural gas production, with total capacity of 35,000 MMBtu/D. We pay a demand charge for this capacity and our own production does not currently fill that capacity. In order to maximize our firm transportation, we have contracted to purchase our partners' share of the gas produced in the Piceance at the market rate for that area through December 2009. We used our excess transportation to move this gas to eastern markets where it was eventually sold. The pre-tax net of our gas marketing revenue and our gas marketing expense in the Statement of Operations is $0.6 million and $1.5 million in the three and nine month periods ended September 30, 2009. Firm transportation costs related to all of our Rockies Express volumes is reflected in Operating costs - oil and gas production and total $3.5 million and $8.5 million for the three months and nine months ended September 30, 2009, respectively.

In addition, Berry has signed a binding precedent agreement with El Paso Corporation for an average of 35,000 MMBtu/D of firm transportation on the proposed Ruby Pipeline from Opal, WY to Malin, OR. While it is not certain that this new line will be constructed, the expectation is that the project will proceed and be in service in 2011. As part of this agreement and in order to access the Ruby pipeline, we also secured firm transportation from Piceance to Opal.

Oil Contracts. California - On September 24, 2009, we executed a crude oil purchase contract with a refiner for the sale of all of our crude oil production from the Midway Sunset field. The volume approximates 12,500 barrels per day. The agreement was effective on October 1, 2009 and continues until September 30, 2010. We also signed a 13 month contract for the sale of the Poso Creek crude oil to a refiner which had an effective date of September 1, 2009. Previously on March 20, 2009, we entered into a crude oil purchase contract with a refiner for the sale of all the Placerita crude. The agreement covers the period April 2009 through December 2009.

Utah - In February 2007, we entered into a multi-staged crude oil sales contract with a refiner for our Uinta basin light crude oil. Under the agreement, the refiner began purchasing 3,200 Bbl/D in July 2007. The refiner has increased its total capacity to 5,000 Bbl/D as provided in our contract. As operator we deliver all produced volumes under our sales contracts, although our working interest partners or royalty owners may take their respective volumes in kind and market their own volumes. Gross oil production averaged approximately 3,100 BOE/D in the quarter ended September 30, 2009. The differential under the contract, which includes transportation and gravity adjustments, is linked to the price for NYMEX WTI.

Crude Oil Inventory. In May 2009, we entered into a sales agreement with a refiner for 1,500 barrels per day of production from our Poso Creek property for the months of May and June 2009. Under this agreement, we delivered approximately 100,000 barrels of oil to the refiner and received inventory of a slightly higher quality crude oil at the refinery. This transaction was accounted for as a non-monetary exchange and the amount recorded in crude oil inventory. The refiner purchased 50,000 barrels from us during the third quarter of 2009 and the remaining balance in “Crude Oil Inventory” at September 30, 2009 reflects the cost of production, transportation costs and quality differentials for the remaining 50,000 barrels of inventory volume.

Hedging. See Note 4 to the unaudited 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 cost-effective production of heavy oil in California. We sell our electricity to utilities under standard offer contracts based on "avoided cost" or SRAC pricing approved by the California Public Utilities Commission (CPUC) and under which our revenues are currently linked to the cost of natural gas. On July 9, 2009, the CPUC issued a resolution that implemented a revised SRAC price methodology effective August 1, 2009 and resolved many of the disputed issues regarding the calculation of SRAC. The revised pricing changes the gas indices upon which SRAC is based and reduces the avoided utility heat rates used to calculate SRAC. These changes are not expected to have a material impact on electricity revenues. Natural gas index prices and an avoided utility heat rate are the primary determinant of our electricity sales price based on the current pricing formula under these contracts. The correlation between electricity sales and natural gas prices allows us to manage our cost of producing steam more effectively.

Electricity revenues and operating costs were down for the quarter ended September 30, 2009 from the quarter ended September 30, 2008 primarily due to 67% lower natural gas prices. Revenues and operating costs were higher in the quarter ended September 30, 2009 than in the quarter ended June 30, 2009 due to a 10% increase in electricity sold offset by 3% lower electricity prices and 3% lower natural gas prices, respectively. We purchased approximately 28,000 MMBtu/D and 26,000 MMBtu/D as fuel for use in our cogeneration facilities in the quarters ended September 30, 2009 and September 30, 2008, respectively.

On September 20, 2007, the CPUC issued a decision (SRAC Decision) that changes the way SRAC energy prices will be determined for existing and new SO contracts, revises the capacity prices paid under current S01 contracts and establishes the capacity prices that will be paid under new SO contracts.

The following table is for the three months ended:

	September 30, 2009	September 30, 2008	June 30, 2009
Electricity			
Revenues (in millions)	$ 9.1	$ 18.3	$ 6.6
Operating costs (in millions)	$ 6.9	$ 13.7	$ 6.4
Electric power produced - MWh/D	2,048	2,096	2,007
Electric power sold - MWh/D	1,966	1,908	1,783
Average sales price/MWh	$ 45.24	$ 104.91	$ 46.99
Fuel gas cost/MMBtu (including transportation)	$ 3.26	$ 8.20	$ 3.54

The following table is for the nine months ended:

	September 30, 2009	September 30, 2008
Electricity		
Revenues (in millions)	$ 26.0	$ 51.2
Operating costs (in millions)	$ 22.1	$ 45.6
Electric power produced - MWh/D	2,048	1,539
Electric power sold - MWh/D	1,896	1,869
Average sales price/MWh	$ 65.88	$ 100.88
Fuel gas cost/MMBtu (including transportation)	$ 3.44	$ 8.70

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

	Amount per BOE			Amount (in thousands)		
	Sept 30, 2009	Sept 30, 2008	June 30, 2009	Sept 30, 2009	Sept 30, 2008	June 30, 2009
Operating costs – oil and gas production	$ 14.99	$ 17.93	$ 13.03	$ 39,195	$ 52,486	$ 34,738
Production taxes	1.48	3.04	1.83	3,874	8,912	4,885
DD&A – oil and gas production	12.81	12.76	12.89	33,502	37,354	34,371
G&A	4.09	4.87	4.94	10,686	14,251	13,164
Interest expense	5.57	2.74	3.97	14,562	8,031	10,589
Total	$ 38.94	$ 41.34	$ 36.66	$ 101,819	$ 121,034	$ 97,747

- ***Operating costs***. Steam costs are the primary variable component of our operating costs and fluctuate based on the amount of steam we inject and the price of fuel used to generate steam. The following table presents steam information:

	September 30, 2009 (3Q09)	September 30, 2008 (3Q08)	3Q09 to 3Q08 Change	June 30, 2009 (2Q09)	3Q09 to 2Q09 Change
Average volume of steam injected (Bbl/D)	110,381	105,574	5%	107,739	2%
Fuel gas cost/MMBtu (including transportation)	$ 3.26	$ 8.20	(60%)	$ 3.12	4%
Approximate net fuel gas volume consumed in steam generation (MMBtu/D)	32,193	29,362	10%	29,459	9%

Operating costs increased by $4.5 million or 13% from the second quarter of 2009 to the third quarter of 2009. During the second quarter of 2009 $2.8 million of the costs related to crude oil inventory were recorded on the balance sheet. During the third quarter of 2009, as a result of the sale of 50,000 barrels of this inventory, we recognized $1.2 million of operating costs. Additionally, fuel gas costs increased approximately 4% as a result of increased natural gas prices and 9% higher fuel gas volume consumed in steam generation. The decrease in operating costs from the third quarter of 2008 to the third quarter of 2009 was due to decreased fuel gas costs of approximately 60% as a result of decreased natural gas prices and 10% lower fuel gas volume.

- ***Production taxes***. Severance taxes paid in Utah, Colorado and Texas are directly related to the field sales price of the commodity. In California and Utah, our properties are burdened with ad valorem taxes on proved reserves. In Colorado, we are also burdened with ad valorem tax on equipment. We take advantage of all credits and exemptions allowed in our various taxing jurisdictions. As the proportion of our production changes from area to area, our production tax rate will vary depending on the quantities produced from each area and the production tax rates in effect for those areas. Our production tax cost per barrel during the third quarter of 2009 compared to the second quarter of 2009 is lower due to decreased ad valorem assessments primarily driven by lower lien date commodity pricing from various assessment jurisdictions. In addition, we have experienced greater reductions in tax from various severance exemptions per state. Rates were higher in 2008 due to increased oil and natural gas prices.

- ***General and administrative.*** Approximately 65% of our G&A is related to compensation. Our G&A decreased during the third quarter of 2009 as compared to the second quarter of 2009 due to a liability that was established during the second quarter of 2009 for a regulatory compliance matter.

- ***Interest expense.*** Our total outstanding borrowings were approximately $1.0 billion at September 30, 2009 compared to $1.1 billion and $1.2 billion at September 30, 2008 and December 31, 2008, respectively. The increase in interest expense between periods is due to the amortization of additional debt issuance costs and amortization of the net discount, which were incurred in June 2009 and August 2009 in connection with the issuance of our 10.25% senior notes due in 2014. For the three months ended September 30, 2009, $8.5 million of interest cost has been capitalized and we expect to capitalize between $28 million and $33 million of interest cost during the full year of 2009.

- ***Debt Extinguishment Costs.*** During the third quarter of 2009 our borrowing base decreased from $969 million to $938 million as a result of the issuance of our $125 million senior unsecured notes add-on. We wrote off $0.3 million of deferred loan fees during the third quarter of 2009 related to this borrowing base reduction.

Estimated 2009 and Actual Nine Months Ended September 30, 2009 and 2008 Oil and Gas Operating, G&A and Interest Expenses. Variances for the nine month periods are discussed below when substantially different from the three month periods.

	Anticipated range	Nine months ended,			
		Amount per BOE		Amount (in thousands)	
	Full Year 2009 per BOE	Sept 30, 2009	Sept 30, 2008	Sept 30, 2009	Sept 30, 2008
Operating costs-oil and gas production	$ 13.00 - 15.00	$ 13.91	$ 19.13	$ 111,317	$ 144,158
Production taxes	1.50 - 2.50	1.80	2.74	14,411	20,663
DD&A – oil and gas production (*1*)	12.50 – 13.50	13.03	11.61	104,271	87,462
G&A	4.25 - 4.75	4.64	4.82	37,143	36,312
Interest expense	4.00 - 4.75	4.40	1.98	35,201	14,910
Total	$ 35.25 – 40.50	$ 37.78	$ 40.28	$ 302,343	$ 303,505

(1) Full year estimate includes both oil and gas and electricity

- ***Operating costs.*** Steam costs are the primary variable component of our operating costs and fluctuate based on the amount of steam we inject and the price of fuel used to generate steam. The following table presents steam information for each of the nine month periods ended:

	September 30, 2009	September 30, 2008	Change
Average volume of steam injected (Bbl/D)	106,892	98,050	9%
Fuel gas cost/MMBtu (including transportation)	$ 3.44	$ 8.70	(60%)
Approximate net fuel gas volume consumed in steam generation (MMBtu/D)	29,308	26,128	12%

Operating costs decreased by $32.8 million or 23% during the nine months ended September 30, 2009 compared to the nine months ended September 30, 2008. The majority of the decrease came from decreased fuel gas costs of 60% from decreased natural gas prices.

- ***Depreciation, depletion and amortization.*** DD&A increased per BOE by 12% for the nine months ended September 30, 2009 as compared to the nine months ended September 30, 2008 due to an increase in the contribution of our development properties with higher drilling and leasehold acquisition costs and the integration of our East Texas assets which have higher finding and development costs than our legacy assets.

- ***Dry Hole, Abandonment, impairment and exploration.*** During the nine months ended September 30, 2009 and 2008, we recorded dry hole, abandonment, impairment and exploration expense of $0.2 million and $7.4 million, respectively. Charges of $2.7 million, $2.6 million and $1.5 million were recorded during the first, second and third quarters of 2008, respectively for technical difficulties that were encountered on five wells in the Piceance basin before reaching total depth. These holes were abandoned in favor of drilling to the same bottom hole location by drilling new wells. In addition, $0.5 million of exploration expense was recorded during the nine months ended September 30, 2008 for exploration activities which were primarily 3-D seismic in nature.

- ***Debt Extinguishment Costs.*** During the nine months ended September 30, 2009 and 2008, we recorded debt extinguishment costs of $10.8 million and $0, respectively. During the second quarter of 2009 our borrowing base decreased from $1.25 billion to $969 million as a result of our scheduled borrowing base redetermination and the issuance of our senior unsecured notes. We wrote off $3.3 million of deferred loan fees during the second quarter of 2009 related to these transactions. Additionally, we paid off our second lien term loan in conjunction with the issuance of our senior unsecured notes. We expensed $7.2 million in fees related to the second lien term loan in the second quarter of 2009. During the third quarter of 2009 our borrowing base decreased from $969 million to $938 million as a result of the issuance of our senior unsecured notes. We wrote off $0.3 million of deferred loan fees during the third quarter of 2009 related to the $31 million borrowing base reduction.

- ***Income Taxes.*** We experienced an effective tax rate of 34.3% and 37.4% in the nine months ended September 30, 2009 and September 30, 2008, respectively. The change for the nine month period ended September 30, 2009 when compared to the same period in 2008 was primarily due to reduced state rates and the reduction in our liability related to uncertain tax positions. Our estimated annual effective tax rate varies from the 35% federal statutory rate due to the effects of state income taxes and estimated permanent differences. See Note 11 to the unaudited financial statements.

Drilling Activity. The following table sets forth certain information regarding drilling activities:

	Three months ended September 30, 2009		Nine months ended September 30, 2009	
Asset Team	Gross Wells	Net Wells	Gross Wells	Net Wells
S. Midway	24	24	34	34
N. Midway	6	6	51	51
Texas	2	2	8	8
Totals	32	32	93	93

Properties

Asset Team Descriptions

S. Midway – Our S. Midway Asset Team includes four assets (Homebase, Formax, Ethel D and Poso Creek). In 2009 through the third quarter we have drilled 14 Homebase horizontal wells and two vertical producers. These wells have been placed deeper and closer to the oil-water contact. All of these wells are currently on production and are performing in line with expectations. An additional five horizontal wells will be drilled at S. Midway during the fourth quarter of 2009. We are also accelerating plans to expand our continuous steam support for these horizontal wells by drilling six steam injectors. At Ethel D we have been encouraged by the performance of our steam flood pilots and are preparing to expand the flood in the fourth quarter of 2009. As part of this preparation we will be increasing our steam generation capacity at Ethel D by 50% by year-end. At Poso Creek we expanded the steam flood by drilling eight new injectors. To provide steam to these wells we also installed a fifth steam generator. Average daily production during the three months ended September 30, 2009 from all S. Midway assets was approximately 11,300 BOE/D.

N. Midway – Our N. Midway Asset Team includes four assets (Diatomite, N. Midway, Placerita and McKittrick). Based on capital spending of $39 million we have drilled 51 diatomite wells and installed additional steam generation and water treating facilities. Production in the third quarter of 2009 was 3,119 Bbl/D and is expected to average 3,000 Bbl/D for the year. During the fourth quarter of this year we will initiate a four pattern steam flood pilot on our recently acquired McKittrick property. Average daily production during the three months ended September 30, 2009 from all N. Midway assets was approximately 5,500 BOE/D.

Uinta – Average daily production during the three months ended September 30, 2009 from all Uinta basin assets averaged 4,900 BOE/D. Implementation of a waterflood pilot in Brundage Canyon continues and we had initial start up in the beginning of the fourth quarter of 2009. While the Ashley Forest Development EIS continues to progress with approval now expected in 2010, we obtained a category exemption for 25 wells in the Ashley Forest.

East Texas – During the three months ended September 30, 2009, production from our East Texas assets averaged 23 MMcf/D. We continue to operate a one rig program and drilled two vertical wells in the Oakes field during the third quarter of 2009. We plan to begin drilling a vertical well in the Darco field during the fourth quarter of 2009 and our first horizontal Haynesville well in the fourth quarter of 2009.

Piceance – During the three months ended September 30, 2009, production from the Piceance basin averaged 17 MMcf/D. Infrastructure expansions were completed in preparation for completions planned over the third and fourth quarters to test new completion techniques. Our initial tests delivered a 25% improvement compared to our historical field average. As of September 30, 2009, we had an inventory of 38 initial completion and recompletion opportunities, of which we expect to complete 18 during the fourth quarter of 2009.

DJ – In March 2009, we announced the sale of our DJ basin assets and related hedges for approximately $154 million. Our assets in the DJ basin produced 3,100 BOE/D during the first quarter of 2009. The sale of the assets closed on April 1, 2009.

Financial Condition, Liquidity and Capital Resources. Substantial capital is required to replace and grow reserves. We achieve reserve replacement and growth primarily through successful development and exploration drilling and the acquisition of properties. Fluctuations in commodity prices, production rates and operating expenses have been the primary reason for changes in our cash flow from operating activities.

Liquidity. The total outstanding debt at September 30, 2009 under the Agreement and the Line of Credit was $365 million and $13 million, respectively, and $4 million in letters of credit have been issued under the facility.

Subsequent to the August 2009 issuance of the $125 million of 10.25% senior unsecured notes due 2014, the borrowing base under our senior secured revolving credit facility is approximately $938 million. This borrowing base was reconfirmed by our banks in October 2009. As of September 30, 2009, we had approximately $378 million outstanding under our senior secured revolving credit facility, with liquidity of approximately $550 million.

Capital Expenditure and Cash Flows. 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 and/or drilling outcomes or significant changes in cash flows.

In 2009, we have a capital program of approximately $130 million and we expect to fully fund this program from operating cash flow. Cash provided by operating activities was impacted during the nine months ended September 30, 2009 by a reduction in accounts payable which, at year-end 2008, reflected our higher 2008 capital budget. Approximately 90% of our oil production is hedged for 2009 and thus our sensitivity to changes in oil prices is limited. A ten dollar change in oil prices has a minimal impact on operating cash flow and a one dollar change in natural gas prices impacts our annual operating cash flow by approximately $1 million.

Capital expenditures, excluding property acquisitions, totaled $22 million and $95 million during the three and nine months ended September 30, 2009.

Working Capital. Cash flow from operations is dependent upon the price of crude oil and natural gas and our ability to increase production and manage costs. Our working capital balance fluctuates as a result of the amount of borrowings and the timing of repayments under our credit arrangements. We use our long-term borrowings under our credit facility primarily to fund property acquisitions. Generally, we use excess cash to pay down borrowings under our credit arrangement. As a result, we often have a working capital deficit or a relatively small amount of positive working capital.

Berry Petroleum Company
Management's Discussion and Analysis of Financial Condition and Results of Operations

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

	September 30, 2009 (3Q09)	September 30, 2008 (3Q08)	3Q09 to 3Q08 Change	June 30, 2009 (2Q09)	3Q09 to 2Q09 Change
Average production (BOE/D)	28,417	31,813	(11%)	29,270	(3%)
Average oil and gas sales prices, per BOE after hedging	46.39	$ 67.04	(31%)	$ 45.74	1%
Net cash provided by operating activities	$ 89	$ 137	(35%)	$ 51	75%
Working capital (deficit)	$ (40)	$ (148)	73%	$ (3)	n/a
Sales of oil and gas	$ 127	$ 194	(35%)	$ 119	7%
Total debt	$ 1,013	$ 1,129	(10%)	$ 1,085	(7%)
Capital expenditures	$ 22	$ 742	(97%)	$ 23	(4%)
Dividends paid	$ 3.4	$ 3.4	-	$ 3.4	-

Contractual Obligations. Our contractual obligations as of September 30, 2009 are as follows (in millions):

	Total	2009	2010	2011	2012	2013	Thereafter
Total debt and interest	$ 1,385.1	$ 30.5	$ 71.8	$ 71.8	$ 430.3	$ 62.6	$ 718.1
Abandonment obligations	43.2	1.3	2.9	2.9	2.8	2.8	30.5
Operating lease obligations	16.6	0.6	2.4	2.4	2.5	2.5	6.2
Drilling and rig obligations	38.6	4.4	8.0	8.0	18.2	-	-
Firm natural gas transportation contracts	140.1	4.6	19.1	19.1	17.8	15.7	63.8
Total	$ 1,623.6	$ 41.4	$ 104.2	$ 104.2	$ 471.6	$ 83.6	$ 818.6

Drilling obligations - Under our June 2006 joint venture agreement in the Piceance basin we are required to have 120 wells drilled by February 2011 to avoid penalties of $0.2 million per well or a maximum of $24 million. As of September 30, 2009 we have drilled 29 of these wells and we expect to meet our obligation.

Other Obligations - As of September 30, 2009 we had a gross liability for uncertain tax benefits of $7.4 million of which $6.2 million, if recognized, would affect the effective tax rate. We are unable to predict the year in which these uncertain tax positions will be settled and have excluded these contingencies from the table above.

In February 2007, we entered into a multi-staged crude oil sales contract with a refiner for our Uinta basin light crude oil. Under the agreement, the refiner began purchasing 3,200 Bbl/D in July 2007. The refiner has increased its total capacity to 5,000 Bbl/D as provided in our contract. As operator we deliver all produced volumes under our sales contracts, although our working interest partners or royalty owners may take their respective volumes in kind and market their own volumes. Gross oil production averaged approximately 3,100 BOE/D in the quarter ended September 30, 2009. The differential under the contract, which includes transportation and gravity adjustments, is linked to the price for NYMEX Light Sweet Crude. This contract provides us an outlet to sell all of our current oil production in the Uinta basin.

On July 17, 2009, we closed on the sale of our East Texas gas gathering system for $18.4 million in cash. We entered into concurrent long-term gas gathering agreements for the East Texas production. There is no minimum payment required under these agreements. For the first nine months of 2009, we have incurred $1.0 million under these agreements.

On June 17, 2009, we amended our natural gas firm transportation agreement with Enbridge Pipelines providing for transportation of our East Texas gas to Orange County, Florida (Zone 1). The agreement provides for minimum volume of 25,000 MMBtu/D and a maximum volume of 55,000 MMBtu/D.

Recent Accounting Developments

In December 2007, the FASB issued authoritative guidance to establish accounting and reporting standards for the noncontrolling interests in a subsidiary (formerly called minority interests) and for the deconsolidation of a subsidiary. The adoption of this authoritative guidance did not have a material impact on our financial statements.

In March 2008, the FASB issued authoritative guidance, which changes the disclosure requirements for derivative instruments and hedging activities. Expanded disclosures are required to provide information about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for, and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. The adoption of this authoritative guidance did not have a material impact on our financial statements. We have expanded our disclosures accordingly. See Note 4 to the unaudited financial statements.

In June 2008, the FASB issued authoritative guidance, which clarifies that share-based payment awards that entitle their holders to receive nonforfeitable dividends before vesting should be considered participating securities. As participating securities, these instruments should be included in the earnings allocation in computing basic earnings per share under the two-class method described in authoritative guidance. All prior period earnings per share data presented shall be adjusted retrospectively to conform with the provisions of this guidance. This guidance is effective for financial statements issued for fiscal years beginning after December 15, 2008 and interim periods within those years. The adoption of this authoritative guidance did not have a material impact on our financial statements. See Note 12 to the unaudited financial statements.

In December 2008, the Securities and Exchange Commission adopted revisions to its oil and gas disclosure requirements that are intended to align them with current practices and changes in technology. Among other things, the amendments will: replace the single-day year-end pricing assumption with a twelve-month average pricing assumption; permit the disclosure of probable and possible reserves; allow the use of certain technologies to establish reserves; require the disclosure of the qualifications of the technical person primarily responsible for preparing the reserves estimates or conducting a reserves audit; require the filing of the independent reserve engineers' summary report; and permit the disclosure of a reserves sensitivity analysis table to illustrate the impact of different price and/or cost assumptions on reserves. These amendments are effective for registration statements filed on or after January 1, 2010, and for annual reports on Form 10-K for fiscal years ending on December 31, 2009, with early adoption prohibited. The Company is currently evaluating the impact that the adoption of this pronouncement will have on the Company's financial position, results of operations, and disclosures.

In April 2009, the FASB issued authoritative guidance which requires disclosures about fair value of financial instruments for interim reporting periods as well as in annual financial statements. The adoption of this authoritative guidance did not have a material impact on our financial statements. We have expanded our disclosures accordingly. See Note 3 – to the unaudited financial statements.

In May 2009, the FASB issued authoritative guidance, which establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. We implemented this guidance during the second quarter of 2009 and we expanded our disclosures accordingly. See Note 15 to the unaudited financial statements.

In June 2009, the FASB approved the FASB Accounting Standards Codification (ASC), which after its effective date of July 1, 2009 is the single source of authoritative, nongovernmental U.S. Generally Accepted Accounting Principles (GAAP). The Codification reorganizes all previous U.S. GAAP pronouncements into roughly 90 accounting topics and displays all topics using a consistent structure. All existing standards that were used to create the Codification are now superseded, replacing the previous references to specific Statements of Financial Accounting Standards (SFAS) with numbers used in the Codification's structural organization. The adoption of this authoritative guidance did not have a material impact on our financial statements. We have updated our disclosures accordingly.

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)," "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. 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 dated February 25, 2009, 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 Form 10-Q.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

As discussed in Note 4 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, we enter into crude oil and natural gas hedge contracts from time to time. 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 some 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.   The collar strike prices allow us to protect our cash flow if oil prices decline below our floor prices which range from $55.00 to $100.00 per barrel while still participating in any oil price increase up to the ceiling prices which range from $68.00 to $163.60 per barrel on the volumes indicated above. In total, we have approximately 90% and 75% of our expected 2009 and 2010 oil production hedged in the form of swaps and collars. Our natural gas collars have a floor of from $6.00 to $6.50 per MMBtu and ceilings ranging from $8.60 to $8.90 per MMBtu. In total, we have approximately 25% of both our 2009 and 2010 expected natural gas production hedged in the form of swaps and collars.

The following table summarizes our commodity hedge position as of September 30, 2009:

Term	Average Barrels Per Day	Average Prices
Crude Oil Sales (NYMEX WTI) Collars		
Full year 2009	295	$80.00/$91.00
Full year 2009	1,000	$100.00/$163.60
Full year 2009	1,000	$100.00/$150.30
Full year 2009	1,000	$100.00/$160.00
Full year 2009	1,000	$100.00/$150.00
Full year 2009	1,000	$100.00/$157.48
Full year 2010	1,000	$65.15 / $75.00
Full year 2010	1,000	$65.50 / $78.50
Full year 2010	280	$80.00 / $90.00
Full year 2010	1,000	$100.00/$161.10
Full year 2010	1,000	$100.00/$150.30
Full year 2010	1,000	$100.00/$160.00
Full year 2010	1,000	$100.00/$150.00
Full year 2010	1,000	$100.00/$158.50
Full year 2010	1,000	$70.00/$86.00
Full year 2011	270	$80.00/$90.00
Full year 2011	1,000	$55.20/$70.00
Full year 2011	1,000	$55.00/$70.50
Full year 2011	1,000	$55.00/$68.65
Full year 2011	1,000	$55.00/$68.00
Full year 2011	1,000	$55.00/$71.20
Full year 2011	1,000	$60.00/$76.00
Full year 2011	1,000	$60.00/$81.25
Full year 2012	1,000	$63.00/$82.60
Full year 2012	1,000	$63.00/$83.50
Full year 2012	1,000	$70.00/$93.00
Crude Oil Sales (NYMEX WTI) Swaps		
Full year 2009	240	$71.50
Full year 2009	1,000	$70.30
Full year 2009	1,000	$70.50
4th Quarter 2009	2,000	$55.00
Full year 2009	1,000	$54.67
Full year 2009	2,000	$54.10
Full year 2009	5,000	$54.39
Full year 2010	1,000	$61.00
Full year 2010	1,000	$61.25
Full year 2010	1,000	$64.80
Full year 2010	1,000	$62.03
Full year 2010	1,000	$63.00
Full year 2010	1,000	$63.75
Full year 2010	650	$56.90
Full year 2011	500	$57.36
Full year 2011	500	$57.40
Full year 2011	500	$57.50
Full year 2011	250	$61.80
October 2009	1,613	$65.85
November 2009	1,667	$65.85

Term	Average MMBtu Per Day	Average Price
Natural Gas Sales (NYMEX HH TO PEPL) Basis Swaps		
4th quarter 2009	4,000	$1.05
Full year 2009	2,000	$1.24
Full year 2009	3,000	$1.19
Full year 2010	2,000	$1.05
Full year 2010	3,000	$1.00
Natural Gas Sales (NYMEX HH) Swaps		
Full year 2009	2,000	$6.15
Full year 2009	3,000	$6.19
4th quarter 2009	4,000	$8.50
July – December 2009	5,000	$4.21
Full year 2010	5,000	$6.02
Full year 2011	5,000	$6.89
Full year 2012	5,000	$7.16
Natural Gas Sales (NYMEX HH) Collars		
Full year 2010	2,000	$6.00/$8.60
Full year 2010	3,000	$6.00/$8.65
Full year 2010	1,000	$6.50/$8.75
Full year 2010	1,000	$6.50/$8.85
Full year 2010	2,000	$6.50/$8.90
Natural Gas Sales (NYMEX HH TO NGPL) Basis Swaps		
Full year 2010	2,000	$0.49
Natural Gas Sales (NYMEX HH TO HSC) Basis Swaps		
Full year 2010	2,000	$0.38
July – December 2009	2,500	$0.031
Full year 2010	2,500	$0.345
Full year 2011	2,500	$0.325
Full year 2012	2,500	$0.320
Natural Gas Sales (NYMEX HH to NGPL-Tex OK) Basis Swaps		
July – December 2009	2,500	$0.475
Full year 2010	2,500	$0.415
Full year 2011	2,500	$0.460
Full year 2012	2,500	$0.440

Berry Petroleum Company

We generally utilize NYMEX WTI based derivatives to hedge cash flows from our California oil sales. Our oil sales contracts with multiple refiners are primarily based on the field posting prices. There is a high correlation between WTI and the field posting prices which allows us to utilize hedge accounting. As there is a ready market for our crude oil in California, we do not believe the loss of any particular refiner impacts the probability that our hedged forecasted transactions will occur. We generally hedge our natural gas at the basis location that corresponds to the sale.

While we designate the majority of our hedges as cash flow hedges, we have not elected hedge accounting on certain of our crude oil and natural gas hedges. During the three and nine months ended September 30, 2009, we recorded $0.5 million and $6.6 million under the caption “Gain (loss) on derivatives” related to hedges for which we either did not elect hedge accounting or which no longer qualified for hedge accounting. In conjunction with the sale of the DJ basin assets, during the first quarter of 2009, we concluded that the forecasted transaction in certain of our hedging relationships was not probable of occurring. As such, we reclassified a gain of $14.3 million from accumulated other comprehensive income (loss) to the statement of operations under the caption “Gain (loss) on derivative.” Additionally, a portion of the change in fair value for hedges that we have designated as cash flow hedges may impact our income as our sales price is not perfectly correlated with our hedges. We recognized an unrealized net loss of $0.5 million and $0.4 million on the statement of operations under the caption “Gain (loss) on derivatives” for the three and nine months ended September 30, 2009, respectively, as a result of ineffectiveness. During the first quarter of 2009, we entered into natural gas derivatives on behalf of the purchaser of our DJ assets. We did not elect hedge accounting for these hedges and recorded an unrealized net loss of $0.5 million on the statement of operations under the caption “(Loss) income from discontinued operations, net of taxes.”

We have entered into interest rate hedges as shown below to swap the floating rate under our senior secured credit facility (LIBOR) for a fixed interest rate. These interest rate swaps have been designated as cash flow hedges.

Hedge Term	Notional Amount $MM	Fixed Rate
4/1/2009 – 6/30/2012	100	4.74%
4/15/2009 – 7/15/2012	100	1.99%
9/15/2009 – 7/15/2012	50	2.31%

The related cash flow impact of all of our hedges is reflected in cash flows from operating activities. At September 30, 2009, our net fair value of derivative liability was $31.3 million as compared to a net fair value asset of $185.9 million at December 31, 2008 which reflects increases in commodity prices. Based on NYMEX strip pricing as of September 30, 2009, we expect to receive cash under the existing derivatives of $14.7 million during the next twelve months. At September 30, 2009, Accumulated Other Comprehensive Income (Loss) consisted of $17.2 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, 2009. Deferred net losses recorded in “Accumulated Other Comprehensive Income (Loss)” at September 30, 2009 and subsequent mark-to-market changes in the underlying hedging contracts are expected to be reclassified to earnings in the same period that the forecasted transaction impacts earnings.

Berry Petroleum Company

Based on average NYMEX futures prices as of September 30, 2009 (WTI $76.24; HH $6.51) for the term of our hedges we would expect to make pre-tax future cash payments or to receive payments over the remaining term of our crude oil and natural gas hedges in place as follows:

	September 30, 2009 NYMEX Futures	Impact of percent change in futures prices on pre-tax future cash (payments) and receipts -40%	-20%	+ 20%	+40%
Average WTI Futures Price (2009 – 2012)	$ 76.24	$ 45.75	$ 61.00	$ 91.49	$ 106.74
Average HH Futures Price (2009 – 2010)	6.51	3.91	5.21	7.81	9.12
Crude Oil gain/(loss) (in millions)	$ (8.8)	$ 276.9	$ 118.0	$ (163.6)	$ (323.9)
Natural Gas gain/(loss) (in millions)	(0.9)	29.9	19.5	0.8	(6.3)
Total	$ (9.7)	$ 306.8	$ 137.5	$ (162.8)	$ (330.2)
Net pre-tax future cash (payments) and receipts by year (in millions) based on average price in each year:					
2009 (WTI $70.76: HH $4.72)	$ (1.7)	$ 47.6	$ 24.2	$ (22.5)	$ (45.8)
2010 (WTI $73.84; HH $6.13)	19.1	199.0	108.3	(53.8)	(134.6)
2011 (WTI $77.15)	(27.2)	43.7	2.3	(79.6)	(134.5)
2012 (WTI $79.11)	0.1	16.5	2.7	(6.9)	(15.3)
Total	$ (9.7)	$ 306.8	$ 137.5	$ (162.8)	$ (330.2)

Interest Rates. Our exposure to changes in interest rates results primarily from long-term debt. In October 2006, we issued, in a public offering, $200 million of 8.25% senior subordinated notes due 2016. In May 2009, we issued, in a public offering, $325 million of 10.25% senior notes due 2014. In August 2009, we issued, in a public offering, an additional $125 million of 10.25% senior notes due 2014. At September 30, 2009, total long-term debt outstanding was $1 billion. Interest on amounts borrowed under our credit facility is charged at LIBOR plus 2.25% to 3.0%, with the exception of the principal for which we have hedged, plus the credit facility's margin through July 15, 2012. Based on September 30, 2009 credit facility borrowings, a 1% change in interest rates, including our interest rate hedges, would have an annualized $1 million after tax impact on our financial statements.

Item 4. Controls and Procedures

As of September 30, 2009, we have carried out an evaluation under the supervision of, and with the participation of, our 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 ("Exchange Act").

Our Chief Executive Officer and Chief Financial Officer have concluded that, as of September 30, 2009, our disclosure controls and procedures are effective to ensure that the information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms, and that information required to be disclosed by us in such reports is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

There was no change in our internal control over financial reporting that occurred during the three months ended September 30, 2009 that materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

In September 2009 a final consent agreement with the U.S. Environmental Protection Agency was approved relating to alleged late filing of certain leak detection and repair reports for one of our facilities in Utah. We paid a penalty of $36,000 and are obligated to spend $114,000 for an agreed supplemental environmental project. In an unrelated matter, also in September 2009, we entered into a settlement agreement with the Colorado Department of Health and Environment relating to an alleged failure to implement certain best management practices designed to limit impacts to storm water discharges at certain of our construction sites in Colorado. Under the agreement, which is currently subject to a public comment period, we will pay a penalty of $150,000 and will spend an additional $250,000 on two agreed supplemental environmental projects.

In July 2009, we received a notice of proposed civil penalty from the Bureau of Land Management (BLM) related to the Company's alleged non-compliance during 2007 with regulations relating to the operation and position of certain valves in our Uinta Basin operations. The proposed civil penalty was $69.6 million and reflects the theoretical maximum penalty amount under applicable regulations, absent mitigating factors. In 2007 we immediately remediated the instances of non-compliance, cooperated fully with the BLM's investigation and we believe no production was lost, all royalties were paid and there was no harm to the environment. Due to the above mitigating factors, among others, we believe this matter will be resolved by the payment of a penalty that will not exceed $2.1 million and have accrued such amount in the second quarter of 2009.

Item 1A. Risk Factors

We are subject to complex federal, state, regional, local and other laws and regulations that could give rise to substantial liabilities from environmental contamination or otherwise adversely affect our cost, manner or feasibility of doing business.

All facets of our operations are regulated extensively at the federal, state, regional and local levels. In addition, a portion of our leases in Uinta are, and some of our future leases may be, regulated by Native American tribes. Environmental laws and regulations impose limitations on our discharge of pollutants into the environment, establish standards for our management, treatment, storage, transportation and disposal of hazardous materials and of solid and hazardous wastes, and impose on us obligations to investigate and remediate contamination in certain circumstances. We also must satisfy, in some cases, federal and state requirements for providing environmental assessments, environmental impact studies and/or plans of development before we commence exploration and production activities. Environmental and other requirements applicable to our operations generally have become more stringent in recent years, and compliance with those requirements more expensive. Frequently changing environmental and other governmental laws and regulations have increased our costs to plan, design, drill, install, operate and abandon oil and natural gas wells and other facilities, and may impose substantial liabilities if we fail to comply with such regulations or for any contamination resulting from our operations. Our business results from operations and financial condition may be adversely affected by any failure to comply with, or future changes to, these laws and regulations. In particular, failure to comply with these laws and regulations may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties.

From time to time we have experienced accidental spills, leaks and other discharges of contaminants at some of our properties. We could be liable for the investigation or remediation of such contamination, as well as other liabilities concerning hazardous materials or contamination such as claims for personal injury or property damage. We have incurred expenses and penalties in connection with remediation of contamination in the past, and we may do so in the future. Such liabilities may arise at many locations, including properties in which we have an ownership interest but no operational control, properties we formerly owned or operated and sites where our wastes have been treated or disposed of, as well as at properties that we currently own or operate, and may arise even where the contamination does not result from any noncompliance with applicable environmental laws. Under a number of environmental laws, including the Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), such liabilities may be joint and several, meaning that we could be held responsible for more than our share of the liability involved, or even the entire share. Some of the properties that we have acquired, or in which we may hold an interest but not operational control, may have past or ongoing contamination for which we may be held responsible. Some of our operations are in environmentally sensitive areas that may provide habitat for endangered or threatened species, and other protected areas, and our operations in such areas must satisfy additional regulatory requirements. Moreover, public interest in environmental protection has increased in recent years, and environmental organizations have opposed certain drilling projects and/or access to prospective lands and have filed litigation to attempt to stop such projects, including decisions by the Bureau of Land Management regarding several leases in Utah that we have been awarded.

Our activities are also subject to regulation by oil and natural gas-producing states and one Native American tribe of conservation practices and protection of correlative rights. These regulations affect our operations and limit the quantity of oil and natural gas we may produce and sell. A major risk inherent in our drilling plans is the need to obtain drilling permits from federal, state, local and Native American tribal authorities. Delays in obtaining regulatory approvals or drilling permits, the failure to obtain a drilling permit for a well, or the receipt of a permit with unreasonable conditions that are more expensive than we have anticipated could have a negative effect on our ability to explore or develop our properties. Additionally, the oil and natural gas regulatory environment could change in ways that might substantially increase the financial and managerial costs to comply with the requirements of these laws and regulations and, consequently, adversely affect our profitability.

Recent and future environmental laws and regulations, including additional federal and state restrictions on greenhouse gas emissions that may be passed in response to climate change concerns, may increase our operating costs and also reduce the demand for the oil and natural gas we produce. The oil and gas industry is a direct source of certain greenhouse gas (GHG) emissions, such as carbon dioxide and methane, and future restrictions on such emissions could impact our future operations. Specifically, on April 17, 2009, EPA issued a notice of its proposed finding and determination that emission of carbon dioxide, methane, and other GHGs present an endangerment to human health and the environment because emissions of such gases are, according to EPA, contributing to warming of the earth’s atmosphere. EPA’s proposed finding and determination~~,~~ allows it to begin regulating emissions of GHGs under existing provisions of the federal Clean Air Act. To this end, on September 22, 2009, EPA issued a “Mandatory Reporting of Greenhouse Gases” final rule (“Reporting Rule”). The Reporting Rule establishes a new comprehensive scheme requiring operators of stationary sources emitting more than established annual thresholds of carbon dioxide-equivalent GHGs to inventory and report their GHG emissions annually on a facility-by-facility basis. EPA has stated that it intends to review public comments and other relevant information before requiring compliance with the Reporting Rule by oil and gas systems sources, such as oil and gas production, processing and transmission. Monitoring obligations for other source categories will begin on January 1, 2010, and reporting of emissions from the 2010 calendar year is required by no later than March 31, 2011. It is unclear how long it will take EPA to revise the Reporting Rule so that it will be applicable to oil and gas systems. In addition, EPA has proposed a stationary source GHG permitting rule that would establish "significance levels" for major GHGs that would trigger review and permitting requirements. Compliance with the Reporting Rule and any other GHG regulation could require us to incur increased costs. . Similarly, on June 26, 2009, the U.S. House of Representatives approved adoption of the “American Clean Energy and Security Act of 2009,” also known as the “Waxman-Markey cap-and-trade legislation” or ACESA. ACESA would establish an economy-wide cap on emissions of GHGs in the United States and would require most sources of GHG emissions to obtain GHG emission “allowances” corresponding to their annual emissions of GHGs. The U.S. Senate has begun work on its own legislation for controlling and reducing emissions of GHGs in the United States. Any laws or regulations that may be adopted to restrict or reduce emissions of GHGs would likely require us to incur increased operating costs and could have an adverse effect on demand for the oil and natural gas we produce. At the state level, more than one-third of the states, including California, have begun taking actions to control and/or reduce emissions of GHGs. The California Global Warming Solutions Act of 2006, also known as “AB 32,” caps California’s greenhouse gas emissions at 1990 levels by 2020, and the California Air Resources Board is currently developing mandatory reporting regulations and early action measures to reduce GHG emissions prior to January 1, 2012. Although most of the regulatory initiatives developed or being developed by the various states have to date been focused on large sources of GHG emissions, such as coal-fired electric power plants, it is possible that smaller sources of emissions could become subject to GHG emission limitations in the future. A number of our personnel are involved in monitoring the establishment of these regulations through industry trade groups and other organizations in which we are a member. It is not possible, at this time, to estimate accurately how these regulations would impact our business.

In addition, the U.S. Congress is currently considering certain other legislation which, if adopted in its current proposed form, could subject companies involved in oil and natural gas exploration and production activities to substantial additional regulation. If such legislation is adopted, federal tax incentives could be curtailed, and hedging activities as well as certain other business activities of exploration and production companies could be limited, resulting in increased operating costs. Any such limitations or increased operating costs could have a material adverse effect on our business.

A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase.

Section 1(b) of the Natural Gas Act (“NGA”) exempts natural gas gathering facilities from regulation by the Federal Energy Regulatory Commission (“FERC”) as a natural gas company under the NGA. We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline’s status as a gatherer not subject to regulation as a natural gas company, but the status of these lines has never been challenged before FERC. The distinction between FERC-regulated transmission services and federally unregulated gathering services is subject to change based on future determinations by FERC, the courts, or Congress, and application of existing FERC policies to individual factual circumstances. Accordingly the classification and regulation of some of our natural gas gathering facilities may be subject to challenge before FERC or subject to change based on future determinations by FERC, the courts, or Congress. In the event our gathering facilities are reclassified to FERC-regulated transmission services, we may be required to charge lower rates and our revenues could thereby be reduced.

Should we fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

FERC has issued an order requiring certain participants in the natural gas market, including natural gas gatherers and marketers that engage in a minimum level of natural gas sales or purchases to submit annual reports regarding those transactions to FERC. In addition, FERC has issued an order requiring major non-interstate pipelines, defined as certain non-interstate pipelines delivering, on an annual basis, more than an average of 50 million MMBtu of gas over the previous three calendar years, to post daily certain information regarding the pipeline’s capacity and scheduled flows for each receipt and delivery point that has design capacity equal to or greater than 15,000 MMBtu per day. Should we fail to comply with these requirements or any other applicable FERC-administered statute, rule, regulation or order, we could be subject to substantial penalties and fines. Under the Energy Policy Act of 2005, or EP Act 2005, FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1 million per day for each violation and disgorgement of profits associated with any violation.

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
4.1	Form of 10¼% Senior Notes due 2014 (included in Exhibit 4.2 to the Registrant's Current Report on Form 8-K on August 17, 2009, File No. 1-9735).
10.1	Underwriting Agreement, dated August 11, 2009, by and among Registrant and Wachovia Capital Markets, LLC, RBS Securities Inc., BNP Paribas Securities Corp., SG Americas Securities, LLC and Calyon Securities (USA) Inc., as representatives of the underwriters named therein (filed as Exhibit 1.1 to the Registrant's Current Report on Form 8-K on August 13, 2009, File No. 1-9735).
10.2*	Crude Oil Purchase Contract dated September 24, 2009 between the Registrant and ExxonMobil Oil Corporation.
12.1	Computation of Ratio of Earnings to Fixed Charges
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

* Portions of this exhibit have been omitted pursuant to a request for confidential treatment.

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
Vice President of Finance
(Principal Accounting Officer)

Date: October 30, 2009

Exhibit 10.2

Confidential Portions Redacted and Filed with the Commission pursuant to 17 CFR 200.83.
"*" Symbolizes Language Omitted Pursuant to an Application For Confidential Treatment.**

EXXONMOBIL OIL CORPORATION – CRUDE CONTRACT

AGREEMENT DATE: 08/19/2009 TODAY'S DATE: 09/24/2009 PAGE: 1 OF 5

TO: BERRY PETROLEUM CO FROM: EXXONMOBIL OIL CORPORATION
RON CROSS (303.999.4141) ***
3039994141 (FAX) *** (FAX)

THIS FORMALIZES OUR AGREEMENT TO AMEND THE REFERENCED AGREEMENT, WHICH HAD AN EFFECTIVE DATE OF 08/19/2009 ENTERED INTO BETWEEN EXXONMOBIL OIL CORPORATION,
HEREINAFTER KNOWN AS "EXXONMOBIL", AND BERRY PETROLEUM CO (HEREINAFTER CALLED "CUSTOMER"), AS SUCH AGREEMENT MAY HAVE BEEN AMENDED THEREAFTER FROM TIME TO TIME.

EXXONMOBIL CONTRACT: 7017521 BRRY1403TE CUSTOMER CONTRACT:

AMENDMENT INTENT:
CHANGING DELIVERY/LOCATION VERBAGE OF CONTRACT TO READ AS FOLLOWS:
A. SECTION 1: "INTO EXXONMOBIL SJV PIPELINE VIA EXXONMOBIL DUVALL VIA SHELL PIPELINE FROM BERRY CENTRAL LEASES."
B. SECTION 4: "INTO CONOCOPHILLIPS COMMON CARRIER PIPELINE LINE 100) FROM FORMAX LEASES."

NOTE: "TOTAL CONTRACT VOLUME …… LIMITED TO 100% OF THE LEASE PRODUCTION AT BERRY CENTRAL, …"
REQUESTED BY BERRY PETROLEUM (RON CROSS), APPROVED BY *** - 09/24/09.

EXXONMOBIL RECEIVES (BUYS) :

CRUDE TYPE: 01) SAN JOAQUIN VALLEY.
02) SAN JOAQUIN VALLEY.
03) SAN JOAQUIN VALLEY.
04) SAN JOAQUIN VALLEY.

VOLUME: 01) 4,900 BARRELS PER DAY
02) 1,400 BARRELS PER DAY
03) 4.200 BARRELS PER DAY
04) 2,100 BARRELS PER DAY

PRICE: EXXONMOBIL AGREES TO PAY BERRY PETROLEUM CO
01) FORMULA NUMBER: 1000202237
PRICE FOR CRUDE OIL SHALL BE THE AVERAGE OF CHEVRON/UNOCAL/EXXONMOBIL/ SHELL TRADING COMPANY PRICES POSTED FOR MIDWAY SUNSET CRUDE OIL DURING THE DELIVERY MONTH, *** $*** PER NET BARREL DIFFERENTIAL, ADJUSTED FOR ACTUAL GRAVITY DELIVERED BASED ON THE AVERAGE OF CHEVRON/UNOCAL/EXXONMOBIL/SHELL TRADING COMPANY GRAVITY SCALES. DELIVERIES TO BE DEEMED EQUAL DAILY QUANTITES.

DELIVERY VOLUME/LOCATION: APPROXIMATELY 4,900 BARRELS PER DAY -

TO: BERRY PETROLEUM CO FROM: EXXONMOBIL OIL CORPORATION
RON CROSS (303.999.4141) ***
3039994141 (FAX) *** (FAX)

INTO EXXONMOBIL SJV PIPELINE VIA EXXONMOBIL DUVALL VIA SHELL PIPELINE FROM BERRY CENTRAL LEASES.

Confidential Portions Redacted and Filed with the Commission pursuant to 17 CFR 200.83.
"*" Symbolizes Language Omitted Pursuant to an Application For Confidential Treatment.**

02) FORMULA NUMBER: 1000202238
PRICE FOR CRUDE OIL SHALL BE THE AVERAGE OF CHEVRON/UNOCAL/EXXONMOBIL/

SHELL TRADING COMPANY PRICES POSTED FOR MIDWAY SUNSET CRUDE OIL
DURING THE DELIVERY MONTH, *** $*** PER NET BARREL DIFFERENTIAL,
ADJUSTED FOR ACTUAL GRAVITY DELIVERED BASED ON THE AVERAGE OF
CHEVRON/UNOCAL/EXXONMOBIL/SHELL TRADING COMPANY GRAVITY SCALES.
DELIVERIES TO BE DEEMED EQUAL DAILY QUANTITES.

DELIVERY VOLUME/LOCATION: APPROXIMATELY 1,400 BARRELS PER DAY –
INTO PLAINS PIPELINE GATHERING LINE
FROM ETHEL D.

03) FORMULA NUMBER: 1000202239
PRICE FOR CRUDE OIL SHALL BE THE AVERAGE OF CHEVRON/UNOCAL/EXXONMOBIL/
SHELL TRADING COMPANY PRICES POSTED FOR MIDWAY SUNSET CRUDE OIL
DURING THE DELIVERY MONTH, *** $*** PER NET BARREL DIFFERENTIAL,
ADJUSTED FOR ACTUAL GRAVITY DELIVERED BASED ON THE AVERAGE OF
CHEVRON/UNOCAL/EXXONMOBIL/SHELL TRADING COMPANY GRAVITY SCALES.
DELIVERIES TO BE DEEMED EQUAL DAILY QUANTITES.

DELIVERY VOLUME/LOCATION: APPROXIMATELY 4,200 BARRELS PER DAY - INTO PLAINS PIPELINE GATHERING LINE
FROM FAIRFIELD LEASES.

04) FORMULA NUMBER: 1000202240
PRICE FOR CRUDE OIL SHALL BE THE AVERAGE OF CHEVRON/UNOCAL/EXXONMOBIL/
SHELL TRADING COMPANY PRICES POSTED FOR MIDWAY SUNSET CRUDE OIL
DURING THE DELIVERY MONTH, *** $*** PER NET BARREL DIFFERENTIAL,
ADJUSTED FOR ACTUAL GRAVITY DELIVERED BASED ON THE AVERAGE OF
CHEVRON/UNOCAL/EXXONMOBIL/SHELL TRADING COMPANY GRAVITY SCALES.
DELIVERIES TO BE DEEMED EQUAL DAILY QUANTITES.

DELIVERY VOLUME/LOCATIONS: APPROXIMATELY 2,100 BARRELS PER DAY –

INTO CONOCOPHILLIPS COMMON CARRIER

PIPELINE (LINE 100) FROM FORMAX LEASES.

NOTE: TOTAL CONTRACT VOLUME IS APPROXIMATELY 12, 600 BARRELS
PER DAY (378k BARRELS PER MONTH) – LIMITED TO 100% OF THE
LEASE PRODUCTION AT BERRY CENTRAL, ETHEL D, FORMAX,
AND FAIRFIELD LEASES.

++
THE FOLLOWING ADDITIONAL PROVISIONS APPLY TO THE ENTIRETY OF
THE CONTRACT:
1) IN THE EVENT THE CRUDE OIL WILL BE EXPORTED FROM THE
UNITED STATES, BUYER UNDERTAKES TO DETERMINE ANY EXPORT
LICENSE REQUIREMENTS. TO OBTAIN ANY EXPORT LICENSE OR
OTHER OFFICIAL AUTHORIZATIOINS, AND TO CARRY OUT ANY
CUSTOMS FORMALITIES FOR THE EXPORT OF THE CRUDE OIL.
2) MEASUREMENT AND TEST: ALL CALIFORNIA CRUDE OIL
PRODUCTION DELIVERED AND RECEIVED BY BOTH PARTIES
SHALL NOT EXCEED 3% BS&W.

3) PRESS RELEASES OR ANNOUNCEMENTS WITH REGARD TO THIS
CONTRACT HAVE TO BE CLEARED IN ADVANCE BY BOTH PARTIES.

DELIVERY: 01) WEST COAST PIPELINE CO AT: DUVALL ROAD, CA
02) PLAINS MARKETING & AT: ETHEL D, CA
03) PLAINS MARKETING & AT: BERRY FAIRFIELD, CA
04) CONOCOPHILLIPS COMMON CARRIER AT: FORMAX LEASE, CA

TERMINATION: BEGINNING OCTOBER 1, 2009 THRU SEPTEMBER 30, 2010.
FOLLOWING THIS INITIAL PERIOD, THIS AGREEMENT SHALL
CONTINUE THEREAFTER ON A MONTH-TO-MONTH BASIS UNLESS
CONTRACT IS CANCELLED BY EITHER PARTY WITH A 60-DAY

NOTICE OF CANCELLATION. FIRST NOTICE OF CANCELLATION
SHALL NOT BE GIVEN PRIOR TO AUGUST 1, 2010.

OTHER SPECIAL PROVISIONS:
PLEASE REFER TO CONTRACT NUMBER BRRY1403TE ON ALL CORRESPONDENCE INCLUDING STATEMENTS AND WIRE TRANSFERS

GENERAL TERMS:
CONOCO'S GENERAL PROVISIONS FOR DOMESTIC CRUDE OIL AGREEMENTS DATED

JANUARY 1, 1993 ARE INCORPORATED HEREIN BY REFERENCE AND MADE PART OF THIS AGREEMENT. IN THE EVENT OF A CONFLICT BETWEEN THESE GENERAL TERMS

AND CONDITIONS AND THE SPECIFIC TERMS AND CONDITIONS OF THE AGREEMENT, THE SPECIFIC TERMS AND CONDITIONS SHALL GOVERN.

PAYMENT TERMS:

TO:	BERRY PETROLEUM CO	FROM:	EXXONMOBIL OIL CORPORATION
RON CROSS (303.999.4141)		***	
3039994141 (FAX)		*** (FAX)	

IN CONSIDERATION FOR THE MUTUAL EFFICIENCIES ARISING FROM NET SETTLEMENT, UNLESS OTHERWISE SPECIFIED, THE PARTIES WILL USE THE FOLLOWING PROCEDURE, EXCEPT AS TO CONTRACTS FOR THE DELIVERY OF CRUDE OIL AND/OR CONDENSATE DELIVERED BY TANKER(S) AND CONTRACTS SECURED BY PREPAYMENT AND/OR DOCUMENTARY LETTER(S) OF CREDIT, WHICH SHALL BE EXCLUDED FROM THIS CLAUSE AND PAID ACCORDING TO THE PROVISIONS OF THE APPLICABLE CONTRACTS BETWEEN THE PARTIES. THE PARTIES SHALL CONTINUE TO ISSUE INVOICES. IN ACCORDANCE WITH CONTRACT TERMS, IN THE NORMAL COURSE OF BUSINESS. ON OR BEFORE THE 20TH CALENDAR DAY (OR THE PRECEDING BUSINESS DAY,   IF THE 20TH IS NOT A BUSINESS DAY) OF THE MONTH FOLLOWING THE MONTH DURING WHICH DELIVERIES OCCUR PURSUANT TO TERMS OF CONTRACTS BETWEEN THE PARTIES, THE PARTIES WILL COMMUNICATE AND CONFIRM THE INVOICED AMOUNTS TO BE INCLUDED IN THE NET PAYMENT (OR NET SETTLEMENT) OF ACCOUNTS. ANY REMAINING BALANCE SHALL BE PAID BY THE PARTY OWING SUCH AMOUNT TO THE OTHER PARTY ON THE DATE THE GROSS AMOUNTS ARE DUE PER THE CONTRACTS.

TITLE TRANSFER:
BY TRANSFER FROM DELIVERING PARTY'S TO RECEIVING PARTY'S ACCOUNT AT THE LOCATION(S) DESCRIBED HEREIN, AT WHICH POINT(S) TITLE SHALL PASS AS EVIDENCED BY RUN TICKETS/ALLOCATION STATEMENTS ISSUED BY THE CARRIER(S) INVOLVED.

FINAL AGREEMENT:
THIS CONTRACT, INCLUDING THE ABOVE REFERENCED GENERAL TERMS COMPRISES THE ENTIRE AGREEMENT BETWEEN THE PARTIES AND MERGES AND SUPERSEDES ALL PRIOR REPRESENTATIONS AND UNDERSTANDINGS BETWEEN THE PARTIES HERETO COVERING THE SUBJECT MATTER HEREOF.

ASSIGNMENT CLAUSE:
NEITHER PARTY SHALL ASSIGN THIS AGREEMENT WITHOUT THE PRIOR WRITTEN CONSENT OF THE OTHER. NOTWITHSTANDING THE FOREGOING, EXXONMOBIL OIL CORPORATION SHALL HAVE THE RIGHT TO ASSIGN THIS AGREEMENT TO AN AFFILIATE WITHOUT WRITTEN CONSENT, BY PROVIDING WRITTEN NOTICE TO THE OTHER PARTY.

DOCUMENTATION INSTRUCTIONS:
THIS DOCUMENT EVIDENCES OUR UNDERSTANDING OF THE ENTIRE AGREEMENT AND SHALL CONSTITUTE THE FORMAL CONTRACT. PLEASE CONFIRM BY IMMEDIATE FAX TO THE EXXONMOBIL CONTRACT ADMINISTRATOR THAT THE ABOVE IS IN ACCORDANCE WITH YOUR UNDERSTANDING. ABSENT WRITTEN NOTICE OF

OBJECTION, WE ASSUME YOUR AGREEMENT TO THESE TERMS AND CONDITIONS. YOUR

RESPONSE SHOULD REFLECT THE APPROPRIATE PARTY IN YOUR ORGANIZATION WHO HAS THE AUTHORITY TO ENTER INTO THIS AGREEMENT.

INVOICES TO EXXONMOBIL SHOULD BE MAILED OR FAXED AS FOLLOWS:
EXXONMOBIL OIL CORPORATION
***

ATTN: RAW MATERIALS ACCOUNTING

TO: BERRY PETROLEUM CO FROM: EXXONMOBIL OIL CORPORATION
RON CROSS (303.999.4141) ***
3039994141 (FAX) *** (FAX)

FAX # *** (INVOICES ONLY)

EXXONMOBIL CONTRACT ADMINISTRATOR: *** (PH) ***

EXCEPT AS NOTED ABOVE, ALL OTHER PROVISIONS FOR THE AGREEMENT REMAIN UNCHANGED. PLEASE ACKNOWLEDGE RECEIPT OF THIS CONFIRMATION BY RETURN FAX TO ***. ABSENT WRITTEN
NOTICE OF OBJECTION, WE ASSUME YOUR ACCEPTANCE OF THESE TERMS AND CONDITIONS.

SIGNATURE: ***

Exhibit 12.1

COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
(in thousands, except ratios)

	Nine months ended September 30, 2009	12/31/08	12/31/07	12/31/06	12/31/05	12/31/04
Pre-tax income from continuing operations	$ 72,030	$ 192,084	$ 206,344	$ 159,906	$ 150,289	$ 89,518
Interest expense	36,016	26,209	17,287	10,247	6,048	2,067
Capitalized interest	21,145	23,209	18,104	9,339	-	-
Earnings	$ 108,046	$ 218,293	$ 233,631	$ 170,153	$ 156,337	$ 91,585
Ratio of earnings to fixed charges	**1.9**	**4.4**	**6.3**	**8.7**	**25.8**	**44.3**

For purposes of this table, "earnings" consists of income before income taxes from continuing operations plus fixed charges and less capitalized interest. "Fixed charges" consists of interest expense and capitalized interest (for both continuing and discontinued operations).

Certification of Chief Executive Officer

Pursuant to Section 302 of Sarbanes Oxley Act of 2002

I, Robert F. Heinemann, 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, and its condolidated subsidiaries, 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

   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
President, Chief Executive Officer and Director

October 30, 2009

Exhibit 31.2

Certification of Chief Financial Officer

Pursuant to Section 302 of Sarbanes Oxley Act of 2002

I, David D. Wolf, 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, including its consolidated subsidiaries, 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/ David D. Wolf
David D. Wolf
Executive Vice President and Chief Financial Officer

October 30, 2009

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, 2009 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
October 30, 2009 President, Chief Executive Officer and Director

Exhibit 32.2

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, 2009 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, David D. Wolf, 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/ David D. Wolf
David D. Wolf
October 30, 2009 Executive Vice President and Chief Financial Officer