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 March 31, 2010

o Transition 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 filer x	Accelerated filer o
Non-accelerated filer o	Smaller reporting company o

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 April 19, 2010, the registrant had 51,131,921 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 April 19, 2010 all of which is held by an affiliate of the registrant.

BERRY PETROLEUM COMPANY
FIRST QUARTER 2010 FORM 10-Q
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BERRY PETROLEUM COMPANY
Unaudited Condensed Balance Sheets
(In Thousands, Except Share Information)

	March 31, 2010	December 31, 2009
ASSETS		
Current assets:		
Cash and cash equivalents	$ 57	$ 5,311
Short-term investments	65	66
Accounts receivable, net of allowance for doubtful accounts of $38,508	84,764	74,337
Deferred income taxes	10,274	5,623
Fair value of derivatives	6,164	11,527
Prepaid expenses and other	10,878	6,612
Total current assets	112,202	103,476
Oil and gas properties (successful efforts basis), buildings and equipment, net	2,269,848	2,106,385
Fair value of derivatives	2,369	735
Other assets	27,973	29,539
	$ 2,412,392	$ 2,240,135
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 76,641	$ 63,096
Revenue and royalties payable	16,909	25,878
Accrued liabilities	42,498	29,320
Fair value of derivatives	44,851	33,843
Total current liabilities	180,899	152,137
Long-term liabilities:		
Deferred income taxes	251,913	237,161
Senior secured revolving credit facility	270,000	372,000
8¼ % Senior subordinated notes due 2016	200,000	200,000
10¼% Senior notes due 2014, net of unamortized discount of $12,877 and $13,456, respectively	437,124	436,544
Asset retirement obligation	46,919	43,487
Other long-term liabilities	20,150	19,711
Fair value of derivatives	57,773	75,836
	1,283,879	1,384,739
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; 51,126,421 shares issued and outstanding	511	430

(42,952,499 in 2009)		
Class B Stock, 3,000,000 shares authorized; 1,797,784 shares issued and outstanding (liquidation preference of $899)	18	18
Capital in excess of par value	316,313	89,068
Accumulated other comprehensive loss	(56,972)	(60,372)
Retained earnings	687,744	674,115
Total shareholders' equity	947,614	703,259
	$ 2,412,392	$ 2,240,135

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

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BERRY PETROLEUM COMPANY
Unaudited Condensed Statements of Income
Three Months Ended March 31, 2010 and 2009
(In Thousands, Except Per Share Data)

	Three months ended March 31,	
	2010	2009
REVENUES AND OTHER INCOME ITEMS		
Sales of oil and gas	$ 147,807	$ 127,869
Sales of electricity	9,933	10,270
Gas marketing	8,272	7,581
Realized and unrealized gain on derivatives, net	1,603	37,164
Interest and other income, net	164	283
	167,779	183,167
EXPENSES		
Operating costs - oil and gas production	47,036	37,384
Operating costs - electricity generation	9,670	8,783
Production taxes	5,204	5,652
Depreciation, depletion & amortization - oil and gas production	35,907	36,398
Depreciation, depletion & amortization - electricity generation	795	959
Gas marketing	7,786	7,284
General and administrative	13,835	13,294
Interest expense	17,447	10,050
Transaction costs on acquisitions, net of gain	727	—
Dry hole, abandonment, impairment and exploration	1,369	122
	139,776	119,926
Income before income taxes	28,003	63,241
Provision for income taxes	10,334	21,462
Income from continuing operations	17,669	41,779
Loss from discontinued operations, net of taxes	—	(6,781)
Net income	$ 17,669	$ 34,998
Basic net income from continuing operations per share	$ 0.34	$ 0.92
Basic net loss from discontinued operations per share	$ —	$ (0.15)
Basic net income per share	$ 0.34	$ 0.77
Diluted net income from continuing operations per share	$ 0.34	$ 0.92
Diluted net loss from discontinued operations per share	$ —	$ (0.15)
Diluted net income per share	$ 0.34	$ 0.77
Dividends per share	$ 0.075	$ 0.075

Unaudited Condensed Statements of Comprehensive Income
Three Months Ended March 31, 2010 and 2009
(In Thousands)

Net income	$ 17,669	$ 34,998
Unrealized gains on derivatives, net of income taxes of $0 and $48,160, respectively	—	78,577
Reclassification of realized gains on derivatives included in net income, net of income tax benefits of $2,084 and $17,788, respectively	(3,400)	(29,022)
Comprehensive income	$ 14,269	$ 84,553

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

BERRY PETROLEUM COMPANY
Unaudited Condensed Statements of Cash Flows
Three Months Ended March 31, 2010 and 2009
(In Thousands)

	Three months ended March 31, 2010	Three months ended March 31, 2009
Cash flows from operating activities:		
Net income	$ 17,669	$ 34,998
Depreciation, depletion and amortization	36,702	39,545
Amortization of debt issue costs and net discount	2,098	1,088
Gain on purchase of oil and natural gas properties	(1,358)	—
Dry hole and impairment	1,207	9,643
Unrealized loss (gain) on derivatives	2,476	(22,842)
Stock-based compensation expense	3,031	2,988
Deferred income taxes	8,548	21,059
Other, net	—	(5,040)
Cash paid for abandonment	(22)	(112)
Change in book overdraft	(1,377)	(23,510)
Increase in current assets other than cash and cash equivalents	(14,179)	(12,933)
Increase (decrease) in current liabilities other than book overdraft, line of credit and fair value of derivatives	8,720	(36,755)
Net cash provided by operating activities	63,515	8,129
Cash flows from investing activities:		
Exploration and development of oil and gas properties	(47,958)	(50,181)
Property acquisitions	(132,515)	(1,173)
Capitalized interest	(5,967)	(5,312)
Deposits on asset sales	—	14,000
Deposits on potential property acquisitions	(500)	—
Net cash used in investing activities	(186,940)	(42,666)
Cash flows from financing activities:		
Proceeds from issuances on line of credit	76,100	147,800
Payments on line of credit	(76,100)	(173,100)
Long-term borrowings under credit facility	125,000	159,600
Repayments of long-term borrowings under credit facility	(227,000)	(92,000)
Debt issue costs	—	(4,538)
Financing obligation	(83)	—
Dividends paid	(4,040)	(3,416)
Proceeds from issuance of common stock, net	224,337	—
Proceeds from stock option exercises	75	—
Excess tax benefit and other	(118)	—
Net cash provided by financing activities	118,171	34,346
Net decrease in cash and cash equivalents	(5,254)	(191)
Cash and cash equivalents at beginning of year	5,311	240
Cash and cash equivalents at end of period	$ 57	$ 49

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

Berry Petroleum Company
Notes to Unaudited Financial Statements

1. Basis of Presentation

These unaudited Condensed Financial Statements have been prepared in accordance with accounting principles generally accepted in the United States (GAAP) for interim financial reporting. All adjustments which are, in the opinion of management, necessary for a fair statement of Berry Petroleum Company's (the Company) financial position at March 31, 2010 and December 31, 2009 and results of operations and accumulated other comprehensive loss (AOCL) for the three months ended March 31, 2010 and 2009, and its cash flows for the three months ended March 31, 2010 and 2009 have been included. In the opinion of management, all adjustments, which are of a normal recurring nature, have been made which are necessary for a fair presentation of the financial position. Changes in these assumptions, judgments and estimates will occur as a result of the passage of time and the occurrence of future events and, accordingly, actual results could differ from amounts initially established.

The unaudited Condensed Financial Statements have been prepared on a basis consistent with the accounting principles and policies reflected in the December 31, 2009 Financial Statements. For a more complete understanding of the Company's operations, financial position and accounting policies, the Unaudited Condensed Financial Statements and the notes thereto should be read in conjunction with the Company's Annual Report on Form 10-K for the year ended December 31, 2009 previously filed with the SEC. The year-end Condensed Balance Sheet was derived from audited Financial Statements, but does not include all disclosures required by GAAP.

The Company's cash management process provides for the daily funding of checks as they are presented to the bank. Included in accounts payable at March 31, 2010 and December 31, 2009 is $14.4 million and $15.7 million, respectively, representing outstanding checks in excess of the bank balance (book overdraft).

2. Fair Value Measurements

The authoritative guidance for fair value measurements 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 fair value 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. The Company utilizes a mid-market pricing convention (the mid-point price between bid and ask prices) for valuation as a practical expedient for assigning fair value. Oil swaps, natural gas swaps and interest rate swaps are valued using models which are based on active market data and are classified within Level 2 of the fair value hierarchy. 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. These models are industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. The fair value of all derivative instruments are estimated using a combined income and market valuation methodology based upon forward commodity price and volatility curves. The curves are obtained from independent pricing services, and the Company has made no adjustments to the obtained prices. The pricing services publish observable market information from multiple brokers and exchanges. No proprietary models are used by the pricing services for the inputs. All valuations were compared against counterparty valuations to verify the reasonableness of prices. The Company also considers counterparty credit risk and its own credit risk in its determination of all estimated fair values. The Company has consistently applied these valuation techniques in all periods presented and believes it has obtained the most accurate information available for the types of derivative contracts it holds. Level 3 derivatives include oil collars, natural gas collars and natural gas basis swaps. The Company recognizes transfers between levels at the end of the reporting period for which the transfer has occurred.

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The following tables set forth by level within the fair value hierarchy the Company's derivative assets and liabilities that were measured at fair value on a recurring basis as of March 31, 2010 and December 31, 2009.

Assets and liabilities measured at fair value on a recurring basis

March 31, 2010 (in millions)	Total carrying value on the Condensed Balance Sheet	Level 2	Level 3
Commodity derivatives liability	$ (83.7)	$ (49.2)	$ (34.5)
Interest rate derivatives liability	(10.4)	(10.4)	—
Total derivative liabilities at fair value	$ (94.1)	$ (59.6)	$ (34.5)

December 31, 2009 (in millions)	Total carrying value on the Condensed Balance Sheet	Level 2	Level 3
Commodity derivatives liability	$ (88.5)	$ (62.5)	$ (26.0)
Interest rate derivatives liability	(8.9)	(8.9)	—
Total derivative liabilities at fair value	$ (97.4)	$ (71.4)	$ (26.0)

Changes in Level 3 fair value measurements

The table below includes a rollforward of the Condensed Balance Sheet amounts (including the change in fair value) for financial instruments classified by the Company within Level 3 of the fair value hierarchy. When a determination is made to classify a financial instrument within Level 3 of the fair value hierarchy, the determination is based upon the significance of the unobservable factors to the overall fair value measurement. Level 3 financial instruments typically include, in addition to the unobservable or Level 3 components, observable components (that is, components that are actively quoted and can be validated to external sources).

(in millions)	Three months ended March 31, 2010	Three months ended March 31, 2009
Fair value (liability) asset, beginning of period	$ (26.0)	$ 172.5
Total realized and unrealized gains included in Realized and unrealized gain on derivatives	(1.4)	(22.9)
Purchases, sales and settlements, net	(7.1)	(15.5)
Transfers in and/or out of Level 3	—	3.4
Fair value (liability) asset, end of period	$ (34.5)	$ 137.5
Total unrealized (losses) gains included in income related to financial assets and liabilities still on the Condensed Balance Sheet at March 31, 2010 and 2009	$ (8.4)	$ 22.8

The $3.4 million of transfers out of Level 3 for the three months ended March 31, 2009 represent crude oil collars that were converted to crude oil swaps during the first quarter of 2009.

For further discussion related to the Company's derivatives see Note 3 to the Condensed Financial Statements.

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Berry Petroleum Company
Notes to Unaudited Financial Statements

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 the 8.25% senior subordinated notes due 2016 and the 10.25% 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.

	As of March 31, 2010	
(in millions)	**Carrying Amount**	**Estimated Fair Value**
Senior secured revolving credit facility	$ 270	$ 270
8.25% Senior subordinated notes due 2016	200	202
10.25% Senior notes due 2014	437	495
	$ 907	$ 967

	As of December 31, 2009	
(in millions)	**Carrying Amount**	**Estimated Fair Value**
Senior secured revolving credit facility	$ 372	$ 372
8.25% Senior subordinated notes due 2016	200	196
10.25% Senior notes due 2014	437	487
	$ 1,009	$ 1,055

3. Derivative Instruments

The Company uses financial derivative instruments as part of its price risk management program to achieve a more predictable, economic cash flow from its oil and natural gas production by reducing its exposure to price fluctuations. The Company has entered into financial commodity swap and collar contracts to fix the floor and ceiling prices received for a portion of the Company's oil and natural gas production. The terms of the contracts depend on various factors, including management's view of future crude oil and natural gas prices, acquisition economics on purchased assets and future financial commitments. The Company periodically enters into interest rate derivative agreements in an attempt to normalize the mix of fixed and floating interest rates within its debt portfolio.

The Company's derivative contracts have been executed primarily with counterparties that are party to its senior secured revolving credit facility.

Neither the Company nor its counterparties are required to post collateral in connection with its derivative positions and netting agreements are in place with each of the Company's counterparties allowing the Company to offset its derivative asset and liability positions. The credit rating of each of these counterparties was AA-/Aa3, or better as of March 31, 2010. As of March 31, 2010, the Company's largest three counterparties accounted for 74% of the value of its total derivative positions.

As of March 31, 2010, the Company had the following commodity derivatives:

	2010	**2011**	**2012**
Oil Bbl/D:	15,930	11,020	5,000
Natural Gas MMBtu/D:	19,000	10,000	10,000

For further discussion related to the fair value of the Company's derivatives see Note 2 to the Condensed Financial Statements.

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Berry Petroleum Company
Notes to Unaudited Financial Statements

The Company entered into the following crude oil collars during the three months ended March 31, 2010:

Term	**Average Barrels Per Day**	**Floor/Ceiling Prices**
Full year 2010	500	$75.00/$93.95
Full year 2010	500	$75.00/$94.45
Full year 2011	500	$75.00/$100.75
Full year 2011	500	$75.00/$101.15
Full year 2011	1,000	$75.00/$91.25
Full year 2012	500	$75.00/$105.00
Full year 2012	500	$75.00/$106.00

Full year 2012	1,000	$75.00/$95.00

Discontinuance of cash flow hedge accounting

Prior to January 1, 2010, the Company designated most of its commodity and interest rate derivative contracts as cash flow hedges, whose unrealized fair value gains and losses were recorded to AOCL. Effective January 1, 2010, however, the Company elected to de-designate all of its commodity and interest rate derivative contracts that had been previously designated as cash flow hedges as of December 31, 2009. As a result, subsequent to December 31, 2009, the Company recognizes all gains and losses from changes in commodity derivative fair values immediately in earnings rather than deferring any such amounts in AOCL.

At December 31, 2009, AOCL consisted of $97.4 million, ($60.4 million, net of tax) of unrealized losses, representing the change in the fair value of the Company's open commodity and interest rate derivative contracts designated as cash flow hedges as of that balance sheet date, less any ineffectiveness recognized. As a result of discontinuing hedge accounting on January 1, 2010, such fair values at December 31, 2009 are frozen in AOCL as of the de-designation date and reclassified into earnings as the original hedge transactions settle. During the three months ended March 31, 2010, $5.5 million ($3.4 million, net of tax) of derivative losses relating to de-designated commodity and interest rate hedges were reclassified from AOCL into earnings. As of March 31, 2010, AOCL consisted of $91.9 million ($57.0 million, net of tax) of unrealized losses on commodity and interest rate derivative contracts that had been previously designated as cash flow hedges. The Company expects to reclassify into earnings from AOCL after-tax net losses of $22.7 million related to de-designated commodity and interest rate derivative contracts during the next twelve months.

At March 31, 2010, the net fair value derivative liability was $94.1 million as compared to a net fair value liability of $97.4 million at December 31, 2009 which reflects changes in commodity prices and interest rates. Based on NYMEX strip pricing as of March 31, 2010, the Company expects to make payments under the existing derivatives of $35.3 million during the next twelve months.

The related cash flow impact of all of the Company's derivatives is reflected in cash flows from operating activities.

The Company presents its derivative assets and liabilities on its Condensed Balance Sheets on a net basis. The Company nets derivative assets and liabilities whenever it has a legally enforceable master netting agreement with a counterparty to a derivative contract. The Company uses these agreements to manage and reduce its potential counterparty credit risk.

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The following table disaggregates the Company's net derivative assets and liabilities into gross components on a contract-by-contract basis before giving effect to master netting arrangements. Finally, the Company identifies the line items on its 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.

	As of March 31, 2010			
	Derivative Assets		Derivative Liabilities	
(in millions)	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
Total derivatives designated as hedging instruments		—		—
Commodity – Oil	Current assets	$ 4.5	Current liability	$ 44.9
Commodity – Oil			Long term liabilities	57.6
Commodity – Natural Gas	Current assets	5.2		
Commodity – Natural Gas	Current liability	3.0		
Commodity – Natural Gas	Long term assets	2.4		
Commodity – Natural Gas	Long term liabilities	3.6		
Interest rate contracts			Current assets	3.5
Interest rate contracts			Current liability	3.0
Interest rate contracts			Long term liabilities	3.8
Total derivatives not designated as hedging instruments		18.7		112.8
Total Derivatives		$ 18.7		$ 112.8

	As of December 31, 2009			
	Derivative Assets		Derivative Liabilities	
(in millions)	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
Commodity – Oil	Current assets	$ 14.2	Current liability	$ 30.8
Commodity – Oil			Long term liabilities	74.1
Commodity – Natural Gas	Current assets	1.3		
Commodity – Natural Gas	Long term assets	0.4		
Commodity – Natural Gas	Current liability	0.2		
Commodity – Natural Gas	Long term liabilities	1.2		
Interest rate contracts	Long term assets	0.3	Current assets	3.5
Interest rate contracts			Current liabilities	2.7
Interest rate contracts			Long term liabilities	3.0
Total derivatives designated as hedging instruments under authoritative guidance		$ 17.6		$ 114.1
Commodity – Natural Gas		—	Current assets	0.4

Commodity – Natural Gas	—	Current liabilities		0.5
Total derivatives not designated as hedging instruments under authoritative guidance	—			0.9
Total Derivatives	$ 17.6			$ 115.0

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Berry Petroleum Company
Notes to Unaudited Financial Statements

The tables below summarize the location and the amount of derivative instrument gains and losses reported in the Condensed Statements of Income for the periods indicated. (in millions):

Three Months Ended March 31, 2010

Derivatives cash flow hedging relationships	Amount of Gain (Loss) Recognized in AOCL on Derivative (Effective portion)	Location of Gain (Loss) Reclassified from AOCL into Income (Effective Portion)	Amount of Gain (Loss) Reclassified from AOCL 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)
Commodity - Oil	$ —	Sales of oil and gas	$ (3.2)		$ —
Commodity - Natural Gas	—	Sales of oil and gas	0.4		—
Interest rate	—	Interest expense	(2.7)		—
Total	$ —		$ (5.5)		$ —

Three Months Ended March 31, 2009

Derivatives cash flow hedging relationships	Amount of Gain (Loss) Recognized in AOCL on Derivative (Effective portion)	Location of Gain (Loss) Reclassified from AOCL into Income (Effective Portion)	Amount of Gain (Loss) Reclassified from AOCL 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)
Commodity - Oil	$ 36.5	Sales of oil and gas	$ 41.6	Realized and unrealized gain on derivatives, net	$ 14.3
Commodity - Natural Gas	8.9	Sales of oil and gas	6.6		
Commodity - Oil				Realized and unrealized gain on derivatives, net	22.7
Interest rate	(3.4)	Interest expense	(1.0)		
Total	$ 42.0		$ 47.2		$ 37.0

Amount of gain or (loss) recognized in income on derivatives not designated as hedging instruments under authoritative guidance for the three months ended March 31, 2010 and 2009:

Three Months Ended March 31, 2010

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
Commodity – Oil	Realized and unrealized gain on derivatives, net	$ (7.5)
Commodity - Natural Gas	Realized and unrealized gain on derivatives, net	12.4
Interest Rates	Realized and unrealized gain on derivatives, net	(3.3)
Total derivatives not designated as hedging instruments		$ 1.6

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Berry Petroleum Company
Notes to Unaudited Financial Statements

Three Months Ended March 31, 2009

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

Commodity – Oil	Realized and unrealized gain on derivatives, net	$	0.2
Commodity - Natural Gas	Loss from discontinued operations, net of taxes		(0.5)
Total derivatives not designated as hedging instruments		$	(0.3)

During the three months ended March 31, 2010, the Company recorded a $1.6 million gain under the caption Realized and unrealized gain on derivatives, net resulting from a gain for the change in fair value of $3.3 million, net of a loss for cash settlements of $1.7 million.

During the three months ended March 31, 2009, the Company recorded a $37.2 million gain under the caption Realized and unrealized gain on derivatives, net. In conjunction with the sale of the DJ basin assets, during the first quarter of 2009, the Company concluded that the forecasted transaction in certain of its hedging relationships was not probable of occurring. As such, the Company reclassified a gain of $14.3 million from AOCL to the Condensed Statements of Income under the caption Realized and unrealized gain on derivatives, net. The Company also recognized an unrealized gain of $22.9 million on the Condensed Statements of Income under the caption Realized and unrealized gain on derivatives, net for the three months ended March 31, 2009, as a result of ineffectiveness related to sales prices that were not highly correlated with the Company's hedges. The Company recorded an unrealized net loss of $0.5 million on the Condensed Statements of Income under the caption Loss from discontinued operations, net of taxes during the first quarter of 2009 related to natural gas derivatives entered into on behalf of the purchaser of the Company's DJ assets for which the Company did not elect hedge accounting.

4. Shareholder's Equity

In January 2010, the Company issued 8,000,000 shares of Class A Common Stock at a price of $29.25 per share. Net proceeds from this offering were $224.3 million after deducting underwriting discounts and commissions and offering expenses. The Company used the net proceeds from the offering to fund the purchase of the Wolfberry Acquisition and to repay a portion of the outstanding borrowings under the senior secured revolving credit facility. See Note 5 to the Condensed Financial Statements.

5. Acquisitions and Divestitures

Acquisitions

On March 5, 2010, the Company acquired interests in producing properties principally on 6,900 acres in the Wolfberry trend in the Permian basin of West Texas (W. Texas) for $132 million, including an initial purchase price of $126 million, and customary post-closing adjustments of approximately $6 million (Wolfberry Acquisition). The acquisition had an effective date of January 1, 2010 and activity from January 1, 2010 through March 4, 2010 was a purchase price adjustment. The acquisition was financed with the proceeds from the issuance of the Company's common stock in January of 2010. The Company operates approximately 70% of, and has an average 68.5% working interest (54.1% net revenue interest) in, the properties acquired in the Wolfberry trend.

The Wolfberry Acquisition qualifies as a business combination and, as such, the Company estimated the fair value of this property as of the March 5, 2010 acquisition date, the date on which the Company obtained control of the properties. The fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Fair value measurements also utilize assumptions of market participants. The Company used a discounted cash flow model and made market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates. These assumptions represent Level 3 inputs.

The fair value of the properties acquired exceeded the consideration paid to the seller by $1.4 million which the Company recorded in the Condensed Statements of Income under the caption Transaction costs on acquisitions, net of gain. The gain resulted from the changes in oil and natural gas prices used to value the reserves.

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The acquisition related costs totaling $2.1 million have been recorded in the Condensed Statements of Income under the caption Transaction costs on acquisitions, net of gain. Revenues of $1.7 million and earnings of $0.5 million generated by the acquired properties from March 5, 2010 to March 31, 2010 have been included in the accompanying Condensed Statements of Income.

The following table summarizes the consideration paid to the seller and the amounts of the assets acquired and liabilities assumed as of March 5, 2010. The purchase price allocation is preliminary and subject to customary adjustments.

	(In thousands)
Consideration paid to seller:	
Cash, net of accrued purchase price adjustment	$ 132,241
Recognized amounts of identifiable assets acquired and liabilities assumed:	
Proved developed and undeveloped properties	134,649
Fair value of derivatives	316
Asset retirement obligation	(1,367)
Total identifiable net assets	$ 133,598

In February 2010, the Company entered into an agreement and paid a deposit of $0.5 million with a private seller to acquire interests in producing properties in the Wolfberry trend in W. Texas for approximately $14 million cash. This transaction closed in April 2010. The initial accounting for the business combination is not complete pending detailed analyses of the facts and circumstances that existed as of the acquisition date.

Divestitures

On March 3, 2009, the Company entered into an agreement to sell its 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. The Company recorded a pre-tax impairment loss of $9.6 million related to the sale, which is aggregated within the $6.8 million Loss from discontinued operations, net of taxes, on its Condensed Statement of Income for the three months ended March 31, 2009.

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

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
Total revenues	—	$ 6,018
Total expenses	—	16,283
Loss from discontinued operations, before income taxes	—	(10,265)
Income tax benefit	—	3,484
Loss from discontinued operations, net of taxes	—	$ (6,781)

6. Dry hole, abandonment, impairment and exploration

In the first quarter of 2010 the Company incurred dry hole, abandonment, impairment and exploration expense of $1.4 million, which was primarily a result of mechanical failure encountered on one well in the Piceance basin. The well was abandoned in favor of drilling a replacement well from the same well pad. In the first quarter of 2009 the Company had dry hole, abandonment, impairment and exploration charges of $0.1 million.

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7. Asset Retirement Obligation (ARO)

The following table summarizes the change in the ARO for the three months ended March 31 (in thousands):

	2010	2009
Beginning balance at January 1	$ 43,487	$ 41,967
Liabilities incurred	1,024	—
Liabilities settled	(22)	(113)
Acquisition of assets	1,367	—
Accretion expense	1,063	1,002
Ending balance at March 31	$ 46,919	$ 42,856

The ARO reflects the estimated present value of the amount of dismantlement, removal, site reclamation and similar activities associated with the Company’s 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.

8. Debt Obligations

Short-term lines of credit

Borrowings under the Secured Line of Credit may be up to $30 million for a maximum of 30 days. The Secured Line of Credit may be terminated at any time upon written notice by either the Company or the lender. In conjunction with the amendment to the Company’s senior secured credit facility, on July 15, 2008, the Secured Line of Credit was collateralized by oil and natural gas properties representing at least 80% of the present value of the Company’s proved reserves.

There were no outstanding borrowings on the Secured Line of Credit at March 31, 2010 or December 31, 2009. Interest on amounts borrowed is charged at LIBOR plus a margin of approximately 1.4%. The weighted average interest rate on outstanding borrowings on the Secured Line of Credit at March 31, 2010 and December 31, 2009 was 0%.

Senior secured revolving credit facility

The Company’s 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 (1) ratio not greater than:		Senior secured debt to EBITDAX ratio not greater than:			
2010	Thereafter	to Sep 2010	Mar 2011	Sep 2011	Thereafter

4.50	4.00	3.75	3.50	3.25	3.0

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(1) Net income before interest expense, income tax expense, depreciation and amortization expense, exploration expense and non-cash items of income.

The Agreement contains a current ratio covenant which, as defined, must be at least 1.0. The total outstanding debt at March 31, 2010 under the Agreement, as amended, and the Line of Credit was $270 million and zero, respectively, and $4 million in letters of credit have been issued under the facility, leaving $664 million in borrowing capacity available. The maximum amount available is subject to semi-annual redeterminations of the borrowing base, based on the value of the Company's proved oil and gas reserves, in April and October of each year in accordance with the lenders' customary procedures and practices. Both the Company and the banks have the bilateral right to one additional redetermination each year. The Company's borrowing base was reconfirmed in April 2010. The Agreement is collateralized by oil and natural gas properties representing at least 80% of the present value of the Company's proved reserves. The Agreement matures on July 15, 2012.

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10.25% senior notes due 2014

On May 27, 2009, the Company issued in a public offering $325 million principal amount of 10.25% senior notes due 2014 ($325 million Notes). Interest on the $325 million Notes is paid semi-annually 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 Condensed 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.

On August 13, 2009, the Company issued in a public offering an additional $125 million principal amount of its 10.25% senior notes due 2014 ($125 million notes and, together with the $325 million notes, the Notes). The $125 million Notes were issued at a premium to par value of 104.75%, and are carried on the Condensed 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 $125 million Notes.

The $125 million Notes and the previously issued $325 million Notes are treated as a single series of debt securities and are carried on the Condensed Balance Sheet at their combined amortized cost.

8.25% senior subordinated notes due 2016

In 2006, the Company 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 Agreement contains restrictive covenants as described above. Under the Company's Sub Notes and Notes as long as the interest coverage ratio (as defined) is greater than 2.5 times, the Company may incur additional debt. The Company was in compliance with all of these covenants as of March 31, 2010.

	As of March 31, 2010
Current Ratio (Not less than 1.0)	5.7
Total Funded Debt Ratio to EBITDAX (Not greater than 4.50)	3.0
Interest Coverage Ratio (Not less than 2.5)	3.7
Senior Secured Debt Ratio to EBITDAX (Not greater than 3.75)	0.9

The weighted average interest rate on the Company's total outstanding borrowings was 7.5% and 7.0% at March 31, 2010 and December 31, 2009, respectively.

9. Income Taxes

The effective income tax rate was 36.9% for the first quarter of 2010 compared to 33.9% for the first quarter of 2009. The increase in rate for the first quarter is primarily due to one-time reductions in deferred state taxes in the prior quarter. Reductions in the rate during the prior quarter were the result of acquisitions in more tax favorable jurisdictions, reducing future state tax obligations in addition to favorable state tax incentives. The Company's 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 March 31, 2010, the Company had a gross liability for uncertain tax benefits of $6.5 million of which $5.3 million, if recognized, would affect the effective tax rate. There were no significant changes to the calculation since December 31, 2009. The Company recognizes potential accrued interest and penalties related to unrecognized tax benefits in income tax expense, which is consistent with the recognition of these items in prior reporting periods. The Company had accrued approximately $0.8 million and $0.7 million of interest related to its uncertain tax positions as of March 31, 2010 and December 31, 2009, respectively.

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10. Earnings per Share

Basic net income per common share is calculated by dividing adjusted net income available to common shareholders by the weighted average number of common shares outstanding during each period. Diluted net income per common share is calculated by dividing adjusted net income by the weighted average number of diluted common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for the diluted earnings per share calculations consist of unvested restricted stock awards and outstanding stock options using the treasury method. When a loss exists, all potentially dilutive securities are anti-dilutive and are therefore excluded from the computation of diluted earnings per share accordingly.

The two-class method of computing earnings per share is required for those entities that have participating securities. The two-class method is an earnings allocation formula that determines earnings per share for participating securities according to dividends declared (or accumulated) and participation rights in undistributed earnings. Restricted stock issued prior to January 1, 2010, under the Company's stock incentive plans has the right to receive non-forfeitable dividends, participating on an equal basis with common stock. Restricted stock issued subsequent to January 1, 2010, under the Company's stock incentive plans no longer has the right to receive non-forfeitable dividends. Stock units issued to directors under the Company's stock incentive plans also have the right to receive non-forfeitable dividends, participating on an equal basis with common stock. Stock options issued under the Company's stock incentive plans do not participate in dividends. Therefore, restricted stock issued to employees prior to January 1, 2010 and stock units issued to directors are participating securities and earnings must now be allocated to both common stock and these participating securities under the two-class method.

The following table shows the computation of basic and diluted net income (loss) per share from continuing and discontinued operations for the three months ended March 31, 2010 and 2009 (in thousands):

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
Net income from continuing operations	$ 17,669	$ 41,779
Less: Income allocable to participating securities	359	3,416
Income available for shareholders	$ 17,310	$ 38,363
Net loss from discontinued operations	$ —	$ (6,781)
Less: Income allocable to participating securities	—	—
Loss from discontinued operations available for shareholders	$ —	$ (6,781)
Basic earnings per share from continuing operations	$ 0.34	$ 0.92
Basic loss per share from discontinued operations	—	(0.15)
Basic earnings per share	$ 0.34	$ 0.77
Diluted earnings per share from continuing operations	$ 0.34	$ 0.92
Diluted loss per share from discontinued operations	—	(0.15)
Diluted earnings per share	$ 0.34	$ 0.77
Weighted average shares outstanding - basic	51,076	44,581
Add: dilutive effects of stock options	365	12
Weighted average shares outstanding - dilutive	51,441	44,593

Options to purchase $1.2 million and $2.3 million shares were not included in the diluted earnings (loss) per share calculation for the three months ended March 31, 2010 and 2009, respectively, because their effect would have been anti-dilutive.

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11. Commitments and Contingencies

The Company's contractual obligations not included in its Condensed Balance Sheet as of March 31, 2010 (except Long-term debt and ARO) are as follows (in millions):

	Total	2010	2011	2012	2013	2014	Thereafter
Long-term debt and interest	$ 1,234	$ 52	$ 69	$ 335	$ 63	$ 485	$ 230
ARO	47	3	3	3	2	3	33
Operating lease obligations	16	2	2	3	3	3	3
Drilling and rig obligations	49	11	28	2	2	6	—
Firm natural gas transportation contracts	132	15	20	17	16	15	49
Total	$ 1,478	$ 83	$ 122	$ 360	$ 86	$ 512	$ 315

Operating leases

The Company leases corporate and field offices in California, Colorado and Texas. Rent expense with respect to its lease commitments was $0.5 million for both the three months ended March 31, 2010 and 2009. In 2006, the Company purchased an airplane for business travel which was subsequently sold and contracted under a ten year operating lease beginning December 2006.

Drilling obligations

The Company amended and restated its Utah Lake Canyon agreement in December 2009 and has a 14 gross well drilling commitment over the amended term (December 2009 to December 2014). The Company's minimum obligation under this exploration and development agreement is $14.7 million as of March 31, 2010. Also included in the table above are the Company's contractual obligations on its Piceance assets in Colorado. The Company must spud 120 wells by February 2011 to avoid penalties of $0.2 million per well. The Company expects to meet all obligations but its ability to meet this commitment depends on the capital resources available to the Company to fund its activities to develop these assets.

Firm natural gas transportation

In July 2009, the Company closed on the financing of its E. Texas gas gathering system for $18.4 million in cash. The Company entered into concurrent long-term gas gathering agreements for the E. Texas production which contained an embedded lease. There is no minimum payment required under these agreements. For the three months ended March 31, 2010 and 2009, the Company incurred $1.0 million and $0, respectively, under the agreements.

In June 2009, the Company amended its natural gas firm transportation agreement providing for transportation of its 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.

The Company has long-term firm transportation contracts that total 35,000 MMBtu/D on the Rockies Express (REX) pipeline for gas production in the Piceance basin. The Company pays a demand charge for this capacity and its own production did not completely fill that capacity. To maximize the utilization of its firm transportation, the Company bought its partners' share of the gas produced in the Piceance basin at the market rate for that area and used its excess transportation to move this gas to the sales point. The pre-tax net of its gas marketing revenue and its gas marketing expense in the Condensed Statements of Income is $0.5 million and $0.3 million for the three months ended March 31, 2010 and 2009, respectively.

Berry has signed firm transportation service agreements with El Paso Corporation for an average total of 35,000 MMBtu/D of firm transportation on the proposed Ruby Pipeline from Opal, WY to Malin, OR. The expectation is that the project will proceed and be in service in 2011.

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Other Commitments

The Company is a party to a crude oil sales contract through June 30, 2013 with a refiner for the purchase of a minimum of 5,000 Bbl/D of its Uinta light crude oil. Pricing under the contract, which includes transportation and gravity adjustments, is at a fixed percentage of WTI. While the contractual differentials under this contract may be less favorable at times than the posted differential, demand for the Company's 40 degree black wax (light) crude oil can vary seasonally and this contract provides a stable outlet for the Company's crude oil. Gross oil production from the Company's Uinta properties averaged approximately 2,427 Bbl/D in the first quarter of 2010.

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 the 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 the Company's December 2008 crude oil sales, an administrative claim under the bankruptcy proceedings, and $26.7 million represents November 2008 and the balance of December 2008 crude oil sales which would have the same priority as other general unsecured claims. BWOC will also be liable to the Company for damages under this contract. The Company has guarantees from Big West Oil and from Flying J, Inc. in the amount of $75 million each, in the event that the claim is not fully collectible from BWOC. While the Company believes that it may recover some or all of the amounts due from BWOC, the data received from the bankruptcy proceedings to date has not provided the Company with adequate data from which to make a conclusion that any amounts will be collected.

The Company has no material accrued environmental liabilities for its sites, including sites in which governmental agencies have designated the Company 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. The Company is involved in various other lawsuits, claims and inquiries, most of which are routine to the nature of its business. In the opinion of management, the resolution of these matters will not have a material effect on its financial position, or on the results of operations or liquidity.

Certain of the Company's royalty payment calculations are being disputed. The Company believes that its royalty calculations are in accordance with applicable leases and other agreements. However, the disputed amounts that it may be required to pay are up to approximately $6 million.

In July 2009, the Company 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 its 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 the Company immediately remediated the instances of non-compliance, cooperated fully with the BLM's investigation and the Company believes no production was lost, all royalties were paid and there was no harm to the environment. Due to the above mitigating factors, among others, the Company believes 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, the Company had electricity sales contracts with various utilities and a portion of the electricity prices paid to the Company 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 the Company may have a liability pending the final outcome of the California Public Utilities Commission (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 the Company. 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.

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

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

The following is management's discussion and analysis of certain significant factors that have affected aspects of our financial position and the results of operations during the periods included in the accompanying unaudited Condensed Financial Statements. You should read this in conjunction with the discussion under "Management's Discussion and Analysis of Financial Conditions and Results of Operations" and the audited Financial Statements for the year ended December 31, 2009 included in our Annual Report on Form 10-K and the unaudited Condensed Financial Statements included elsewhere herein.

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. We benefit from lower natural gas prices as we are a consumer of natural gas in our California operations. In the Rocky Mountains and E. Texas we benefit from higher natural gas pricing. 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.

Notable First Quarter Items.

- Achieved production averaging 29,391 BOE/D supported by a 500 BOE/D increase in oil
- Generated discretionary cash flow of $70 million (a)
- Increased diatomite net production to an average of 3,570 BOE/D, up 34% from the first quarter of 2009
- Closed on the acquisition of 6,900 net acres and 11 MMBOE of proved reserves, primarily in the Wolfberry trend in W. Texas for approximately $132 million
- Completed our first horizontal Haynesville well with an initial potential of approximately 10.3 MMcf/D gross production and 30-day average production of 9.0 MMcf/D
- Issued 8 million shares of Class A Common Stock for net proceeds of $224 million to fund the Wolfberry Acquisition and reduce debt

Notable Items and Expectations for the Second Quarter and Full Year 2010.

- Acquired a 90 acre lease from Chevron U.S.A. Inc. increasing diatomite acreage by 20%
- Closed on the acquisition of an additional 3,200 acres and 2 MMBOE of proved reserves in the Wolfberry trend for $14 million
- Expecting 2010 development capital expenditures between $250 million and $290 million to be fully funded from operating cash flow
- Anticipating average production between 32,250 and 33,000 BOE/D, an 8% to 10% increase over 2009

(a) Discretionary cash flow is considered a non-GAAP performance measure and reference should be made to *"Reconciliation of Non-GAAP Measures"* at the end of this Item 2 for further explanation of this performance measure, as well as a reconciliation to the most directly comparable GAAP measure.

Overview of the First Quarter of 2010.

We had net income from continuing operations of $17.7 million, or $0.34 per diluted share, and net cash from operations was $63.5 million in the first quarter of 2010. Net income from continuing operations includes a $0.9 million gain on purchase of oil and natural gas properties related to the Wolfberry Acquisition offset by $1.3 million of acquisition-related expenses. Also included in net income is a $0.9 million loss on derivatives as a result of amortization of frozen fair values and non-cash changes in fair values and $0.8 million of dry hole costs resulting from mechanical failure on one well in the Piceance basin. We drilled 59 gross wells and capital expenditures, excluding property acquisitions, totaled $48 million. We achieved average production of 29,391 BOE/D in the first quarter of 2010, up 1% and down 3% from an average of 29,149 BOE/D and 30,231 BOE/D in the fourth quarter of 2009 and the first quarter of 2009, respectively.

Acquisitions.

During the first quarter of 2010, we acquired certain properties primarily in the Wolfberry trend in W. Texas from a private seller for total consideration of $132 million, including an initial purchase price of $126 million, and normal post-closing adjustments of $6 million. The properties included total proved reserves of 11.2 MMBOE, of which 85% were crude oil and 23% were proved developed. We have identified over 130 drilling locations on forty acre spacing in the Wolfberry trend targeting the Spraberry, Dean, Wolfcamp and Strawn formations. We plan to test twenty acre down spacing in late 2010, which would provide an additional 150 drilling locations. We operate approximately 70% of, and have an average 68.5% working interest (54.1% net revenue interest) in, the properties acquired in the Wolfberry trend.

Revenues.

Approximately 88% of our revenues are generated through the sale of oil and natural gas production under either negotiated contracts or spot gas purchase contracts at market prices. Approximately 6% of our revenues are derived from electricity sales from cogeneration facilities which supply approximately 28% of our steam requirement for use in our California thermal heavy oil operations. We have invested in these facilities for the purpose of lowering our steam costs, which are significant in the production of heavy crude oil. The remaining 6% of our revenues are primarily derived from gas marketing sales which represent our excess capacity on the Rockies Express pipeline which we used to market natural gas for our working interest partners.

The following results from continuing operations are in millions (except per share data) for the three months ended:

	March 31, 2010 (1Q10)	March 31, 2009 (1Q09)	1Q10 to 1Q09 Change	December 31, 2009 (4Q09)	1Q10 to 4Q09 Change
Sales of oil (1)	$ 122	$ 99	23%	$ 109	12%
Sales of gas	26	29	(10)%	24	8%
Total sales of oil and gas	$ 148	$ 128	16%	$ 133	11%
Sales of electricity	10	10	—	10	—
Gas marketing	8	8	—	5	60%
Realized and unrealized gain on derivatives, net	2	37	(95)%	—	—
Total revenues and other income	$ 168	$ 183	(8)%	$ 148	14%
Net income from continuing operations	$ 18	$ 42	(57)%	$ 13	38%
Diluted earnings per share from continuing operations	$ 0.34	$ 0.92	(63)%	$ 0.28	21%

(1) Included in the fourth quarter of 2009 are adjustments to correct the prior accounting for royalties in the amount of $3 million, which resulted in decreasing our sales of oil and gas and increasing our royalties payable. Management concluded the impact was immaterial to the fourth quarter of 2009 and prior periods.

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

	March 31, 2010	%	March 31, 2009	%	December 31, 2009	%
Heavy Oil Production (Bbl/D)	17,752	61	16,436	50	17,280	60
Light Oil Production (Bbl/D)	2,754	9	3,066	9	2,719	9
Total Oil Production (Bbl/D)	20,506	70	19,502	59	19,999	69
Natural Gas Production (Mcf/D)	53,309	30	82,979	41	54,899	31
Total operations (BOE/D)	29,391	100	33,332	100	29,149	100
DJ Basin Production (BOE/D)	—		3,101		—	
Production - Continuing Operations (BOE/D)	29,391		30,231		29,149	
Oil and gas BOE for continuing operations						
Average sales price before hedging	$ 57.06		$ 29.36		$ 50.76	
Average sales price after hedging	55.99		47.11		48.77	
Oil, per Bbl, for continuing operations:						
Average WTI price	$ 78.88		$ 43.24		$ 76.13	
Price sensitive royalties	(3.04)		(1.02)		(2.64)	
Quality differential and other	(8.12)		(9.53)		(9.63)	
Crude oil hedges reported with Sales of oil and gas	(1.72)	(a)	23.79	(b)	(3.96)	(b)
Correction to royalties payable (c)	—		—		(1.78)	
Average oil sales price after hedging	$ 66.00		$ 56.48		$ 58.12	
Natural gas price for continuing operations:						
Average Henry Hub price per MMBtu	$ 5.30		$ 4.90		$ 4.17	
Conversion to Mcf	0.27		0.25		0.21	
Natural gas hedges reported with Sales of oil and gas	0.07	(a)	1.14	(b)	0.40	(b)
Location, quality differentials and other	(0.15)		(1.27)		(0.13)	
Average gas sales price after hedging per Mcf	$ 5.49		$ 5.02		$ 4.65	

(a) Includes non-cash amortization of frozen December 31, 2009 fair values resulting from January 1, 2010 discontinuing of hedge accounting
(b) Includes cash settlements on derivatives for which we had elected hedge accounting
(c) Included in the fourth quarter of 2009 is a correction to one of our royalties in the amount of $3 million, which resulted in decreasing our sales of oil and gas and increasing our royalties payable.

Sales of Oil and Gas:

Oil and gas revenue increased 16% to $148 million in the first quarter of 2010 compared to $128 million in the first quarter of 2009. The increase is primarily due to an increase in the average sales price after hedging to $55.99 per BOE in the first quarter of 2010 from $47.11 per BOE in the first quarter of 2009. Oil and gas revenue increased 11% in the first quarter of 2010 compared to the fourth quarter of 2009. The increase is primarily due to an increase in the average sales price after hedging to $55.99 per BOE in the first quarter of 2010 from $48.77 per BOE in the fourth quarter of 2009. Approximately 70% of our oil and gas sales volumes in the first quarter of 2010 were crude oil, with 87% of the crude oil being heavy oil produced in California which was sold under various contracts with prices tied to the San Joaquin posted price.

Effective January 1, 2010, we elected to de-designate all of our commodity derivative contracts that had previously been designated as cash flow hedges as of December 31, 2009 and have elected to discontinue hedge accounting prospectively. As a result of discontinuing hedge accounting on January 1, 2010, changes in fair values at December 31, 2009 are frozen in accumulated other comprehensive loss (AOCL) as of the de-designation date and will be reclassified into oil and gas revenues in future periods as the original hedged transactions affect earnings. As a result, in the first quarter of 2010, we reclassified $2.8 million of non-cash derivative losses relating to de-designated commodity hedges from AOCL into earnings under the caption Sales of oil and gas. Beginning January 1, 2010 all of our derivative contracts are recorded at fair value each quarter with fair value gains and losses recognized immediately in earnings as Realized and unrealized gain on derivatives, net. Cash flow is impacted to the extent that actual cash settlements under these contracts result in making or receiving a payment from the counterparty, and such cash settlement gains and losses are also recorded to earnings as Realized and unrealized gain on derivatives, net. See Realized and unrealized gain on derivatives, net below.

The average sales price received for oil sales during the first quarter of 2010 was $66.00 per BOE, an increase of 17% or $9.52 per BOE compared to the first quarter of 2009. The range of NYMEX light sweet crude prices for the first quarter of 2010, based upon settlements, was from a low of $71.19 to a high of $83.76. NYMEX light sweet crude prices for the first quarter of 2009, based upon settlements, was a low of $33.98 and a high of $54.34. In California the differential on March 31, 2010 was $8.31 and ranged from a low of $6.82 to a high of $8.32 per barrel during the first quarter of 2010. The California differential ranged from a low of $5.20 to a high of $14.02 per barrel during the first quarter of 2009. In Utah, we are a party to a crude oil sales contract through June 30, 2013 with a refiner for the purchase of our Uinta light crude oil. Pricing under the contract, which includes transportation and gravity adjustments, is at a fixed percentage of WTI. While the contractual differentials under this contract may be less favorable at times than the posted differential, demand for our 40 degree black wax (light) crude oil can vary seasonally and this contract provides a stable outlet for the our crude oil.

The average sales price received for gas sales during the first quarter of 2010 was $5.49 per Mcf, an increase of 9% or $0.47 per Mcf compared to the first quarter of 2009. We sell our produced natural gas at various indices. Henry Hub (HH) natural gas averaged $5.30 in the first quarter of 2010 and $4.90 in the first quarter of 2009. As of mid-2009, the pricing of our Piceance basin natural gas production is tied to the eastern markets in Lebanon or Clarington Ohio, which averaged $0.21 above HH for the first quarter of 2010. The Piceance basin natural gas was sold in the first quarter of 2009 based upon a mid-continent index such as PEPL, which averaged $1.51 below HH. Correspondingly, most of the Uinta basin natural gas is sold based on a Questar index which averaged $0.28 below HH for the first quarter of 2010 and $1.72 below HH for the first quarter of 2009. The E. Texas natural gas production was generally sold during the first quarter of 2010 at the Florida Zone 1 index which was $0.01 below HH for the first quarter of 2010. The E. Texas natural gas production was sold during the first quarter of 2009 at the Texas Eastern - East Texas index, which averaged $0.78 below HH for the first quarter of 2009.

Sales of Electricity:

Electricity revenues remained relatively unchanged and operating costs increased in the first quarter of 2010 compared to the fourth quarter of 2009 as a result of flat electricity prices and 27% higher natural gas prices. Electricity revenues decreased and operating costs increased in the first quarter of 2010 compared to the first quarter of 2009 due to 5% lower electricity prices and 8% higher natural gas prices. We purchased approximately 28 MMBtu/D and 27 MMBtu/D of natural gas as fuel for use in our cogeneration facilities for the three months ended March 31, 2010 and December 31, 2009, respectively.

The following table is for the three months ended:

	March 31, 2010	March 31, 2009	December 31, 2009
Electricity			
Revenues (in millions)	$ 9.9	$ 10.3	$ 10.0
Operating costs (in millions)	$ 9.7	$ 8.8	$ 9.3
Electric power produced - MWh/D	2,154	2,068	2,141
Electric power sold - MWh/D	1,979	1,939	1,942
Average sales price/MWh	$ 56.17	$ 58.85	$ 56.17
Fuel gas cost/MMBtu (including transportation)	$ 5.39	$ 4.01	$ 4.57

Natural Gas Marketing

We have 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 bought our partners' share of the gas produced in the Piceance at the market rate for that area. We used our excess transportation to move this gas to where it was eventually sold. The pre-tax net of our gas marketing revenue and our gas marketing expense in the Condensed Statements of Income is $0.5 million and $0.3 million in the three months ended March 31, 2010 and 2009, respectively. Firm transportation costs related to all of our Rockies Express volumes is reflected in Operating costs - oil and gas production and total $3.2 million and $2.9 million for the three months ended March 31, 2010 and 2009, respectively.

Realized and unrealized gain on derivatives, net

Realized and unrealized gain on derivatives, net is primarily related to derivatives which did not qualify for cash flow hedge accounting either at their inception or where hedge accounting was discontinued during their term. When the criteria for cash flow hedge accounting is not met or when cash flow hedge accounting is not elected, realized gains and losses (i.e., cash settlements) are recorded in Realized and unrealized gain on derivatives, net in the condensed statements of income. Similarly, changes in the fair value of the derivative instruments are recorded as unrealized gains or losses in the Condensed

Statements of Income. In contrast, cash settlements for derivative instruments that qualify for hedge accounting are recorded as additions to or reductions of oil and gas revenues, while changes in fair value of cash flow hedges are recognized, to the extent the hedge is effective, in AOCL until the hedged item is recognized in earnings. Realized and unrealized gain on derivatives, net also includes any hedge ineffectiveness on cash flow hedges that qualify for hedge accounting.

During 2009, we entered into certain commodity derivative contracts that we did not designate as cash flow hedges. In addition, effective January 1, 2010, we elected to de-designate all of our commodity and interest rate derivative contracts that had been previously designated as cash flow hedges as of December 31, 2009 and have elected to discontinue hedge accounting prospectively. Accordingly, beginning January 1, 2010 all of our derivative contracts are recorded at fair value each quarter with fair value gains and losses recognized immediately in earnings. Cash flow is impacted to the extent that actual cash settlements under these contracts result in making or receiving a payment from the counterparty, and such cash settlement gains and losses are also recorded to earnings under the caption Realized and unrealized gain on derivatives, net.

During the three months ended March 31, 2010, we recorded a $1.6 million gain under the caption Realized and unrealized gain on derivatives, net resulting from a gain for the change in fair value of $3.3 million, net of a loss on cash settlements of $1.7 million.

During the three months ended March 31, 2009, we recorded a $37.2 million gain under the caption Realized and unrealized gain on derivatives, net. 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 AOCL to the Condensed Statements of Income under the caption Realized and unrealized gain on derivatives, net. We also recognized an unrealized net gain of $22.9 million on the Condensed Statements of Income under the caption Realized and unrealized gain on derivatives, net for the three months ended March 31, 2009, respectively, as a result of ineffectiveness related to sales prices that were not perfectly correlated with our hedges. We recorded an unrealized net loss of $0.5 million on the Condensed Statements of Income under the caption Loss from discontinued operations, net of taxes during the first quarter of 2009 related to natural gas derivatives entered into on behalf of the purchaser of our DJ assets for which we did not elect hedge accounting.

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Oil and Gas Operating and Other 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)		
	March 31, 2010	March 31, 2009	December 31, 2009	March 31, 2010	March 31, 2009	December 31, 2009
Operating costs – oil and gas production	$ 17.78	$ 13.74	$ 16.89	$ 47,036	$ 37,384	$ 45,295
Production taxes	1.97	2.08	1.39	5,204	5,652	3,733
DD&A – oil and gas production	13.57	13.38	13.29	35,907	36,398	35,648
G&A	5.23	4.89	4.51	13,835	13,294	12,094
Interest expense	6.60	3.69	5.49	17,447	10,050	14,722
Total	$ 45.15	$ 37.78	$ 41.57	$ 119,429	$ 102,778	$ 111,492

- Operating costs in the first quarter of 2010 were $47.0 million or $17.78 per BOE, compared to $37.4 million or $13.74 per BOE in the first quarter of 2009 and $45.3 million or $16.89 per BOE in the fourth quarter of 2009. 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:

	March 31, 2010 (1Q10)	March 31, 2009 (1Q09)	1Q10 to 1Q09 Change	December 31, 2009 (4Q09)	1Q10 to 4Q09 Change
Average volume of steam injected (Bbl/D)	118,733	103,342	15%	115,864	2%
Fuel gas cost/MMBtu (including transportation)	$ 5.39	$ 4.01	34%	$ 4.57	18%
Approximate net fuel gas volume consumed in steam generation (MMBtu/D)	36,699	26,427	39%	33,830	8%

- The increase in operating costs compared to the first quarter of 2009 is due to a $9.1 million increase in steam costs. The increase in steam costs is due to a 34% increase in fuel gas costs as a result of increased natural gas prices and a 39% increase in fuel gas volume consumed in steam generation. The increase in operating costs compared to the fourth quarter of 2009 is due to a $3.1 million increase in steam costs. The increase in steam costs is due to an 18% increase in fuel gas costs as a result of increased natural gas prices and an 8% increase in fuel gas volume consumed in steam generation. Operating costs in the fourth quarter of 2009 included $1.2 million of operating costs associated with 50,000 barrels of oil inventory sold in October 2009.

- Production taxes in the first quarter of 2010 were $5.2 million or $1.97 per BOE, compared to $5.7 million or $2.08 per BOE in the first quarter of 2009 and $3.7 million or $1.39 per BOE in the fourth quarter of 2009. Severance taxes paid in Utah, Colorado and Texas are directly related to the field sales price of the commodity. In California, our production is burdened with ad valorem taxes on our total proved reserves. The decrease in production taxes compared to the first quarter of 2009 is due to a decrease in the assessed ad valorem tax values attributed to our California properties. The increase in production taxes compared to the fourth quarter of 2009 is primarily related to increased oil and natural gas prices.

- Depreciation, depletion and amortization (DD&A) in the first quarter of 2010 was $35.9 million or $13.57 per BOE, compared to $36.4 million or $13.38 per BOE in the first quarter of 2009 and $35.6 million or $13.29 per BOE in the fourth quarter of 2009. On a per barrel basis DD&A remained consistent in the first quarter of 2010 compared to both the first quarter of 2009 and the fourth quarter of 2009.

- General and administrative expense (G&A) in the first quarter of 2010 was $13.8 million or $5.23 per BOE, compared to $13.3 million or $4.89 in the first quarter of 2009 and $12.1 million or $4.51 per BOE in the fourth quarter of 2009. G&A in the first quarter of 2010 is consistent with the prior quarters with the exception of additional headcount due to staffing of the Permian asset team. Approximately 65% of our G&A is related to compensation.

· Interest expense in the first quarter of 2010 was $17.4 million or $6.60 per BOE, compared to $10.1 million or $3.69 per BOE in the first quarter of 2009 and $14.7 million or $5.49 per BOE in the fourth quarter 2009. The increase in interest expense compared to the first quarter of 2009 was due to the issuance of our 10.25% senior notes due 2014, subsequent to the first quarter of 2009. The amortization of the net discount and deferred loan costs attributable to the senior notes is also included in interest expense. Interest expense increased compared to the fourth quarter of 2009 due primarily to a decrease in interest costs capitalized in the first quarter of 2010 as a result of our development activities. Interest cost is capitalized as a component of property cost for significant exploration and development activity projects. Additionally, in the first quarter of 2010, we reclassified $2.7 million, or $1.02 per BOE of non-cash derivative losses relating to de-designated interest rate hedges from AOCL into earnings. Interest expense in the first quarter of 2010 was $5.58 per BOE, excluding the non-cash derivative losses.

2010 Guidance:

For 2010 the Company is issuing the following guidance:

	Anticipated Range per BOE in 2010 ($/BOE)		
	$60 WTI/$4 HH	$60 WTI/$5 HH	$75 WTI/$6 HH
Operating costs-oil and gas production	$ 17.00 – 18.00	$ 18.00 – 19.00	$ 19.00 – 20.00
Production taxes	1.75 – 2.25	1.75 – 2.25	2.00 – 2.50
DD&A – oil and gas production		12.00 – 14.00	
G&A		4.00 – 4.50	
Interest expense		5.00 - 6.50	
Total		$ 40.75 – 46.25	

Transaction costs on acquisitions, net of gain: In the first quarter of 2010 transaction costs on acquisitions, net of gain was $0.7 million. We recorded $2.1 million of acquisition related expenses for our acquisition of certain properties, primarily in the Wolfberry trend in W. Texas, from a private seller in the first quarter of 2010. This acquisition resulted in a $1.4 million gain on purchase of oil and natural gas properties. The gain resulted from the changes in oil and natural gas prices used to value the reserves.

Dry hole, abandonment, impairment and exploration: In the first quarter of 2010 we incurred dry hole, abandonment, impairment and exploration expense of $1.4 million, which was primarily a result of mechanical failure encountered on one well in the Piceance basin. The well was abandoned in favor of drilling a replacement well from the same well pad. In the first quarter of 2009 we had dry hole, abandonment, impairment and exploration charges of $0.1 million. In the fourth quarter of 2009 we had dry hole, abandonment, impairment and exploration charges of $5.2 million primarily due to a $4.2 million impairment charge related to the write-down of a rig to its fair market value.

Loss on discontinued operations: 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 of $9.6 million, which is aggregated within loss from discontinued operations, net of tax, on the Condensed Statement of Income for the three months ended March 31, 2009.

Income Tax Expense: The effective tax rate for the first quarters of March 31, 2010 and 2009 was 36.9% and 33.9%, respectively. In comparison with prior quarters, the increase in rate for the first quarter of 2010 is primarily due to one-time reductions in deferred state taxes in previous quarters. Reductions in the rate during prior quarters was the result of acquisitions in more tax favorable jurisdictions reducing future state tax obligations in addition to favorable state tax incentives. 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 9 to the Condensed Financial Statements.

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

	Three months ended March 31, 2010	
Asset Team	Gross Wells	Net Wells
S. Midway	27	27
N. Midway	14	14
Permian	1	1
Uinta	12	12
E. Texas	2	2
Piceance	3	2
Totals	59	58

Properties

We currently have six asset teams as follows: South Midway-Sunset (S. Midway), North Midway-Sunset including diatomite (N. Midway), Permian, Uinta, E. Texas and Piceance. Our S. Midway asset team is primarily focused on production and generates significant cash flow to fund our planned drilling inventory in our N. Midway, Piceance, E. Texas, Uinta and W. Texas projects.

S. Midway — This asset team is responsible for our S. Midway leases including Formax and Ethel D, as well as our Poso Creek property. In the first quarter of 2010 we drilled 27 wells, almost all of which were focused on the redevelopment of Ethel D. All of these wells are currently on production and are performing in line with expectations. Average daily production in the first quarter of 2010 from all S. Midway assets was approximately 11,690 BOE/D, a 4% increase from the fourth quarter of 2009.

N. Midway — Our N. Midway asset team includes our diatomite, Placerita and McKittrick assets and several N. Midway-Sunset leases. In the first quarter of 2010 we drilled 2 diatomite wells and 12 non-diatomite wells. We are currently waiting for permits to cyclically steam new diatomite wells and our diatomite development plan has shifted from the second quarter to the third quarter of 2010. We expect to run a two rig drilling program in the second half of 2010. Production in the first quarter of 2010 was 3,568 Bbl/D. In the first quarter of 2010, we initiated injection on a four pattern steam flood pilot on our recently acquired McKittrick property, which we will be monitoring over the course of the year. Average daily production in the first quarter of 2010 from all N. Midway assets was approximately 6,059 BOE/D.

Permian — Our Permian asset team is executing a one rig drilling program in 2010 and we plan to increase production over the course of the year. Taking into account both of our recent Permian acquisitions, we now have identified over 170 drilling locations on forty acre spacing in the Wolfberry trend. We have opened a Midland, Texas office and have fully staffed our Permian asset team. We operate approximately 70% of our acquired properties, and have an average 68.5% working interest (54.1% net revenue interest).

Uinta — In the first quarter of 2010, production from our Uinta basin assets averaged 4,261 BOE/D. We drilled 12 wells targeting higher oil potential areas of Brundage Canyon. We are currently operating two drilling rigs and expect to begin drilling in both our Lake Canyon and Ashley Forest acreage in the second quarter of 2010 once winter restrictions have passed. The Ashley Forest Development EIS continues to progress with the draft EIS now released for public comment. Approval of the final EIS is anticipated later this year. The Environmental Protection Agency approvals were received in the first quarter of 2010 for three additional injectors in the initial waterflood pilot at Brundage Canyon and we are currently finalizing our permit submittal for a second waterflood pilot that is expected to be initiated later this year.

E. Texas — In the first quarter of 2010, production from our E. Texas assets averaged 20.6 MMcfe/D. We continue to operate a one rig program which is now drilling horizontal Haynesville wells in our Darco field located in Harrison County. In the first quarter of 2010, we successfully drilled our first two horizontal wells achieving lateral lengths of 4,257 feet and 4,590 feet, respectively, and have recently reached total depth on our third horizontal well. Late in the first quarter of 2010, we successfully completed our first Haynesville well with a 13-stage fracture stimulation treatment. That well yielded an initial potential of 10.3 MMcf/D gross production, with the first 30 days of production averaging 9.0 MMcf/D, which surpassed our expectations.

Piceance — In the first quarter of 2010, production from the Piceance basin averaged 21.9 MMcfe/D. We resumed drilling with a one rig program, focusing on remaining lease earning obligations. We drilled three wells in the first quarter and continued to test improved completions techniques with two new well completions and 10 uphole recompletions in the first quarter. Results from these completions continue to meet expectations.

Financial Condition, Liquidity and Capital Resources.

Our exploration, development, and acquisition activities require us to make significant operating and capital expenditures. Historically, we have used cash flow from operations and our bank credit facilities as our primary sources of liquidity. We have also used the private and public markets as other sources of financing and, as market conditions have permitted, we have engaged in asset monetization transactions.

Changes in the market prices for oil and natural gas directly impact our level of cash flow generated from operations. We employ derivative instruments in our risk management strategy in an attempt to minimize the adverse effects of wide fluctuations in the commodity prices on our cash flow. As of March 31, 2010 we have approximately 75% and 40% of our expected 2010 and 2011 oil production hedged with derivative instruments in the form of swaps and collars and we have approximately 30% and 10% of our 2010 and 2011 expected natural gas production hedged with derivative instruments in the form of swaps and collars. This level of derivatives will provide a measure of certainty of the cash flow that we will receive for a portion of our production in 2010 and 2011. In the future, we may determine to increase or decrease our derivative positions. Most of our derivatives counterparties were commercial banks that are parties to our credit facilities, or their affiliates. See Item 3, “Quantitative and Qualitative Disclosures About Market Risk” for further details concerning our hedging activities.

We have a $1.5 billion senior secured revolving credit facility with a current borrowing base of $938 million and $664 million of available borrowing capacity. At March 31, 2010, we had $270 million in borrowings and $4 million in letters of credit outstanding under the credit facility. Our borrowing base is subject to semi-annual redeterminations in April and October of each year and was reconfirmed in April 2010. The borrowing base is determined by the lenders (a syndicate of banks), taking into consideration the estimated value of our proved oil and gas reserves based on pricing models determined by the lenders. See Note 8 to the Condensed Financial Statements.

The public and private capital markets have served as our primary source of financing to fund large acquisitions and other exceptional transactions. In January 2010, we sold to the public 8 million shares of our common stock at a price of $29.25 per share and received $224 million of net proceeds after deducting the underwriting discounts and the offering expenses. We used the net proceeds to fund the Wolfberry Acquisition and to reduce our outstanding borrowings under our senior secured revolving credit facility. In May 2009, we issued $325 million principal amount of 10.25% senior notes due 2014 and in August 2009 we issued an additional $125 million principal amount of our 10.25% senior notes due 2014. See Note 8 to the Condensed Financial Statements.

Our ability to access the debt and equity capital markets on economical terms is affected by general economic conditions, the financial markets, the credit ratings assigned to our debt by independent credit rating agencies, our operational and financial performance, the value and performance of equity and debt securities, prevailing commodity prices, and other macroeconomic factors outside of our control.

We also have engaged in asset dispositions as a means of generating additional cash to fund expenditures and enhance our financial flexibility. For example, in April 2009, we sold our DJ basin assets and related hedges for $154 million before customary closing adjustments and in July 2009 we completed the sale of our E. Texas gathering system for $18.4 million in cash.

Cash Flows

Operating activities - Net cash flows provided by operating activities are primarily affected by the price of crude oil and natural gas, production volumes, and changes in working capital. The increase in net cash provided by operating activities of $55.4 million in the first quarter of 2010 compared to the first quarter of 2009 is primarily due to higher realized commodity sales prices in the first quarter of 2010 compared to the first quarter of 2009.

Investing Activities - Cash flows used by investing activities are primarily comprised of acquisition, exploration and development of oil and gas properties net of dispositions of oil and gas properties. The increase in net cash used in investing activities of $144.3 million in the first quarter of 2010 compared to the first quarter of 2009 is due to the Wolfberry Acquisition in the first quarter of 2010.

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Financing Activities - Net cash provided by financing activities in the first quarter of 2010 included proceeds from the issuance of stock of $224.3 million, the net repayment of the senior secured revolving credit facility of $102 million and dividends paid of $4.0 million. Net cash provided by financing activities in the first quarter of 2009 included the net borrowing of the senior secured revolving credit facility and the money market line of credit of $42.3 million, debt issuance costs of $4.5 million and dividends paid of $3.4 million.

Capital Expenditures

We establish a capital budget for each calendar year based on our development opportunities and the expected cash flow from operations for that year. 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 2010, we have a capital program of approximately $285 million, and we expect to fully fund this program from operating cash flow. Our capital expenditures for the first quarter of 2010 totaled $48.0 million for development and capitalized interest of $6.0 million compared to total capital expenditures for the first quarter of 2009 of $50.2 million for development and capitalized interest of $5.3 million. We expect our 2010 capital program will allow us to increase production from 2009 levels to average 2010 production between 32,250 BOE/D and 33,000 BOE/D.

We believe that our cash flow provided by operating activities and funds available under our credit facilities will be sufficient to fund our operating and capital expenditures budget and our short-term contractual operations during 2010. However, if our revenue and cash flow decrease in the future as a result of deterioration in economic conditions or an adverse change in commodity prices, we may have to reduce our spending levels. As we have operational control of all of our assets and we have limited drilling commitments, we believe that we have the financial flexibility to adjust our spending levels, if necessary, to meet our financial obligations.

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Critical Accounting Policies and Estimates

Reference should be made to the corresponding section in Part II, Item 7 of our Annual Report on Form 10-K for the year ended December 31, 2009 for a discussion of other critical accounting policies that we consider as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by management.

Derivatives and Hedging. We periodically enter into commodity derivative contracts to manage our exposure to oil and natural gas price volatility. We also enter into derivative contracts to mitigate the risk of interest rate fluctuations. The accounting treatment for the changes in fair value of a derivative instrument is dependent upon whether or not a derivative instrument is a cash flow hedge or a fair value hedge, and upon whether or not the derivative is designated as a hedge. Changes in fair value of a derivative designated as a cash flow hedge are recognized, to the extent the hedge is effective, in AOCL until the hedged item is recognized in earnings. Changes in the fair value of a derivative instrument designated as a fair value hedge, to the extent the hedge is effective, have no effect on the Condensed Statements of Income because changes in fair value of the derivative offsets changes in the fair value of the hedged item. Where hedge accounting is not elected or if a derivative instrument does not qualify as either a fair value hedge or a cash flow hedge, changes in fair value are recognized in earnings. Hedge effectiveness is assessed at least quarterly based on total changes in the derivative's fair value and any ineffective portion of the derivative instrument's change in fair value is recognized immediately in earnings. The estimated fair value of our derivative instruments requires substantial judgment. These values are based upon, among other things, whether or not the forecasted hedged transaction will occur, option pricing models, futures prices, volatility, time to maturity and credit risk. The values we report in our Condensed Financial Statements changes as these estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control. Effective January 1, 2010, we have elected to de-designate all of our commodity and interest rate contracts that had previously been designated as cash flow hedges as of December 31, 2009 and have elected to discontinue hedge accounting prospectively. At December 31, 2009, AOCL consisted of $97 million ($60 million after tax) of unrealized losses, representing the fair value of our cash flow hedges as of the Condensed Balance Sheet date, less any ineffectiveness recognized. As a result of discontinuing hedge accounting on January 1, 2010, such changes in fair values at December 31, 2009 are frozen in AOCL as of the de-designation date and will be reclassified into earnings in future periods as the original hedged transactions affect earnings. We expect to reclassify into earnings from AOCL the frozen value related to de-designated commodity hedges during the next three years. See Note 3 to the Condensed Financial Statements.

Recent Accounting Standards and Updates

In January 2010, the FASB issued Accounting Standards Update (ASU) No. 2010-06 "*Improving Disclosures about Fair Value Measurements.*" The ASU amends previously issued authoritative guidance and requires new disclosures and clarifies existing disclosures and is effective for interim and annual reporting periods beginning after December 15, 2009, except for the disclosures about purchases, sales, issuances, and settlements in the rollforward activity in Level 3 fair value measurements. Those disclosures are effective for fiscal years beginning after December 15, 2010 and for interim periods within those fiscal years. As this requires only additional disclosures, the guidance will have no impact on our financial position or results of operations.

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Reconciliation of Non-GAAP Measures

Discretionary Cash Flow

In addition to reporting cash provided by operating activities as defined under GAAP, we present discretionary cash flow, which is a non-GAAP liquidity measure. Discretionary cash flow consists of cash provided by operating activities before changes in working capital items. Management uses discretionary cash flow as a measure of liquidity and believes it provides useful information to investors because it assesses cash flow from operations for each period before changes in working capital, which fluctuates due to the timing of collections of receivables and the settlements of liabilities. The following table provides a reconciliation of cash provided by operating activities, the most directly comparable GAAP measure, to adjusted discretionary cash flow for the period presented.

(in millions)	**For the Three Months Ended March 31, 2010**
Net cash provided by operating activities	$ 63.5
Add back: Net increase in current assets	14.2
Add back: Net increase in current liabilities including book overdraft	(7.3)
Discretionary cash flow	$ 70.4

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Berry Petroleum Company
Quantitative and Qualitative Disclosures About Market Risk

Item 3. Quantitative and Qualitative Disclosures About Market Risk

As discussed in Note 3 to the 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 derivative 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 and in accordance with policy established by our board of directors. Currently, our derivatives are in the form of swaps and collars. However, we may use a variety of derivative 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 $161.10 per barrel on the volumes indicated below. In total, we have approximately 75% and 40% of our expected 2010 and 2011 oil production, respectively, hedged in the form of swaps and collars. Our natural gas collars have a floor from $6.00 to $6.50 per MMBtu and ceilings ranging from $7.25 to $8.90 per MMBtu. In total, we have approximately 30% and 10% of our 2010 and 2011 expected natural gas production, respectively, hedged in the form of swaps and collars. A ten dollar change in oil prices impacts our annual operating cash flow by approximately $13 million. A one dollar change in natural gas prices impacts annual operating cash flow by approximately $3 million.

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The following table summarizes our commodity derivative position as of March 31, 2010:

Term	**Average Barrels Per Day**	**Average Prices**
Crude Oil Sales (NYMEX WTI) Collars		
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 2010	500	$75.00/$93.95
Full year 2010	500	$75.00/$94.45
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 2011	500	$75.00/$100.75
Full year 2011	500	$75.00/$101.15
Full year 2011	1,000	$75.00/$91.25

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
Full year 2012	500	$75.00/$105.00
Full year 2012	500	$75.00/$106.00
Full year 2012	1,000	$75.00/$95.00
Crude Oil Sales (NYMEX WTI) Swaps		
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

Term	Average MMBtu Per Day	Average Price
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
Full year 2011	5,000	$6.00/$7.25
Full year 2012	5,000	$6.00/$7.70
Natural Gas Sales (NYMEX HH TO PEPL) Basis Swaps		
Full year 2010	2,000	$1.05
Full year 2010	3,000	$1.00
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
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		
Full year 2010	2,500	$0.415
Full year 2011	2,500	$0.460
Full year 2012	2,500	$0.440
Natural Gas Sales (NYMEX HH) Swaps		
Full year 2010	5,000	$5.73
Full year 2010	5,000	$6.02
Full year 2011	5,000	$6.89
Full year 2012	5,000	$7.16

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The related cash flow impact of all of our derivatives is reflected in cash flows from operating activities.

Based on average NYMEX futures prices as of March 31, 2010 (WTI $85.97; HH $5.12) for the term of our derivatives 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 derivatives in place as follows:

	March 31, 2010 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 (2010 – 2012)	$ 85.97	$ 51.58	$ 68.77	$ 103.16	$ 120.35
Average HH Futures Price (2010 – 2012)	5.12	3.07	4.09	6.14	7.16
Crude Oil gain/(loss) (in millions)	$ (85.2)	$ 194.7	$ 44.2	$ (219.7)	$ (335.2)
Natural Gas gain/(loss) (in millions)	10.3	39.5	27.1	5.9	(0.7)
Total	$ (74.9)	$ 234.2	$ 71.3	$ (213.8)	$ (335.9)

Net pre-tax future cash (payments) and receipts by year (in millions) based on average price in each year:					
2010 (WTI $84.70; HH $4.26)	(23.4)	132.7	50.7	(93.0)	(145.6)
2011 (WTI $86.08; HH $5.22)	(51.3)	49.2	5.8	(112.7)	(173.3)
2012 (WTI $86.80; HH $5.65)	(0.2)	52.3	14.8	(8.1)	(17.0)
Total	$ (74.9)	$ 234.2	$ 71.3	$ (213.8)	$ (335.9)

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 principal amount 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 March 31, 2010, total long-term debt outstanding was $907 million. Interest on amounts borrowed under our credit facility is charged at LIBOR plus 2.25% to 3.0% plus the credit facility's margin through July 15, 2012. Based on March 31, 2010 credit facility borrowings, a 1% change in interest rates, including our interest rate derivatives, would have an annualized $0.1 million after tax impact on our Condensed Financial Statements.

We have entered into interest rate derivatives as shown below to swap the floating rate under our senior secured credit facility (LIBOR) for a fixed interest rate.

Derivative 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%

As of March 31, 2010, as a result of our interest rate derivative contracts, senior subordinated notes and senior notes, we have a total of $900 million of fixed rate positions averaging 7.8%.

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Item 4. Controls and Procedures

As of March 31, 2010, 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.

Based on their evaluation as of March 31, 2010, our Chief Executive Officer and Chief Financial Officer have concluded that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e)) under the Securities Exchange Act of 1934) are effective to ensure that the information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms, and include controls and procedures designed to ensure 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 March 31, 2010 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. We may make changes in our internal control procedures from time to time in the future.

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," "estimate" 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 17 of our Form 10-K dated February 25, 2010, 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.

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings

None.

Item 1A. Risk Factors

None.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Removed and Reserved

Item 5. Other Information

None.

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Item 6. Exhibits

Exhibit No.	Description of Exhibit
10.1*	Award Grant under the Performance Share Award Program to Robert H. Heinemann (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K on March 18, 2010, File No. 1-9735)
10.2*	Award Grant under the Performance Share Award Program to David D. Wolf (filed as Exhibit 10.2 to the Registrant's Current Report on Form 8-K on March 18, 2010, File No. 1-9735)
10.3*	Award Grant under the Performance Share Award Program to Michael Duginski (filed as Exhibit 10.3 to the Registrant's Current Report on Form 8-K on March 18, 2010, File No. 1-9735)
10.4*	Form of Award Grant under the Performance Share Award Program for select officers of the Company (filed as Exhibit 10.4 to the Registrant's Current Report on Form 8-K on March 18, 2010, File No. 1-9735)
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

* Incorporated herein by reference

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/ Jamie L. Wheat

Jamie L. Wheat
Controller
(Principal Accounting Officer)

Date: April 28, 2010

COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES

(in thousands, except ratios)

	Three Months Ended March 31, 2010	12/31/09	12/31/08	12/31/07	12/31/06	12/31/05
Pre-tax income from continuing operations	$ 28,003	$ 88,317	$ 192,084	$ 206,344	$ 159,906	$ 150,289
Interest expense	17,447	50,738	26,209	17,287	10,247	6,048
Capitalized interest	5,967	30,107	23,209	18,104	9,339	—
Earnings	$ 45,450	$ 139,055	$ 218,293	$ 233,631	$ 170,153	$ 156,337
Ratio of earnings to fixed charges	**1.9**	**1.7**	**4.4**	**6.3**	**8.7**	**25.8**

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).

Exhibit 31.1

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 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 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

April 28, 2010

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

April 28, 2010

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 March 31, 2010 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

April 28, 2010

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 March 31, 2010 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

April 28, 2010

Executive Vice President and Chief Financial Officer