BERRY PETROLEUM CO
Form 10-Q
April 30, 2009

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, 2009
oTransition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from __to ___
Commission file number 1-9735

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

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

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

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.
Large accelerated 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 20, 2009, the registrant had 42,790,536 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 20, 2009 all of which is held by an affiliate of the registrant.

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

	March 31, 2009	December 31, 2008
ASSETS		
Current assets:		
Cash and cash equivalents	$ 49	$ 240
Short-term investments	65	66
Accounts receivable	72,846	65,873
Fair value of derivatives	95,931	111,886
Assets held for sale	142,820	-
Prepaid expenses and other	8,035	11,015
Total current assets	319,746	189,080
Oil and gas properties (successful efforts basis), buildings and equipment, net	2,096,593	2,254,425
Fair value of derivatives	48,641	79,696
Other assets	27,649	19,182
	$ 2,492,629	$ 2,542,383
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 51,257	$ 119,221
Revenue and royalties payable	14,848	34,416
Accrued liabilities	42,088	34,566
Line of credit	-	25,300
Income taxes payable	460	187
Fair value of derivatives	2,983	1,445
Deferred income taxes	35,191	45,490
Liabilities held for sale	4,228	-
Total current liabilities	151,055	260,625
Long-term liabilities:		
Deferred income taxes	272,351	270,323
Long-term debt	1,199,400	1,131,800
Abandonment obligation	40,105	41,967
Other long-term liabilities	4,835	5,921
Fair value of derivatives	12,324	4,203
	1,529,015	1,454,214
Shareholders' equity:		
Preferred stock, $.01 par value, 2,000,000 shares authorized; no shares outstanding	-	-
Capital stock, $.01 par value:		
Class A Common Stock, 100,000,000 shares authorized; 42,783,498 shares issued and outstanding (42,782,365 in 2008)	427	427
Class B Stock, 3,000,000 shares authorized; 1,797,784 shares issued and outstanding in 2009 and 2008 (liquidation preference of $899)	18	18
Capital in excess of par value	82,641	79,653
Accumulated other comprehensive income	64,142	113,697
Retained earnings	665,331	633,749
Total shareholders' equity	812,559	827,544
	$ 2,492,629	$ 2,542,383

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

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BERRY PETROLEUM COMPANY
Unaudited Condensed Statements of Income
Three Months Ended March 31, 2009 and 2008
(In Thousands, Except Per Share Data)

	Three months ended March 31, 2009	Three months ended March 31, 2008
REVENUES AND OTHER INCOME ITEMS		
Sales of oil and gas	$ 127,869	$ 151,666
Sales of electricity	10,270	15,927
Gas marketing	7,581	3,231
Gain on derivative terminations	14,270	-
Gain (loss) on ineffective commodity derivatives	22,894	(708)
Interest and other income, net	283	830
	183,167	170,946
EXPENSES		
Operating costs - oil and gas production	37,384	39,340
Operating costs - electricity generation	8,783	16,399
Production taxes	5,652	5,183
Depreciation, depletion & amortization - oil and gas production	36,398	24,207
Depreciation, depletion & amortization - electricity generation	959	693
Gas marketing	7,284	2,982
General and administrative	13,294	11,132
Interest expense	10,050	3,327
Dry hole, abandonment, impairment and exploration	122	2,728
	119,926	105,991
Income before income taxes	63,241	64,955
Provision for income taxes	21,462	25,419
Income from continuing operations	41,779	39,536
(Loss) income from discontinued operations, net of taxes	(6,781)	3,495
Net income	$ 34,998	$ 43,031
Basic net income from continuing operations per share	$ .92	$ .88
Basic net (loss) income from discontinued operations per share	$ (.15)	$ .08
Basic net income per share	$ .77	$ .96
Diluted net income from continuing operations per share	$ .92	$ .86
Diluted net (loss) income from discontinued operations per share	$ (.15)	$ .08
Diluted net income per share	$ .77	$ .94
Dividends per share	$ .075	$ .075

Unaudited Condensed Statements of Comprehensive Income
Three Months Ended March 31, 2009 and 2008

(In Thousands)				
Net income	$	34,998	$	43,031
Unrealized gains (losses) on derivatives, net of income taxes (benefits) of $48,160 and ($40,349), respectively		78,577		(60,523)
Reclassification of realized gains on derivatives included in net income, net of income taxes (benefits) of ($17,788) and $11,698, respectively		(29,022)		17,547
Comprehensive income	$	84,553	$	55

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

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BERRY PETROLEUM COMPANY
Unaudited Condensed Statements of Cash Flows
Three Months Ended March 31, 2009 and 2008
(In Thousands)

	Three months ended March 31, 2009	2008
Cash flows from operating activities:		
Net income	$ 34,998	$ 43,031
Depreciation, depletion and amortization	39,545	27,769
Dry hole and impairment	9,643	2,728
Commodity derivatives	(22,842)	271
Stock-based compensation expense	2,988	2,107
Deferred income taxes	21,059	22,082
Gain on sale of oil and gas properties	-	(415)
Other, net	(3,952)	491
Change in book overdraft	(23,510)	4,609
Cash paid for abandonment	(112)	(971)
Increase in current assets other than cash and cash equivalents	(12,933)	(78)
Decrease in current liabilities other than book overdraft, line of credit and fair value of derivatives	(36,755)	(14,389)
Net cash provided by operating activities	8,129	87,235
Cash flows from investing activities:		
Exploration and development of oil and gas properties	(49,898)	(75,869)
Property acquisitions	(1,173)	(261)
Additions to vehicles, drilling rigs and other fixed assets	(283)	(909)
Proceeds from sale of assets	-	1,809
Deposits on asset sales	14,000	-
Capitalized interest	(5,312)	(4,485)
Net cash used in investing activities	(42,666)	(79,715)
Cash flows from financing activities:		
Proceeds from issuances on line of credit	147,800	100,600
Payments on line of credit	(173,100)	(104,700)
Proceeds from issuance of long-term debt	159,600	69,200
Payments on long-term debt	(92,000)	(69,200)
Debt issuance cost	(4,538)	-
Dividends paid	(3,416)	(3,327)
Proceeds from stock option exercises	-	1,388
Excess tax benefit and other	-	882
Net cash provided by (used in) financing activities	34,346	(5,157)
Net (decrease) increase in cash and cash equivalents	(191)	2,363
Cash and cash equivalents at beginning of year	240	316
Cash and cash equivalents at end of period	$ 49	$ 2,679

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

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Berry Petroleum Company
Notes to the Unaudited Condensed Financial Statements

1. General

All adjustments which are, in the opinion of management, necessary for a fair statement of Berry Petroleum Company's (the Company) financial position at March 31, 2009 and December 31, 2008 and results of operations and other comprehensive income and cash flows for the three months ended March 31, 2009 and 2008 have been included. All such adjustments, except as described below, are of a normal recurring nature. The results of operations and cash flows are not necessarily indicative of the results for a full year.

The accompanying unaudited condensed financial statements have been prepared on a basis consistent with the accounting principles and policies reflected in the December 31, 2008 financial statements. The December 31, 2008 Form 10-K should be read in conjunction herewith. The year-end condensed Balance Sheet was derived from audited financial statements, but does not include all disclosures required by accounting principles generally accepted in the United States of America.

In the first quarter of 2008, we determined there was an error in computing royalties payable in prior years, accumulating to $10.5 million as of December 31, 2007. We concluded the error was not material to any individual prior interim or annual period (or to the projected earnings for 2008) and, therefore, the error was corrected during the first quarter of 2008, with the effect of increasing our sales of oil and gas by $10.5 million and reducing our royalties payable.

Our cash management process provides for the daily funding of checks as they are presented to the bank. Included in accounts payable at March 31, 2009 and December 31, 2008 is $8.2 million and $31.8 million, respectively, representing outstanding checks in excess of the bank balance (book overdraft).

2. Recent Accounting Developments

In September 2008, the Financial Accounting Standards Board (FASB) issued FASB Staff Positions (FSP) No. 133-1 and FIN 45-4 to amend FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities, to require disclosures by sellers of credit derivatives, including credit derivatives embedded in a hybrid instrument. This FSP also amends FASB Interpretation No.45, Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others, to require an additional disclosure about the current status of the payment/performance risk of a guarantee. Further, this FSP clarifies the FASB's intent about the effective date of FASB Statement No. 161, Disclosures about Derivative Instruments and Hedging Activities. This FSP became effective for our fiscal year beginning January 1, 2009 and we expanded our disclosures accordingly.

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities—an amendment of FASB Statement No. 133, which changes the disclosure requirements for derivative instruments and hedging activities. Expanded disclosures are required to provide information about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under Statement 133 and its related interpretations, and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. We adopted this Statement January 1, 2009 and we expanded our disclosures accordingly.

In December 2007, the FASB issued Statement of Financial Accounting Standard (SFAS) No. 160, Noncontrolling Interests in Consolidated Financial Statements. SFAS 160 was issued to establish accounting and reporting standards for the noncontrolling interests in a subsidiary (formerly called minority interests) and for the deconsolidation of a subsidiary. We adopted this Statement January 1, 2009 and it did not have a material effect on our financial statements.

In December 2007, the FASB issued SFAS No. 141(R), Business Combinations, which expands the information that a reporting entity provides in its financial reports about a business combination and its effects. This Statement establishes principles and requirements for how the acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any non-controlling interests in the acquiree, recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase, and determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. This Statement applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. An entity may not apply the statement before that date. We may experience a financial statement impact depending on the nature and extent of any new business combinations entered into after the effective date of SFAS No. 141(R).

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In June 2008, the FASB issued FASB Staff Position No. EITF 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities ("FSP EITF 03-6-1"), which clarifies that share-based payment awards that entitle their holders to receive nonforfeitable dividends before vesting should be considered participating securities. As participating securities, these instruments should be included in the earnings allocation in computing basic earnings per share under the two-class method described in SFAS No. 128, Earnings per Share. All prior period earnings per share data presented shall be adjusted retrospectively to conform with the provisions of this pronouncement. FSP EITF 03-6-1 is effective for financial statements issued for fiscal years beginning after December 15, 2008 and interim periods within those years. We implemented EITF 03-06-1 during the first quarter of 2009. See Note 10 to the condensed financial statements.

In April 2009, the FASB issued FSP No. FAS 107-1, Interim Disclosures about Fair Value of Financial Instruments. FSP 107-1 requires disclosures about fair value of financial instruments for interim reporting periods as well as in annual financial statements. FSP 107-1 will be effective for us for the quarter ending June 30, 2009. The adoption of FSP 107-1 will not have an impact on our financial position and results of operations.

3. Fair Value Measurements

In September 2006, SFAS No. 157, Fair Value Measurements was issued by the FASB. This Statement defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. We adopted this Statement for financial instruments on January 1, 2008.

In February 2008, the FASB issued FSP FAS 157-2, Effective Date of FASB Statement No. 157. This Statement delayed the effective date of SFAS No. 157 for nonfinancial assets and nonfinancial liabilities. We adopted SFAS 157 for nonfinancial assets and nonfinancial liabilities on January 1, 2009 and it did not have a material effect on our financial statements.

In February of 2007, the FASB issued SFAS 159 The Fair Value Option for Financial Assets and Financial Liabilities—Including an amendment of FASB Statement No. 115, which is effective for fiscal years beginning after November 15, 2007. SFAS 159 provides an option to elect fair value as an alternative measurement for selected financial assets and financial liabilities not previously carried at fair value. We adopted this Statement at January 1, 2008, but did not elect fair value as an alternative for any financial assets or liabilities.

Determination of fair value
We have established and documented a process for determining fair values. Fair value is based upon quoted market prices, where available. We have various controls in place to ensure that valuations are appropriate. These controls include: identification of the inputs to the fair value methodology through review of counterparty statements and other supporting documentation, determination of the validity of the source of the inputs, corroboration of the original source of inputs through access to multiple quotes, if available, or other information and monitoring changes in valuation methods and assumptions. The methods described above may produce a fair value calculation that may not be indicative of future fair values. Furthermore, while we believe these valuation methods are appropriate and consistent with that used by other market participants, the use of different methodologies, or assumptions, to determine the fair value of certain financial instruments could result in a different estimate of fair value.

Valuation hierarchy
SFAS 157 establishes a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy is based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date.

The three levels are defined as follows:

- Level 1 - inputs to the valuation methodology that are quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2 - inputs to the valuation methodology that include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.
- Level 3 - inputs to the valuation methodology that are unobservable and significant to the fair value measurement. A financial instrument's categorization within the valuation hierarchy is based upon the lowest level of input that is significant to the fair value measurement.

Our oil swaps, natural gas swaps and interest rate swaps are valued using the counterparties' mark-to-market statements which are validated by our internally developed models and are classified within Level 2 of the valuation hierarchy. The observable inputs include underlying commodity and interest rate levels and quoted prices of these instruments on actively traded markets. Derivatives that are valued based upon models with significant unobservable market inputs (primarily volatility), and that are normally traded less actively are classified within Level 3 of the valuation hierarchy. Level 3 derivatives include oil collars, natural gas collars and natural gas basis swaps.

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Assets and (liabilities) measured at fair value on a recurring basis

March 31, 2009 (in millions)	Total carrying value on the condensed Balance Sheet	Level 2	Level 3
Commodity derivative assets	143.5	6.0	137.5
Interest rate swaps	(14.7)	(14.7)	-
Total fair value	128.8	(8.7)	137.5

Included in the total $128.8 million asset above is a $0.5 million liability associated with our DJ liabilities which are classified as "Liabilities held for sale" as of March 31, 2009.

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

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 us within Level 3 of the valuation hierarchy. When a determination is made to classify a financial instrument within Level 3 of the valuation 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, 2009
Fair value of Level 3 derivative assets, beginning of period	$ 172.5
Total realized and unrealized gains and (losses) included in sales of oil and gas	(22.9)
Purchases, sales and settlements, net	(15.5)
Transfers in and/or out of Level 3	3.4
Fair value of Level 3 derivative assets, March 31, 2009	$ 137.5

Total unrealized gains and (losses) included in income related to financial assets and liabilities still on the condensed balance sheet at March 31, 2009	$	22.8

The fair value of our DJ basin asset sale determined by our Borad of Directors was confirmed by the sales price paid to us. The following nonrecurring fair value measurements were recorded during the three months ended March 31, 2009 in conjunction with the sale of our DJ basin assets:

	Three Months Ended March 31, 2009	Significant Unobservable Inputs Level 3	Total Gains (Losses)
Long lived assets and liabilities held for sale (in millions)	$ 138,592	$ 138,592	$ (9,637)

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4. Hedging

To minimize the effect of a downturn in oil and gas prices and protect our profitability and the economics of our development plans, we enter into crude oil and natural gas hedge contracts from time to time. The terms of contracts depend on various factors, including management's view of future crude oil and natural gas prices, acquisition economics on purchased assets and our future financial commitments. This price hedging program is designed to moderate the effects of a severe crude oil and natural gas price downturn while allowing us to participate in some commodity price increases. We benefit from lower natural gas pricing as we are a consumer of natural gas in our California operations and in the Rocky Mountains and East Texas, we benefit from higher natural gas pricing. We have hedged, and may hedge in the future, both natural gas purchases and sales as determined appropriate by management. Management regularly monitors the crude oil and natural gas markets and our financial commitments to determine if, when, and at what level some form of crude oil and/or natural gas hedging and/or basis adjustments or other price protection is appropriate in accordance with policy established by our board of directors. Currently, our hedges are in the form of swaps and collars. However, we may use a variety of hedge instruments in the future to hedge WTI or the index gas price. We also utilize interest rate derivatives to protect against changes in interest rates on our floating rate debt.

The related cash flow impact of all of our hedges is reflected in cash flows from operating activities. At March 31, 2009, our net fair value of derivative assets was $128.8 million as compared to $185.9 million at December 31, 2008 which reflects decreases in commodity prices in the period. Based on NYMEX strip pricing as of March 31, 2009, we expect to receive hedge proceeds under the existing derivatives of $104.4 million during the next twelve months. At March 31, 2009, Accumulated Other Comprehensive Income consisted of $64.1 million, net of tax, of unrealized gains from our crude oil and natural gas swaps and collars that qualified for hedge accounting treatment at March 31, 2009. Deferred net gains recorded in “Accumulated Other Comprehensive Income” at March 31, 2009 and subsequent mark-to-market changes in the underlying hedging contracts are expected to be reclassified to earnings in the same period that the forecasted transaction impacts earnings.

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

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

	As of March 31, 2009			
	Derivative Assets		Derivative Liabilities	
(in millions)	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Commodity – Oil	Current assets	94.6	Current liability	2.3
Commodity – Natural Gas	Current assets	4.1	Current liability	0.3

Commodity – Oil	Long term assets	52.4	Long term liabilities	6.5
Commodity – Natural Gas	Long term assets	0.7		-
Commodity – Natural Gas	Long term liabilities	1.1		-
Interest rate contracts		-	Current assets	2.9
Interest rate contracts		-	Long term assets	4.4
Interest rate contracts		-	Current liabilities	0.4
Interest rate contracts		-	Long term liabilities	7.0
Total derivatives designated as hedging instruments under Statement 133		152.9		23.8
Commodity – Oil	Current assets	0.2	Current liabilities	-
Commodity – Natural Gas	Liabilities held for sale	0.8	Liabilities held for sale	1.3
Total derivatives not designated as hedging instruments under Statement 133		1.0		1.3
Total Derivatives		153.9		25.1

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Berry Petroleum Company

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The tables below summarize the Statement of Income impacts on our derivative instruments:

Derivatives in Statement 133 cash flow hedging relationships	Amount of gain (loss) Recognized in OCI on Derivative (Effective portion)	Location of Gain (Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Gain (Loss) Reclassified from AOCI into Income (Effective Portion)	Location of Gain Recognized in Income on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)	Amount of Gain Recognized in Income on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)
	Three Months Ended March 31, 2009		Three Months Ended March 31, 2009		Three Months Ended March 31, 2009
Commodity - Oil	$ 36.5	Sales of oil and gas	$ 41.6	Sales of oil and gas	$ -
Commodity - Natural Gas	8.9	Sales of oil and gas	6.6	Sales of oil and gas	-
Commodity – Oil	-	Gain (loss) on commodity –Oil	-	Gain (loss) on commodity-Oil	22.7
Interest rate	(3.4)	Interest expense	(1.0)	Interest expense	-
Total	$ 42.0		$ 47.2		$ 22.7

Amount of Gain or (Loss) Recognized in Income on Derivatives not designated as Hedging Instruments under Statement 133:

Derivatives not designated as Hedging Instruments under Statement 133	Location of Gain (Loss) Recognized in Income on Derivative	Amount of Gain (Loss) Recognized in Income on Derivate for Derivatives not designated as Hedging Instruments under Statement 133
		Three months ended March 31, 2009
Commodity – Oil	Gain (loss) on ineffective commodity derivatives	$ 0.2
Commodity - Natural Gas	(Loss) income from discontinued operations, net of tax	(0.5)
Total Derivatives		$ (0.3)

We entered into the following natural gas hedges during the three months ended March 31, 2009:

- Houston Ship Channel basis swaps on 2,000 MMBtu/D for $0.38 for full year 2010
- NGPL basis swaps on 2,000 MMBtu/D for $0.49 for the full year 2010
- Collars on 4,000 MMBtu/D with floors of $6.50 and ceilings ranging from $8.75 to $8.90 for full year 2010

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

During the first quarter of 2009, we entered into natural gas derivatives on behalf of the purchaser of our DJ assets. We did not elect hedge accounting for these hedges and recorded the unrealized net loss of $0.5 million on the income statement under the caption "Income from discontinued operations, net of taxes."

In conjunction with the sale of the DJ assets, during the first quarter of 2009, we concluded that the forecasted transaction in certain of our hedging relationships was not probable of occurring. As such, we reclassified a gain of $14.3 million from accumulated other comprehensive income to the statement of income under the caption "Gain on derivative terminations."

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We entered into the following oil collar derivatives during the three months ended March 31, 2009:

Crude Oil Sales (NYMEX WTI) Collars	Average Barrels Per Day	Floor/Ceiling Prices
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

These oil hedge derivatives have been designated as cash flow hedges in accordance with SFAS No. 133.

We entered into the following oil swap derivatives during the three months ended March 31, 2009:

Crude Oil Sales (NYMEX WTI) Collars	Average Barrels Per Day	Swap Price
May 2009	1,000	$ 55.60
June 2009	400	$ 57.00
3rd Quarter 2009	500	$ 52.40
Full year 2010	650	$ 56.90
Full year 2011	250	$ 61.80
Full year 2011	500	$ 57.36
Full year 2011	500	$ 57.40
Full year 2011	500	$ 57.50

The oil hedge derivatives have been designated as cash flow hedges in accordance with SFAS No. 133, except as noted below. We did not elect hedge accounting for the May and June 2009 hedges and recorded an unrealized net gain of $0.2 million at March 31, 2009 on the income statement under the caption “Gain (loss) on ineffective commodity derivatives”.

During the first quarter of 2009, we also converted 6,000 Bbl/D oil collars ranging from floors of $55.00 to $60.00 and ceilings of $75.00 to $83.10 for full year 2010 swaps for the same volumes with swap prices ranging from $61.00 to $64.80.

In December 2008, Big West Oil of California filed for bankruptcy protection under Chapter 11 of the United States Bankruptcy Code. Our contract with Big West provided for an oil price differential that was linked to NYMEX WTI prices and allowed us to effectively hedge our oil production at the NYMEX WTI index. Subsequent to the Big West bankruptcy, our crude oil has been sold at field posting prices which resulted in some ineffectiveness related to our WTI linked hedges. We recognized an unrealized net gain of approximately $22.8 million on the income statement under the caption “Gain (loss) on ineffective commodity derivatives” for the quarter ended March 31, 2009 as a result of this ineffectiveness.

We entered into the following interest rate hedges during the three months ended March 31, 2009 which have been designated as cash flow hedges:

Beginning/Maturity	Rate	Notional Amount (in millions)
4/15/09 – 7/15/12	1.89%	$ 25
12/15/09 – 7/15/12	2.15%	$ 25
12/15/09 – 7/15/12	2.05%	$ 25
12/15/09 – 7/15/12	2.00%	$ 25
12/15/09 – 7/15/12	2.00%	$ 25
12/15/09 – 7/15/12	1.94%	$ 25

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Our hedge contracts have been primarily executed with the counterparties that are party to our senior secured revolving credit facility. Neither we nor our counterparties are required to post collateral in connection with our derivative positions and netting agreements are in place with each of our counterparties allowing us to offset our derivative asset and liability positions. The credit rating of each of these counterparties is AA-/Aa2, or better. Our derivatives are held with a small number of counterparties and as of March 31, 2009, our largest two counterparties accounted for 80% of the value of our total derivative positions.

As of March 31, 2009, we had the following outstanding commodity contracts:

	Commodity Hedges			
	2009	2010	2011	2012
Oil Bbl/D:	17,435	14,930	9,020	1,000
Natural Gas MMBtu/D:	5,000	9,000	-	-

5. Asset Retirement Obligations

Inherent in the fair value calculation of the asset retirement obligation (ARO) are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the oil and gas property balance.

The following table summarizes the change in abandonment obligation for the three months ended March 31, 2009 (in thousands):

Beginning balance at January 1, 2009	$ 41,967
Liabilities incurred	-
Liabilities settled	(113)
Revisions in estimated liabilities	-
Accretion expense	1,002
Ending balance at March 31, 2009	$ 42,856

Included in the total of $42.9 million above is $2.8 million in AROs that are associated with our DJ liabilities which are classified as "Liabilities held for sale" as of March 31, 2009.

6. Dispositions and 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 $14 million sale of our DJ basin related hedges was completed in March 2009. The hedge forecasted transaction is no longer expected to occur and the gain on the sale of these hedges is recorded under the caption “Gain on derivative terminations” in the condensed statement of income and is included in operating cash flows for the three months ended March 31, 2009. We received a deposit of $14 million on the sale of the DJ basin assets which is included in “Accrued Liabilities” on the condensed balance sheet as of March 31,

2009. The closing date of the sale was April 1, 2009. In accordance with SFAS No. 144, these properties have been separately presented in the accompanying condensed balance sheet at fair value less the cost to sell, as of March 31, 2009. The sales cost associated with the DJ basin assets were $1.2 million. We recorded a pre-tax impairment loss of $9.6 million, which is aggregated within the $6.8 million “(loss) income from discontinued operations, net of tax” on our statement of income for the three months ended March 31, 2009.

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

	For the Three Months Ended March 31, 2009	2008
Oil and gas revenue	$ 5,396	$ 12,829
Other revenue	622	914
Total Revenue	6,018	13,743
Operating expenses	2,576	2,289
Production taxes	195	784
DD&A	2,188	2,869
General and administrative	388	251
Interest expense	815	411
Commodity derivatives	484	-
Dry hole, abandonment, impairment and exploration	9,637	1,398
Total Expenses	16,283	8,002
Income (loss) from discontinued operations, before income taxes	(10,265)	5,741
Income tax benefit (expense)	3,484	(2,246)
Income (loss) from discontinued operations	$ (6,781)	$ 3,495

The following is a summary of the assets and liabilities held for sale related to the DJ Basin sale at March 31, 2009 (in thousands):

	March 31, 2009
Inventory	$ 1,275
Oil and gas properties, net of accumulated depreciation and impairment	140,730
Other Assets	815
Total assets	$ 142,820
Asset retirement obligation	$ 2,751
Other liabilities	1,477
Total liabilities	$ 4,228

7. Dry Hole, Abandonment and Impairment

During the three months ended March 31, 2009 and 2008, we recorded dry hole, abandonment, impairment and exploration expense of $0.1 million and $2.7 million, respectively. In the first quarter of 2008, technical difficulties on three wells in the Piceance basin were encountered before reaching total depth and these holes were abandoned in favor of drilling to the same bottom hole location by drilling a new well.

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8. Pro Forma Results

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

The unaudited pro forma results presented below for the three months ended March 31, 2008 have been prepared to give effect to the East Texas Acquisition on the Company's results of continuing operations under the purchase method of accounting as if it had been consummated at January 1, 2008. The unaudited pro forma results (in millions) do not purport to represent the results of continuing operations that actually would have occurred on such date or to project the Company's results of operations for any future date or period:

	Three Months Ended March 31, 2008
Pro forma revenue	$ 185,960
Pro forma income from operations	$ 60,073
Pro forma net income	$ 36,942
Pro forma basic earnings per share	$ 0.82
Pro forma diluted earnings per share	$ 0.81

9. Income Taxes

The effective income tax rate was 33.9% for the first quarter of 2009 compared to 45.1% for the fourth quarter of 2008 and 39% for the first quarter of 2008. The decrease in rate for first quarter is primarily due to a decrease in anticipated state taxes. Our estimated annual effective tax rate varies from the 35% federal statutory rate due to the effects of state income taxes and estimated permanent differences.

As of March 31, 2009, we had a gross liability for uncertain tax benefits of $11.2 million of which $10.0 million, if recognized, would affect the effective tax rate. There were no significant changes to the calculation since year end 2008.

We anticipate the balance of our unrecognized tax benefits could be reduced during the next 12 months as the IRS finalizes certain examinations which are in progress, however, we cannot reasonably estimate the impact of the examination at this time.

10. Earnings per Share

In SFAS No. 128, "Earnings per Share (as amended)", the two-class method is an earnings allocation formula that determines earnings per share for each class of stock according to dividends declared (or accumulated) and participation rights in undistributed earnings. In June 2008, the FASB issued FASB Staff Position No. EITF 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities ("FSP EITF 03-6-1"), which clarifies that share-based payment awards that entitle their holders to receive nonforfeitable dividends before vesting should be considered participating securities. As participating securities, these instruments should be included in the earnings allocation in computing basic earnings per share under the two-class method described in SFAS No. 128. All prior period earnings per share data presented were adjusted retrospectively to conform with the provisions of this pronouncement. FSP EITF 03-6-1 is effective for financial statements issued for fiscal years beginning after December 15, 2008 and interim periods within those years. Accordingly, we have adopted this pronouncement as of January 1, 2009.

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Undistributed and distributed earnings allocated to shareholders are calculated as follows for the three month periods ended:

	March 31, 2009	March 31, 2008
Income from continuing operations	$ 41,779	$ 39,536
Less:		
Dividends paid - shareholders	3,344	3,289
Dividends paid - unvested shares and deferred stock units	72	38
Undistributed income from continuing operations	$ 38,363	$ 36,209
(Loss) income from discontinued operations	$ (6,781)	$ 3,495

	March 31, 2009	March 31, 2008
Income from continuing operations available to shareholders		
Distributed earnings to shareholders	$ 3,344	$ 3,289
Allocation of undistributed earnings to shareholders	37,387	35,705
Total income from continuing operations available to shareholders	$ 40,731	$ 38,994
Income from discontinued operations available to shareholders		
Distributed earnings to shareholders	$ -	$ -
Allocation of undistributed (loss) earnings available to shareholders	(6,608)	3,445
Total (loss) income from discontinued operations available to shareholders	$ (6,608)	$ 3,445

Undistributed earnings available to shareholders is calculated by dividing weighted average shares outstanding by the total of weighted shares outstanding plus weighted average of unvested shares outstanding plus the weighted average of deferred stock units outstanding multiplied by undistributed earnings. Shares issued during the period and shares reacquired during the period are weighted for the portion of the period in which the shares were outstanding. The weighted average number of unvested shares and deferred stock units for the three month periods ended March 31, 2009 and 2008 is 1,164,391 and 628,685, respectively.

Weighted average shares outstanding and dilutive shares outstanding are calculated as follows:

	March 31, 2009	March 31, 2008
Weighted average shares outstanding:	44,581	44,392
Add: dilutive effects of stock options	12	623
Weighted average shares outstanding, including the effects of dilutive common shares	44,593	45,015

Options to purchase 2.3 million and .2 million shares were outstanding at March 31, 2009 and 2008, respectively, and were excluded from the calculation of diluted earnings per share because the options' exercise price was greater than the average market price of the shares.

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Basic and dilutive earnings per share from continuing and discontinued operations are calculated as follows:

		March 31, 2009		March 31, 2008
Basic				
Income from continuing operations available to shareholders	$	40,731	$	38,994
shares outstanding		44,581		44,392
Basic earnings per share from continuing operations	$	.92	$	.88
(Loss) income from discontinued operations available to shareholders	$	(6,608)	$	3,445
Shares outstanding		44,581		44,392
Basic (loss) earnings per share from discontinued operations	$	(.15)	$	.08
Basic earnings per share	$	.77	$	.96
Dilutive				
Income from continuing operations available to shareholders	$	40,731	$	38,994
Dilutive shares		44,593		45,015
Dilutive earnings per share from continuing operations	$	.92	$	.86
(Loss) income from discontinued operations available to shareholders	$	(6,608)	$	3,445
Dilutive shares		44,593		45,015
Dilutive (loss) earnings per share from discontinued operations	$	(.15)	$	.08
Dilutive earnings per share	$	.77	$	.94

Upon adoption, both basic income and dilutive income per share for the first quarter of 2008 decreased by $.01 for continuing operations. Basic income and dilutive income per share was unchanged for discontinued operations.

11. Debt Obligations

Short-term lines of credit
In 2005, we completed an unsecured uncommitted money market line of credit (Line of Credit). Borrowings under the Line of Credit may be up to $30 million for a maximum of 30 days. The Line of Credit may be terminated at any time upon written notice by either us or the lender. In conjunction with the amendment to our senior secured credit facility, on July 15, 2008, the Line of Credit was secured by our assets. At March 31, 2009 and December 31, 2008, the outstanding balance under this Line of Credit was $0 and $25.3 million, respectively. Interest on amounts borrowed is charged at LIBOR plus a margin of approximately 1%.

Senior Secured Revolving Credit Facility
On July 15, 2008, we entered into a five year amended and restated credit agreement (the Agreement) with Wells Fargo Bank, N.A. as administrative agent and other lenders. The Agreement is a revolving credit facility for up to $1.5 billion with a borrowing base of $1.0 billion. The outstanding Line of Credit reduces our borrowing capacity available under the Agreement. Interest on amounts borrowed under the Agreement was charged at LIBOR plus a margin of 1.125% to 1.875% or the prime rate, with margins on the various rate options based on the ratio of credit outstanding to the borrowing base. An annual commitment fee of .25% to .375% was charged on the unused portion

of this credit facility.

On October 17, 2008, we amended the Agreement which increased our borrowing base from $1.0 billion to $1.25 billion with commitments of $1.08 billion and a new maturity date of July 15, 2012. Commitments were increased during the fourth quarter of 2008 with the addition of $130 million in commitments bringing the total commitments under the facility to $1.21 billion from 19 banks.

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On February 19, 2009, we executed another amendment to the Agreement which modified our covenants as follows:

Total funded debt to EBITDAX ratio		
2009	2010	Thereafter
4.75	4.50	4.00

Senior secured debt to EBITDAX ratio			
to Sep 2010	Mar 2011	Sep 2011	Thereafter
3.75	3.50	3.25	3.0

Additionally, the write off of $38.5 million to bad debt expense associated with the bankruptcy of Big West is excluded from the calculation of EBITDAX. There were no changes to the current ratio covenant which, as defined, must be at least 1.0. The LIBOR and prime rate margins increased to between 2.25% and 3.0% based on the ratio of credit outstanding to the borrowing base. Additionally, the annual commitment fee on the unused portion of the credit facility increased to 0.50%, regardless of the amount outstanding. This transaction was accounted for in accordance with Emerging Issues Task Force (EITF) 98-14, Debtor's Accounting for Changes in Line-of-Credit or Revolving-Debt Arrangements.

The total outstanding debt at March 31, 2009 under the Agreement, as amended, and the Line of Credit was $999 million and $0, respectively, and $3 million in letters of credit have been issued under the facility, leaving $208 million in borrowing capacity available. The maximum amount available is subject to semi-annual redeterminations of the borrowing base, based on the value of our proved oil and gas reserves, in April and October of each year in accordance with the lenders' customary procedures and practices. Both we and the banks have the bilateral right to one additional redetermination each year.

We further amended the Agreement on April 27, 2009. See Note 13 "Subsequent Events."

Senior Subordinated 8.25% notes due 2016
In 2006, we issued in a public offering $200 million of 8.25% senior subordinated notes due 2016 (the Notes). Interest on the Notes is paid semiannually in May and November of each year. Under the Notes, as long as the interest coverage ratio (as defined) is greater than 2.5 times, we may incur additional debt. The deferred costs of approximately $5 million associated with the issuance of this debt are being amortized over the ten year life of the Notes.

Financial Covenants
The senior secured revolving credit facility contains restrictive covenants which, among other things, require us to currently maintain a debt to EBITDAX ratio of not greater than 4.75 and a minimum current ratio, as defined, of 1.0. The $200 million Notes are subordinated to our credit facility indebtedness. Under the Notes, as long as the interest coverage ratio (as defined) is greater than 2.5 times, we may incur additional debt. We were in compliance with all of these covenants as of March 31, 2009.

	As of March 31, 2009

Current Ratio (Not less than 1.0)	2.9
EBITDAX To Total Funded Debt Ratio (Not greater than 4.75)	2.8
Interest Coverage Ratio (Not less than 2.5)	7.4

The weighted average interest rate on total outstanding borrowings at March 31, 2009 was 4.2%.

12. Contingencies and Commitments

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

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

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In December 2008, Flying J, Inc., and its wholly owned subsidiary Big West Oil and its wholly owned subsidiary BWOC filed for bankruptcy protection under Chapter 11 of the United States Bankruptcy Code. Also in December 2008, BWOC informed the Company that it was unable to receive the Company's production. Included in our allowance for doubtful accounts is $38.5 million due from BWOC. Of the $38.5 million due from BWOC, $12.4 million represents December crude oil sales by the Company and $26.1 million represents November crude oil sales. BWOC will also be liable to us for damages under this contract. We have guarantees from Big West Oil and from Flying J, Inc. in the amount of $75 million each, in the event that our claim is not fully collectible from BWOC. While we believe that we may recover some or all of the amounts due from BWOC, the data received from the bankruptcy proceedings to date has not provided us with adequate data from which to make a conclusion that any amounts will be collected.

On March 20, 2009, we entered into a crude oil purchase contract with a refiner for the sale of all of the Company's crude oil production from the Midway Sunset Field. The volume approximates 12,000 Bbl/d. The agreement is effective April 1, 2009 and continues until September 30, 2009.

In February 2007, we entered into a multi-staged crude oil sales contract with a refiner for our Uinta light crude oil. Under the agreement, the refiner began purchasing 3,200 Bbl/D in July 2007. After partial completion of its refinery expansion in Salt Lake City in March 2008, the refiner increased its total purchase capacity to 5,000 Bbl/D. This contract is in effect through June 30, 2013. Pricing under the contract, which includes transportation and gravity adjustments, is at a fixed percentage of WTI, which ranges from $10 to $15 per barrel at WTI prices between $40 and $60 per barrel. This contract is our only sales contract for our Uinta oil.

We have two long-term firm transportation contracts that total 35,000 MMBtu/D on the Rockies Express (REX) pipeline for gas production in the Piceance basin. We pay a demand charge for this capacity and our own production did not completely fill that capacity. To maximize the utilization of our firm transportation, we bought our partners' share of the gas produced in the Piceance basin at the market rate for that area and used our excess transportation to move this gas to the sales point. The pre-tax net of our gas marketing revenue and our gas marketing expense in the Statements of Income is $0.3 million and $0.2 million for the three month periods ended March 31, 2009 and 2008, respectively.

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

13. Subsequent Events

On April 1, 2009, we completed the sale of our DJ basin assets. Total proceeds received for the sale were $139 million, including closing adjustments and the $14 million deposit received in March 2009.

On April 27, 2009, we completed the scheduled redetermination of the borrowing under our credit facility. Our borrowing base was reduced from $1.25 billion to $1.05 billion, with $100 million of the reduction resulting from the sale of our DJ basin assets. Also on April 27, 2009 we completed a $140 million second lien credit facility, with lenders from among our current lending group, which matures on January 16, 2013. Interest on the facility is charged at LIBOR plus a margin of eight percent with a minimum LIBOR rate of three percent. Covenants under this facility are similar but slightly less restrictive than our senior secured credit facility. Our Line of Credit is suspended as long as the second lien credit facility is outstanding. Additionally, each dollar outstanding under the second lien credit facility reduces the borrowing base under our senior secured credit facility by 30 cents such that the $140 million second lien facility reduces our borrowing base from $1.05 billion to $1.0 billion. Proceeds from the second lien facility were used to pay down borrowings under our senior secured credit facility. On April 27, 2009, following the closing of the second lien credit facility, the outstanding amount under our senior secured credit facility was approximately $735 million providing us with approximately $275 million of liquidity.

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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

General. The following discussion provides information on the results of operations for the three months ended March 31, 2009 and 2008 and our financial condition, liquidity and capital resources as of March 31, 2009. The financial statements and the notes thereto contain detailed information that should be referred to in conjunction with this discussion.

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

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

- Investing our capital in a disciplined manner and maintaining a strong financial position
- Developing our existing resource base
- Calibrating our cost structure to the current commodity price environment
- Acquiring additional assets with significant growth potential
- Accumulating significant acreage positions near our producing operations

Notable First Quarter Items.

- Achieved production averaging 33,330 BOE/D, up 19% from the first quarter of 2008
- Announced the sale of our DJ basin assets and related hedges for approximately $154 million
- Entered into short-term sales contracts for our California crude oil to replace our terminated contract with Big West
- Continued to return California wells to production after the December 2008 Big West bankruptcy, increasing average California production from 16,000 Bbl/D in the fourth quarter of 2008 to 16,440 Bbl/D in the first quarter of 2009
- Increased Diatomite net production to an average of 2,670 BOE/D, up 94% from the first quarter of 2008
- Amended the covenants under our credit facility providing increased financial flexibility going forward
- Added to our oil hedge positions increasing 2011 hedged volumes to 9,000 BOE/D and 2012 volumes to 2,000 BOE/D
- Increased our fixed rate debt position to $725 million utilizing interest rate swaps

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

- Closed on the sale of our DJ assets using proceeds for the repayment of debt
- Completed the redetermination of our credit facility with a borrowing base of $1.05 billion with no changes to the terms or interest rate margins
- Completed a $140 million second lien facility, with existing lenders, increasing our liquidity to approximately $275 million

- Expect production to average approximately 30,000 BOED with no future contributions from the DJ assets which averaged approximately 3,100 BOE/D in the first quarter of 2009.

Overview of the first Quarter of 2009. We had net income from continuing operations of $41.8 million, or $0.92 per diluted share, and net cash from operations was $8.1 million in the first quarter of 2009. We drilled 26 gross wells and capital expenditures, excluding property acquisitions, totaled $50.2 million. We achieved average production of 33,330 BOE/D in the first quarter of 2009, down 6% from an average of 35,583 BOE/D in the fourth quarter of 2008.

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

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

	March 31, 2009 (1Q09)	March 31, 2008 (1Q08)	1Q09 to 1Q08 Change	December 31, 2008 (4Q08)	1Q09 to 4Q08 Change
Sales of oil	$ 99	$ 131	(24%)	$ 97	2%
Sales of gas	29	21	38%	38	(24%)
Total sales of oil and gas	$ 128	$ 152	(16%)	$ 135	(6%)
Sales of electricity	10	16	(38%)	12	(17%)
Gas Marketing	8	3	167%	8	-
Gain on sale of assets	-	-	-	(2)	-
Gain on hedge terminations	14	-	-	-	-
Gain (loss) on commodity derivatives	23	(1)	-	(2)	-
Interest and other income, net	-	1	-	1	-
Total revenues and other income	$ 183	$ 171	7%	$ 152	20%
Net income (loss) from continuing operations	$ 42	$ 40		$ (12)	
Diluted earnings (loss) per share from continuing operations	$ 0.92	$ 0.88		$ (.26)	

Our revenues may vary significantly from period to period as a result of changes in commodity prices and/or production volumes. Crude oil sales in the three months ended March 31, 2009 were relatively flat with the three months ended December 31, 2008 resulting from price increases of 5% offset by sales volume decreases of 3%. Total oil sales volumes decreased primarily from lower sales volumes in the Uinta basin where no capital activity occurred during the first quarter of 2009 offset by increased production in California where wells were brought back online after disruptions from the Big West bankruptcy. The decrease in revenue when compared to the first quarter of 2008 is primarily the result of a 23% decrease in realized prices. Natural gas revenues decreased from the quarter ended December 31, 2008 as a result of a 13% decrease in volumes from our Piceance and Uinta properties where no capital activity occurred during the quarter and a 9% decrease in realized prices. Natural gas revenues were higher in the first quarter of 2009 compared to the first quarter of 2008 from volume increases of 69%, primarily due to the contribution of our East Texas assets and the results of our 2008 capital program offset by a 32% decrease in realized prices.

In the first quarter of 2008, we determined there was an error in computing royalties payable in prior years, accumulating to $10.5 million as of December 31, 2007. We concluded the error was not material to any individual prior interim or annual period (or to the projected earnings for 2008) and, therefore, the error was corrected during the first quarter of 2008, with the effect of increasing our sales of oil and gas by $10.5 million and reducing our royalties payable.

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Management’s Discussion and Analysis of Financial Condition and Results of Operations

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

	March 31, 2009	%	March 31, 2008	%	December 31, 2008	%
Heavy Oil Production (Bbl/D)	16,436	50	16,375	58	15,999	45
Light Oil Production (Bbl/D)	3,066	9	3,510	13	3,659	10
Total Oil Production (Bbl/D)	19,502	59	19,885	71	19,658	55
Natural Gas Production (Mcf/D)	82,979	41	49,086	29	95,548	45
Total operations (BOE/D)	33,332	100	28,066	100	35,583	100
DJ Basin Production (BOE/D)	3,101		3,157		3,415	
Production - Continuing Operations (BOE/D)	30,231		24,909		32,168	
Oil and gas BOE for continuing operations						
Average sales price before hedging	$ 29.36		$ 75.11		$ 40.61	
Average sales price after hedging	47.11		62.44		45.57	
Oil, per Bbl, for continuing operations:						
Average WTI price	$ 43.24		$ 97.82		$ 59.08	
Price sensitive royalties	(1.02)		(4.47)		(1.69)	
Quality differential and other	(9.53)		(10.78)		(8.55)	
Crude oil hedges	23.79		(15.60)		4.69	
Correction to royalties payable	-		5.85		-	
Average oil sales price after hedging	$ 56.48		$ 72.82		$ 53.53	
Natural gas price for continuing operations:						
Average Henry Hub price per MMBtu	$ 4.90		$ 8.74		$ 6.95	
Conversion to Mcf	.25		.44		.35	
Natural gas hedges	1.14		(.19)		.89	
	(1.27)		(1.56)		(2.67)	

Location, quality differentials and other						
Average gas sales price after hedging per Mcf	$	5.02	$	7.43	$	5.52

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

Gas Basis Differential. Natural gas prices in the Rockies continue to decline due to various factors, including takeaway pipeline capacity, supply / inventory volumes, and regional demand issues. We have contracted a total of 35,000 MMBtu/D on the Rockies Express Pipeline under two separate transactions to provide firm transport for our Piceance gas production. The CIG basis differential per MMBtu, based upon first-of-month values, averaged $2.81 below HH and ranged from $0.93 to $6.61 below HH in 2008. For the first quarter of 2009, the CIG basis averaged $1.62 below HH. The Piceance gas was sold in the first quarter of 2009 based upon a mid-continent index such as PEPL. For the first three months of 2009, the mid-continent PEPL index averaged $1.51 below HH. Correspondingly, most of the Uinta Basis gas is sold based upon a Questar index which averaged $1.72 below HH. For E. Texas, the Texas Eastern - East Texas index averaged $0.78 below HH for the first quarter of 2009.

Gas Marketing. We have two long-term (ten year) firm transportation contracts for our Piceance natural gas production. The first contract is for 10,000 MMBtu/D on the Rockies Express (REX) pipeline for gas production in the Piceance basin. The second contract is for 25,000 MMBtu/D on the REX pipeline for gas production in the Piceance basin. We pay a demand charge for this capacity and our own production did not fill that capacity. In order to maximize our firm transportation capacity, we bought our partners' share of the gas produced in the Piceance at the market rate for that area. We then 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 Statement of Income is $0.3 million in the three month period ended March 31, 2009.

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

Oil Contracts. California - On March 20, 2009, we entered into a crude oil purchase contract with a refiner for the sale of all of the Company's crude oil production from the Midway Sunset field. The volume approximates 12,000 barrels per day. The agreement is effective on April 1, 2009 and continues until September 30, 2009.

We continue to market our California crude oil production, other than production from the Midway Sunset field discussed above, to various parties. The term of these contracts range from nine months to one month.

Utah - In February 2007, we entered into a multi-staged crude oil sales contract with a refiner for our Uinta basin light crude oil. Under the agreement, the refiner began purchasing 3,200 Bbl/D in July 2007. The refiner has increased its total capacity to 5,000 Bbl/D as provided in our contract. As operator we deliver all produced volumes under our sales contracts, although our working interest partners or royalty owners may take their respective volumes in kind and market their own volumes. Gross oil production averaged approximately 3,280 BOE/D in the quarter ended March

31, 2009. The differential under the contract, which includes transportation and gravity adjustments, is linked to WTI and would range from $10 to $15 per barrel at WTI prices between $40 and $60. This contract provides us an outlet to sell all of our current oil production in the Uinta basin.

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Hedging. See Note 4 to the unaudited condensed financial statements and Item 3. Quantitative and Qualitative Disclosures about Market Risk.

Electricity. We consume natural gas as fuel to operate our three cogeneration facilities which are intended to provide an efficient and secure long-term supply of steam necessary for the cost-effective production of heavy oil in California. We sell our electricity to utilities under standard offer contracts based on "avoided cost" or SRAC pricing approved by the California Public Utilities Commission (CPUC) and under which our revenues are currently linked to the cost of natural gas. Natural gas index prices are the primary determinant of our electricity sales price based on the current pricing formula under these contracts. The correlation between electricity sales and natural gas prices allows us to manage our cost of producing steam more effectively.

Our electricity margins continued to benefit from lower Rockies natural gas prices during 2009. We purchase and transport 12,000 MMBtu/D on the Kern River Pipeline under our firm transportation contract and use this gas to produce cogeneration steam in the Midway-Sunset field. The Rocky Mountain natural gas price differentials have been greater than California differentials allowing us to purchase a portion of our gas at a discount to the California price. As our electricity revenue is linked to California prices, the fuel we purchased at lower Rocky Mountain prices is the primary contributor to our electricity margin.

Revenues and operating costs were down for the quarter ended March 31, 2009 from the quarter ended March 31, 2008 due to 35% lower electricity prices and 50% lower natural gas prices. Revenues and operating costs were down for the quarter ended March 31, 2009 from the quarter ended December 31, 2008 due to 16% lower electricity prices and 16% lower natural gas prices, respectively. We purchased approximately 27 MMBtu/D as fuel for use in our cogeneration facilities in both the quarter ended March 31, 2009 and the quarter ended March 31, 2008.

We generally expect to have small gains or losses on electricity on a quarterly basis which depends on seasonality as we receive improved pricing during the summer months. However, wider natural gas price differentials in the Rockies when compared to California will increase our margin on electricity as described above. In the first quarter of 2009, our margin on electricity increased to $1.5 million.

On September 20, 2007, the CPUC issued a decision (SRAC Decision) that changes the way SRAC energy prices will be determined for existing and new Standard Offer (SO) contracts and revises the capacity prices paid under current SO1 contracts. The effective date of the new pricing under the SRAC Decision has not been determined as of yet and a portion of the SRAC Decision is being reconsidered by the CPUC. We do not believe that the proposed pricing changes will materially affect us in 2009.

The following table is for the three months ended:

	March 31, 2009	March 31, 2008	December 31, 2008
Electricity			
Revenues (in millions)	$ 10.3	$ 15.9	$ 12.3
Operating costs (in millions)	$ 8.8	$ 16.4	$ 9.3
Electric power produced - MWh/D	2,068	2,152	2,086
Electric power sold - MWh/D	1,939	1,959	1,904
Average sales price/MWh	$ 58.85	$ 90.48	$ 69.94
Fuel gas cost/MMBtu (including transportation)	$ 4.01	$ 7.94	$ 4.80

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

	Amount per BOE			Amount (in thousands)		
	March 31, 2009	March 31, 2008	December 31, 2008	March 31, 2009	March 31, 2008	December 31, 2008
Operating costs – oil and gas production	$ 13.74	$ 17.36	$ 15.07	$ 37,384	$ 39,340	$ 44,598
Production taxes	2.08	2.29	2.10	5,652	5,183	6,213
DD&A – oil and gas production	13.38	10.68	12.89	36,398	24,207	38,133
G&A	4.89	4.91	6.07	13,294	11,132	17,972
Interest expense	3.69	1.47	3.05	10,050	3,327	9,032
Total	$ 37.78	$ 36.71	$ 39.18	$ 102,778	$ 83,189	$ 115,948

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

	March 31, 2009 (1Q09)	March 31, 2008 (1Q08)	1Q09 to 1Q08 Change	December 31, 2008 (4Q08)	1Q09 to 4Q08 Change
Average volume of steam injected (Bbl/D)	103,342	91,326	13%	105,443	(2%)
Fuel gas cost/MMBtu (including transportation)	$ 4.01	$ 7.94	(49%)	$ 4.80	(16%)
Approximate net fuel gas volume consumed in steam generation (MMBtu/D)	26,427	21,634	22%	27,978	(6%)

Operating costs decreased by $7.2 million or 16% between the fourth quarter of 2008 and the first quarter of 2009. The majority of the decrease came from decreased fuel gas costs of $4 million from decreased natural gas prices and a $1 million decrease in compression, gathering and dehydration from lower natural gas production volumes. The remainder of the decrease is due to decreased activity levels and our cost reduction efforts. The decrease in operating costs from the first quarter of 2008 to the first quarter of 2009 was also primarily due to natural gas prices which decreased 49%, offset, on an absolute basis by the addition of our East Texas assets.

- Production taxes: 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. Our production taxes have remained consistent on a per BOE basis and primarily fluctuates with changes in oil and natural gas prices.

- Depreciation, depletion and amortization: DD&A increased per BOE by 25% and 4% in the first quarter of 2009 as compared to the first quarter of 2008 and fourth quarter of 2008, respectively. The increase per BOE is due to an increase in the contribution of our development properties with higher drilling and leasehold acquisition costs and the integration of our East Texas assets which have higher finding and development costs than our legacy assets.

- General and administrative: Approximately 70% of our G&A is related to compensation. The primary reasons for the increase in G&A during the first quarter of 2009 as compared to the first quarter of 2008 were due to director compensation of $0.9 million which was paid in the first quarter of 2009 and additional staffing related to our 2008 East Texas acquisition. General and administrative costs for the quarter ended December 31, 2008 included $2.3 million of rig termination penalties, $0.6 million of costs to complete the relocation of our corporate headquarters and the costs to establish our regional office in E. Texas.

- Interest expense: Our total outstanding borrowings were approximately $1.2 billion at March 31, 2009 compared to $455 million and $1.2 billion at March 31, 2008 and December 31, 2008, respectively. Our average borrowings increased since June 30, 2008 primarily due to the East Texas acquisition in the third quarter of 2008. For the three months ended March 31, 2009, $5 million of interest cost has been capitalized and we expect to capitalize approximately $25 million of interest cost during the full year of 2009.

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Estimated 2009 and Actual Three Months Ended March 31, 2009 and 2008 Oil and Gas Operating, G&A and Interest Expenses. Based upon our reduced activity in the fourth quarter of 2008, we estimate our average 2009 production volume will be approximately 30,000 BOE/D.

	Anticipated range Full Year 2009 per BOE	Three months ended March 31, 2009	Three months ended March 31, 2008
Operating costs-oil and gas production	$ 13.50 - 15.00	$ 13.74	$ 17.36
Production taxes	1.50 - 2.50	2.08	2.29
DD&A – oil and gas production (1)	13.50 - 14.50	13.38	10.68
G&A	4.25 - 4.75	4.89	4.91
Interest expense	4.00 - 4.75	3.69	1.47
Total	$ 36.75- 41.50	$ 37.78	$ 36.71

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

Asset Dispositions. 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 $14 million sale of our DJ basin related hedges was completed in March 2009 and is recorded under the caption "Gain on hedge terminations" in the condensed statements of income and is included in operating cash flows for the three months ended March 31, 2009. We received a deposit of $14 million on the sale of the DJ basin assets which is included in "Accrued Liabilities" on the condensed balance sheets as of March 31, 2009. The closing date of the sale of our DJ basin assets was April 1, 2009. In accordance with SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, these properties have been separately presented in the accompanying balance sheet at fair value less estimated costs to sell, which were determined as of March 31, 2009. We recorded an impairment charge of $9.6 million, which is aggregated within "(loss) income from discontinued operations, net of tax," on the condensed statements of income for the three months ended March 31, 2009.

Dry Hole, Abandonment, impairment and exploration. In the three months ended March 31, 2009 and 2008, we recorded dry hole, abandonment, impairment and exploration expense of $0.1 million and $2.7 million, respectively. In the first quarter of 2008, technical difficulties on three wells in the Piceance basin were encountered before reaching total depth and these holes were abandoned, in favor of drilling to the same bottom hole location by drilling a new well.

Income Taxes. We experienced an effective tax rate of 33.9% and 39.1% in the three months ended March 31, 2009 and March 31, 2008, respectively. 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.

Development, Exploitation and Exploration Activity. We drilled 26 gross (26 net) wells during the first quarter of 2009.

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

	Three months ended March 31, 2009	
Asset Team	Gross Wells	Net Wells
S. Midway	8	8
N. Midway	15	15
Texas	3	3
Totals	26	26

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Recent Accounting Developments
In September 2008, the Financial Accounting Standards Board (FASB) issued FASB Staff Positions (FSP) No. 133-1 and FIN 45-4 to amend FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities, to require disclosures by sellers of credit derivatives, including credit derivatives embedded in a hybrid instrument. This FSP also amends FASB Interpretation No.45, Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others, to require an additional disclosure about the current status of the payment/performance risk of a guarantee. Further, this FSP clarifies the FASB's intent about the effective date of FASB Statement No. 161, Disclosures about Derivative Instruments and Hedging Activities. This FSP became effective for our fiscal year beginning January 1, 2009 and we expanded our disclosures accordingly.

In December 2007, the FASB issued Statement of Financial Accounting Standard (SFAS) No. 160, Noncontrolling Interests in Consolidated Financial Statements. SFAS 160 was issued to establish accounting and reporting standards for the noncontrolling interest in a subsidiary (formerly called minority interests) and for the deconsolidation of a subsidiary. We adopted this Statement January 1, 2009 and it did not have a material effect on our financial statements.

In December 2007, the FASB issued SFAS No. 141(R), Business Combinations, which expands the information that a reporting entity provides in its financial reports about a business combination and its effects. This Statement establishes principles and requirements for how the acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any non controlling interest in the acquiree, recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase, and determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. This Statement applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. An entity may not apply the principle before that date. We may experience a financial statement impact depending on the nature and extent of any new business combinations entered into after the effective date of SFAS No. 141(R).

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities—an amendment of FASB Statement No. 133, which changes the disclosure requirements for derivative instruments and hedging activities. Expanded disclosures are required to provide information about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under Statement 133 and its related interpretations, and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. We adopted this Statement January 1, 2009 and we expanded our disclosures accordingly.

In June 2008, the FASB issued FASB Staff Position No. EITF 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities ("FSP EITF 03-6-1"), which clarifies that share-based payment awards that entitle their holders to receive nonforfeitable dividends before vesting should be considered participating securities. As participating securities, these instruments should be included in the earnings allocation in computing basic earnings per share under the two-class method described in SFAS No. 128, Earnings per Share. All prior period earnings per share data presented shall be adjusted retrospectively to conform with the provisions of this pronouncement. FSP EITF 03-6-1 is effective for financial statements issued for fiscal years beginning after December 15, 2008 and interim periods within those years. We implemented EITF 03-06-1 during the first quarter of 2009, see Note 10 to the financial statements.

In April 2009, the FASB issued FSP No. FAS 107-1, Interim Disclosures about Fair Value of Financial Instruments. FSP 107-1 requires disclosures about fair value of financial instruments for interim reporting periods as well as in annual financial statements. FSP 107-1 will be effective for us for the quarter ending June 30, 2009. The adoption of FSP 107-1 will not have an impact on our financial position and results of operations.

Properties

Asset Team Descriptions

To improve the efficiency of our operations we have consolidated our S. Cal Asset Team into the S. Midway and N. Midway Asset Teams. The Poso Creek Field has been incorporated into the S. Midway Asset Team and the Placerita Field into our N. Midway Asset Team.

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S. Midway – Our S. Midway Asset Team now includes four assets (Poso Creek, Ethel D, Homebase and Formax). We are in the process of drilling 10 additional Homebase horizontal wells. These wells have been placed deeper and closer to the oil-water contact. The first 8 of these wells are currently on production and performing in line with expectations. At Ethel D we are evaluating the steam flood pilots in preparation for future steam flood expansion. Poso Creek production is recovering from the disruptions associated with the Big West bankruptcy. Further production recovery is expected as the number of steam flood patterns is increased and as the steam flood patterns developed in 2008 respond. The team is focused on improving steam-oil ratios and lowering operating expenses in all of its operations. Average daily production during the three months ended March 31, 2009 from all S. Midway assets was approximately 11,350 BOE/D.

N. Midway – Our N. Midway Asset Team now includes three assets (Diatomite, N. Midway, and Placerita). We began the full scale development of our N. Midway diatomite asset in late 2006 and through the end of 2008 drilled 190 wells on this property. The delineation drilling in 2008 increased our original oil in place estimates by 35% to 330 million barrels. We are targeting ultimate recovery between 23% and 40%, similar to other diatomite developments in California.

We plan to invest $37 million during 2009 to drill an additional 44 diatomite wells and install additional steam generation facilities during 2009 and have drilled 15 of these wells. Additionally, we are seeking operating and capital cost reductions through initiatives such as steam management to improve our steam oil ratio and improved project management to reduce overall well costs. Production in the first quarter of 2009 was 2,670 Bbl/D and is expected to average over 3,000 Bbl/D for the year. Average daily production during the three months ended March 31, 2009 from all N. Midway assets was approximately 5,085 BOE/D.

Piceance – During the three months ended March 31, 2009, production from the Piceance basin averaged 20 MMcf/D. No drilling or completion activity was performed during the quarter. Currently we have an inventory of 44 initial completions and recompletions that will be evaluated for supplemental capital should commodity prices warrant.

Uinta – Average daily production during the three months ended March 31, 2009 from all Uinta basin assets was approximately 5,410 BOE/D. No drilling or completion activity was performed during the quarter. The Ashley Forest Development EIS continues to progress with approval now expected in the second half of 2009.

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

E. Texas – During the three months ended March 31, 2009, production from our East Texas assets averaged 30 MMcf/D. We continue to operate a one rig program and drilled three vertical wells in the Oakes field during the first quarter of 2009. We are currently drilling the fourth of the five planned vertical Oakes wells for 2009. After completion of drilling in the Oakes field, we expect to begin drilling in the Darco Field with our first horizontal Haynesville well.

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

Liquidity. The total outstanding debt at March 31, 2009 under the Agreement and the Line of Credit was $999 million and $0, respectively, and $3 million in letters of credit have been issued under the facility, leaving $208 million in borrowing capacity available under the Agreement at March 31, 2009.

On April 27, 2009, we completed the scheduled redetermination of the borrowing under our credit facility. Our borrowing base was reduced from $1.25 billion to $1.05 billion, with $100 million of the reduction resulting from the sale of our DJ basin assets. Also on April 27, 2009 we completed a $140 million second lien credit facility, with lenders from among our existing lending group, which matures on January 16, 2013. Interest on the facility is charged at LIBOR plus a margin of eight percent with a minimum LIBOR rate of three percent. Each dollar outstanding under the second lien credit facility reduces the borrowing base under our senior secured credit facility by 30 cents such that the $140 million second lien facility reduces our borrowing base from $1.05 billion to $1.0 billion. Proceeds from the second lien facility were used to pay down borrowings under our senior secured credit facility. On April 27, 2009, following the closing of the second lien credit facility, the outstanding amount under our senior secured credit facility was approximately $735 million providing us with $275 million of liquidity. With the second lien facility in place, we expect our weighted average interest rate to increase from 4.2% at March 31, 2009 to 5.0% for the remainder of 2009, based on current LIBOR rates.

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Capital Expenditure and Cash Flows. We establish a capital budget for each calendar year based on our development opportunities and the expected cash flow from operations for that year. Acquisitions are typically debt financed. We may revise our capital budget during the year as a result of acquisitions and/or drilling outcomes or significant changes in cash flows.

In 2009, we have a capital program of approximately $100 million and we expect to fully fund this program from operating cash flow which should approximate $175 million. Cash provided by operating activities was impacted in the first quarter of 2009 by an annual royalty payment of $22 million which is paid each February and a reduction in accounts payable which, at year-end 2008, reflected our higher 2008 capital budget. Approximately 90% of our oil production is hedged for 2009 and thus our sensitivity to changes in oil prices is limited. A ten dollar change in oil prices impacts our annual operating cash flow by approximately $2 million in 2009. A one dollar change in natural gas prices impacts our annual operating cash flow by approximately $5 million.

Capital expenditures, excluding property acquisitions, totaled $50.2 million during the three months ended March 31, 2009. A portion of our capital budget reflects expenditures to complete projects initiated during 2008 and we expect lower quarterly expenditures for the remainder of 2009.

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

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

	March 31, 2009 (1Q09)	March 31, 2008 (1Q08)	1Q09 to 1Q09 Change	December 31, 2008 (4Q08)	1Q09 to 4Q08 Change
Average production (BOE/D)	33,332	28,066	19%	35,583	(6%)
Average oil and gas sales prices, per BOE after hedging	$ 47.11	$ 62.44	(25%)	$ 45.57	3%
Net cash provided by operating activities	$ 8	$ 87	(91%)	$ 78	(90%)
Working capital (deficit)	$ 169	$ (123)	237%	$ (72)	335%
Sales of oil and gas	$ 128	$ 152	(16%)	$ 135	(5%)
Total debt	$ 1,199	$ 455	164%	$ 1,157	4%
Capital expenditures	$ 50	$ 76	(34%)	$ 92	(46%)
Dividends paid	$ 3.4	$ 3.3	3%	$ 3.4	-%

Contractual Obligations. Our contractual obligations as of March 31, 2009 are as follows (in millions):

Total	2009	2010	2011	2012	2013	Thereafter
$ 1,358.8	$ 46.8	$ 46.8	$ 46.8	$ 952.3	$ 16.5	$ 249.6

Total debt and interest							
Abandonment obligations	40.1	1.6	1.6	1.6	1.6	1.6	32.1
Operating lease obligations	17.8	1.9	2.4	2.5	2.4	2.5	6.1
Drilling and rig obligations	45.6	11.4	8.0	8.0	18.2	-	-
Firm natural gas transportation contracts	160.1	14.9	19.8	19.8	19.7	17.5	68.4
Total	$ 1,622.4	$ 76.6	$ 78.6	$ 78.7	$ 994.2	$ 38.1	$ 356.2

Drilling obligations - Under our June 2006 joint venture agreement in the Piceance basin we are required to have 120 wells drilled by February 2011 to avoid penalties of $.2 million per well or a maximum of $24 million. As of March 31, 2009 we have drilled 29 of these wells and we expect to meet our February 2011 obligation.

Other Obligations - As of March 31, 2009 we had a gross liability for uncertain tax benefits of $11.2 million of which $10.0 million, if recognized, would affect the effective tax rate. We are unable to predict the year in which these uncertain tax positions will be settled and have excluded these commitments from the table above.

In February 2007, we entered into a multi-staged crude oil sales contract with a refiner for our Uinta basin light crude oil. Under the agreement, the refiner began purchasing 3,200 Bbl/D in July 2007, as provided in our contract. The refiner has increased its total purchase capacity to 5,000 Bbl/D as provided in our contract. The differential under the contract, which includes transportation and gravity adjustments, is linked to WTI and would range from $10 to $15 per barrel at WTI prices between $40 and $60. Gross oil production averaged approximately 3,280 BOE/D in the quarter ended March 31, 2009.

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Quantitative and Qualitative Disclosures About Market Risk

Item 3. Quantitative and Qualitative Disclosures About Market Risk

As discussed in Note 4 to the unaudited condensed financial statements, to minimize the effect of a downturn in oil and gas prices and protect our profitability and the economics of our development plans, we enter into crude oil and natural gas hedge contracts from time to time. The terms of contracts depend on various factors, including management's view of future crude oil and natural gas prices, acquisition economics on purchased assets and our future financial commitments. This price hedging program is designed to moderate the effects of a severe crude oil and natural gas price downturn while allowing us to participate in some commodity price increases. In California, we benefit from lower natural gas pricing as we are a consumer of natural gas in our operations and elsewhere, we benefit from higher natural gas pricing. We have hedged, and may hedge in the future, both natural gas purchases and sales as determined appropriate by management. Management regularly monitors the crude oil and natural gas markets and our financial commitments to determine if, when, and at what level some form of crude oil and/or natural gas hedging and/or basis adjustments or other price protection is appropriate in accordance with policy established by our board of directors. Currently, our hedges are in the form of swaps and collars. However, we may use a variety of hedge instruments in the future to hedge WTI or the index gas price.

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Quantitative and Qualitative Disclosures About Market Risk

The following table summarizes our hedge position as of March 31, 2009:

Term	Average Barrels Per Day		Average Prices
Crude Oil Sales (NYMEX WTI) Collars			
Full year 2009	295	$	80.00/$91.00
Full year 2009	1,000	$	100.00/$163.60
Full year 2009	1,000	$	100.00/$150.30
Full year 2009	1,000	$	100.00/$160.00
Full year 2009	1,000	$	100.00/$150.00
Full year 2009	1,000	$	100.00/$157.48
Full year 2010	1,000	$	65.15 / $75.00
Full year 2010	1,000	$	65.50 / $78.50
Full year 2010	280	$	80.00 / $90.00
Full year 2010	1,000	$	100.00/$161.10
Full year 2010	1,000	$	100.00/$150.30
Full year 2010	1,000	$	100.00/$160.00
Full year 2010	1,000	$	100.00/$150.00
Full year 2010	1,000	$	100.00/$158.50
Full year 2010	1,000	$	70.00/$86.00
Full year 2011	270	$	80.00 / $90.00
Full year 2011	1,000	$	55.20/$70.00
Full year 2011	1,000	$	55.00 / $70.50
Full year 2011	1,000	$	55.00/$68.65
Full year 2011	1,000	$	55.00/$68.00
Full year 2011	1,000	$	55.00/$71.20
Full year 2011	1,000	$	60.00/$76.00
Full year 2011	1,000	$	60.00/$81.25
Full year 2012	1,000	$	63.00/$82.60
Crude Oil Sales (NYMEX WTI) Swaps			
May 2009	1,000	$	55.60
June 2009	400	$	57.00
Full year 2009	240	$	71.50
Full year 2009	1,000	$	70.30
Full year 2009	1,000	$	70.50
3rd Quarter 2009	500	$	52.40
2nd, 3rd & 4th Quarters 2009	2,000	$	55.00
Full year 2009	1,000	$	54.67
Full year 2009	2,000	$	54.10
Full year 2009	5,000	$	54.39
Full year 2010	1,000	$	61.00
Full year 2010	1,000	$	61.25
Full year 2010	1,000	$	64.80

Full year 2010	1,000	$	62.03
Full year 2010	1,000	$	63.00
Full year 2010	1,000	$	63.75
Full year 2010	650	$	56.90
Full year 2011	500	$	57.36
Full year 2011	500	$	57.40
Full year 2011	500	$	57.50
Full year 2011	250	$	61.80

Term	Average MMBtu Per Day		Average Price
Natural Gas Sales (NYMEX HH TO PEPL) Basis Swaps			
4th quarter 2009	4,000	$	1.05
Full year 2009	2,000	$	1.24
Full year 2009	3,000	$	1.19
Full year 2010	2,000	$	1.05
Full year 2010	3,000	$	1.00
Natural Gas Sales (NYMEX HH) Swaps			
Full year 2009	2,000	$	6.15
Full year 2009	3,000	$	6.19
4th quarter 2009	4,000	$	8.50
Natural Gas Sales (NYMEX HH) Collars			
Full year 2010	2,000	$	6.00/$8.60
Full year 2010	3,000	$	6.00/$8.65
Full year 2010	1,000	$	6.50/$8.75
Full year 2010	1,000	$	6.50/$8.85
Full year 2010	2,000	$	6.50/$8.90
Natural Gas Sales (NYMEX HH TO NGPL) Basis Swaps			
Full year 2010	2,000	$	0.49
Natural Gas Sales (NYMEX HH TO HSC) Basis Swaps			
Full year 2010	2,000	$	0.38

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Berry Petroleum Company
Quantitative and Qualitative Disclosures About Market Risk

The collar strike prices will allow us to protect a significant portion of our future cash flow if prices decline below our floor prices while still participating in any price increase up to the ceiling prices. These hedges improve our financial flexibility by locking in significant revenues and cash flow upon a substantial decline in crude oil or natural gas prices, including certain basis differentials. It also allows us to develop our long-lived assets and pursue exploitation opportunities with greater confidence in the projected economic outcomes and allows us to borrow a higher amount under our credit facility.

While we have designated our hedges as cash flow hedges in accordance with SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, a portion of the hedges related to the movement in the WTI to California heavy crude oil price differential will likely be ineffective. Likewise, we may have some ineffectiveness in our natural gas hedges due to the movement of HH pricing as compared to actual sales points. If this occurs, the ineffective portion will directly impact net income rather than being reported as Other Comprehensive Income (Loss). If the differential were to change significantly, it is possible that our hedges, when marked-to-market, could have a material impact on earnings in any given quarter and, thus, add increased volatility to our net income. The mark-to-market values reflect the fair values of such hedges and not necessarily the values of the hedges if they are held to maturity.

In December 2008, Big West Oil of California filed for bankruptcy protection under Chapter 11 of the United States Bankruptcy Code. Our contract with Big West provided for an oil price differential that was linked to NYMEX WTI prices and allowed us to effectively hedge our oil production at the NYMEX WTI index. Subsequent to the Big West bankruptcy, our crude oil has been sold at field posting prices which resulted in some ineffectiveness related to our WTI linked hedges. We recognized an unrealized net gain of approximately $22.8 million in the condensed statement of income under the caption “Gain (loss) on ineffective commodity derivatives” for the quarter ended March 31, 2009 as a result of this ineffectiveness.

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

Hedge Term	Notional Amount $MM	Fixed Rate
4/1/2009 – 6/30/2012	100	4.74%
4/15/2009 – 7/15/2012	150	1.95%
9/15/2009 – 7/15/2012	150	2.44%
12/15/2009 – 7/15/2012	125	2.03%

The related cash flow impact of all of our derivative activities are reflected as cash flows from operating activities. Irrespective of the unrealized gains reflected in Other Comprehensive Income (Loss), the ultimate impact to net income over the life of the hedges will reflect the actual settlement values. All of these hedges have historically been deemed to be cash flow hedges and are booked at fair value.

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Berry Petroleum Company
Quantitative and Qualitative Disclosures About Market Risk

Based on average NYMEX futures prices as of March 31, 2009 (WTI $63.88; HH $5.15) for the term of our hedges we would expect to make pre-tax future cash payments or to receive payments over the remaining term of our crude oil and natural gas hedges in place as follows:

	March 31, 2009 NYMEX Futures	Impact of percent change in futures prices on pre-tax future cash (payments) and receipts -40%	-20%	+ 20%	+40%
Average WTI Futures Price (2009 – 2012)	$ 63.88	$ 38.33	$ 51.11	$ 76.66	$ 89.43
Average HH Futures Price (2009 – 2010)	5.15	3.09	4.12	6.19	7.22
Crude Oil gain/(loss) (in millions)	$ 153.8	$ 472.0	$ 297.9	$ 6.1	$ (159.5)
Natural Gas gain/(loss) (in millions)	3.1	21.4	18.6	14.8	15.2
Total	$ 156.9	$ 493.4	$ 316.5	$ 20.9	$ (144.3)
Net pre-tax future cash (payments) and receipts by year (in millions) based on average price in each year:					
2009 (WTI $53.70; HH $4.25)	$ 80.5	$ 192.1	$ 139.1	$ 33.0	$ (20.1)
2010 (WTI $61.92; HH $5.84)	81.1	237.3	162.7	24.8	(39.0)
2011 (WTI $67.24)	(4.7)	56.4	12.1	(36.4)	(79.5)
2012 (WTI $70.12)	-	7.6	2.6	(0.5)	(5.7)
Total	$ 156.9	$ 493.4	$ 316.5	$ 20.9	$ (144.3)

Interest Rates. Our exposure to changes in interest rates results primarily from long-term debt. In October 2006, we issued, in a public offering, $200 million of 8.25% senior subordinated notes due 2016. At March 31, 2009, total long-term debt outstanding was $1.2 billion. Interest on amounts borrowed under our credit facility is charged at LIBOR plus 2.25% to 3.0%, with the exception of the principal for which we have hedged, plus the credit facility’s margin through July 15, 2012. Based on March 31, 2009 credit facility borrowings, a 1% change in interest rates would have an annualized $––3 million after tax impact on our financial statements.

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Berry Petroleum Company
Controls and Procedures

Item 4. Controls and Procedures

As of March 31, 2009, we have carried out an evaluation under the supervision of, and with the participation of, our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15 under the Securities Exchange Act of 1934, as amended.

Based on their evaluation as of March 31, 2009, 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, 2009 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," or other comparable words or ph the negative of those words, and other words of similar meaning indicate forward-looking statements and important factors which could affect actual results. Forward-looking statements are made based on management's current expectations and beliefs concerning future developments and their potential effects upon Berry Petroleum Company. These items are discussed at length in Part I, Item 1A on page 15 of our Form 10-K dated February 25, 2009, filed with the Securities and Exchange Commission, under the heading "Risk Factors" and all material changes are updated in Part II, Item 1A within this Form 10-Q.

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Berry Petroleum Company
Part II. Other Information

PART II. OTHER INFORMATION

Item 1. Legal Proceedings
None.

Item 1A. Risk Factors
None.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds
None.

Item 3. Defaults Upon Senior Securities
None.

Item 4. Submission of Matters to a Vote of Security Holders
None.

Item 5. Other Information
None.

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Berry Petroleum Company
Part II. Other Information

Item 6. Exhibits

Exhibit No.	Description of Exhibit
10.1*	Crude Oil Purchase Contract dated March 20, 2009 between the [Registrant] and Tesoro Corporation.
10.2	Third Amendment to Amended and Restated Credit Agreement dated April 27, 2009 by and among Registrant, Wells Fargo Bank National Association, individually and as administrative agent, and certain financial institutions, as lenders.
10.3	Second Lien Credit Agreement dated April 27, 2009 among Registrant, Wells Fargo Energy Capital, Inc., as administrative agent, and certain financial institutions, as Lenders and agents.
31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

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

SIGNATURE

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

BERRY PETROLEUM COMPANY

/s/ Shawn M. Canaday
Shawn M. Canaday
Vice President and Controller
(Principal Accounting Officer)

Date: April 30, 2009