UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

T Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the quarterly period ended **June 30, 2009**
£ Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from __to ___
Commission file number **1-9735**

BERRY PETROLEUM COMPANY

(Exact name of registrant as specified in its charter)

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

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

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

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

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 £ NO £

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 T Accelerated filer £ Non-accelerated filer £ Smaller reporting company £

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

As of July 20, 2009, the registrant had 42,826,373 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 July 20, 2009 all of which is held by an affiliate of the registrant.

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

	June 30, 2009	December 31, 2008
ASSETS		
Current assets:		
Cash and cash equivalents	$ 236	$ 240
Short-term investments	67	66
Accounts receivable, net of allowance for doubtful accounts of $38,511 and $38,511	65,854	65,873
Deferred income taxes	428	-
Fair value of derivatives	35,453	111,886
Crude oil inventory	2,794	-
Prepaid expenses and other	8,046	11,015
Total current assets	112,878	189,080
Oil and gas properties (successful efforts basis), buildings and equipment, net	2,096,966	2,254,425
Fair value of derivatives	3,614	79,696
Other assets	32,888	19,182
	$ 2,246,346	$ 2,542,383
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 42,606	$ 119,221
Revenue and royalties payable	12,291	34,416
Accrued liabilities	26,084	34,566
Line of credit	-	25,300
Income taxes payable	-	187
Fair value of derivatives	34,235	1,445
Deferred income taxes	222	45,490
Total current liabilities	115,438	260,625
Long-term liabilities:		
Deferred income taxes	243,537	270,323
Senior secured revolving credit facility	580,900	931,800
8 ¼ % Senior subordinated notes due 2016	200,000	200,000
10 ¼ % Senior notes due 2014, net of unamortized discount of $20,707 and $0, respectively	304,293	-
Abandonment obligation	40,986	41,967
Other long-term liabilities	4,789	5,921
Fair value of derivatives	40,462	4,203
Total long-term liabilities	1,414,967	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; 42,826,373 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	84,786	79,653
Accumulated other comprehensive (loss) income	(18,227)	113,697
Retained earnings	648,937	633,749
Total shareholders' equity	715,941	827,544
	$ 2,246,346	$ 2,542,383

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

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

	Three months ended June 30, 2009	Three months ended June 30, 2008
REVENUES AND OTHER INCOME ITEMS		
Sales of oil and gas	$ 118,793	$ 169,022
Sales of electricity	6,624	16,979
Gas marketing	4,848	11,531
Loss on derivatives	(31,130)	(20)
Gain on sale of assets	-	414
Interest and other income, net	806	934
	99,941	198,860
EXPENSES		
Operating costs - oil and gas production	34,738	52,332
Operating costs - electricity generation	6,397	15,515
Production taxes	4,885	6,568
Depreciation, depletion & amortization - oil and gas production	34,371	25,902
Depreciation, depletion & amortization - electricity generation	1,028	652
Gas marketing	4,232	11,071
General and administrative	13,164	10,929
Interest expense	10,589	3,552
Loss on extinguishment of debt	10,492	-
Dry hole, abandonment, impairment and exploration	17	3,180
	119,913	129,701
(Loss) income before income taxes	(19,972)	69,159
(Benefit) provision for income taxes	(7,204)	25,447
(Loss) income from continuing operations	(12,768)	43,712
(Loss) income from discontinued operations, net of taxes	(212)	5,429
Net (loss) income	$ (12,980)	$ 49,141
Basic net (loss) income from continuing operations per share	$ (0.28)	$ 0.97
Basic net (loss) income from discontinued operations per share	$ -	$ 0.12
Basic net (loss) income per share	$ (0.28)	$ 1.09
Diluted net (loss) income from continuing operations per share	$ (0.28)	$ 0.95
Diluted net (loss) income from discontinued operations per share	$ -	$ 0.12
Diluted net (loss) income per share	$ (0.28)	$ 1.07
Dividends per share	$ .075	$ .075

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

	2009	2008
Net (loss) income	$ (12,980)	$ 49,141
Unrealized gains (losses) on derivatives, net of income taxes (benefits) of $56,358 and ($162,792), respectively	91,952	(260,225)
Reclassification of realized (losses) gains on derivatives included in net (loss) income, net of income taxes (benefits) of ($5,873) and $21,898, respectively	(9,583)	37,268
Comprehensive income (loss)	$ 69,389	$ (173,816)

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

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

	Six months ended June 30, 2009	Six months ended June 30, 2008
REVENUES AND OTHER INCOME ITEMS		
Sales of oil and gas	$ 246,662	$ 320,688
Sales of electricity	16,895	32,906
Gas marketing	12,429	14,762
Gain (loss) on derivatives	6,034	(728)
Gain on sale of assets	-	414
Interest and other income, net	1,088	1,763
	283,108	369,805
EXPENSES		
Operating costs - oil and gas production	72,122	91,672
Operating costs - electricity generation	15,179	31,914
Production taxes	10,537	11,751
Depreciation, depletion & amortization - oil and gas production	70,769	50,108
Depreciation, depletion & amortization - electricity generation	1,987	1,345
Gas marketing	11,516	14,053
General and administrative	26,457	22,061
Interest expense	20,639	6,879
Loss on extinguishment of debt	10,494	-
Dry hole, abandonment, impairment and exploration	140	5,908
	239,840	235,691
Income before income taxes	43,268	134,114
Provision for income taxes	14,258	50,866
Income from continuing operations	29,010	83,248
(Loss) income from discontinued operations, net of taxes	(6,991)	8,924
Net income	$ 22,019	$ 92,172
Basic net income from continuing operations per share	$ 0.63	$ 1.85
Basic net (loss) income from discontinued operations per share	$ (0.15)	$ 0.20
Basic net income per share	$ 0.48	$ 2.05
Diluted net income from continuing operations per share	$ 0.63	$ 1.82
Diluted net (loss) income from discontinued operations per share	$ (0.15)	$ 0.19
Diluted net income per share	$ 0.48	$ 2.01
Dividends per share	$ 0.15	$ 0.15

Unaudited Condensed Statements of Comprehensive Income (Loss)
Six Months Ended June 30, 2009 and 2008
(In Thousands)

	2009	2008
Net income	$ 22,019	$ 92,172
Unrealized gains (losses) on derivatives, net of income taxes (benefits) of $104,518 and ($203,141), respectively	170,529	(320,748)
Reclassification of realized gains on derivatives included in net income, net of income taxes (benefits) of ($23,661) and $33,596, respectively	(38,605)	54,815
Comprehensive income (loss)	$ 153,943	$ (173,761)

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

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

	Six months ended June 30, 2009	Six months ended June 30, 2008
Cash flows from operating activities:		
Net income	$ 22,019	$ 92,172
Depreciation, depletion and amortization	74,944	57,493
Loss on extinguishment of debt	10,494	-
Dry hole and impairment	9,643	5,332
Commodity derivatives	8,287	494
Stock-based compensation expense	4,980	4,412
Deferred income taxes	8,090	39,030
Loss (gain) on sale of oil and gas properties	330	(414)
Other, net	(2,385)	689
Change in book overdraft	(24,988)	13,075
Cash paid for abandonment	(176)	(2,127)
Increase in current assets other than cash and cash equivalents	(7,982)	(29,294)
(Decrease) increase in current liabilities other than book overdraft, line of credit and fair value of derivatives	(44,076)	12,952
Net cash provided by operating activities	59,180	193,814
Cash flows from investing activities:		
Exploration and development of oil and gas properties	(72,651)	(168,382)
Property acquisitions	(11,668)	(380)
Additions to vehicles, drilling rigs and other fixed assets	(475)	(3,201)
Deposits on acquisitions	-	(59,000)
Proceeds from sale of assets	138,597	1,809
Capitalized interest	(12,626)	(8,463)
Net cash provided by (used in) investing activities	41,177	(237,617)
Cash flows from financing activities:		
Proceeds from line of credit	248,500	187,100
Payments on line of credit	(273,800)	(201,400)
Proceeds from issuance of long-term debt	890,300	286,300
Payments on long-term debt	(937,176)	(220,300)
Debt issuance cost	(21,508)	-
Dividends paid	(6,831)	(6,705)
Proceeds from stock option exercises	87	2,640
Excess tax benefit and other	67	1,435
Net cash (used in) provided by financing activities	(100,361)	49,070
Net (decrease) increase in cash and cash equivalents	(4)	5,267
Cash and cash equivalents at beginning of year	240	316
Cash and cash equivalents at end of period	$ 236	$ 5,583

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

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

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 June 30, 2009 and December 31, 2008 and results of operations and other comprehensive income (loss) and cash flows for the three and six months ended June 30, 2009 and 2008 have been included. All such adjustments, except as described below, are of a normal recurring nature. The results of operations and cash flows are not necessarily indicative of the results for a full year.

The accompanying unaudited condensed financial statements have been prepared on a basis consistent with the accounting principles and policies reflected in the December 31, 2008 financial statements, except that the DJ basin operations are now accounted for as discontinued operations as a result of the 2009 sale. The 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.

Our cash management process provides for the daily funding of checks as they are presented to the bank. Included in accounts payable at June 30, 2009 and December 31, 2008 is $6.8 million and $31.8 million, respectively, representing outstanding checks in excess of the bank balance (book overdraft).

2. Recent Accounting Developments

In December 2007, the 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 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 12 to the condensed financial statements.

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 2009, the FASB unanimously voted for the FASB "*Accounting Standards Codification*" (the "Codification") to be effective beginning on July 1, 2009. Other than resolving certain minor inconsistencies in current United States Generally Accepted Accounting Principles ("GAAP"), the Codification is not supposed to change GAAP, but is intended to make it easier to find and research GAAP applicable to particular transactions or specific accounting issues. The Codification is a new structure which takes accounting pronouncements and organizes them by approximately ninety accounting topics. Once approved, the Codification will be the single source of authoritative U.S. GAAP. All guidance included in the Codification will be considered authoritative at that time, even guidance that comes from what is currently deemed to be a non-authoritative section of a standard. Once the Codification becomes effective in the third quarter of 2009, all non-grandfathered, non-SEC accounting literature not included in the Codification will become non-authoritative and we will update our disclosures accordingly.

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 was effective for us for the quarter ended June 30, 2009 and we expanded our disclosures accordingly. See Note 3 to the condensed financial statements.

In May 2009, the FASB issued SFAS No. 165, *Subsequent Events*, which establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. We implemented SFAS No. 165 during the second quarter of 2009 and we expanded our disclosures accordingly. See Note 15 to the condensed financial statements.

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, 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.

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

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

June 30, 2009 (in millions)	Total carrying value on the condensed Balance Sheet	Level 2	Level 3
Commodity derivative asset (liability)	(28.7)	(71.8)	43.1
Interest rate swap asset (liability)	(6.9)	(6.9)	-
Total fair value asset (liability)	(35.6)	(78.7)	43.1

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

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 June 30, 2009	Six months ended June 30, 2009
Fair value of Level 3 derivative assets, beginning of period	$ 137.5	$ 172.5
Total realized and unrealized (gains) losses included in Gain (loss) on derivatives	31.1	(6.0)
Purchases, sales and settlements, net	(125.5)	(126.8)
Transfers in and/or out of Level 3	-	3.4
Fair value of Level 3 derivative liabilities, June 30, 2009	$ 43.1	$ 43.1
Total unrealized gains (losses) included in income related to financial assets and liabilities still on the condensed balance sheet at June 30, 2009	$ (31.1)	(8.3)

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

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

4. Hedging

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

The related cash flow impact of all of our hedges is reflected in cash flows from operating activities. At June 30, 2009, our net fair value derivative liability was $35.6 million as compared to a net fair value asset of $185.9 million at December 31, 2008 which reflects changes in commodity prices and interest rates. Based on NYMEX strip pricing as of June 30, 2009, we expect to make cash hedge payments under the existing derivatives of $4.7 million during the next twelve months. At June 30, 2009, "Accumulated Other Comprehensive Loss" ("AOCL") consisted of $18.2 million, net of tax, of unrealized losses from our crude oil and natural gas swaps and collars that qualified for hedge accounting treatment at June 30, 2009. Deferred net losses recorded in AOCL at June 30, 2009 and subsequent mark-to-market changes in the underlying hedging contracts are expected to be reclassified to earnings in the same period that the forecasted transaction impacts earnings.

We present our derivative assets and liabilities 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 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 June 30, 2009			
	Derivative Assets		Derivative Liabilities	
(in millions)	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Commodity – Oil	Current assets	35.8	Current liability	25.3
Commodity – Natural Gas	Current assets	2.5		-
Commodity – Oil	Long term assets	3.9	Long term liabilities	39.3
Commodity – Natural Gas	Long term liabilities	0.4		-
Commodity – Natural Gas	Current liability	1.1		
Interest rate contracts			Current assets	2.8
Interest rate contracts			Long term assets	0.3
Interest rate contracts			Current liabilities	2.4
Interest rate contracts			Long term liabilities	1.4
Total derivatives designated as hedging instruments under Statement 133		43.7		71.5
Commodity – Oil		-	Current liabilities	7.3
Commodity – Natural Gas		-	Current liabilities	0.3
Commodity – Natural Gas		-	Long term liabilities	0.2
Total derivatives not designated as hedging instruments under Statement 133		-		7.8
Total Derivatives		43.7		79.3

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The tables below summarize the Statement of Operations 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 (loss) Recognized in Income on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)	Amount of Gain (loss) Recognized in Income on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)	
	Six Months Ended June 30, 2009			Six Months Ended June 30, 2009			Six Months Ended June 30, 2009	
Commodity - Oil	$	163.9	Sales of oil and gas	$	35.4	Sales of oil and gas	$	-
Commodity - Natural Gas		11.3	Sales of oil and gas		4.8	Gain (loss) on derivatives		14.6
Interest rate		(4.6)	Interest expense		(1.6)	Gain (loss) on derivatives		(0.3)
Total	$	170.6		$	38.6		$	14.3

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 Derivatives not designated as Hedging Instruments under Statement 133	
		Six months ended June 30, 2009	
Commodity – Oil	Gain (loss) on derivatives	$	(7.3)
Commodity - Natural Gas	Gain (loss) on derivatives		(1.0)
Total Derivatives		$	(8.3)

We entered into the following natural gas hedges during the three months ended June 30, 2009:

Instrument	Duration	Average MMBtu/D	Swap Price
NYMEX HH Swap	July – December 2009	5,000	$4.210
NYMEX HH Swap	Full year 2010	5,000	$6.020
NYMEX HH Swap	Full year 2011	5,000	$6.885
NYMEX HH Swap	Full year 2012	5,000	$7.160
Houston Ship Channel basis swap	July – December 2009	2,500	$0.305
Houston Ship Channel basis swap	Full year 2010	2,500	$0.345
Houston Ship Channel basis swap	Full year 2011	2,500	$0.325
Houston Ship Channel basis swap	Full year 2012	2,500	$0.320
NGPL-Tex OK basis swap	July – December 2009	2,500	$0.475
NGPL-Tex OK basis swap	Full year 2010	2,500	$0.415
NGPL-Tex OK basis swap	Full year 2011	2,500	$0.460
NGPL-Tex OK basis swap	Full year 2012	2,500	$0.440

The NYMEX HH swaps have been designated as cash flow hedges in accordance with SFAS No. 133. The basis hedges at Houston Ship Channel and NGPL-Tex OK did not qualify for hedge accounting at June 30, 2009.

We entered into the following oil collar derivatives during the three months ended June 30, 2009:

Crude Oil Sales (NYMEX WTI) Collars	Average Barrels Per Day	Floor/Ceiling Prices
Full year 2012	1,000	$63.00 / $83.50
Full year 2012	1,000	$70.00 / $93.00

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 June 30, 2009:

Crude Oil Sales (NYMEX WTI) Collars	Average Barrels Per Day	Swap Price
October 2009	1,613	$65.85
November 2009	1,667	$65.85

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

During the first quarter of 2009, we also converted oil collars for 6,000 Bbl/D 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.

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

While we designate the majority of our hedges as cash flow hedges, we have not elected hedge accounting on certain of our crude oil and natural gas hedges. During the three and six months ended June 30, 2009, we recorded ($8.3) million and $6.0 million under the caption "Gain (loss) on derivatives" related to hedges for which we either did not elect hedge accounting or they no longer qualified for hedge accounting. In conjunction with the sale of the DJ basin assets, during the first quarter of 2009, we concluded that the forecasted transaction in certain of our hedging relationships was not probable of occurring. As such, we reclassified a gain of $14.3 million from accumulated other comprehensive income (loss) to the statement of operations under the caption "Gain (loss) on derivative." Additionally, a portion of the change in fair value for hedges that we have designated as cash flow hedges impacts our income as our sales price is not perfectly correlated with our hedges. We recognized an unrealized net loss of approximately $22.8 million and $0 million on the statement of operations under the caption "Gain (loss) on derivatives" for the second quarter and six months ended June 30, 2009, respectively, as a result of this ineffectiveness. During the first quarter of 2009, we entered into natural gas derivatives on behalf of the purchaser of our DJ assets. We did not elect hedge accounting for these hedges and recorded an unrealized net loss of $0.5 million on the statement of operations under the caption "(Loss) income from discontinued operations, net of taxes."

Our hedge contracts have been primarily executed with counterparties that are party to our senior secured revolving credit facility. Neither we nor our counterparties are required to post collateral in connection with our derivative positions and netting agreements are in place with each of our counterparties allowing us to offset our derivative asset and liability positions. The credit rating of each of these counterparties was AA-/Aa2, or better as of June 30, 2009. Our derivatives are held with a small number of counterparties and as of June 30, 2009, our largest three counterparties accounted for 70% of the value of our total derivative positions.

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

	2009	2010	2011	2012
Oil Bbl/D:	17,535	14,930	9,020	3,000
Natural Gas MMBtu/D:	10,000	14,000	5,000	5,000

5. Crude Oil Inventory

In May 2009, we entered into a sales agreement with a refiner for 1,500 barrels per day of production from our Poso Creek property for the months of May and June 2009. Under this agreement, we delivered approximately 100,000 barrels of oil to the refiner and received inventory of a slightly higher quality crude oil at the refinery. The refiner will purchase the inventory from us in September and October 2009 at the then current market price. This transaction was accounted for as a non-monetary exchange and the amount recorded in crude oil inventory as of June 30, 2009 reflects the cost of production, transportation costs and quality differentials for the inventory volume.

6. 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 six months ended June 30, 2009 (in thousands):

Beginning balance at January 1, 2009	$ 41,967
Liabilities incurred	-
Liabilities settled	(2,927)
Revisions in estimated liabilities	-
Accretion expense	1,946
Ending balance at June 30, 2009	$ 40,986

7. Acquisitions

During the six months ended June 30, 2009, we completed acquisitions totaling $11.7 million. In June 2009, we acquired property near McKittrick, California; the deep rights to one of the leases in our Darco property in E. Texas; and additional interests in our Piceance Garden Gulch assets.

8. 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 closing date of the sale of the assets was April 1, 2009. We recorded a pre-tax impairment loss of $9.6 million related to the sale, which is aggregated within the $7.0 million "(Loss) income from discontinued operations, net of taxes" on our statement of operations for the six months ended June 30, 2009.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2009	2008	2009	2008
Oil and gas revenue	$ -	$ 16,310	$ 5,396	$ 29,139
Loss on sale of asset	(330)	(414)	(330)	-
Other revenue	-	591	623	1,091
Total Revenue	(330)	16,487	5,689	30,230
Operating expenses	-	2,853	2,576	5,142
Production taxes	-	913	195	1,697
DD&A	-	3,171	2,188	6,040
General and administrative	-	231	388	482
Interest expense	-	399	815	810
Commodity derivatives	-	-	484	-
Dry hole, abandonment, impairment and exploration	-	284	9,637	1,682
Total Expenses	-	7,851	16,283	15,853
(Loss) income from discontinued operations, before income taxes	(330)	8,636	(10,594)	14,377
Income tax benefit (expense)	118	(3,207)	3,603	(5,453)
(Loss) income from discontinued operations	$ (212)	$ 5,429	$ (6,991)	$ 8,924

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9. Dry Hole, Abandonment and Impairment

During the six months ended June 30, 2009 and 2008, we recorded dry hole, abandonment, impairment and exploration expense of $0.1 million and $5.9 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.

10. Pro Forma Results

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

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

	Three Months Ended June 30, 2008	Six Months Ended June 30, 2008
Pro forma revenue	$ 224,200	$ 410,160
Pro forma income from operations	$ 73,703	$ 133,776
Pro forma net income	$ 46,097	$ 83,039
Pro forma basic earnings per share	$ 1.02	$ 1.81
Pro forma diluted earnings per share	$ 1.00	$ 1.81

11. Income Taxes

The effective income tax rate was 36.1% for the second quarter of 2009 compared to 33.9% for the first quarter of 2009 and 36.8% for the second quarter of 2008. Our estimated annual effective tax rate varies from the 35% federal statutory rate due to the effects of state income taxes, the reduction in our liability related to uncertain tax positions and estimated permanent differences.

As of June 30, 2009, we had a gross liability for uncertain tax benefits of $8.8 million of which $7.1 million, if recognized, would affect the effective tax rate. The liability related to uncertain tax positions has been reduced during the second quarter ended June 30, 2009 due to the resolution of our IRS examination for 2005.

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

12. Earnings per Share

In 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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The following table shows the computation of basic and diluted net (loss) income per share from continuing and discontinued operations for the three and six months ended June 30, 2009 and 2008.

	Three months ended		Six months ended	
	June 30, 2009	June 30, 2008	June 30, 2009	June 30, 2008
Net (loss) income from continuing operations	$ (12,768)	$ 43,712	$ 29,010	$ 83,248
Less: Income allocable to participating securities	-	601	712	1,142
(Loss) income available for shareholders	(12,768)	43,111	28,298	82,106
Net (loss) income from discontinued operations	(212)	5,429	(6,991)	8,924
Less: Income allocable to participating securities	-	76	-	131
Loss (income) from discontinued operations available for shareholders	(212)	5,353	(6,991)	8,793
Basic (loss) earnings per share from continuing operations	(.28)	.97	.63	1.85
Basic (loss) earnings per share from discontinued operations	-	.12	(.15)	.20
Basic (loss) earnings per share	(.28)	1.09	.48	2.05
Diluted (loss) earnings per share from continuing operations	(.28)	.95	.63	1.82
Diluted (loss) earnings per share from discontinued operations	-	.12	(.15)	.19
Basic (loss) earnings per share	$ (.28)	$ 1.07	$ .48	$ 2.01
Weighted average shares outstanding - basic	44,606	44,478	44,594	44,435
Add: dilutive effects of stock options	206	783	126	723
Weighted average shares outstanding - dilutive	44,812	45,261	44,720	45,158

Options to purchase 1.7 million and 1.9 million shares were not included in the diluted (loss) earnings per share calculation for the three and six months ended June 30, 2009, because their effect would have been anti-dilutive. All outstanding options for the three and six months ended June 30, 2008 were included in the calculation of dilutive (loss) earnings per share.

The adoption of EITF 03-06-1 decreased basic (loss) earnings per share from continuing operations by $.01 and $.02 for the three and six months ended June 30, 2008 and dilutive (loss) earnings per share from continuing operations by $.01 for the three and six months ended June 30, 2008. Basic (loss) earnings per share from discontinued operations remained unchanged for the three and six months ended June 30, 2008 and diluted (loss) earnings per share from discontinued operations remained unchanged for the three months ended June 30, 2008 and decreased $.01 for the six months ended June 30, 2008.

13. Debt Obligations

Short-term lines of credit

In 2005, we completed an unsecured uncommitted money market line of credit (Line of Credit). Borrowings under the Line of Credit may be up to $30 million for a maximum of 30 days. The Line of Credit may be terminated at any time upon written notice by either us or the lender. In conjunction with the amendment to our senior secured credit facility, on July 15, 2008, the Line of Credit was secured by our assets. At June 30, 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 1.5%.

Senior Secured Revolving Credit Facility

Our Senior Secured Revolving Credit Facility (the Agreement) has a current borrowing base and lender commitments of $969 million. The LIBOR and prime rate margins are between 2.25% and 3.0% based on the ratio of credit outstanding to the borrowing base and the annual commitment fee on the unused portion of the credit facility is 0.50%.

Covenants under the Agreement are as follows:

Total funded debt to EBITDAX ratio		
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

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The write off of $38.5 million to bad debt expense associated with the bankruptcy of Big West Oil of California ('Big West") is excluded from the calculation of EBITDAX. The Agreement contains a current ratio covenant which, as defined, must be at least 1.0. During the second quarter of 2009 our borrowing base decreased from $1.25 billion to $969 million as a result of our scheduled semi-annual borrowing base redetermination and the issuance of our senior unsecured notes. We wrote off $3.3 million of deferred loan fees during the second quarter of 2009 as a result of the decrease to our borrowing base 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 June 30, 2009 under the Agreement, as amended, and the Line of Credit was $581 million and $0, respectively, and $3 million in letters of credit have been issued under the facility, leaving $384 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.

2nd Lien Term Loan

On April 27, 2009 we completed a $140 million second lien credit facility, with lenders from among our current lending group, with a maturity of January 16, 2013. We paid off the 2nd lien term loan on May 29, 2009 from the proceeds of our senior unsecured notes issuance and expensed $7.2 million in associated fees in the second quarter of 2009.

Senior Unsecured 10.25% notes due 2014

On May 27, 2009, we issued in a public offering $325 million of 10.25% senior subordinated notes due 2014 (the Notes). Interest on the Notes is paid semiannually in June and December of each year. The notes were issued at a discount to par value of 93.546%, and are carried on the balance sheet at their amortized cost. The deferred costs of approximately $9.5 million associated with the issuance of this debt are being amortized over the five year life of the Notes. The proceeds were used to pay down the $140 million second lien facility in full and to reduce outstanding amounts under our credit facility. Pursuant to the terms of our senior secured credit facility, the issuance of the Notes automatically reduced our borrowing base by 25 cents per dollar of Notes issued, or approximately $81 million.

Senior Subordinated 8.25% notes due 2016

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

Financial Covenants

The senior secured revolving credit facility contains restrictive covenants as described above. The $200 million Sub notes are subordinated to our credit facility indebtedness, and 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 June 30, 2009.

	As of June 30, 2009
Current Ratio (Not less than 1.0)	5.7
EBITDAX To Total Funded Debt Ratio (Not greater than 4.75)	3.1
Interest Coverage Ratio (Not less than 2.5)	5.2

The weighted average interest rate on total outstanding borrowings at June 30, 2009 was 6.0%.

Fair Value of Debt Instruments

The estimated fair value of financial instruments is the amount at which the instrument could be exchanged currently between willing parties. We use available quoted market prices to estimate the fair value of debt. The cost and fair value of our debt instruments are as follows at June 30, 2009:

(in millions)	Cost	Fair Value
Senior secured revolving credit facility	$ 581	$ 581
8 ¼ % Senior subordinated notes due 2016	200	171
10 ¼ % Senior notes due 2014	325	327
	$ 1,106	$ 1,079

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14. Contingencies and Commitments

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

	Total	2009	2010	2011	2012	2013	Thereafter
Total debt and interest	$ 1,440.5	$ 33.1	$ 66.2	$ 66.2	$ 639.6	$ 49.8	$ 585.6
Abandonment obligations	41.0	1.6	1.6	1.6	1.6	1.6	33.0
Operating lease obligations	17.1	1.2	2.4	2.4	2.4	2.5	6.2
Drilling and rig obligations	40.7	6.5	8.0	8.0	18.2	-	-
Firm natural gas transportation contracts	144.7	9.2	19.1	19.1	17.8	15.7	63.8
Total	$ 1,684.0	$ 51.6	$ 97.3	$ 97.3	$ 679.6	$ 69.6	$ 688.6

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.

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

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

Certain of our royalty payment calculations are being disputed. We believe that our royalty calculations are in accordance with applicable leases and other agreements. However, the disputed amounts that we may be required to pay are up to approximately $4 million.

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, $11.8 million represents 20 days of our December crude oil sales and an administrative claim under the bankruptcy proceedings and $26.7 million represents November and the balance of December crude oil sales which would have the same priority as other general unsecured claims. BWOC will also be liable to us for damages under this contract. We have guarantees from Big West Oil and from Flying J, Inc. in the amount of $75 million each, in the event that our claim is not fully collectible from BWOC. While we believe that we may recover some or all of the amounts due from BWOC, the data received from the bankruptcy proceedings to date has not provided us with adequate data from which to make a conclusion that any amounts will be collected.

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 Operations is $0.6 million and $0.9 million for the three and six month periods ended June 30, 2009, respectively.

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

15. Subsequent Events

Subsequent events have been evaluated through August 5, 2009, the date these financial statements were issued.

On July 17, 2009, we closed on the sale of our E. Texas gas gathering system for $18.4 million in cash. We entered into concurrent long-term gas gathering agreements for the E. Texas production. The transaction meets the criteria to be accounted for as a sale-leaseback and a capital lease.

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

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

General. The following discussion provides information on the results of operations for the three and six months ended June 30, 2009 and 2008 and our financial condition, liquidity and capital resources as of June 30, 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:

- Developing our existing resource base
- Investing our capital in a disciplined manner and maintaining a strong financial position
- Accumulating acreage positions near our producing operations
- Acquiring additional assets with significant growth potential

Notable Second Quarter Items.

- Achieved production averaging 29,270 BOE/D, of which 68% is crude oil production
- Increased Diatomite net production to an average of 2,930 BOE/D, up 72% from the second quarter of 2008
- Reduced operating expenses by 42% on a BOE basis from the second quarter of 2008
- Completed our credit facility borrowing base redetermination with a current borrowing base of $969 million
- Issued $325 million of 10.25% senior unsecured notes due in 2014
- Acquired property near McKittrick, California with development potential similar to our Poso Creek asset and plan to initiate a steam flood pilot in late 2009
- Acquired deep rights on our E. Texas Darco property providing an additional 13 Haynesville horizontal locations
- Completed the sale of our DJ basin assets using proceeds for the repayment of debt
- Agreed to sell our E. Texas midstream assets for $18.4 million and increased our capital budget by up to $32 million

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

- On July 17, 2009, closed the sale of our E. Texas midstream assets with net proceeds after closing adjustments of $18.4 million
- Increased liquidity to approximately $400 million subsequent to closing our E. Texas midstream asset sale
- Expect production to average approximately 30,000 BOED for the full year 2009

Overview of the second Quarter of 2009. We had a net loss from continuing operations of $12.8 million, or $0.28 per diluted share, and net cash from operations was $51.1 million in the second quarter of 2009. The net loss includes a pre-tax non-cash loss on derivatives of $31.1 million and a pre-tax charge of $10.5 million for debt extinguishment costs and a liability for a regulatory compliance matter of $2.1 million. We drilled 35 gross wells and capital expenditures, excluding property acquisitions, totaled $22.9 million. We achieved average production of 29,270 BOE/D in the second quarter of 2009.

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

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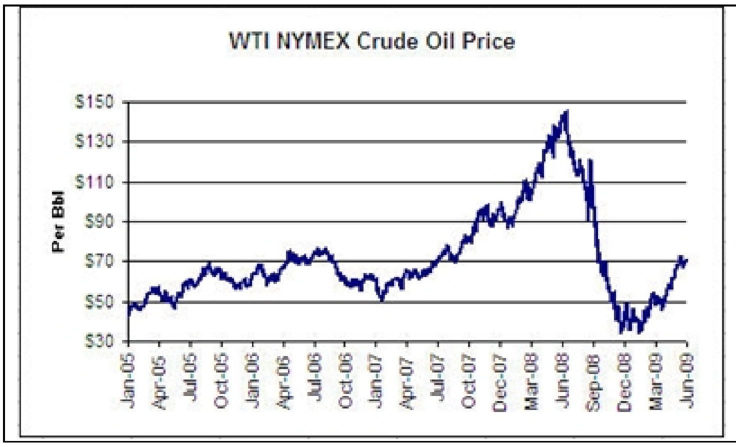
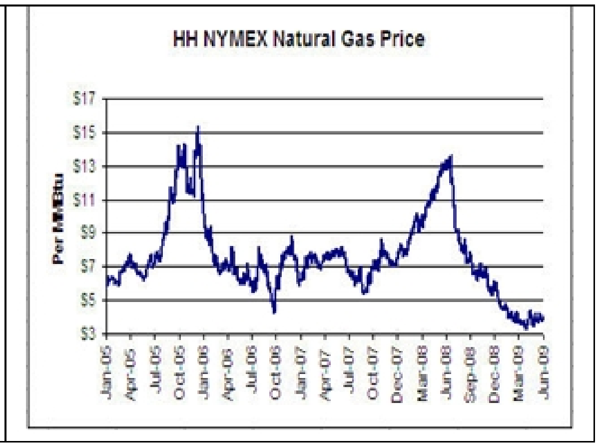
Asset Dispositions. On March 3, 2009, we entered into an agreement to sell our DJ basin assets and related hedges for $154 million before customary closing adjustments. The closing date of the sale of our DJ basin assets was April 1, 2009. We recorded an impairment charge associated with the sale of $9.6 million during the first quarter of 2009. Post closing adjustments recorded in the second quarter of 2009 were $0.2 million. The total loss on sale was recorded within "(Loss) income from discontinued operations, net of tax," on the condensed statements of operations for the six months ended June 30, 2009.

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

	Three months ended,			Six months ended,	
	June 30, 2009	June 30, 2008	March 31, 2009	June 30, 2009	June 30, 2008
Sales of oil	$ 103	$ 146	$ 99	$ 201	$ 277
Sales of gas	16	23	29	46	44
Total sales of oil and gas	$ 119	$ 169	$ 128	$ 247	$ 321
Sales of electricity	6	17	10	17	33
Gas Marketing	5	12	8	12	15
Gain (loss) on derivative	(31)	-	37	6	(1)
Interest and other income, net	1	1	-	1	2
Total revenues and other income	$ 100	$ 199	$ 183	$ 283	$ 370
Net income (loss) from continuing operations	$ (13)	$ 44	$ 42	$ 29	$ 83
Diluted earnings (loss) per share from continuing operations	$ (0.28)	$ 0.95	$ 0.92	$ .63	$ 1.82

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 June 30, 2009 were higher than the three months ended March 31, 2009 resulting from price increases of 4% and relatively flat sales volume. The decrease in revenue when compared to the second quarter of 2008 is primarily the result of a 24% decrease in realized prices. Natural gas revenues decreased from the quarter ended March 31, 2009 as a result of a 37% decrease in realized prices and a 6 % decrease in volumes from our Piceance and Uinta properties where no capital activity occurred during the quarter. Natural gas revenues were lower in the second quarter of 2009 compared to the second quarter of 2008 primarily due to a 65% decrease in realized prices, offset by the 25 MMcfe/D contribution from our East Texas assets which we purchased in July of 2008.





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

	June 30, 2009	%	June 30, 2008	%	March 31, 2009	%
Heavy Oil Production (Bbl/D)	16,822	57	16,888	58	16,436	50
Light Oil Production (Bbl/D)	3,085	11	3,723	13	3,066	9
Total Oil Production (Bbl/D)	19,907	68	20,611	71	19,502	59
Natural Gas Production (Mcf/D)	56,174	32	50,339	29	82,979	41
Total operations (BOE/D)	29,270	100	29,000	100	33,332	100
DJ Basin Production (BOE/D)	-		3,269		3,101	
Production - Continuing Operations (BOE/D)	29,270		25,731		30,231	
Oil and gas, per BOE for continuing operations						
Average sales price before hedging	$ 39.34		$ 96.55		$ 29.36	
Average sales price after hedging	45.74		71.64		47.11	
Oil, per Bbl, for continuing operations:						
Average WTI price	$ 59.79		$ 123.80		$ 43.24	
Price sensitive royalties	(2.08)		(5.92)		(1.02)	
Quality differential and other	(7.86)		(11.52)		(9.53)	
Crude oil hedges	8.91		(29.37)		23.79	
Average oil sales price after hedging	$ 58.76		$ 76.99		$ 56.48	
Natural gas price for continuing operations:						
Average Henry Hub price per MMBtu	$ 3.51		$ 10.49		$ 4.90	
Conversion to Mcf	0.18		0.53		0.25	
Natural gas hedges	0.21		-		1.14	
Location, quality differentials and other	(0.72)		(1.87)		(1.27)	
Average gas sales price after hedging per Mcf	$ 3.18		$ 9.15		$ 5.02	

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

	June 30, 2009	%	June 30, 2008	%
Heavy Oil Production (Bbl/D)	16,646	53	16,631	58
Light Oil Production (Bbl/D)	3,076	10	3,617	13
Total Oil Production (Bbl/D)	19,722	63	20,248	71
Natural Gas Production (Mcf/D)	69,502	37	49,712	29
Total operations (BOE/D)	31,305	100	28,534	100
DJ Basin Production (BOE/D)	1,542		3,213	
Production - Continuing Operations (BOE/D)	29,763		25,321	
Oil and gas, per BOE for continuing operations				
Average sales price before hedging	$ 34.24		$ 88.34	
Average sales price after hedging	46.44		69.42	
Oil, per Bbl, for continuing operations:				
Average WTI price	$ 51.58		$ 111.12	
Price sensitive royalties	(1.55)		(5.21)	
Quality differential and other	(8.77)		(11.15)	
Crude oil hedges	16.36		(22.66)	
Correction to royalties payable	-		2.85	
Average oil sales price after hedging	$ 57.62		$ 74.95	
Natural gas price for continuing operations:				
Average Henry Hub price per MMBtu	$ 4.21		$ 9.26	
Conversion to Mcf	0.21		0.46	
Natural gas hedges	0.70		-	
Location, quality differentials and other	(0.96)		(1.41)	
Average gas sales price after hedging per Mcf	$ 4.16		$ 8.31	

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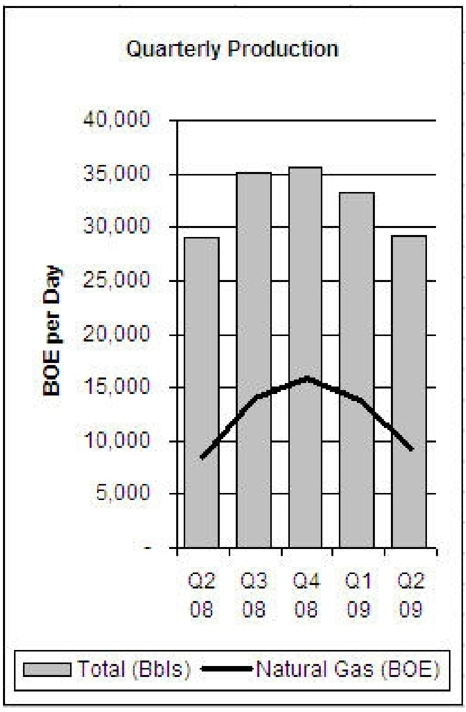

Gas Basis Differential. We have contracted a total of 35,000 MMBtu/D on the Rockies Express Pipeline under two separate transactions to provide firm transport for our Piceance gas production. As was the case during the first quarter, the Piceance gas was sold based upon a mid-continent index such as PEPL. For the second quarter of 2009, the mid-continent PEPL index averaged $0.91 below HH. Our Uinta basin gas is sold based upon a Questar index which averaged $1.12 below HH. In East Texas, the majority of the gas was sold based on the Florida Gas Transmission Zone 1 index which averaged $0.06 below HH.

Gas Marketing. We have two long-term firm transportation contracts for our Piceance natural gas production, with total capacity of 35,000 MMBtu/D. We pay a demand charge for this capacity and our own production does not currently fill that capacity. In order to maximize our firm transportation, we bought our partners' share of the gas produced in the Piceance at the market rate for that area. We used our excess transportation to move this gas to where it was eventually sold. The pre-tax net of our gas marketing revenue and our gas marketing expense in the Statement of Operations is $0.6 million and $0.9 million in the three and six month periods ended June 30, 2009. Firm transportation costs related to all of our Rockies Express volumes is reflected in Operating costs - oil and gas production and total $5.0 million for the six months ended June 30, 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. Also on March 20, 2009, we entered into a crude oil purchase contract with a refiner for the sale of all the Placerita crude. The agreement covers the period April 2009 through December 2009.

Utah - In February 2007, we entered into a multi-staged crude oil sales contract with a refiner for our Uinta basin light crude oil. Under the agreement, the refiner began purchasing 3,200 Bbl/D in July 2007. The refiner has increased its total capacity to 5,000 Bbl/D as provided in our contract. As operator we deliver all produced volumes under our sales contracts, although our working interest partners or royalty owners may take their respective volumes in kind and market their own volumes. Gross oil production averaged approximately 3,623 BOE/D in the quarter ended June 30, 2009. The differential under the contract, which includes transportation and gravity adjustments, is linked to the price for NYMEX WTI.

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

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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 and an avoided utility heat rate are the primary determinant of our electricity sales price based on the current pricing formula under these contracts. The correlation between electricity sales and natural gas prices allows us to manage our cost of producing steam more effectively.

Our electricity margins benefited from lower Rockies natural gas prices during the first six months of 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 natural gas 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 June 30, 2009 from the quarter ended June 30, 2008 due to 57% lower electricity prices and 67% lower natural gas prices. Revenues and operating costs were down for the quarter ended June 30, 2009 from the quarter ended March 31, 2009 due to 20% lower electricity prices and 28% lower natural gas prices, respectively. We purchased approximately 26,000 MMBtu/D and 25,000 MMBtu/D as fuel for use in our cogeneration facilities in the quarter ended June 30, 2009 and the quarter ended June 30, 2008, respectively.

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 second quarter of 2009, our margin on electricity was $0.2 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 SO contracts, revises the capacity prices paid under current S01 contracts and establishes the capacity prices that will be paid under new SO contracts. On July 9, 2009, the CPUC issued a resolution that implements a revised SRAC price methodology effective August 1, 2009 and resolves many of the disputed issues regarding the calculation of SRAC. The revised pricing changes the gas indices upon which SRAC is based and reduces the avoided utility heat rates used to calculate SRAC. These changes are not expected to have a material impact on electricity revenues.

The following table is for the three months ended:

	June 30, 2009	June 30, 2008	March 31, 2009
Electricity			
Revenues (in millions)	$ 6.6	$ 17.0	$ 10.3
Operating costs (in millions)	$ 6.4	$ 15.5	$ 8.8
Electric power produced - MWh/D	2,007	1,919	2,068
Electric power sold - MWh/D	1,783	1,724	1,939
Average sales price/MWh	$ 46.99	$ 108.21	$ 58.85
Fuel gas cost/MMBtu (including transportation)	$ 3.54	$ 10.01	$ 4.01

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)		
	June 30, 2009	June 30, 2008	March 31, 2009	June 30, 2009	June 30, 2008	March 31, 2009
Operating costs – oil and gas production	$ 13.03	$ 22.35	$ 13.74	$ 34,738	$ 52,332	$ 37,384
Production taxes	1.83	2.80	2.08	4,885	6,568	5,652
DD&A – oil and gas production	12.89	11.06	13.38	34,371	25,902	36,398
G&A	4.94	4.67	4.89	13,163	10,929	13,294
Interest expense	3.97	1.52	3.69	10,589	3,552	10,050
Total	$ 36.66	$ 42.40	$ 37.78	$ 97,746	$ 99,283	$ 102,778

- 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:

	June 30, 2009 (2Q09)	June 30, 2008 (2Q08)	2Q09 to 2Q08 Change	March 31, 2009 (1Q09)	2Q09 to 1Q09 Change
Average volume of steam injected (Bbl/D)	107,739	97,853	10%	103,342	4%
Fuel gas cost/MMBtu (including transportation)	$ 3.12	$ 10.01	(69%)	$ 4.01	(22%)
Approximate net fuel gas volume consumed in steam generation (MMBtu/D)	29,459	27,382	8%	26,427	11%

  Operating costs decreased by $2.6 million or 7% between the first quarter of 2009 and the second quarter of 2009. The majority of the decrease came from decreased fuel gas costs of approximately $1.5 million from decreased natural gas prices. The remainder of the decrease is due to our cost reduction efforts. The decrease in operating costs from the second quarter of 2008 to the second quarter of 2009 was also primarily due to natural gas prices which decreased 67%, 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 during 2009 with the higher rates in 2008 resulting from higher oil and natural gas prices.

- Depreciation, depletion and amortization: DD&A increased per BOE by 17% in the second quarter of 2009 as compared to the second quarter of 2008 due to an increase in the contribution of our development properties with higher drilling and leasehold acquisition costs and the integration of our East Texas assets which have higher finding and development costs than our legacy assets. DD&A decreased per BOE by 4% in the second quarter of 2009 as compared to the first quarter of 2009 due to reserve additions from acquisitions and from our drilling activities.

- General and administrative: Approximately 70% of our G&A is related to compensation. Our G&A increased during the second quarter of 2009 as compared to the first quarter of 2009 due to a liability that was established for a regulatory compliance matter.

- Interest expense: Our total outstanding borrowings were approximately $1.1 billion at June 30, 2009 compared to $511 million and $1.2 billion at June 30, 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 and the Notes that were issued in the second quarter of 2009. For the three months ended June 30, 2009, $7.3 million of interest cost has been capitalized and we expect to capitalize between $25 million and $30 million of interest cost during the full year of 2009.

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Estimated 2009 and Actual Six Months Ended June 30, 2009 and 2008 Oil and Gas Operating, G&A and Interest Expenses. Variances for the six month periods are described below when substantially different from the three month periods.

	Anticipated range Full Year 2009 per BOE	Six months ended, Amount per BOE June 30, 2009	June 30, 2008	Amount (in thousands) June 30, 2009	June 30, 2008
Operating costs-oil and gas production	$ 13.00 - 15.00	$ 13.39	$ 19.89	$ 72,122	$ 91,672
Production taxes	1.50 - 2.50	1.96	2.55	10,537	11,751
DD&A – oil and gas production (*1*)	13.00 - 14.00	13.14	10.87	70,769	50,108
G&A	4.25 - 4.75	4.91	4.79	26,457	22,061
Interest expense	4.00 - 4.75	3.83	1.49	20,639	6,879
Total	$ 35.75 - 41.00	$ 37.23	$ 39.59	$ 200,524	$ 182,471

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

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

	June 30, 2009	June 30, 2008	Change
Average volume of steam injected (Bbl/D)	105,118	94,589	11%
Fuel gas cost/MMBtu (including transportation)	$ 3.54	$ 8.98	(61%)
Approximate net fuel gas volume consumed in steam generation (MMBtu/D)	27,887	24,536	14%

Dry Hole, Abandonment, impairment and exploration. During the six months ended June 30, 2009 and 2008, we recorded dry hole, abandonment, impairment and exploration expense of $0.1 million and $5.9 million, respectively. Charges of $2.7 million and $2.6 million were recorded during the first and second quarters of 2008, respectively for technical difficulties that were encountered on four wells in the Piceance basin before reaching total depth. These holes were abandoned, in favor of drilling to the same bottom hole location by drilling new wells.

Debt Extinguishment Costs. During the second quarter of 2009 our borrowing base decreased from $1.25 billion to $969 million as a result of our scheduled borrowing base redetermination and the issuance of our senior unsecured notes. We wrote off $3.3 million of deferred loan fees during the second quarter of 2009 related to these transactions. Additionally, we paid off our 2nd lien term loan in conjunction with the issuance of our senior unsecured notes. We expensed $7.2 million in fees related to the 2nd lien term loan in the second quarter of 2009.

Income Taxes. We experienced an effective tax rate of 36% and 37% in the three months ended June 30, 2009 and June 30, 2008, respectively. We experienced an effective tax rate of 33% and 38% in the six months ended June 30, 2009 and June 30, 2008, respectively. The change for the six month period ended June 30, 2009 when compared to the same period in 2008 was primarily due to reduced state rates and the reduction in our liability related to uncertain tax positions. Our estimated annual effective tax rate varies from the 35% federal statutory rate due to the effects of state income taxes and estimated permanent differences. See Note 11 to the condensed financial statements.

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

	Three months ended June 30, 2009		Six months ended June 30, 2009	
Asset Team	Gross Wells	Net Wells	Gross Wells	Net Wells
S. Midway	2	2	10	10
N. Midway	30	30	45	45
Texas	3	3	6	6
Totals	35	35	61	61

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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.

S. Midway – Our S. Midway Asset Team includes four assets (Homebase, Formax, Ethel D and Poso Creek). Through the second quarter of 2009 we have drilled 10 Homebase horizontal wells. These wells have been placed deeper and closer to the oil-water contact. All 10 of these wells are currently on production and are performing in line with expectations. An additional nine horizontal wells will be drilled at S. Midway during the second half of 2009. We are also accelerating plans to expand our continuous steam support for these horizontal wells by drilling eight steam injectors. At Ethel D we have been encouraged by the performance of our steam flood pilots and we are preparing for future steam flood expansion. As part of this preparation we will be increasing our steam generation capacity at Ethel D by 50% by year-end. Average daily production during the three months ended June 30, 2009 from all S. Midway assets was approximately 11,570 BOE/D.

N. Midway – Our N. Midway Asset Team includes three assets (Diatomite, N. Midway, and Placerita). We plan to invest $39 million during 2009 to drill an additional 49 diatomite wells and install additional steam generation and water treating facilities. Through the second quarter of 2009 we have drilled 45 of these wells and commissioned two additional steam generators. Our Diatomite steam generation capacity is currently 30,000 BSPD and will increase to 40,000 BSPD by the end of 2009. Additionally, we have lowered operating and capital costs through initiatives such as completing an interconnection to the Kern River Gas Pipeline and application of process management techniques to reduce overall well costs. Production in the second quarter of 2009 was 2,930 Bbl/D and is expected to average over 3,000 Bbl/D for the year. Average daily production during the three months ended June 30, 2009 from all N. Midway assets was approximately 5,250 BOE/D.

Piceance– During the three months ended June 30, 2009, production from the Piceance basin averaged 18 MMcf/D. No drilling or completion activity was performed during the quarter. Infrastructure expansions are now under way in preparation for 10 completions planned in the third quarter that will meet lease earning commitments and test new completion techniques. Currently we have an inventory of 44 initial completion and recompletion projects remaining from our 2008 drilling program. Effective June 1, 2009 Berry acquired an additional 12.5% working interest in Garden Gulch, increasing our ownership in that portion of the project to 62.5%.

Uinta – Average daily production during the three months ended June 30, 2009 from all Uinta basin assets averaged 5,310 BOE/D. Two of the shallow Lake Canyon wells drilled in 2008 were completed late in the second quarter with encouraging results producing a combined 225 BOE/D. A third well from the 2008 Lake Canyon drilling program was just completed and placed online and is currently producing back the load fluid that was pumped during its completion. We are also planning the implementation of a waterflood pilot in Brundage Canyon with initial start up scheduled for late in the third quarter of 2009. The Ashley Forest Development EIS continues to progress with approval now expected in the second half of 2009.

E. Texas – During the three months ended June 30, 2009, production from our East Texas assets averaged 25 MMcfe/D. We continue to operate a one rig program and drilled 3 vertical wells in the Oakes field during the second quarter of 2009 and are currently drilling the first well of two remaining 2009 vertical wells. Once complete we plan to move the rig to the Darco field to begin drilling our first horizontal Haynesville well.

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

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

Liquidity. The total outstanding debt at June 30, 2009 under the Agreement and the Line of Credit was $581 million and $0, respectively, and $3 million in letters of credit have been issued under the facility.

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Subsequent to our April 2009 borrowing base redetermination and the issuance of our senior unsecured notes, the borrowing base under our senior secured revolving credit facility is approximately $969 million. As of June 30, 2009, we had approximately $584 million outstanding under our senior secured revolving credit facility, with liquidity of $384 million.

Pursuant to the terms of our senior secured credit facility, the issuance of the Notes automatically reduced our borrowing base by 25 cents per dollar of Notes issued, or approximately $81 million.

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

In 2009, we have a capital program of approximately $130 million and we expect to fully fund this program from operating cash flow which should approximate $175 million. Cash provided by operating activities was impacted during the six months ended June 30, 2009 by a reduction in accounts payable which, at year-end 2008, reflected our higher 2008 capital budget. Approximately 90% of our oil production is hedged for 2009 and thus our sensitivity to changes in oil prices is limited. A ten dollar change in oil prices has a minimal impact on operating cash flow and a one dollar change in natural gas prices impacts our annual operating cash flow by approximately $1.4 million.

Capital expenditures, excluding property acquisitions, totaled $22.9 million and $73.1 million during the three and six months ended June 30, 2009.

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

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):

	June 30, 2009 (2Q09)	June 30, 2008 (2Q08)	2Q09 to 2Q08 Change	March 31, 2009 (1Q09)	2Q09 to 1Q09 Change
Average production (BOE/D)	29,270	25,731	14%	30,231	(3%)
Average oil and gas sales prices, per BOE after hedging	$ 45.74	$ 71.64	(36%)	$ 47.11	(3%)
Net cash provided by operating activities	$ 51	$ 107	(52%)	$ 8	538%
Working capital (deficit)	$ (3)	$ (225)	99%	$ 169	(102%)
Sales of oil and gas	$ 119	$ 169	(30%)	$ 128	(7%)
Total debt	$ 1,085	$ 511	112%	$ 1,199	(10%)
Capital expenditures	$ 23	$ 95	(76%)	$ 50	(54%)
Dividends paid	$ 3.4	$ 3.4	-%	$ 3.4	-%

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

	Total	2009	2010	2011	2012	2013	Thereafter
Total debt and interest	$ 1,440.5	$ 33.1	$ 66.2	$ 66.2	$ 639.6	$ 49.8	$ 585.6
Abandonment obligations	41.0	1.6	1.6	1.6	1.6	1.6	33.0
Operating lease obligations	17.1	1.2	2.4	2.4	2.4	2.5	6.2
Drilling and rig obligations	40.7	6.5	8.0	8.0	18.2	-	-
Firm natural gas transportation contracts	144.7	9.2	19.1	19.1	17.8	15.7	63.8
Total	$ 1,684.0	$ 51.6	$ 97.3	$ 97.3	$ 679.6	$ 69.6	$ 688.6

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

Other Obligations - As of June 30, 2009 we had a gross liability for uncertain tax benefits of $8.8 million of which $7.1 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.

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 3,623 BOE/D in the quarter ended June 30, 2009. The differential under the contract, which includes transportation and gravity adjustments, is linked to the price for NYMEX Light Sweet Crude. This contract provides us an outlet to sell all of our current oil production in the Uinta basin.

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

On July 17, 2009, we closed on the sale of our E. Texas gas gathering system for $18.4 million in cash. We entered into concurrent long-term gas gathering agreements for the E. Texas production. The transaction will be accounted for as sale-leaseback and we will record the transaction as a capital lease.

Recent Accounting Developments

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 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 12 to the condensed financial statements.

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.

Berry Petroleum Company
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In March 2009, the FASB unanimously voted for the FASB "*Accounting Standards Codification*" (the "Codification") to be effective beginning on July 1, 2009. Other than resolving certain minor inconsistencies in current United States Generally Accepted Accounting Principles ("GAAP"), the Codification is not supposed to change GAAP, but is intended to make it easier to find and research GAAP applicable to particular transactions or specific accounting issues. The Codification is a new structure which takes accounting pronouncements and organizes them by approximately ninety accounting topics. Once approved, the Codification will be the single source of authoritative U.S. GAAP. All guidance included in the Codification will be considered authoritative at that time, even guidance that comes from what is currently deemed to be a non-authoritative section of a standard. Once the Codification becomes effective in the third quarter of 2009, all non-grandfathered, non-SEC accounting literature not included in the Codification will become non-authoritative and we will update our disclosures accordingly.

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 was effective for us for the quarter ending June 30, 2009 and we expanded our disclosures accordingly. See Note 3 to the condensed financial statements.

In May 2009, the FASB issued SFAS No. 165, *Subsequent Events*, which establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. We implemented SFAS No. 165 during the second quarter of 2009 and we expanded our disclosures accordingly. See Note 15 to the condensed financial statements.

Forward Looking Statements

“Safe harbor under the Private Securities Litigation Reform Act of 1995:” Any statements in this Form 10-Q that are not historical facts are forward-looking statements that involve risks and uncertainties. Words such as “plan,” “will,” “intend,” “continue,” “target(s),” “expect,” “achieve,” “future,” “may,” “could,” “goal(s),” “anticipate,” or other comparable words or phrases, or the negative of those words, and other words of similar meaning indicate forward-looking statements and important factors which could affect actual results. Forward-looking statements are made based on management’s current expectations and beliefs concerning future developments and their potential effects upon Berry Petroleum Company. These items are discussed at length in Part I, Item 1A on page 15 of our Form 10-K dated February 25, 2009, filed with the Securities and Exchange Commission, under the heading “Risk Factors” and all material changes are updated in Part II, Item 1A within this Form 10-Q.

Berry Petroleum Company
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. The collar strike prices allow us to protect our cash flow if oil prices decline below our floor prices which range from $55.00 to $100.00 per barrel while still participating in any oil price increase up to the ceiling prices which range from $75.00 to $163.60 per barrel on the volumes indicated above. In total , we have approximately 90% and 45% of our expected 2009 and 2010 oil production hedged in the form of swaps and collars . Our natural gas collars have a floor of $6.00 per MMBtu and ceilings ranging from $8.60 to $8.65 per MMBtu. In total, we have approximately 25% and 5% of our 2009 and 2010 expected natural gas production hedged in the form of swaps and collars.

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

Term	Average Barrels Per Day	Average Prices
Crude Oil Sales (NYMEX WTI) Collars		
Full year 2009	295	$ 80.00/$91.00
Full year 2009	1,000	$ 100.00/$163.60
Full year 2009	1,000	$ 100.00/$150.30
Full year 2009	1,000	$ 100.00/$160.00
Full year 2009	1,000	$ 100.00/$150.00
Full year 2009	1,000	$ 100.00/$157.48
Full year 2010	1,000	$ 65.15 / $75.00
Full year 2010	1,000	$ 65.50 / $78.50
Full year 2010	280	$ 80.00 / $90.00
Full year 2010	1,000	$ 100.00/$161.10
Full year 2010	1,000	$ 100.00/$150.30
Full year 2010	1,000	$ 100.00/$160.00
Full year 2010	1,000	$ 100.00/$150.00
Full year 2010	1,000	$ 100.00/$158.50
Full year 2010	1,000	$ 70.00/$86.00
Full year 2011	270	$ 80.00/$90.00
Full year 2011	1,000	$ 55.20/$70.00
Full year 2011	1,000	$ 55.00/$70.50
Full year 2011	1,000	$ 55.00/$68.65
Full year 2011	1,000	$ 55.00/$68.00
Full year 2011	1,000	$ 55.00/$71.20
Full year 2011	1,000	$ 60.00/$76.00
Full year 2011	1,000	$ 60.00/$81.25
Full year 2012	1,000	$ 63.00/$82.60
Full year 2012	1,000	$ 63.00/$83.50
Full year 2012	1,000	$ 70.00/$93.00
Crude Oil Sales (NYMEX WTI) Swaps		
Full year 2009	240	$ 71.50
Full year 2009	1,000	$ 70.30
Full year 2009	1,000	$ 70.50
3rd Quarter 2009	500	$ 52.40
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
October 2009	1,613	$ 65.85
November 2009	1,667	$ 65.85

Term	Average MMBtu Per Day	Average Price
Natural Gas Sales (NYMEX HH TO PEPL) Basis Swaps		
4th quarter 2009	4,000	$ 1.05
Full year 2009	2,000	$ 1.24
Full year 2009	3,000	$ 1.19
Full year 2010	2,000	$ 1.05
Full year 2010	3,000	$ 1.00
Natural Gas Sales (NYMEX HH) Swaps		
Full year 2009	2,000	$ 6.15
Full year 2009	3,000	$ 6.19
4th quarter 2009	4,000	$ 8.50
July – December 2009	5,000	$ 4.21
Full year 2010	5,000	$ 6.02
Full year 2011	5,000	$ 6.885
Full year 2012	5,000	$ 7.16
Natural Gas Sales (NYMEX HH) Collars		
Full year 2010	2,000	$ 6.00/$8.60
Full year 2010	3,000	$ 6.00/$8.65
Full year 2010	1,000	$ 6.50/$8.75
Full year 2010	1,000	$ 6.50/$8.85
Full year 2010	2,000	$ 6.50/$8.90
Natural Gas Sales (NYMEX HH TO NGPL) Basis Swaps		
Full year 2010	2,000	$ 0.49
Natural Gas Sales (NYMEX HH TO HSC) Basis Swaps		
Full year 2010	2,000	$ 0.38
July – December 2009	2,500	$ 0.0305
Full year 2010	2,500	$ 0.345
Full year 2011	2,500	$ 0.325
Full year 2012	2,500	$ 0.320
Natural Gas Sales (NYMEX HH to NGPL-Tex OK) Basis Swaps		
July – December 2009	2,500	$ 0.475
Full year 2010	2,500	$ 0.415
Full year 2011	2,500	$ 0.460
Full year 2012	2,500	$ 0.440

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

While we designate the majority of our hedges as cash flow hedges, we have not elected hedge accounting on certain of our crude oil and natural gas hedges. During the three and six months ended June 30, 2009, we recorded ($8.3) and $6.0 under the caption "Gain (loss) on derivatives" for hedges with respect to which we either did not elect hedge accounting or which no longer qualified for hedge accounting. In conjunction with the sale of the DJ basin assets, during the first quarter of 2009, we concluded that the forecasted transaction in certain of our hedging relationships was not probable of occurring. As such, we reclassified a gain of $14.3 million from accumulated other comprehensive income (loss) to the statement of operations under the caption "Gain (loss) on derivative." Additionally, a portion of the change in fair value for hedges that we have designated as cash flow hedges impacts our income as our sales price is not perfectly correlated with our hedges. We recognized an unrealized net loss of approximately $22.8 million and $0 million on the statement of operations under the caption "Gain (loss) on derivatives" for the second quarter and six months ended June 30, 2009 as a result of this ineffectiveness. During the first quarter of 2009, we entered into natural gas derivatives on behalf of the purchaser of our DJ assets. We did not elect hedge accounting for these hedges and recorded an unrealized net loss of $0.5 million on the statement of operations under the caption "(Loss) income from discontinued operations, net of taxes."

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

Hedge Term	Notional Amount $MM	Fixed Rate
4/1/2009 – 6/30/2012	100	4.74%
4/15/2009 – 7/15/2012	150	1.95%
9/15/2009 – 7/15/2012	50	2.31%
12/15/2009 – 7/15/2012	75	2.05%

The related cash flow impact of all of our hedges is reflected in cash flows from operating activities. At June 30, 2009, our net fair value of derivative liability was $35.6 million as compared to a net fair value asset of $185.9 million at December 31, 2008 which reflects increases in commodity prices. Based on NYMEX strip pricing as of June 30, 2009, we expect to make cash hedge payments under the existing derivatives of $4.7 million during the next twelve months. At June 30, 2009, Accumulated Other Comprehensive Income (Loss) consisted of $18.2 million, net of tax, of unrealized losses from our crude oil and natural gas swaps and collars that qualified for hedge accounting treatment at June 30, 2009. Deferred net losses recorded in "Accumulated Other Comprehensive Income (Loss)" at June 30, 2009 and subsequent mark-to-market changes in the underlying hedging contracts are expected to be reclassified to earnings in the same period that the forecasted transaction impacts earnings.

Based on average NYMEX futures prices as of June 30, 2009 (WTI $76.80; HH $6.51) for the term of our hedges we would expect to make pre-tax future cash payments or to receive payments over the remaining term of our crude oil and natural gas hedges in place as follows:

	June 30, 2009 NYMEX Futures	Impact of percent change in futures prices on pre-tax future cash (payments) and receipts			
		-40%	-20%	+ 20%	+40%
Average WTI Futures Price (2009 – 2012)	$ 76.80	$ 46.08	$ 61.44	$ 92.16	$ 107.52
Average HH Futures Price (2009 – 2010)	6.52	3.91	5.22	7.82	9.13
Crude Oil gain/(loss) (in millions)	$ (20.3)	$ 314.6	$ 132.3	$ (202.8)	$ (385.6)
Natural Gas gain/(loss) (in millions)	(0.7)	33.5	22.3	2.7	(5.2)
Total	$ (21.0)	$ 348.1	$ 154.6	$ (200.1)	$ (390.8)
Net pre-tax future cash (payments) and receipts by year (in millions) based on average price in each year:					
2009 (WTI $71.24: HH $4.59)	$ (4.8)	$ 95.0	$ 47.3	$ (47.8)	$ (94.9)
2010 (WTI $74.93; HH $6.25)	14.2	195.3	103.2	(60.7)	(140.3)
2011 (WTI $78.12)	(30.4)	41.6	1.5	(83.8)	(139.4)
2012 (WTI $80.13)	-	16.2	2.6	(7.8)	(16.2)
Total	$ (21.0)	$ 348.1	$ 154.6	$ (200.1)	$ (390.8)

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Interest Rates. Our exposure to changes in interest rates results primarily from long-term debt. In October 2006, we issued, in a public offering, $200 million of 8.25% senior subordinated notes due 2016. In May, 2009, we issued, in a public offering, $325 million of 10.25% senior notes due 2014. At June 30, 2009, total long-term debt outstanding was $1.1 billion. Interest on amounts borrowed under our credit facility is charged at LIBOR plus 2.25% to 3.0%, with the exception of the principal for which we have hedged, plus the credit facility's margin through July 15, 2012. Based on June 30, 2009 credit facility borrowings, a 1% change in interest rates, including our interest rate hedges, would have an annualized $1 million after tax impact on our financial statements.

Berry Petroleum Company
Controls and Procedures

Item 4. Controls and Procedures

As of June 30, 2009, we have carried out an evaluation under the supervision of, and with the participation of, our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15 under the Securities Exchange Act of 1934, as amended ("Exchange Act").

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

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

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

We are currently involved in negotiations with the U.S. Environmental Protection Agency (EPA) relating to alleged late filing of a certain leak detection and repair reports for one of our facilities in Utah. We believe this matter will be resolved by the payment of a penalty that will not exceed $150,000. In an unrelated matter, we are also involved in negotiations with the Colorado Department of Health and Environment relating to an alleged failure to implement certain best management practices designed to limit impacts to storm water discharges at certain of our construction sites in Colorado. We believe this matter will be resolved by the payment of a penalty that will not exceed $400,000.

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

Item 1A. Risk Factors

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

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

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

Berry Petroleum Company
Part II. Other Information

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

Recent and future environmental laws and regulations, including additional federal and state restrictions on greenhouse gas emissions that may be passed in response to climate change concerns, may increase our operating costs and also reduce the demand for the oil and natural gas we produce. The oil and gas industry is a direct source of certain greenhouse gas (GHG) emissions, such as carbon dioxide and methane, and future restrictions on such emissions could impact our future operations. Specifically, on April 17, 2009, EPA issued a notice of its proposed finding and determination that emission of carbon dioxide, methane, and other GHGs present an endangerment to human health and the environment because emissions of such gases are, according to EPA, contributing to warming of the earth's atmosphere. EPA's proposed finding and determination, and any final action in the future, will allow it to begin regulating emissions of GHGs under existing provisions of the federal Clean Air Act. Although it may take EPA several years to adopt and impose regulations limiting emissions of GHGs, any such regulation could require us to incur costs to reduce emissions of GHGs associated with our operations. Similarly, on June 26, 2009, the U.S. House of Representatives approved adoption of the "American Clean Energy and Security Act of 2009," also known as the "Waxman-Markey cap-and-trade legislation" or ACESA. ACESA would establish an economy-wide cap on emissions of GHGs in the United States and would require most sources of GHG emissions to obtain GHG emission "allowances" corresponding to their annual emissions of GHGs. The U.S. Senate has begun work on its own legislation for controlling and reducing emissions of GHGs in the United States. Any laws or regulations that may be adopted to restrict or reduce emissions of GHGs would likely require us to incur increased operating costs and could have an adverse effect on demand for the oil and natural gas we produce. At the state level, more than one-third of the states, including California, have begun taking actions to control and/or reduce emissions of GHGs. The California Global Warming Solutions Act of 2006, also known as "AB 32," caps California's greenhouse gas emissions at 1990 levels by 2020, and the California Air Resources Board is currently developing mandatory reporting regulations and early action measures to reduce GHG emissions prior to January 1, 2012. Although most of the regulatory initiatives developed or being developed by the various states have to date been focused on large sources of GHG emissions, such as coal-fired electric power plants, it is possible that smaller sources of emissions could become subject to GHG emission limitations in the future. A number of our personnel are involved in monitoring the establishment of these regulations through industry trade groups and other organizations in which we are a member. It is not possible, at this time, to estimate accurately how these regulations would impact our business.

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

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

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

Berry Petroleum Company
Part II. Other Information

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

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

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

None.

Item 3. Defaults Upon Senior Securities

None.

Berry Petroleum Company
Part II. Other Information

Item 4. Submission of Matters to a Vote of Security Holders

At the annual meeting of Shareholders which was held in Denver, Colorado, on May 13, 2009, ten incumbent directors were re-elected. The results of voting as reported by the inspector of elections are noted below:

1. There were 42,783,075 and 1,797,784 shares (or 44,580,859 on a combined basis), respectively, of Class A Common Stock and Class B Stock, of the Company's capital stock issued, outstanding and generally entitled to vote as of the record date, March 16, 2009.

2. There were present at the meeting, in person or by proxy, the holders of 39,691,939 shares, representing 89.04% of the total number of shares outstanding and entitled to vote at the meeting, such percentage representing a quorum.

NOMINEE	VOTES CAST FOR	PERCENTAGE OF QUORUM VOTES CAST	WITHHOLD AUTHORITY WITHHELD
Joseph H. Bryant	35,044,803	88.30%	4,647,136
Ralph B. Busch, III	34,896,396	87.92%	4,795,543
William E. Bush, Jr	34,898,650	87.93%	4,793,289
Stephen L. Cropper	35,994,400	90.69%	3,697,539
J. Herbert Gaul, Jr.	36,002,647	90.71%	3,689,292
Robert F. Heinemann	35,069,354	88.36%	4,622,585
Thomas J. Jamieson	35,044,090	88.29%	4,647,849
J. Frank Keller	35,985,403	90.67%	3,706,536
Ronald J. Robinson	35,784,806	90.16%	3,907,133
Martin H. Young, Jr	35,780,570	90.15%	3,911,369

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

PROPOSAL TWO: Ratification of the appointment of PricewaterhouseCoopers LLP as the Independent Registered Public Accounting Firm (Independent Auditors).

	For	Against	Abstentions	Broker Non-Votes
Shares	38,425,521	1,031,594	234,824	-

Item 5. Other Information

None.

Berry Petroleum Company
Part II. Other Information

Item 6. Exhibits

Exhibit No.	Description of Exhibit
3.1	Amended and Restated By-Laws, as amended and restated through May 14, 2009 (filed as Exhibit 3.1 to the Registrant's Current Report on Form 8-K on May 14, 2009, File No. 1-9735).
4.1	Indenture, dated June 15, 2006, between Registrant and Wells Fargo Bank, National Association, as Trustee (filed as Exhibit 4.1 to the Registrant's Current Report on Form 8-K on May 29, 2009, File No. 1-9735).
4.2	First Supplemental Indenture, dated May 27, 2009, between Berry Petroleum Company and Wells Fargo Bank, National Association, as Trustee (filed as Exhibit 4.2 to the Registrant's Current Report on Form 8-K on May 29, 2009, File No. 1-9735).
4.3	Form of 10¼% Senior Notes due 2014 (included in Exhibit 4.2 to the Registrant's Current Report on Form 8-K on May 29, 2009, File No. 1-9735).
10.1	Underwriting Agreement, dated May 21, 2009, by and among Registrant and Wachovia Capital Markets, LLC, RBS Securities Inc., BNP Paribas Securities Corp., SG Americas Securities, LLC and Calyon Securities (USA) Inc., as representatives of the underwriters named therein (filed as Exhibit 1.1 to the Registrant's Current Report on Form 8-K on May 27, 2009, File No. 1-9735).
12.1	Computation of Ratio of Earnings to Fixed Charges
31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

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: August 5, 2009

Exhibit 12.1

COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES

(in thousands, except ratios)

	Six months ended June 30, 2009	12/31/08	12/31/07	12/31/06	12/31/05	12/31/04
Pre-tax income from continuing operations	$ 43,268	$ 192,084	$ 206,344	$ 159,906	$ 150,289	$ 89,518
Interest expense	21,454	26,209	17,287	10,247	6,048	2,067
Capitalized interest	12,626	23,209	18,104	9,339	-	-
Earnings	$ 64,722	$ 218,293	$ 233,631	$ 170,153	$ 156,337	$ 91,585
Ratio of earnings to fixed charges	**1.9**	**4.4**	**6.3**	**8.7**	**25.8**	**44.3**

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

Exhibit 31.1

Certification of Chief Executive Officer

Pursuant to Section 302 of Sarbanes Oxley Act of 2002

I, Robert F. Heinemann, certify that:

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

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

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

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

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

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

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

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

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

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

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

/s/ Robert F. Heinemann
Robert F. Heinemann
President, Chief Executive Officer and Director

August 5, 2009

Exhibit 31.2

Certification of Chief Financial Officer

Pursuant to Section 302 of Sarbanes Oxley Act of 2002

I, David D. Wolf, certify that:

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

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

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

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

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

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

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

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

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

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

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

/s/ David D. Wolf
David D. Wolf
Executive Vice President and Chief Financial Officer

August 5, 2009

Exhibit 32.1

Certification of Chief Executive Officer

Pursuant to Section 906 of Sarbanes Oxley Act of 2002

In Connection with the Quarterly Report of Berry Petroleum Company (the "Company") on Form 10-Q for the period ending June 30, 2009 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Robert F. Heinemann, President, Chief Executive Officer and Director of the Company, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

/s/ Robert F. Heinemann
Robert F. Heinemann
President, Chief Executive Officer and Director

August 5, 2009

Exhibit 32.2

Certification of Chief Financial Officer

Pursuant to Section 906 of Sarbanes Oxley Act of 2002

In Connection with the Quarterly Report of Berry Petroleum Company (the "Company") on Form 10-Q for the period ending June 30, 2009 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, David D. Wolf, Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

/s/ David D. Wolf
David D. Wolf
Executive Vice President and Chief Financial Officer

August 5, 2009