Use these links to rapidly review the document
TABLE OF CONTENTS

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

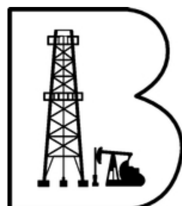
T **Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the quarterly period ended September 30, 2013

o **Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the transition period from to

Commission file number 1-9735



BERRY PETROLEUM COMPANY

(Exact name of registrant as specified in its charter)

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. YES 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 T 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 £ (Do not check if a smaller reporting company)	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 October 21, 2013 the registrant had 52,712,863 shares of Class A Common Stock ($0.01 par value) outstanding. The registrant also had 1,763,866 shares of Class B Stock ($0.01 par value) outstanding on October 21, 2013, all of which is held by a single holder.

BERRY PETROLEUM COMPANY
INDEX TO FORM 10-Q
September 30, 2013

	Page
PART I. FINANCIAL INFORMATION	3
Item 1. Condensed Financial Statements (Unaudited)	3
Condensed Balance Sheets at September 30, 2013 and December 31, 2012	3
Condensed Statements of Operations for the three and nine months ended September 30, 2013 and 2012	4
Condensed Statements of Comprehensive Earnings for the three and nine months ended September 30, 2013 and 2012	5
Condensed Statements of Cash Flows for the nine months ended September 30, 2013 and 2012	6
Condensed Statements of Shareholders' Equity for the nine months ended September 30, 2013	7
Notes to Condensed Financial Statements	8
Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations	21
Item 3. Quantitative and Qualitative Disclosures About Market Risk	39
Item 4. Controls and Procedures	42
PART II. OTHER INFORMATION	
Item 1. Legal Proceedings	43
Item 1A. Risk Factors	43
Item 2. Unregistered Sales of Equity Securities and Use of Proceeds	43
Item 3. Defaults Upon Senior Securities	43
Item 4. Removed and Reserved	43
Item 5. Other Information	43
Item 6. Exhibits	44
Signatures	45

PART I. FINANCIAL INFORMATION

BERRY PETROLEUM COMPANY

Condensed Balance Sheets

(Unaudited)

(In Thousands, Except Share Information)

	September 30, 2013	December 31, 2012
ASSETS		
Current assets:		
Cash and cash equivalents	$ 24,055	$ 312
Restricted short-term investments	125	125
Accounts receivable	148,019	122,159
Deferred income taxes	1,574	703
Derivative instruments	4,960	14,661
Prepaid expenses and other	18,304	19,065
Total current assets	197,037	157,025
Oil and natural gas properties (successful efforts basis), buildings and equipment, net	3,315,247	3,128,502
Derivative instruments	17,245	10,891
Other assets	24,382	28,984
	$ 3,553,911	$ 3,325,402
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 103,034	$ 175,893
Revenue and royalties payable	50,859	57,021
Accrued liabilities	53,969	51,151
Derivative instruments	8,561	1,111
Deferred income taxes	—	1,456
10.25% Senior notes due 2014, net of unamortized discount of $1,141	204,116	—
Total current liabilities	420,539	286,632
Long-term liabilities:		
Deferred income taxes	331,734	255,471
Senior secured revolving credit facility	636,000	562,900
10.25% Senior notes due 2014, net of unamortized discount of $2,340	—	202,917
6.75% Senior notes due 2020	300,000	300,000
6.375% Senior notes due 2022	600,000	600,000
Asset retirement obligations	98,374	82,316
Derivative instruments	—	1,239
Other long-term liabilities	33,870	19,136
	1,999,978	2,023,979
Shareholders' equity:		
Preferred stock, $0.01 par value, 2,000,000 shares authorized; no shares outstanding	—	—
Capital stock, $0.01 par value:		
Class A Common Stock, 100,000,000 shares authorized; 52,691,955 and 52,428,423 shares issued and outstanding, respectively	527	524
Class B Stock, 3,000,000 shares authorized; 1,763,866 shares issued and outstanding (liquidation preference of $0.50 per share)	18	18
Capital in excess of par value	374,538	364,710
Retained earnings	758,311	649,539
Total shareholders' equity	1,133,394	1,014,791
	$ 3,553,911	$ 3,325,402

The accompanying notes are an integral part of these Condensed Financial Statements.

BERRY PETROLEUM COMPANY

Condensed Statements of Operations

(Unaudited)

(In Thousands, Except Per Share Data)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
REVENUES				
Oil and natural gas sales	$ 306,183	$ 232,916	$ 847,670	$ 688,350
Electricity sales	10,046	9,514	27,148	21,354
Natural gas marketing	1,916	1,939	6,198	5,378
Gain on sale of assets	—	170	23	1,770
Interest and other income, net	249	286	1,098	1,678
	318,394	244,825	882,137	718,530
EXPENSES				
Operating costs—oil and natural gas production	91,416	70,670	268,841	187,318
Operating costs—electricity generation	5,401	4,727	17,034	14,000
Production taxes	11,060	9,700	32,848	30,048
Depreciation, depletion & amortization—oil and natural gas production	73,011	58,887	210,934	158,869
Depreciation, depletion & amortization—electricity generation	456	461	1,283	1,382
Natural gas marketing	1,895	1,753	5,971	4,917
General and administrative	17,834	17,767	59,542	53,473
Interest	24,996	20,572	74,562	61,446
Dry hole, abandonment, impairment and exploration	1,624	2,837	3,458	7,456
Impairment of oil and natural gas properties	—	—	2,467	67
Extinguishment of debt	—	—	—	41,545
Realized and unrealized loss (gain) on derivatives, net	45,293	28,287	10,408	(56,314)
	272,986	215,661	687,348	504,207
Earnings before income taxes	45,408	29,164	194,789	214,323
Income tax provision	17,230	11,038	72,813	81,283
Net earnings	$ 28,178	$ 18,126	$ 121,976	$ 133,040
Basic net earnings per share	$ 0.51	$ 0.33	$ 2.20	$ 2.41
Diluted net earnings per share	$ 0.50	$ 0.33	$ 2.19	$ 2.39
Dividends per share	$ 0.08	$ 0.08	$ 0.24	$ 0.24

The accompanying notes are an integral part of these Condensed Financial Statements.

BERRY PETROLEUM COMPANY

Condensed Statements of Comprehensive Earnings

(Unaudited)

(In Thousands)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Net earnings	$ 28,178	$ 18,126	$ 121,976	$ 133,040
Other comprehensive earnings, net of income taxes:				
Amortization of accumulated other comprehensive loss (AOCL) related to de-designated hedges, net of income tax benefits of $0, $924, $0 and $2,318, respectively	—	1,505	—	3,781
Other comprehensive earnings	$ —	$ 1,505	$ —	$ 3,781
Comprehensive earnings	$ 28,178	$ 19,631	$ 121,976	$ 136,821

The accompanying notes are an integral part of these Condensed Financial Statements.

BERRY PETROLEUM COMPANY

Condensed Statements of Cash Flows

(Unaudited)

(In Thousands)

	Nine Months Ended September 30,	
	2013	**2012**
Cash flows from operating activities:		
Net earnings	$ 121,976	$ 133,040
Depreciation, depletion and amortization	212,217	160,251
Gain on sale of assets	(23)	(1,770)
Extinguishment of debt	—	6,842
Amortization of debt issuance costs and net discount	5,197	5,350
Impairment of oil and natural gas properties	2,467	67
Dry hole and impairment	1,441	2,515
Derivatives	9,559	(34,760)
Stock-based compensation expense	8,491	7,589
Deferred income taxes	85,280	77,511
Other, net	5,208	(1,620)
Allowance for bad debt	—	450
Change in book overdraft	(14,885)	7,573
Changes in operating assets and liabilities:		
Accounts receivable	(29,975)	504
Inventories, prepaid expenses, and other current assets	456	(2,634)
Accounts payable and revenue and royalties payable	(4,888)	15,097
Accrued interest and other accrued liabilities	2,785	15,611
Net cash provided by operating activities	405,306	391,616
Cash flows from investing activities:		
Development and exploration of oil and natural gas properties	(445,645)	(524,036)
Property acquisitions	(3,367)	(75,706)
Capitalized interest	(4,978)	(13,977)
Proceeds from sale of assets	11,530	17,294
Deposits on asset sales	—	(3,300)
Net cash used in investing activities	(442,460)	(599,725)
Cash flows from financing activities:		
Proceeds from issuance of 6.375% Senior notes due 2022	—	600,000
Repurchase of 8.25% Senior subordinated notes due 2016	—	(200,000)
Repurchase of 10.25% Senior notes due 2014	—	(149,999)
Long-term borrowings under credit facility	559,900	1,215,500
Repayments of long-term borrowings under credit facility	(486,800)	(1,237,000)
Financing obligation	(339)	(309)
Debt issuance costs	—	(11,424)
Dividends paid	(13,204)	(13,160)
Stock options and restricted stock issued	368	3,551
Excess income tax benefit	972	756
Net cash provided by financing activities	60,897	207,915
Net increase (decrease) in cash and cash equivalents	23,743	(194)
Cash and cash equivalents at beginning of period	312	298
Cash and cash equivalents at end of period	$ 24,055	$ 104
Noncash investing activities:		
Accrued capital expenditures	$ 40,164	$ 61,044
Asset retirement obligations	13,222	16,854

The accompanying notes are an integral part of these Condensed Financial Statements.

BERRY PETROLEUM COMPANY

Condensed Statements of Shareholders' Equity

(Unaudited)

(In Thousands, Except Per Share Data)

	Class A	Class B	Capital in Excess of Par Value	Retained Earnings	Total Shareholders' Equity
Balances at December 31, 2012	$ 524	$ 18	$ 364,710	$ 649,539	$ 1,014,791
Stock options and restricted stock issued	3	—	365	—	368
Stock based compensation expense	—	—	8,491	—	8,491
Income tax effect of stock option exercises	—	—	972	—	972
Dividends ($0.24 per share)	—	—	—	(13,204)	(13,204)
Net earnings	—	—	—	121,976	121,976
Balances at September 30, 2013	$ 527	$ 18	$ 374,538	$ 758,311	$ 1,133,394

The accompanying notes are an integral part of these Condensed Financial Statements.

BERRY PETROLEUM COMPANY

Notes to Condensed Financial Statements

(Unaudited)

1. Basis of Presentation

These Condensed Financial Statements have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP) for interim financial reporting. Pursuant to the rules and regulations of the Securities and Exchange Commission (SEC), the unaudited Condensed Financial Statements do not include all disclosures required by GAAP. For a more complete understanding of Berry Petroleum Company's (the Company) operations, financial position and accounting policies, the unaudited Condensed Financial Statements and notes thereto should be read in conjunction with the Company's Annual Report on Form 10-K for the year ended December 31, 2012, previously filed with the SEC.

All adjustments, consisting of normal and recurring accruals, which are, in the opinion of management, necessary to fairly state the Company's Condensed Financial Statements have been included herein. Interim results are not necessarily indicative of expected annual results because of the impact of fluctuations in prices received for oil and natural gas, as well as other factors. In the course of preparing the Condensed Financial Statements, management makes various assumptions, judgments and estimates to determine the reported amounts of assets, liabilities, revenues and expenses, and to prepare disclosures of commitments and contingencies. Changes in these assumptions, judgments and estimates will occur as a result of the passage of time and the occurrence of future events, and, accordingly, actual results could differ from amounts previously established.

The Company's cash management process provides for the daily funding of checks as they are presented to the bank. Included in accounts payable at December 31, 2012 was $14.9 million, representing outstanding checks in excess of the bank balance (book overdraft). There were no outstanding checks in excess of the bank balance at September 30, 2013.

Recent Accounting Standards

There are no material new accounting pronouncements that have been issued but not yet adopted by the Company as of September 30, 2013.

2. Acquisitions and Divestitures

2012 Acquisitions

On September 12, 2012, the Company completed the acquisition of approximately 14,000 net acres contiguous to the Company's Brundage Canyon asset in the Uinta for an aggregate purchase price of $39.6 million, including usual and customary post-closing adjustments. Disclosures of purchase price allocation and also of pro forma revenues and net earnings for this acquisition are not material and have not been presented.

On April 13, 2012, the Company completed the acquisition of approximately 2,000 net acres and one well in the Wolfberry trend in the Permian for an aggregate purchase price of $14.9 million including usual and customary post-closing adjustments. Disclosures of purchase price allocation and also of pro forma revenues and net earnings for this acquisition are not material and have not been presented.

2012 Divestiture

On December 21, 2011, the Company entered into an agreement to sell its proved developed properties in Elko, Eureka and Nye Counties, Nevada, which closed on January 31, 2012, for total cash consideration of $15.6 million. The Company recorded a $1.6 million gain in conjunction with the sale. The gain was recorded in the Condensed Statements of Operations under the caption gain on sale of assets.

3. Debt

Senior Secured Revolving Credit Facility

As of September 30, 2013, the Company's credit facility, which matures on May 13, 2016, had a borrowing base of $1.4 billion, subject to lender commitments. At September 30, 2013, lender commitments under the facility were $1.2 billion. Borrowings under the credit facility bear interest at either (i) LIBOR plus a margin between 1.50% and 2.50% or (ii) the prime rate plus a margin between 0.50% and 1.50%, in each case, based on the amount utilized. The annual commitment fee on the unused portion of the credit facility ranges between 0.35% and 0.50% based on the amount utilized.

As of September 30, 2013, there were $636.0 million in outstanding borrowings under the credit facility and $26.8 million in outstanding letters of credit, leaving $537.2 million in borrowing capacity available under the credit facility. The maximum amount available under the credit facility is subject to semi-annual redeterminations of the borrowing base in April and October of each year, based on the value of the Company's proved oil and natural gas reserves, in accordance with the lenders' customary procedures and practices. The Company and the lenders each have the right to one additional redetermination each year. On October 22, 2013, the Company entered into a Sixth Amendment to its credit facility, which amended certain terms of the credit facility. See Note 12 to the Condensed Financial Statements.

Maturity of 2014 Notes

The Company's 10.25% senior notes due 2014 (2014 Notes) are scheduled to mature on June 1, 2014. As a result, all $205.3 million aggregate principal amount of the 2014 Notes is classified as a current obligation on the Company's Condensed Balance Sheet as of September 30, 2013. The Company's ability to repay or refinance the aggregate principal amount of the 2014 Notes is subject to restrictions contained in the Merger Agreement. See Note 11 to the Condensed Financial Statements. While the Company has not yet determined how it will repay or refinance the 2014 Notes, the Company may do so through multiple methods which it may pursue separately or in combination, including (i) issuing new debt or equity securities and (ii) borrowing under the Company's credit facility. Although the Company believes it will be able to complete a refinancing transaction prior to the maturity of the 2014 Notes, if the Company is unable to complete a refinancing or otherwise repay such debt, it would be in default under the indenture governing the 2014 Notes, which would also cause the Company to be in default under its credit facility and the indentures governing its other senior notes, and would result in indebtedness outstanding under those agreements to be declared immediately due and payable.

4. Income Taxes

The effective income tax rate for the three months ended September 30, 2013 and 2012 was 37.9% and 37.8%, respectively. The effective income tax rate for the nine months ended September 30, 2013 and 2012 was 37.4% and 37.9%, respectively. The Company's provision for income taxes differed from the U.S. statutory rate of 35% primarily due to state income taxes, domestic production activities deduction, percentage depletion, nondeductible employee compensation and other permanent differences.

As of September 30, 2013, the Company had a gross liability for uncertain income tax benefits of $20.1 million, $15.0 million of which, if recognized, would impact the effective income tax rate. During the second quarter of 2013, the Company recognized a benefit of $1.9 million related to closing statutes. Consistent with the Company's policy, interest and penalties on income taxes have been recorded as a component of the income tax provision. The Company estimates that it is reasonably possible that the balance of unrecognized income tax benefits as of September 30, 2013 could decrease by a maximum of $4.8 million in the next 12 months due to the expiration of statutes of limitation and audit settlements.

5. Earnings Per Share

Basic net earnings per share is computed using the two-class method by dividing net earnings attributable to common shareholders by the weighted average shares outstanding-basic during each period. The two-class method of computing net earnings per share is required for those entities that have participating securities. The two-class method is an earnings allocation formula that determines net earnings per share for participating securities according to dividends declared (or accumulated) and participation rights in undistributed earnings. Unvested restricted shares issued under the Company's equity incentive plans prior to January 1, 2010 have the right to receive non-forfeitable dividends, participating on an equal basis with common shares, and thus are classified as participating securities. Participating securities do not have a contractual obligation to share in the Company's losses. Therefore, in periods of net loss, no portion of the loss is allocated to participating securities.

Diluted earnings per share is computed using the two-class method by dividing earnings available to common shareholders by the weighted average shares outstanding-dilutive, which includes the effect of potentially dilutive securities. Under the two-class method, potentially dilutive securities consist of non-participating securities (e.g. stock options and unvested restricted stock awards issued subsequent to January 1, 2010). No potential shares of common stock are included in the computation of any diluted per share amount when a net loss exists.

The following table shows the computation of basic and diluted net earnings per share for the three and nine months ended September 30, 2013 and 2012:

(in thousands, except per share data)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Net earnings	$ 28,178	$ 18,126	$ 121,976	$ 133,040
Less: Net earnings allocable to participating securities	72	118	265	709
Net earnings available for common shareholders	$ 28,106	$ 18,008	$ 121,711	$ 132,331
Basic net earnings per share	$ 0.51	$ 0.33	$ 2.20	$ 2.41
Diluted net earnings per share	$ 0.50	$ 0.33	$ 2.19	$ 2.39
Basic weighted average shares outstanding	55,308	54,945	55,267	54,883
Add: Dilutive effects of stock options and RSUs	370	336	384	395
Dilutive weighted average shares outstanding	55,678	55,281	55,651	55,278

Not included in the diluted earnings per share calculation were 0.4 million and 0.7 million stock options and RSUs, for the three and nine months ended September 30, 2013, respectively, because their effect would have been anti-dilutive. Not included in the diluted earnings per share calculation were 0.7 million and 0.6 million stock options and RSUs, for the three and nine months ended September 30, 2012, respectively, because their effect would have been anti-dilutive.

BERRY PETROLEUM COMPANY

Notes to Condensed Financial Statements (Continued)

(Unaudited)

6. Asset Retirement Obligations

The following table summarizes the activity for the Company's asset retirement obligations (AROs) for the nine months ended September 30, 2013 and 2012:

(in thousands)	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Beginning balance at January 1	$ 86,746	$ 64,019
Liabilities incurred	7,315	5,862
Liabilities settled	(2,589)	(2,763)
Liabilities assumed	—	2,651
Disposition of assets	(40)	(705)
Accretion expense	5,465	4,201
Revisions in estimated cash flows	5,907	10,992
Ending balance at September 30	$ 102,804	$ 84,257

ARO reflects the estimated present value of the amount of dismantlement, removal, site reclamation and similar activities associated with the Company's oil and natural gas properties. Inherent in the fair value calculation of 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 natural gas property balance.

7. Equity Incentive Compensation Plans

Stock-based compensation is measured at the grant date based on the fair value of the awards. The fair value is recognized on a straight-line basis over the requisite service period (generally the vesting period).

Total compensation cost recognized in the Condensed Statements of Operations for the grants under the Company's equity incentive compensation plans was $2.5 million and $2.0 million during the three months ended September 30, 2013 and 2012, respectively, and $8.1 million and $7.2 million during the nine months ended September 30, 2013 and 2012, respectively.

BERRY PETROLEUM COMPANY

Notes to Condensed Financial Statements (Continued)

(Unaudited)

Stock Options

The following table summarizes stock option activity for the nine months ended September 30, 2013:

	Number of Shares	Weighted Average Exercise Price	Aggregate Intrinsic Value (in thousands)(1)	Weighted Average Remaining Contractual Term (Years)
Outstanding at January 1, 2013	1,387,592	$ 33.71	$ 4,681	4.08
Granted	—	—		
Exercised	(22,350)	17.23	604	
Canceled/expired	—	—		
Outstanding at September 30, 2013	1,365,242	$ 33.98	$ 13,561	3.38
Vested and expected to vest at September 30, 2013	1,364,054	$ 33.96	$ 13,561	3.37
Exercisable at September 30, 2013	1,259,022	$ 32.53	$ 13,561	2.99

(1) The intrinsic value of a stock option is the amount by which the market value of the underlying stock at the end of the related period exceeds the exercise price of the option.

As of September 30, 2013, there were $1.8 million of total unrecognized compensation costs related to outstanding stock options. These costs are expected to be recognized over 2.5 years.

Restricted Stock Units

The following table summarizes restricted stock unit (RSU) activity for the nine months ended September 30, 2013:

	RSUs	Weighted Average Grant Date Fair Value	Vest Date Fair Value (in thousands)
Outstanding at January 1, 2013	981,877	$ 26.72	
Granted	264,033	45.27	
Issued	(182,180)	24.76	$ 7,122
Canceled/expired	(21,048)	44.81	
Outstanding at September 30, 2013(1)(2)	1,042,682	$ 31.97	

(1) The balance outstanding includes 58,036 RSUs granted to non-employee directors that are 100% vested at date of grant, but are subject to deferral elections delaying the date on which the corresponding shares are issued.
(2) The balance outstanding includes 510,967 RSUs granted to executive officers and other officers that have vested in accordance with the RSU agreement but are subject to deferral elections delaying the date on which the corresponding shares are issued.

As of September 30, 2013, there were $17.0 million of total unrecognized compensation costs related to RSUs granted. These costs are expected to be recognized over 3.5 years.

BERRY PETROLEUM COMPANY

Notes to Condensed Financial Statements (Continued)

(Unaudited)

7. Equity Incentive Compensation Plans (Continued)

Performance Share Program

The following table summarizes performance share award activity for the nine months ended September 30, 2013:

	Performance Share Awards(1)	Weighted Average Grant Date Fair Value	Vest Date Fair Value (in thousands)
Outstanding at January 1, 2013	222,587	$ 45.79	
Granted	—	—	
Issued	(64,922)	32.75	$ 2,990
Canceled/expired	(34,742)	28.32	
Outstanding at September 30, 2013	122,923	$ 57.61	

(1) For outstanding shares, reflects the maximum number of performance shares that can be issued.

As of September 30, 2013, there were $1.2 million of total unrecognized compensation costs related to performance shares granted. These costs are expected to be recognized over 1.3 years.

8. Derivative Instruments

The Company uses financial derivative instruments as part of its price risk management program to achieve a more predictable, economic cash flow from its oil production by reducing its exposure to price fluctuations. The Company has historically entered into financial commodity swap and collar contracts to fix the floor and ceiling prices received for a portion of the Company's oil and natural gas production. During the second quarter of 2012, the Company began entering into derivative contracts to fix the floor and ceiling prices paid for a portion of its natural gas consumption. The terms of the Company's derivative contracts depend on various factors, including management's view of future crude oil and natural gas prices, acquisition economics on purchased assets, future financial commitments, and other considerations. The Company periodically enters into interest rate derivative agreements to protect against changes in interest rates on its floating rate debt. The Company recognizes all gains and losses from changes in commodity derivative fair values immediately in earnings. For further discussion related to the fair value of the Company's derivatives, see Note 9 to the Condensed Financial Statements.

As of September 30, 2013, the Company had commodity derivatives associated with the following volumes:

	2013	2014	2015
Oil sales, Bbl/D	19,800	21,000	3,000
Natural gas purchases, MMBtu/D	10,000	—	—

The Company entered into the following derivative instruments during the nine months ended September 30, 2013:

Crude Oil Sales Three-Way Collars

Term	Index	Average Barrels Per Day	Sold Put / Purchased Put / Sold Call
Full year 2013 and 2014	ICE Brent	1,000	$80.00 / $100.00 / $114.05
Full year 2014	NYMEX WTI	1,000	$70.00 / $90.00 / $102.00

Crude Oil Sales (NYMEX WTI) Swaps

Term	Average Barrels Per Day	Weighted Average Price
Full year 2014	11,500	$90.14

BERRY PETROLEUM COMPANY

Notes to Condensed Financial Statements (Continued)

(Unaudited)

8. Derivative Instruments (Continued)

Crude Oil Sales (NYMEX WTI to ICE Brent) Basis Swaps		
Term	Average Barrels Per Day	Weighted Average Price
Full year 2014	10,000	$11.60
Full year 2015	8,000	$11.60

Crude Oil Sales (NYMEX WTI to Midland) Basis Swaps		
Term	Average Barrels Per Day	Weighted Average Price
April 2013 - December 2013	4,000	$1.48

In March 2012, the Company terminated certain of its natural gas derivative instruments, which were associated with a total of 15,000 MMBtu/D for the remainder of 2012. The termination resulted in a net loss of $1.9 million, including cash settlements and non-cash fair value losses, and was recorded in the Condensed Statements of Operations under the caption realized and unrealized loss (gain) on derivatives, net.

The Company routinely enters into derivative contracts with a variety of counterparties, typically resulting in individual derivative instruments with both fair value asset and liability positions. The Company nets the fair values of derivative instruments executed with the same counterparty pursuant to ISDA master agreements, which mitigate the credit risk of the Company's derivative instruments by providing for net settlement over the term of the contract and in the event of default or termination of the contract. The tables below summarize the fair value of derivative assets and liabilities and the effect of netting on the Condensed Balance Sheets:

(in millions)	September 30, 2013			
Description	Balance Sheet Classification	Gross Amounts of Recognized Assets or Liabilities	Gross Amounts Offset in the Condensed Balance Sheets	Net Amounts of Assets or Liabilities Presented in the Condensed Balance Sheets
Assets				
Commodity derivative instruments	Current	$ 21.8	$ (16.8)	$ 5.0
Commodity derivative instruments	Long-term	19.6	(2.4)	17.2
Total assets		$ 41.4	$ (19.2)	$ 22.2
Liabilities				
Commodity derivative instruments	Current	$ 25.4	$ (16.8)	$ 8.6
Commodity derivative instruments	Long-term	2.4	(2.4)	—
Total liabilities		$ 27.8	$ (19.2)	$ 8.6

8. Derivative Instruments (Continued)

(in millions)		December 31, 2012		
Description	Balance Sheet Classification	Gross Amounts of Recognized Assets or Liabilities	Gross Amounts Offset in the Condensed Balance Sheets	Net Amounts of Assets or Liabilities Presented in the Condensed Balance Sheets
Assets				
Commodity derivative instruments	Current	$ 16.4	$ (1.7)	$ 14.7
Commodity derivative instruments	Long-term	10.9	—	10.9
Total assets		$ 27.3	$ (1.7)	$ 25.6
Liabilities				
Commodity derivative instruments	Current	$ 2.8	$ (1.7)	$ 1.1
Commodity derivative instruments	Long-term	1.2	—	1.2
Total liabilities		$ 4.0	$ (1.7)	$ 2.3

The table below summarizes the location and the amount of derivative instrument losses (gains) before income taxes reported in the Condensed Statements of Operations for the periods indicated:

(in millions)		Three Months Ended September 30,		Nine Months Ended September 30,	
Description of Loss (Gain)	Location of Loss (Gain) Recognized in Earnings	2013	2012	2013	2012
Commodity					
Loss reclassified from AOCL into earnings (amortization of frozen amounts)	Oil and natural gas sales	$ —	$ 2.7	$ —	$ 7.9
Loss (gain) recognized in earnings (cash settlements and mark-to-market movements)	Realized and unrealized loss (gain) on derivatives, net	45.3	28.3	10.4	(56.3)
Interest rate					
Gain reclassified from AOCL into earnings (amortization of frozen amounts)	Interest	$ —	$ (0.3)	$ —	$ (1.8)

Credit Risk

The Company does not require collateral or other security from counterparties to support derivative instruments. However, the agreements with those counterparties typically contain netting provisions such that if a default occurs, the non-defaulting party can offset the amount payable to the defaulting party under the derivative contract with the amount due from the defaulting party. As a result of the netting provisions, the Company's maximum amount of loss due to credit risk is limited to the net amounts due to and from the counterparties under the derivative contracts. The maximum amount of loss due to credit risk that the Company would have incurred if all counterparties to its derivative contracts failed to perform at September 30, 2013 was $16.0 million.

As of September 30, 2013, the counterparties to the Company's commodity derivative contracts consist of nine financial institutions. The Company's counterparties or their affiliates are also lenders under the Company's credit facility. As a result, the counterparties to the Company's derivative agreements share in the collateral supporting the Company's credit facility. The Company is not generally required to post additional collateral under derivative agreements.

Certain of the Company's derivative agreements contain cross default provisions that require acceleration of amounts due under such agreements if the Company were to default on its obligations under its material debt agreements. In addition, if the Company were to default on certain of its material debt agreements, including its derivative agreements, the Company would be

8. Derivative Instruments (Continued)

in default under the credit facility. As of September 30, 2013, the Company was in a net liability position with one of the counterparties to the Company's derivative instruments, totaling $2.3 million. As of September 30, 2013, the Company's largest two counterparties accounted for 62% of the value of its total net derivative positions.

9. Fair Value Measurements

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

A financial instrument's categorization within the fair value hierarchy is based upon the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the classification of assets and liabilities within the fair value hierarchy. The Company recognizes transfers between levels at the end of the reporting period for which the transfer has occurred.

The fair value of all derivative instruments is estimated with industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. The fair value of all derivative instruments is estimated using a combined income and market valuation methodology based upon forward commodity price and volatility curves. The curves are obtained from independent pricing services, and the Company has made no adjustments to the obtained prices. The independent pricing services publish observable market information from multiple brokers and exchanges. All valuations were compared against counterparty valuations to verify the reasonableness of prices. The Company also considers counterparty credit risk and its own credit risk in its determination of all estimated fair values. The Company has consistently applied these valuation techniques in all periods presented and believes it has obtained the most accurate information available for the types of derivative contracts it holds.

Assets (Liabilities) Measured at Fair Value on a Recurring Basis

The following table presents information about the Company's financial assets and liabilities measured at fair value on a recurring basis as of September 30, 2013 and December 31, 2012, and indicates the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair values:

(in millions)	Total	Level 1	Level 2	Level 3
Commodity derivative asset, net				
September 30, 2013	$ 13.6	$ —	$ 13.6	$ —
December 31, 2012	$ 23.2	$ —	$ 23.2	$ —

9. Fair Value Measurements (Continued)

Fair Market Value of Financial Instruments

The Company uses various assumptions and methods in estimating the fair values of its financial instruments. The following table presents fair value information about the Company's financial instruments:

September 30, 2013	Carrying Amount	Estimated Fair Value			
(in millions)		Level 1	Level 2	Level 3	Total
Cash and cash equivalents	$ 24	$ 24	$ —	$ —	$ 24
Senior secured revolving credit facility(1)	636	—	636	—	636
10.25% Senior notes due 2014(2)	205	217	—	—	217
6.75% Senior notes due 2020	300	308	—	—	308
6.375% Senior notes due 2022	600	605	—	—	605

(1) The Company's credit facility can be repaid at any time without penalty. Interest is generally fixed for 30-day increments at the prime rate or LIBOR plus a stipulated margin for the amount utilized and at a stipulated percentage as a commitment fee for the portion not utilized. The carrying amount of the credit facility approximated fair value due to the short-term maturities of the borrowings and because the borrowings bear interest at variable market rates.

(2) Carrying amount does not include unamortized discount of $1.1 million.

December 31, 2012	Carrying Amount	Estimated Fair Value			
(in millions)		Level 1	Level 2	Level 3	Total
Cash and cash equivalents	$ —	$ —	$ —	$ —	$ —
Senior secured revolving credit facility(1)	563	—	563	—	563
10.25% Senior notes due 2014(2)	205	229	—	—	229
6.75% Senior notes due 2020	300	323	—	—	323
6.375% Senior notes due 2022	600	627	—	—	627

(1) The Company's credit facility can be repaid at any time without penalty. Interest is generally fixed for 30-day increments at the prime rate or LIBOR plus a stipulated margin for the amount utilized and at a stipulated percentage as a commitment fee for the portion not utilized. The carrying amount of the credit facility approximated fair value due to the short-term maturities of the borrowings and because the borrowings bear interest at variable market rates.

(2) Carrying amount does not include unamortized discount of $2.3 million.

10. Commitments and Contingencies

E. Texas Gathering System

In July 2009, the Company closed on the financing of its E. Texas natural gas gathering system for $18.4 million in cash. The Company entered into concurrent long-term natural gas gathering agreements for the E. Texas production which contained an embedded lease. Accordingly, the $16.7 million net book value of the property is being depreciated over the remaining useful life of the asset and the cash received of $18.4 million was recorded as a financing obligation. A portion of the payments under the agreements is recorded as gathering expense and is presented in the Condensed Financial Statements under the caption operating costs—oil and natural gas production. In addition, a portion of the payments is recorded as interest expense, and the balance of the payments is recorded as a reduction to the financing obligation. There are no minimum payments required under these agreements. For the three months ended September 30, 2013 and 2012, the Company incurred net costs of $0.5 million and $0.6 million, respectively, under the agreements. For the nine months ended September 30, 2013 and 2012, the Company incurred net costs of $1.5 million and $2.0 million, respectively, under the agreements.

Carry and Earning Agreement

In January 2011, the Company entered into an amendment relating to certain contractual obligations to a third-party co-owner of certain Piceance assets in Colorado. The amendment waives the $0.2 million penalty for each well not spud by February 2011 and requires the Company to reassign to such co-owner, by January 31, 2020, all of the interest acquired by the Company from the co-owner in each 160-acre tract in which the Company has not drilled and completed a well that is producing or capable of producing from a designated formation, or deeper formation, on January 1, 2020. The amendment also requires the Company to pay the first $9.0 million of costs incurred in connection with the construction of either an extension of the existing access road or a new access road, including the third party's 50% share. Pursuant to the terms of a further amendment effective June 2013, if by September 30, 2014, the Company does not expend $9.0 million on the construction of either the extension of the road or a new road, the Company is obligated to pay the third party 50% of the difference between $12.0 million and the actual amount expended on road construction as of such date. This deadline is subject to further extension to no later than December 31, 2014 under the terms of the amendment. Due to the need to obtain regulatory approvals, among other reasons, the Company has not yet commenced construction of either an extension of the existing access road or a new access road and may be unable to do so by the extended deadline, thus triggering the payment obligation to the third party.

Legal Matters

Department of the Interior Notice of Proposed Debarment. On June 14, 2012, the Company received a Notice of Proposed Debarment issued by the United States Department of the Interior (DOI). Pursuant to the notice, the DOI's Office of the Inspector General proposed to debar the Company from participation in certain federal contracts and assistance activities, including oil and natural gas leases, for a period of three years. The basis for the proposed debarment relates to the Company's purported noncompliance with Bureau of Land Management (BLM) regulations relating to the operation of certain equipment, and the submission of related site facility diagrams, in its Uinta operations. In 2011, the Company entered into a settlement agreement with the BLM and paid a $2.1 million civil penalty relating to the matter. The Company has contested the proposed debarment and believes the matter is without merit; nevertheless, in June 2013, the Company entered into an agreement with the DOI to resolve the matter administratively through an independent compliance review. The Company believes the compliance review will be completed during the fourth quarter of 2013.

Other. The Company is involved in various other lawsuits, claims and inquiries, most of which are routine to the nature of its business. In the opinion of management, the resolution of these matters will not have a material effect on its financial position, results of operations or operating cash flows.

Environmental Matters

The Company has no material accrued environmental liabilities for its sites, including sites in which governmental agencies have designated the Company as a potentially responsible party, because it is not probable that a loss will be incurred and the minimum cost and/or amount of loss cannot be reasonably estimated. However, due to some 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 material costs incurred.

11. LinnCo, LLC Merger

On February 20, 2013, the Company, Linn Energy, LLC (Linn), LinnCo, LLC (LinnCo), Linn Acquisition Company, LLC, a direct wholly owned subsidiary of LinnCo (LinnCo Merger Sub), Bacchus HoldCo, Inc., a direct wholly owned subsidiary of the Company (HoldCo), and Bacchus Merger Sub, Inc., a direct wholly owned subsidiary of HoldCo (Bacchus Merger Sub), entered into a definitive Agreement and Plan of Merger (the Merger Agreement), pursuant to which LinnCo agreed to acquire the Company in an all-stock transaction in which the Company's stockholders would receive 1.25 shares representing limited liability company interests in LinnCo (LinnCo Shares) for each share of the Company's common stock.

11. LinnCo, LLC Merger (Continued)

The transaction will occur through multiple steps. First, the Company will engage in a holding company merger (the HoldCo Merger) involving HoldCo and Bacchus Merger Sub. In the HoldCo Merger, Bacchus Merger Sub will merge with and into the Company, with the Company surviving as a wholly owned subsidiary of HoldCo, and each issued and outstanding share of the Company's Class A common stock and Class B common stock will convert into the right to receive one equivalent share of Class A common stock and one equivalent share of Class B common stock, respectively, of HoldCo.

Second, promptly after the HoldCo Merger, the Company will be converted into a limited liability company. Third, promptly following such conversion, HoldCo will be merged with and into LinnCo Merger Sub, with LinnCo Merger Sub surviving as the surviving company (the LinnCo Merger). In the LinnCo Merger, each share of Holdco's Class A common stock and each share of Holdco's Class B common stock will be converted into 1.25 LinnCo Shares.

Finally, promptly following the LinnCo Merger, LinnCo will contribute all of the outstanding equity interests in LinnCo Merger Sub (and therefore also its indirect ownership interest in the Company) to Linn (the Contribution) in exchange for the issuance to LinnCo (the Issuance) of newly issued Linn common units. The number of Linn common units to be issued to LinnCo in the Issuance will be equal to the greater of (i) the aggregate number of LinnCo Shares issued in the LinnCo Merger and (ii) the number of Linn common units required to cause LinnCo to own no less than one-third of all of the outstanding Linn common units following the Contribution. In addition, for three years following the closing, Linn will pay to LinnCo additional cash distributions in the amount of $6 million per year.

The closing of the transactions is subject to customary closing conditions, including approval of the Merger Agreement and the transactions contemplated thereby by the stockholders of the Company and the holders of the shares or units of LinnCo and Linn, respectively, receipt of certain opinions by the parties with respect to the tax-free nature of the transactions, and other customary conditions. The closing will not occur on or prior to October 31, 2013 (the End Date), and any of the Company, Linn, or LinnCo may unilaterally terminate the Merger Agreement after the End Date. There can be no assurances as to whether the parties will agree to extend the End Date or that the parties will refrain from exercising their rights to terminate the Merger Agreement.

On March 21, 2013, a purported stockholder class action captioned Nancy P. Assad Trust v. Berry Petroleum Co., et al. was filed in the District Court for the City and County of Denver, Colorado, No. 13-CV-31365. The action names as defendants the Company, the members of its board of directors, HoldCo, Bacchus Merger Sub, LinnCo, LINN and LinnCo Merger Sub. On April 5, 2013, an amended complaint was filed, which alleges that the individual defendants breached their fiduciary duties in connection with the transactions by engaging in an unfair sales process that resulted in an unfair price for the Company, by failing to disclose all material information regarding the transactions, and that the entity defendants aided and abetted those breaches of fiduciary duty. The amended complaint seeks a declaration that the transactions are unlawful and unenforceable, an order directing the individual defendants to comply with their fiduciary duties, an injunction against consummation of the transactions, or, in the event they are completed, rescission of the transactions, an award of fees and costs, including attorneys' and experts' fees and expenses, and other relief. On May 21, 2013, the Colorado District Court stayed and administratively closed the Nancy P. Assad Trust action in favor of the Hall action described below that is pending in the Delaware Court of Chancery. On July 19, 2013, the plaintiffs in the Nancy P. Assad Trust action voluntarily dismissed the case without prejudice.

On April 12, 2013, a purported stockholder class action captioned David Hall v. Berry Petroleum Co., et al. was filed in the Delaware Court of Chancery, C.A. No. 8476-VCG. The complaint names as defendants the Company, the members of its board of directors, HoldCo, Bacchus Merger Sub, LinnCo, LINN and LinnCo Merger Sub. The complaint alleges that the individual defendants breached their fiduciary duties in connection with the transactions by engaging in an unfair sales process that resulted in an unfair price for the Company, by failing to disclose all material information regarding the transactions, and that the entity defendants aided and abetted those breaches of fiduciary duty. The complaint seeks a declaration that the transactions are unlawful and unenforceable, an order directing the individual defendants to comply with their fiduciary duties, an injunction against consummation of the transactions, or, in the event they are completed, rescission of the transactions, an award of fees and costs, including attorneys' and experts' fees and expenses, and other relief. The Company is unable to estimate a possible loss, or range of possible losses, if any, at this time. The Company believes the claims relating to the merger are without merit, and intends to defend such actions vigorously.

12. Subsequent Event

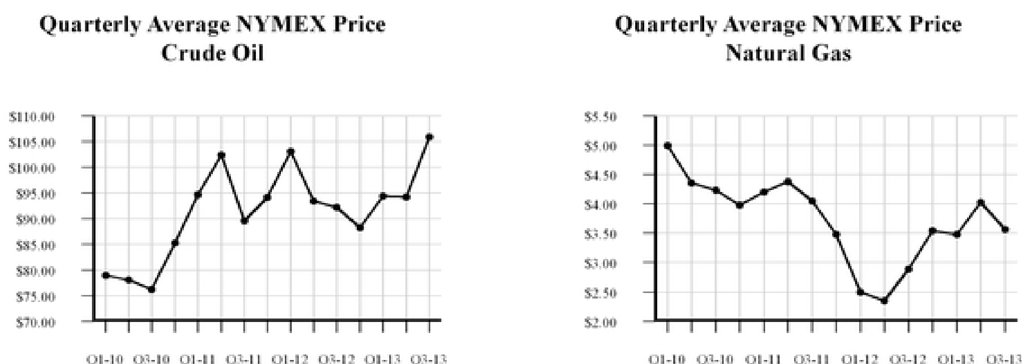
Credit Facility Amendment

On October 22, 2013, as part of the semi-annual borrowing base redetermination process, the Company entered into the Sixth Amendment to its Second Amended and Restated Credit Agreement by and among the Company, Wells Fargo Bank, N.A., as administrative agent, and the lenders party thereto (the Sixth Amendment). Among other things, the Sixth Amendment eliminates the requirement that the maturity date for borrowings under the Company's credit facility would be accelerated to February 28, 2014 if the Company's 2014 Notes have not been refinanced by such date. In addition, the Sixth Amendment eliminates the leverage and pro forma liquidity tests that the Company would otherwise be required to meet under the credit facility in order to refinance the 2014 Notes. The amendment did not result in any changes to the Company's borrowing base or lender commitments under the credit facility.

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

The following is management's discussion and analysis of certain significant factors that have affected aspects of our financial position and the results of operations during the periods included in the accompanying Condensed Financial Statements. The following discussion and analysis should be read in conjunction with the discussion under "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the audited Financial Statements for the year ended December 31, 2012, included in our Annual Report on Form 10-K and the Condensed Financial Statements included elsewhere herein.

Our revenue, profitability and future growth rate depend on many factors beyond our control, such as economic, political and regulatory developments and competition from other sources of energy. Oil and natural gas prices have been volatile and may fluctuate widely in the future. The following charts highlight the quarterly average NYMEX price trends for crude oil and natural gas since the first quarter of 2010:



Lower oil and natural gas prices may not only decrease our revenues, but may also reduce the amount of oil and natural gas that we can produce economically and therefore potentially lower our oil and natural gas reserves. A substantial or extended decline in oil or natural gas prices may result in impairments of our proved oil and natural gas properties and may materially and adversely affect our future business, financial condition, results of operations, operating cash flows, liquidity or ability to finance planned capital expenditures. Lower oil and natural gas prices may also reduce the amount of our borrowing base under our credit agreement, which is determined at the discretion of the lenders and is based on the collateral value of our proved reserves that have been mortgaged to the lenders. Alternatively, higher oil prices may result in significant non-cash fair value losses being incurred on our oil derivatives, which could cause us to experience net losses when prices rise.

Steam costs are a significant variable component of our operating costs and fluctuate based on the amount of steam we inject and the price of natural gas used to generate steam. We benefit from lower natural gas prices as a consumer of natural gas in our California operations. In the Permian, Uinta, E. Texas and Piceance, we benefit from higher natural gas pricing as a producer of natural gas. In addition, production rates, labor and equipment costs, maintenance expenses and production taxes influence our operating costs. Our results of operations may fluctuate from period to period based on such factors.

LinnCo, LLC Merger

On February 20, 2013, the Company, Linn Energy, LLC (Linn), LinnCo, LLC (LinnCo), Linn Acquisition Company, LLC, a direct wholly owned subsidiary of LinnCo (LinnCo Merger Sub), Bacchus HoldCo, Inc., a direct wholly owned subsidiary of the Company (HoldCo), and Bacchus Merger Sub, Inc., a direct wholly owned subsidiary of HoldCo (Bacchus Merger Sub), entered into a definitive Agreement and Plan of Merger (the Merger Agreement), pursuant to which LinnCo agreed to acquire the Company in an all-stock transaction in which the Company's stockholders would receive 1.25 shares representing limited liability company interests in LinnCo (LinnCo Shares) for each share of the Company's common stock.

The transaction will occur through multiple steps. First, the Company will engage in a holding company merger (the HoldCo Merger) involving HoldCo and Bacchus Merger Sub. In the HoldCo Merger, Bacchus Merger Sub will merge with and into the Company, with the Company surviving as a wholly owned subsidiary of HoldCo, and each issued and outstanding share of the Company's Class A common stock and Class B common stock will convert into the right to receive one equivalent share of Class A common stock and one equivalent share of Class B common stock, respectively, of HoldCo.

Second, promptly after the HoldCo Merger, the Company will be converted into a limited liability company. Third, promptly following such conversion, HoldCo will be merged with and into LinnCo Merger Sub, with LinnCo Merger Sub surviving as the surviving company (the LinnCo Merger). In the LinnCo Merger, each share of Holdco's Class A common stock and each share of Holdco's Class B common stock will be converted into 1.25 LinnCo Shares.

Finally, promptly following the LinnCo Merger, LinnCo will contribute all of the outstanding equity interests in LinnCo Merger Sub (and therefore also its indirect ownership interest in the Company) to Linn (the Contribution) in exchange for the issuance to LinnCo (the Issuance) of newly issued Linn common units. The number of Linn common units to be issued to LinnCo in the Issuance will be equal to the greater of (i) the aggregate number of LinnCo Shares issued in the LinnCo Merger and (ii) the number of Linn common units required to cause LinnCo to own no less than one-third of all of the outstanding Linn common units following the Contribution. In addition, for three years following the closing, Linn will pay to LinnCo additional cash distributions in the amount of $6 million per year.

Following the execution of the Merger Agreement, the Company entered into certain derivative transactions with respect to our production. See Item 3. Quantitative and Qualitative Disclosures About Market Risk for additional information.

The closing of the transactions is subject to customary closing conditions, including approval of the Merger Agreement and the transactions contemplated thereby by the stockholders of the Company and the holders of the shares or units of LinnCo and Linn, respectively, receipt of certain opinions by the parties with respect to the tax-free nature of the transactions, and other customary conditions. The closing will not occur on or prior to October 31, 2013 (the End Date), and any of the Company, Linn, or LinnCo may unilaterally terminate the Merger Agreement after the End Date. There can be no assurances as to whether the parties will agree to extend the End Date or that the parties will refrain from exercising their rights to terminate the Merger Agreement.

On March 21, 2013, a purported stockholder class action captioned Nancy P. Assad Trust v. Berry Petroleum Co., et al. was filed in the District Court for the City and County of Denver, Colorado, No. 13-CV-31365. The action names as defendants the Company, the members of its board of directors, HoldCo, Bacchus Merger Sub, LinnCo, LINN and LinnCo Merger Sub. On April 5, 2013, an amended complaint was filed, which alleges that the individual defendants breached their fiduciary duties in connection with the transactions by engaging in an unfair sales process that resulted in an unfair price for the Company, by failing to disclose all material information regarding the transactions, and that the entity defendants aided and abetted those breaches of fiduciary duty. The amended complaint seeks a declaration that the transactions are unlawful and unenforceable, an order directing the individual defendants to comply with their fiduciary duties, an injunction against consummation of the transactions, or, in the event they are completed, rescission of the transactions, an award of fees and costs, including attorneys' and experts' fees and expenses, and other relief. On May 21, 2013, the Colorado District Court stayed and administratively closed the Nancy P. Assad Trust action in favor of the Hall action described below that is pending in the Delaware Court of Chancery. On July 19, 2013, the plaintiffs in the Nancy P. Assad Trust action voluntarily dismissed the case without prejudice.

On April 12, 2013, a purported stockholder class action captioned David Hall v. Berry Petroleum Co., et al. was filed in the Delaware Court of Chancery, C.A. No. 8476-VCG. The complaint names as defendants the Company, the members of its board of directors, HoldCo, Bacchus Merger Sub, LinnCo, LINN and LinnCo Merger Sub. The complaint alleges that the individual defendants breached their fiduciary duties in connection with the transactions by engaging in an unfair sales process that resulted in an unfair price for the Company, by failing to disclose all material information regarding the transactions, and that the entity defendants aided and abetted those breaches of fiduciary duty. The complaint seeks a declaration that the transactions are unlawful and unenforceable, an order directing the individual defendants to comply with their fiduciary duties, an injunction against consummation of the transactions, or, in the event they are completed, rescission of the transactions, an award of fees and costs, including attorneys' and experts' fees and expenses, and other relief. The Company is unable to estimate a possible loss, or range of possible loss, if any, at this time. The Company believes the claims relating to the merger are without merit, and intends to defend such actions vigorously.

Notable Third Quarter 2013 Items

- Generated discretionary cash flow of $172.9 million from production of 41,413 BOE/D, of which 80% was oil(1)
- Generated an operating margin of $51.45 per BOE(1)
- Increased total production and oil production by 5% from the second quarter of 2013
- Increased total production by 14% and oil production by 20% from the third quarter of 2012
- Diatomite production averaged 5,260 BOE/D, an 11% increase from the second quarter of 2013
- Production from our North Midway-Sunset—New Steam Floods (NMWSS—NSF) properties, which include McKittrick, averaged 3,290 BOE/D, a 24% increase from the second quarter of 2013
- Uinta production averaged 8,055 BOE/D, a 10% increase from the second quarter of 2013
- Drilled 35 Diatomite wells, 32 Uinta wells, 11 Permian wells and 18 South Midway-Sunset—Steam Floods (SMWSS—Steam Floods) wells

Notable Items and Expectations for the Fourth Quarter and Full Year 2013

- Expect to drill approximately 35 Diatomite wells, 19 NMWSS—NSF steam injection wells, 36 Uinta wells and ten Permian wells during the fourth quarter of 2013
- Expect full-year 2013 development capital of approximately $600 million
- Expect full-year 2013 production of between 40,500 and 40,800 BOE/D, comprised of approximately 80% oil

---

(1) Discretionary cash flow and operating margin are considered non-GAAP measures and reference should be made to "Reconciliation of Non-GAAP Measures" for further explanation as well as reconciliations to the most directly comparable GAAP measures.

Results of Operations.

In the third quarter of 2013, we reported net earnings of $28.2 million, or $0.50 per diluted share, and net cash provided by operating activities of $173.3 million. Net earnings in the third quarter of 2013 included a loss on derivatives of $24.6 million, net of income taxes, resulting from non-cash changes in fair values. For the first nine months of 2013, we reported net earnings of $122.0 million, or $2.19 per diluted share, and net cash provided by operating activities of $405.3 million. Net earnings for the first nine months of 2013 included a loss on derivatives of $6.0 million resulting from non-cash changes in fair values, lease write offs of $1.5 million and professional fees of $1.6 million associated with the pending LinnCo merger, in each case net of income taxes.

Operating Data.

The following table sets forth selected operating data for the three months ended:

	September 30, 2013	%	September 30, 2012	%	June 30, 2013	%
Heavy oil production (BOE/D)	20,824	50	18,149	50	19,775	50
Light oil production (BOE/D)	12,173	30	9,344	26	11,681	30
Total oil production (BOE/D)	32,997	80	27,493	76	31,456	80
Natural gas production (Mcf/D)	50,494	20	52,758	24	48,436	20
Total (BOE/D)(1)	41,413	100	36,286	100	39,529	100
Oil and natural gas, per BOE:						
Average realized sales price	$ 79.83		$ 70.22		$ 74.91	
Average sales price including cash derivative settlements	$ 78.34		$ 71.45		$ 75.58	
Oil, per BOE:						
Average WTI price	$ 105.81		$ 92.20		$ 94.17	
Price sensitive royalties(2)	(2.59)		(3.12)		(2.64)	
Location differential and other(3)	(8.75)		(0.68)		(4.00)	
Oil derivatives non-cash amortization(4)	—		(1.10)		—	
Oil revenue	$ 94.47		$ 87.30		$ 87.53	
Add: Oil derivatives non-cash amortization(4)	—		1.10		—	
Oil derivative cash settlements(5)	(1.88)		0.64		0.70	
Average realized oil price	$ 92.59		$ 89.04		$ 88.23	
Natural gas price:						
Average Henry Hub price per MMBtu	$ 3.58		$ 2.80		$ 4.10	
Conversion to Mcf	0.25		0.19		0.28	
Natural gas derivatives non-cash amortization(4)	—		0.02		—	
Location differential and other	(0.18)		(0.13)		(0.29)	
Natural gas revenue per Mcf	$ 3.65		$ 2.88		$ 4.09	
Add: Natural gas derivatives non-cash amortization(4)	—		(0.02)		—	
Natural gas derivative cash settlements(5)	0.02		(0.04)		0.09	
Average realized natural gas price per Mcf	$ 3.67		$ 2.82		$ 4.18	

(1) Oil equivalents are determined using the ratio of six Mcf of natural gas to one barrel of oil.
(2) Our Formax property in SMWSS—Steam Floods is subject to a price-sensitive royalty burden. The royalty is 53% of the amount of the heavy oil posted price above the 2013 base price of $17.78 per barrel as long as we maintain a minimum steam injection level. We met the steam injection level in the third quarter of 2013 and expect to meet the requirement going forward. The base price escalates at 2% annually and will be $18.14 in 2014.
(3) In California, the per barrel oil posting differential at September 30, 2013 was ($3.99), ranged from $1.58 to ($3.99) during the third quarter of 2013 and averaged ($2.38) during the third quarter of 2013. In Utah, the per barrel oil posting differential during the third quarter of 2013 was ($16.50).
(4) Non-cash amortization of accumulated other comprehensive loss (AOCL) resulting from discontinuing hedge accounting effective January 1, 2010. Recorded in the Condensed Statements of Operations under the caption oil and natural gas sales. At December 31, 2012, the entire balance of AOCL had been reclassified into earnings.
(5) Cash settlements on derivatives are recorded in the Condensed Statements of Operations under the caption realized and unrealized loss (gain) on derivatives, net.

Table of Contents

The following table sets forth selected operating data for the nine months ended:

	September 30, 2013	%	September 30, 2012	%
Heavy oil production (BOE/D)	20,060	50	17,519	50
Light oil production (BOE/D)	11,816	29	8,781	24
Total oil production (BOE/D)	31,876	79	26,300	74
Natural gas production (Mcf/D)	50,018	21	54,372	26
Total (BOE/D)(1)	40,212	100	35,362	100
Oil and natural gas, per BOE:				
Average realized sales price	$ 76.73		$ 71.18	
Average sales price including cash derivative settlements	$ 76.66		$ 72.08	
Oil, per BOE:				
Average WTI price	$ 98.20		$ 96.16	
Price sensitive royalties(2)	(2.68)		(3.62)	
Location differential and other(3)	(4.69)		(1.00)	
Oil derivatives non-cash amortization(4)	—		(1.12)	
Oil revenue	$ 90.83		$ 90.42	
Add: Oil derivatives non-cash amortization(4)	—		1.12	
Oil derivative cash settlements(5)	(0.14)		(0.50)	
Average realized oil price	$ 90.69		$ 91.04	
Natural gas price:				
Average Henry Hub price per MMBtu	$ 3.67		$ 2.58	
Conversion to Mcf	0.26		0.17	
Natural gas derivatives non-cash amortization(4)	—		0.01	
Location differential and other	(0.20)		(0.18)	
Natural gas revenue per Mcf	$ 3.73		$ 2.58	
Add: Natural gas derivatives non-cash amortization(4)	—		(0.01)	
Natural gas derivative cash settlements(5)	0.03		0.29	
Average realized natural gas price per Mcf	$ 3.76		$ 2.86	

(1) Oil equivalents are determined using the ratio of six Mcf of natural gas to one barrel of oil.

(2) Our Formax property in SMWSS—Steam Floods is subject to a price-sensitive royalty burden. The royalty is 53% of the amount of the heavy oil posted price above the 2013 base price of $17.78 per barrel as long as we maintain a minimum steam injection level. We met the steam injection level in the third quarter of 2013 and expect to meet the requirement going forward. The base price escalates at 2% annually and will be $18.14 in 2014.

(3) In California, the per barrel oil posting differential at September 30, 2013 was ($3.99), ranged from $11.02 to ($3.99) during the first nine months of 2013 and averaged $4.16 during the first nine months of 2013. In Utah, the per barrel oil posting differential at September 30, 2013 was ($16.50), ranged from ($14.50) to ($16.50) during the first nine months of 2013 and averaged ($16.23) during the first nine months of 2013.

(4) Non-cash amortization of AOCL resulting from discontinuing hedge accounting effective January 1, 2010. Recorded in the Condensed Statements of Operations under the caption oil and natural gas sales. At December 31, 2012, the entire balance of AOCL had been reclassified into earnings.

(5) Cash settlements on derivatives are recorded in the Condensed Statements of Operations under the caption realized and unrealized loss (gain) on derivatives, net.

The following table sets forth results of operations (in thousands except per share data) for the three month periods ended:

	September 30, 2013	September 30, 2012	3Q12 to 3Q13 Change	June 30, 2013	2Q13 to 3Q13 Change
Oil sales	$ 289,217	$ 218,952	32 %	$ 256,682	13 %
Natural gas sales	16,966	13,964	21 %	18,033	(6)%
Total oil and natural gas sales	$ 306,183	$ 232,916	31 %	$ 274,715	11 %
Electricity sales	10,046	9,514	6 %	9,513	6 %
Natural gas marketing	1,916	1,939	(1)%	2,255	(15)%
Gain on sale of assets	—	170	(100)%	—	— %
Interest and other income, net	249	286	(13)%	374	(33)%
Total revenues and other income	$ 318,394	$ 244,825	30 %	$ 286,857	11 %
Net earnings	$ 28,178	$ 18,126	55 %	$ 61,364	(54)%
Diluted earnings per share	$ 0.50	$ 0.33	52 %	$ 1.10	(55)%

The following table sets forth results of operations (in thousands except per share data) for the nine month periods ended:

	September 30, 2013	September 30, 2012	% Change
Oil sales	$ 796,676	$ 649,922	23 %
Natural gas sales	50,994	38,428	33 %
Total oil and natural gas sales	$ 847,670	$ 688,350	23 %
Electricity sales	27,148	21,354	27 %
Natural gas marketing	6,198	5,378	15 %
Gain on sale of assets	23	1,770	(99)%
Interest and other income, net	1,098	1,678	(35)%
Total revenues and other income	$ 882,137	$ 718,530	23 %
Net earnings	$ 121,976	$ 133,040	(8)%
Diluted earnings per share	$ 2.19	$ 2.39	(8)%

Oil and Natural Gas Sales.

Oil and natural gas sales increased $73.3 million, or 31%, to $306.2 million in the third quarter of 2013 compared to the same period in 2012. The increase was primarily due to an increase in oil sales volumes between periods. Our oil sales volumes increased 22% in the third quarter of 2013 compared to the same period in 2012, while our natural gas sales volumes decreased 4%. The oil sales volume increase was primarily due to increased oil production from all of our oil properties with the exception of SMWSS—Steam Floods, which declined marginally as expected. Diatomite oil production in the third quarter of 2013 increased 1,760 BOE/D, or 50%, Uinta oil production increased 1,555 BOE/D, or 44%, NMWSS—NSF oil production increased 1,365 BOE/D, or 71%, and Permian oil production increased 1,345 BOE/D, or 24%, in each case compared to the same period in 2012. The decrease in natural gas sales volumes was primarily due to expected production declines from our E. Texas and Piceance properties, partially offset by increased natural gas production from our other natural gas producing properties. In addition to increased oil production, a 14% increase in the average realized sales price, largely due to an 8% increase in realized oil prices and a 27% increase in realized natural gas prices, contributed to the increase in oil and natural gas sales in the third quarter of 2013 from the third quarter of 2012.

Oil and natural gas sales increased $31.5 million, or 11%, to $306.2 million in the third quarter of 2013 compared to the second quarter of 2013. The increase was primarily due to a 7% increase in the average realized sales price between periods, largely due to an 8% increase in the average realized oil price. In addition, our oil sales volumes increased 4% between periods primarily due to increased oil production from all of our oil properties with the exception of SMWSS—Steam Floods, which declined marginally as expected. NMWSS—NSF oil production in the third quarter of 2013 increased 640 BOE/D, or 24%, Diatomite oil production increased 530 BOE/D, or 11%, Permian oil production increased 360 BOE/D, or 5%, and Uinta oil

production increased 165 BOE/D, or 3%, in each case compared to the second quarter of 2013. The decrease in natural gas sales volumes was primarily due to expected field decline in E. Texas and the Piceance.

Oil and natural gas sales increased $159.3 million, or 23%, to $847.7 million in the nine months ended September 30, 2013 compared to the same period in 2012. The increase was primarily due to a 22% increase in the oil sales volume between periods, while our natural gas sales volumes decreased 8%. The oil sales volume increase was primarily due to increased oil production from all of our oil properties with the exception of SMWSS—Steam Floods, which declined marginally as expected. Diatomite oil production in the nine months ended September 30, 2013 increased 1,655 BOE/D, or 54%, Uinta oil production increased 1,580 BOE/D, or 48%, Permian oil production increased 1,535 BOE/D, or 29%, and NMWSS—NSF oil production increased 1,040 BOE/D, or 60%, in each case compared to the same period in 2012. The decrease in natural gas sales volumes was primarily due to expected production declines from our E. Texas and Piceance properties, partially offset by increased natural gas production from our other properties. In addition to increased oil production, an 8% increase in the average sales price, primarily due to a 45% increase in realized natural gas prices contributed to the increase in oil and natural gas sales in the nine months ended September 30, 2013 from the same period in 2012.

Electricity Sales.

The following table sets forth selected results of operations for the periods ended:

	Three Months Ended			Nine Months Ended	
	September 30, 2013	September 30, 2012	June 30, 2013	September 30, 2013	September 30, 2012
Electricity					
Electricity sales (in thousands)	$ 10,046	$ 9,514	$ 9,513	$ 27,148	$ 21,354
Operating costs—electricity generation (in thousands)	$ 5,401	$ 4,727	$ 6,337	$ 17,034	$ 14,000
Electric power produced (MWh/D)	1,793	2,146	1,957	1,922	2,099
Electric power sold (MWh/D)	1,720	1,939	1,772	1,781	1,919
Average sales price per MWh	$ 63.30	$ 53.34	$ 58.98	$ 55.52	$ 40.62
Fuel gas cost per MMBtu (including transportation)	$ 3.60	$ 2.97	$ 3.95	$ 3.70	$ 2.68
Estimated natural gas volumes consumed to produce electricity (MMBtu/D)(1)	13,192	15,417	14,612	14,181	15,187

(1) Estimate is based on the historical allocation of fuel costs to electricity.

Electricity sales in the third quarter of 2013 increased 6% compared to the third quarter of 2012 primarily due to a 19% increase in the average sales price of electricity, partially offset by an 11% decrease in electric power sold. Electricity operating costs in the third quarter of 2013 increased 14% compared to the third quarter of 2012 largely due to a 21% increase in fuel gas cost, partially offset by a 16% decrease in electric power produced primarily due to with the shut down of one of our three cogeneration facilities for unscheduled maintenance in August and September 2013.

Electricity sales in the third quarter of 2013 increased 6% compared to the second quarter of 2013, primarily due to a 7% increase in the average sales price of electricity partially offset by a 3% decrease in electric power sold. Electricity operating costs in the third quarter of 2013 decreased 15% compared to the second quarter of 2013 due to a 9% decrease in fuel gas cost and an 8% decrease in electric power produced, primarily due to the shut down of one of our three cogeneration facilities for unscheduled maintenance in August and September 2013.

Electricity sales in the nine months ended September 30, 2013 increased 27% compared to the nine months ended September 30, 2012 primarily due to a 37% increase in the average sales price of electricity, partially offset by a 7% decrease in electric power sold. Electricity operating costs in the nine months ended September 30, 2013 increased 22% compared to the nine months ended September 30, 2012 primarily due to a 38% increase in fuel gas cost, partially offset by an 8% decrease in electric power produced.

Electricity Sales Contracts. We sell electricity produced by our cogeneration facilities under long-term contracts approved by the California Public Utilities Commission (CPUC) to two California investor owned utilities (IOUs): Southern California Edison Company (Edison) and Pacific Gas and Electric Company (PG&E). Under these power purchase agreements (PPAs), we are paid an energy payment that reflects the utility's Short Run Avoided Cost (SRAC) of energy plus a capacity payment that reflects a recovery of capital expenditures that would otherwise have been made by the utility. Beginning in 2015, the energy prices we will be paid under the contracts for our Cogen 18 and Cogen 38 facilities will be based on market prices for electricity in California.

Our legacy PPAs for our Cogen 42 facilities expired in May 2012, at which time a transition PPA with Edison became effective. The transition PPA will terminate on July 1, 2014, upon the effectiveness of a seven-year contract for our Cogen 42 facilities pursuant to a competitive solicitation (the RFO PPA).

Our legacy PPA for our Cogen 38 facility expired in March 2012, at which time a transition PPA with PG&E became effective. We intend to participate in future competitive solicitations for the sale of energy and capacity from our Cogen 38 facility, although there is no assurance we will be successful in entering into a new RFO PPA for this facility. Our transition PPA with PG&E will remain in effect until June 2015.

Our legacy PPA with PG&E for our Cogen 18 facility terminated on September 30, 2012 and was replaced with a new Public Utilities Regulatory Policy Act of 1978, as amended (PURPA) PPA with PG&E, effective October 1, 2012, for a term of seven years. Because the rated capacity of our Cogen 18 facility is less than 20 MW, it continues to be eligible for PPAs pursuant to PURPA.

Under the PURPA PPA for our Cogen 18 facility and the transition PPAs for our Cogen 38 and Cogen 42 facilities, we will be paid the CPUC-determined SRAC energy price and a combination of firm and "as-available" capacity payments. Under the RFO PPA for our Cogen 42 facility, we will be paid a negotiated energy and capacity price stipulated in the contract.

The following table summarizes our cogeneration facilities and related contract information as of September 30, 2013:

Facility	Type of Contract	Purchaser	Contract Expiration
Cogen 42	Transition	Edison	Jul 2014(1)
Cogen 18	PURPA	PG&E	Sept 2019
Cogen 38	Transition	PG&E	Jun 2015(2)

(1) A new seven-year RFO PPA with Edison will be effective on July 1, 2014.
(2) We anticipate the current contract will be replaced by a long-term contract with a term of up to seven years pursuant to a future competitive solicitation.

Natural Gas Marketing.

We have long-term firm transportation contracts on the Rockies Express, Wyoming Interstate Company, and Ruby pipelines, each with a total average capacity of 35,000 MMBtu/D. Demand charges for our capacity are reflected in operating costs—oil and natural gas production in our Condensed Statements of Operations. Our current production is insufficient to fully utilize this capacity. To optimize our remaining capacity, we purchase third-party natural gas at the market rate in our producing areas and utilize FERC-approved asset management agreements. Sales and purchases of third-party natural gas are recorded under natural gas marketing in the revenues and expenses sections of the Condensed Statements of Operations, respectively. The pre-tax net earnings of natural gas marketing operations for the three months ended September 30, 2013 and 2012 were $0.0 million and $0.2 million, respectively. The pre-tax net earnings of natural gas marketing operations for the nine months ended September 30, 2013 and 2012 was $0.2 million and $0.5 million, respectively.

Gain on Sale of Assets.

In the third quarter of 2012, we recorded a $0.2 million gain in conjunction with the sale of our three drilling rigs, which had previously been impaired and recorded at fair value less cost to sell. In the first quarter of 2012, we recorded a $1.6 million gain in conjunction with the sale of our Nevada Assets. These gains were recorded in the Condensed Statements of Operations under the caption gain on sale of assets.

Oil and Natural Gas Operating and Other Expenses.

The following table sets forth our operating expenses for the three months ended:

	Amount Per BOE			Amount (in thousands)		
	September 30, 2013	September 30, 2012	June 30, 2013	September 30, 2013	September 30, 2012	June 30, 2013
Operating costs—oil and natural gas production(1)	$ 23.99	$ 21.17	$ 25.37	$ 91,416	$ 70,670	$ 91,277
Production taxes	2.90	2.91	3.06	11,060	9,700	11,004
DD&A—oil and natural gas production	19.16	17.64	19.42	73,011	58,887	69,839
General and administrative	4.68	5.32	5.40	17,834	17,767	19,430
Interest expense	6.56	6.16	6.92	24,996	20,572	24,879
Total	$ 57.29	$ 53.20	$ 60.17	$ 218,317	$ 177,596	$ 216,429

(1) Operating costs—oil and natural gas production includes firm transportation costs of $8.7 million and $7.4 million for the three months ended September 30, 2013 and 2012, respectively, and $8.3 million for the three months ended June 30, 2013.

- Operating costs—oil and natural gas production in the third quarter of 2013 were $91.4 million, or $23.99 per BOE, compared to $70.7 million, or $21.17 per BOE, in the third quarter of 2012 and $91.3 million, or $25.37 per BOE, in the second quarter of 2013. The increase in the third quarter of 2013 compared to the third quarter of 2012 was primarily due to an increase of approximately $13.5 million in steam costs, largely due to a 21% increase in the price of natural gas used in steam generation and a 28% increase in the volume of natural gas used in steam generation. In addition, $3.6 million of emissions expense related to California greenhouse gas regulatory compliance in the third quarter of 2013 contributed to the increase in steam costs between periods.

The increase in operating costs—oil and natural gas production in the third quarter of 2013 compared to the second quarter of 2013 was primarily due to a $4.6 million increase in steam costs, largely due to a 7% increase in fuel consumed in steam generation, partially offset by a 9% decrease in the price of natural gas used in steam generation. Increases in operating costs—oil and natural gas production were partially offset by reductions in well workover activity, primarily in the Permian.

The following table sets forth information relating to steam injection for the three months ended:

	September 30, 2013	September 30, 2012	3Q12 to 3Q13 Change	June 30, 2013	2Q13 to 3Q13 Change
Average net volume of steam injected (Bbl/D)	198,774	178,545	11%	190,085	5 %
Fuel gas cost per MMBtu (including transportation)	$ 3.60	$ 2.97	21%	$ 3.95	(9)%
Approximate net fuel gas volume consumed in steam generation (MMBtu/D)	70,040	54,911	28%	65,313	7 %

- Production taxes in the third quarter of 2013 were $11.1 million, or $2.90 per BOE, compared to $9.7 million, or $2.91 per BOE, in the third quarter of 2012 and $11.0 million, or $3.06 per BOE, in the second quarter of 2013. Our production taxes are comprised of both ad valorem taxes and severance taxes. Ad valorem tax is a property tax based on the assessed value of our reserves, well equipment and facilities, and may vary with changes in assessed values or tax rates. Severance tax is a production tax based on the volume of oil and natural gas production, and may vary with changes in production volumes, commodity sales prices and severance tax rates or exemptions. The following table sets forth ad valorem and severance taxes for the three months ended:

	Amount Per BOE			Amount (in thousands)		
	September 30, 2013	September 30, 2012	June 30, 2013	September 30, 2013	September 30, 2012	June 30, 2013
Ad valorem taxes	$ 1.54	$ 1.80	$ 1.86	$ 5,870	$ 5,999	$ 6,687
Severance taxes	1.36	1.11	1.20	5,190	3,701	4,317
Total production taxes	$ 2.90	$ 2.91	$ 3.06	$ 11,060	$ 9,700	$ 11,004

The decrease in ad valorem taxes in the third quarter of 2013 compared to the second quarter of 2013 was primarily due to decreases in assessed values stemming from successful appraisal disputes in the Permian and Uinta. The increase in severance taxes per BOE in the third quarter of 2013 compared to the third quarter of 2012 was due to an increase in the average realized sales price and a shift in Utah production toward tribal properties, which are subject to higher severance tax rates. The increase in severance taxes per BOE in the third quarter of 2013 compared to the second quarter of 2013 was primarily due an increase in the average realized sales price between periods.

- Depreciation, depletion and amortization—oil and natural gas production (DD&A—oil and natural gas production) in the third quarter of 2013 was $73.0 million, or $19.16 per BOE, compared to $58.9 million, or $17.64 per BOE, in the third quarter of 2012 and $69.8 million, or $19.42 per BOE, in the second quarter of 2013. The increase in the third quarter of 2013 compared to the third quarter of 2012 was primarily due to an increase in our DD&A—oil and natural gas production rate per BOE (DD&A rate). Our DD&A rate can fluctuate as a result of changes in the mix of our production, impairments, acquisition and development expenditures and changes in our proved reserves. Our DD&A rate in the third quarter of 2013 was 9% higher than the third quarter of 2012, primarily due to our development expenditures during the past twelve months, which were partially offset by reserve additions, and the increased contribution of our development properties with higher drilling and leasehold acquisition costs than our legacy California properties. The increase in DD&A expense in the third quarter of 2013 compared to the second quarter of 2013 was primarily due to increased production during the third quarter of 2013.

- General and administrative expense (G&A) in the third quarter of 2013 was $17.8 million, or $4.68 per BOE, compared to $17.8 million, or $5.32 per BOE, in the third quarter of 2012 and $19.4 million, or $5.40 per BOE, in the second quarter of 2013. The increase in the third quarter of 2013 compared to the third quarter of 2012 was primarily due to an increase in employee benefits resulting from new personnel hired during the previous twelve months, as well as an increase in consulting costs. These increases were offset by decreases in employee travel, employee relocation, legal fees and accounting costs. The decrease in the third quarter of 2013 compared to the second quarter of 2013 was primarily due to a decrease in employee insurance costs during the third quarter and $0.4 million recorded in the second quarter of 2013 related to professional fees associated with the pending LinnCo merger. These decreases in the third quarter compared to the second quarter of 2013 were partially offset by an increase in consulting costs between periods.

- The following table sets forth components of interest expense for the three months ended:

(in thousands)	September 30, 2013	September 30, 2012	June 30, 2013
Senior notes	$ 19,885	$ 19,904	$ 19,884
Credit facility	4,477	3,247	4,588
Amortization of debt issuance costs and net discount	1,759	1,662	1,729
Amortization of AOCL	—	(221)	—
Other	403	234	329
Capitalized interest	(1,528)	(4,254)	(1,651)
	$ 24,996	$ 20,572	$ 24,879

Interest expense in the third quarter of 2013 was $25.0 million, or $6.56 per BOE, compared to $20.6 million, or $6.16 per BOE, in the third quarter of 2012 and $24.9 million, or $6.92 per BOE, in the second quarter of 2013. The increase in the third quarter of 2013 compared to the third quarter of 2012 was primarily due to a decrease in capitalized interest and an increase in the amount outstanding under our credit facility.

The following table sets forth our operating expenses for the nine months ended:

	Amount Per BOE		Amount (in thousands)	
	September 30, 2013	September 30, 2012	September 30, 2013	September 30, 2012
Operating costs—oil and natural gas production(1)	$ 24.49	$ 19.33	$ 268,841	$ 187,318
Production taxes	2.99	3.10	32,848	30,048
DD&A—oil and natural gas production	19.21	16.40	210,934	158,869
General and administrative	5.42	5.52	59,542	53,473
Interest expense	6.79	6.34	74,562	61,446
Total	$ 58.90	$ 50.69	$ 646,727	$ 491,154

(1) Operating costs—oil and natural gas production includes firm transportation costs of $24.7 million and $21.5 million for the nine months ended September 30, 2013 and 2012, respectively.

- Operating costs in the nine months ended September 30, 2013 were $268.8 million, or $24.49 per BOE, compared to $187.3 million, or $19.33 per BOE, in the nine months ended September 30, 2012. The increase was primarily due to an increase of approximately $43.7 million in steam costs, largely related to a 38% increase in the price of natural gas used in steam generation and a 29% increase in the volume of natural gas used in steam generation. In addition, $10.0 million of emissions expense related to California greenhouse gas regulatory compliance in the nine months ended September 30, 2013 contributed to the increase in steam costs between periods. Also increasing over the same time period were well workover costs and contract services costs associated with new wells and increased production in the Uinta and Permian.

The following table sets forth information relating to steam injection for the nine months ended:

	September 30, 2013	September 30, 2012	% Change
Average net volume of steam injected (Bbl/D)	195,566	160,087	22%
Fuel gas cost per MMBtu (including transportation)	$ 3.70	$ 2.68	38%
Approximate net fuel gas volume consumed in steam generation (MMBtu/D)	67,179	52,015	29%

- Production taxes in the nine months ended September 30, 2013 were $32.8 million, or $2.99 per BOE, compared to $30.0 million, or $3.10 per BOE, in the nine months ended September 30, 2012. Our production taxes are comprised of both ad valorem taxes and severance taxes. Ad valorem tax is a property tax based on the assessed value of our reserves, well equipment and facilities, and may vary with changes in assessed values or tax rates. Severance tax is a production tax based

on the volume of oil and natural gas production, and may vary with changes in production volumes, commodity sales prices and severance tax rates or exemptions. The following table sets forth ad valorem and severance taxes for the nine months ended:

	Amount Per BOE		Amount (in thousands)	
	September 30, 2013	September 30, 2012	September 30, 2013	September 30, 2012
Ad valorem taxes	$ 1.76	$ 1.88	$ 19,315	$ 18,191
Severance taxes	1.23	1.22	13,533	11,857
Total production taxes	$ 2.99	$ 3.10	$ 32,848	$ 30,048

The increase in ad valorem taxes was primarily due to increased reserves in California and increased well count in the Permian and Uinta, partially offset by decreased property valuations in E. Texas and the Piceance. The increase in severance taxes per BOE was primarily due to an increase in the average realized sales price between periods, primarily in the Permian, partially offset by certain severance tax exemptions related to new Uinta wells.

- DD&A—oil and natural gas production in the nine months ended September 30, 2013 was $210.9 million, or $19.21 per BOE, compared to $158.9 million, or $16.40 per BOE, in the nine months ended September 30, 2012. The increase was primarily due to an increase in our DD&A rate, which was 17% higher in the nine months ended September 30, 2013 than in the nine months ended September 30, 2012. The higher DD&A rate was primarily due to our development expenditures during the past twelve months, which were partially offset by reserve additions, and the increased contribution of our development properties with higher drilling and leasehold acquisition costs than our legacy California properties. In addition, our overall increase in production of 14% contributed to higher DD&A—oil and natural gas production costs.

- G&A in the nine months ended September 30, 2013 was $59.5 million, or $5.42 per BOE, compared to $53.5 million, or $5.52 per BOE, in the nine months ended September 30, 2012. The increase in G&A was primarily due to an increase in employee compensation and benefits resulting from new personnel hired and general pay increases during the previous twelve months and $2.5 million of professional fees recorded during the first nine months of 2013 associated with the pending LinnCo merger.

- The following table sets forth components of interest expense for nine months ended:

(in thousands)	September 30, 2013	September 30, 2012
Senior subordinated notes	$ —	$ 4,492
Senior notes	59,654	56,252
Credit facility	13,477	8,310
Amortization of debt issuance costs and net discount	5,197	6,131
Amortization of AOCL	—	(1,785)
Other	1,212	2,023
Capitalized interest	(4,978)	(13,977)
	$ 74,562	$ 61,446

Interest expense in the nine months ended September 30, 2013 was $74.6 million, or $6.79 per BOE, compared to $61.4 million, or $6.34 per BOE, in the nine months ended September 30, 2012. The increase was primarily due to a decrease in capitalized interest, an increase in the amount outstanding under our credit facility, the issuance of our 6.375% Senior notes due 2022 (2022 Notes) in March 2012 and a decrease in the amortization of AOCL, which was fully amortized in the fourth quarter of 2012. These increases were partially offset by decreases in interest payments related to the repurchase of $150 million aggregate principal amount of our 10.25% Senior notes due 2014 (2014 Notes) and related to the redemption of our 8.25% Senior Subordinated notes due 2016 (2016 Notes).

Dry Hole, Abandonment, Impairment and Exploration. For the three and nine months ended September 30, 2013, we incurred dry hole, abandonment, impairment and exploration expense of $1.6 million and $3.5 million, respectively. The cost recognized in the first nine months of 2013 was primarily related to plugging and abandonment activities, largely in California, and additional dry hole costs associated with our Borden County appraisal wells that were written off in the fourth quarter of

2012. For the three and nine months ended September 30, 2012, we incurred dry hole, abandonment, impairment and exploration expense of $2.8 million and $7.5 million, respectively. In the third quarter of 2012, we recorded dry hole expense of $2.3 million associated with mechanical failure encountered on one well near Lake Canyon, which was abandoned in favor of drilling a nearby replacement well. The remaining amounts recorded in dry hole, abandonment, impairment, and exploration in the first nine months of 2012 were primarily related to the purchase of seismic data and plugging and abandonment activities.

Impairment of Oil and Natural Gas Properties. In the first quarter of 2013, we wrote off $2.5 million related to the expiration of certain leases in the Permian.

Extinguishment of Debt. In the second quarter of 2012, we incurred debt extinguishment expense of $41.5 million related to the redemption of the entire $200 million aggregate principal amount our 2016 Notes and the repurchase of $150 million aggregate principal amount of our 2014 Notes for a total aggregate purchase price of $397.0 million, including accrued and unpaid interest. The loss of $41.5 million, recorded in the second quarter of 2012, consists of $34.7 million for premiums paid over par and $6.8 million for write-offs of net discounts and debt issuance costs.

Realized and Unrealized Loss (Gain) on Derivatives, Net. The following table sets forth the derivative cash settlements and non-cash fair value gains and losses recorded in the Condensed Statements of Operations under the caption realized and unrealized loss (gain) on derivatives, net for the periods indicated. See Notes 8 and 9 to the Condensed Financial Statements for more information on our derivative instruments.

	Three Months Ended			Nine Months Ended	
(in thousands)	September 30, 2013	September 30, 2012	June 30, 2013	September 30, 2013	September 30, 2012
Cash payments (receipts):					
Commodity derivatives—oil	$ 5,760	$ (1,595)	$ (2,051)	$ 1,239	$ 3,609
Commodity derivatives—natural gas(1)	(67)	170	(384)	(390)	(19,064)
Total cash payments (receipts)	$ 5,693	$ (1,425)	$ (2,435)	$ 849	$ (15,455)
Mark-to-market loss (gain):					
Commodity derivatives—oil	$ 39,401	$ 30,228	$ (34,248)	$ 8,846	$ (56,465)
Commodity derivatives—natural gas(1)	199	(516)	1,061	713	15,606
Total mark-to-market loss (gain)	$ 39,600	$ 29,712	$ (33,187)	$ 9,559	$ (40,859)
Total realized and unrealized loss (gain) on derivatives, net	$ 45,293	$ 28,287	$ (35,622)	$ 10,408	$ (56,314)

(1) In March 2012, we terminated certain of our natural gas derivative instruments, which were associated with a total of 15,000 MMBtu/D for the remainder of 2012. The termination resulted in cash settlements of $14.7 million, offset by a non-cash fair value loss of $16.6 million. The net loss of $1.9 million was recorded in the Condensed Statements of Operations under the caption realized and unrealized loss (gain) on derivatives, net.

Income Tax Expense. The effective income tax rate for the three months ended September 30, 2013 and 2012 was 37.9% and 37.8%, respectively. The effective income tax rate for the nine months ended September 30, 2013 and 2012 was 37.4% and 37.9%, respectively. Our provision for income taxes differed from the U.S. statutory rate of 35% primarily due to state income taxes, domestic production activities deduction, percentage depletion, nondeductible employee compensation and other permanent differences.

Drilling Activity.

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

Asset Team	Three Months Ended September 30, 2013 Gross Production Wells	Three Months Ended September 30, 2013 Net Production Wells	Nine Months Ended September 30, 2013 Gross Production Wells	Nine Months Ended September 30, 2013 Net Production Wells
SMWSS—Steam Floods	18	18	28	28
NMWSS—Diatomite	35	35	105	105
NMWSS—New Steam Floods	—	—	—	—
Permian	16 (1)	11	50 (2)	34
Uinta	32	31	76 (3)	70
E. Texas	—	—	—	—
Piceance	—	—	—	—
Total	101	95	259	237

(1) Includes five non-operated wells in which we have an average interest of approximately 0.68% each, or approximately 0.03 total net wells, and 11 gross operated wells.
(2) Includes 16 non-operated wells in which we have an average interest of approximately 0.68% each, or approximately 0.11 total net wells, and 34 gross operated wells.
(3) Includes two non-operated wells in which we have an average interest of approximately 18.75% each, or approximately 0.4 total net wells.

Properties.

We currently have seven asset teams, as follows: SMWSS—Steam Floods, North Midway-Sunset—Diatomite (NMWSS—Diatomite), NMWSS—NSF, Permian, Uinta, E. Texas and Piceance.

SMWSS—Steam Floods. Our SMWSS—Steam Floods asset team includes our Homebase, Formax, Ethel D, Placerita and Poso Creek properties. These are our legacy assets in California, and we expect total average production to slowly decline over time. In the third quarter of 2013, we drilled nine new producing wells at Placerita, seven new producing wells at Poso Creek, and two new producing wells at Ethel D. In addition, we drilled two new steam injection wells at Homebase. Average daily production in the third quarter of 2013 from all of our SMWSS—Steam Floods properties was approximately 12,275 BOE/D, a 1% decrease from 12,395 BOE/D in the second quarter of 2013.

NMWSS—Diatomite. Our NMWSS—Diatomite asset team includes our Diatomite properties in the San Joaquin Valley. Utilizing our integrated surveillance systems and growing knowledge of the reservoir, in conjunction with a continuous drilling program and expanded infrastructure, we have been able to demonstrate steady quarterly production growth for six consecutive quarters. In the third quarter of 2013, we drilled 35 wells, and we plan to drill approximately 35 additional wells in the fourth quarter of 2013. Average daily production from our NMWSS—Diatomite assets in the third quarter of 2013 was approximately 5,260 BOE/D, an 11% increase from 4,735 BOE/D in the second quarter of 2013.

NMWSS—NSF. Our NMWSS—NSF asset team includes our non-Diatomite North Midway-Sunset assets including our McKittrick, Main Camp, Fairfield, Pan, and USL-12 properties. In the third quarter of 2013, we initiated a steam flood pilot at Pan and continued to expand our infrastructure and increase steam flood injection at McKittrick. Positive response from steam flood activities increased McKittrick production by approximately 45% in the third quarter of 2013. In the fourth quarter of 2013, we plan to drill 13 steam injection wells and initiate a steam flood pilot at Main Camp, drill four new steam injection wells at McKittrick and drill two additional steam injection wells at Pan. Average daily production from all of our NMWSS—NSF assets in the third quarter of 2013 was approximately 3,290 BOE/D, a 24% increase from 2,645 BOE/D in the second quarter of 2013.

Permian. During the third quarter of 2013, we drilled 11 net wells using a three-rig program, and we plan to continue at this pace, drilling approximately ten additional gross wells in the fourth quarter of 2013. Constraints in the form of higher line pressure, shut-ins, periodic gas plant downtime and ethane rejection have continued as a result of record activity levels in the area, and are expected to continue during the fourth quarter of 2013. Average daily production in the third quarter of 2013 from our Permian assets was approximately 8,355 BOE/D, a 4% increase from 8,000 BOE/D in the second quarter of 2013.

Uinta. During the third quarter of 2013, we drilled 32 gross (31 net) wells at our Uinta properties utilizing a two-rig drilling program. All wells we drilled in the third quarter of 2013 were Wasatch/Green River commingled wells; 29 were in Ashley National Forest and three were in Lake Canyon. Our Uinta crude oil is primarily sold in the Salt Lake City market; however, we have the ability to ship our Uinta crude oil via rail to markets outside Salt Lake City and continued to do so in the third quarter of 2013. In the fourth quarter of 2013, we plan to drill 36 gross wells utilizing a three-rig program, including six in Ashley National Forest, three in Lake Canyon and 27 on properties contiguous to Brundage Canyon that were acquired in the third quarter of 2012. Average daily production from our Uinta assets was approximately 8,055 BOE/D in the third quarter of 2013, a 10% increase compared to 7,315 BOE/D in the second quarter of 2013.

E. Texas. We have deferred drilling activities in E. Texas while we focus on higher return oil development opportunities at our other properties. Average daily production in the third quarter of 2013 from the E. Texas assets was approximately 11 MMcf/D compared to 12 MMcf/D in the second quarter of 2013.

Piceance. We have deferred drilling activities in the Piceance while we focus on higher return oil development opportunities at our other properties. Average daily production in the third quarter of 2013 from the Piceance assets was approximately 14 MMcf/D, consistent with 14 MMcf/D in the second quarter of 2013.

Financial Condition, Liquidity and Capital Resources.

Our development, exploitation, and acquisition activities require us to make significant operating and capital expenditures. Historically, we have used cash flow from operations and borrowings under our credit facility as our primary sources of liquidity. We have also used the debt and equity markets as other sources of financing to fund large acquisitions and other transactions and, as market conditions have permitted, we have engaged in asset monetization transactions. Our ability to access the debt and equity capital markets on economic terms is affected by general economic conditions, the financial markets, the credit ratings assigned to our debt by independent credit rating agencies, our operational and financial performance, the value and performance of equity and debt securities, prevailing commodity prices and other macroeconomic factors outside of our control.

At September 30, 2013, we had a working capital deficit of approximately $223.5 million. This deficit included $204.1 million, net of unamortized discount of $1.1 million, related to our 2014 Notes, which mature on June 1, 2014. Although we believe we will be able to complete a refinancing transaction prior to the maturity of the 2014 Notes, no assurances can be made that we will be able to do so. See Maturity of 2014 Notes below. We generally maintain a working capital deficit because we use excess cash to reduce borrowings under our credit facility. Other than current maturities of senior notes, our working capital fluctuates for various reasons, including changes in the fair value of our commodity derivative instruments.

Changes in the market prices for oil and natural gas directly impact the level of cash flows generated from our operations. We employ derivative instruments in our risk management strategy in an attempt to minimize the adverse effects of wide fluctuations in commodity prices on our cash flow. As of September 30, 2013, we had approximately 60% and 55% of our expected 2013 and 2014 oil production hedged, respectively. This level of derivatives is expected to provide a measure of certainty of the cash flows that we will receive for a portion of our production in 2013 and 2014. In the future, we may increase or decrease our derivative positions. Our derivatives counterparties are commercial banks that are parties to our credit facility or affiliates of those banks. See Item 3. Quantitative and Qualitative Disclosures About Market Risk below and Notes 8 and 9 to the Condensed Financial Statements for further details about our derivative instruments.

Senior Secured Revolving Credit Facility. As of September 30, 2013, our credit facility, which matures on May 13, 2016, had a borrowing base of $1.4 billion, subject to lender commitments. At September 30, 2013, lender commitments under the facility were $1.2 billion.

Borrowings under the credit facility bear interest at either (i) LIBOR plus a margin between 1.50% and 2.50% or (ii) the prime rate plus a margin between 0.50% and 1.50%, in each case based on the amount utilized. The annual commitment fee on the unused portion of the credit facility ranges between 0.35% and 0.50% based on the amount utilized.

As of September 30, 2013, there were $636.0 million in outstanding borrowings under the credit facility and $26.8 million in outstanding letters of credit, leaving $537.2 million in borrowing capacity available under the credit facility. The maximum amount available under the credit facility is subject to semi-annual redeterminations of the borrowing base in April and October of each year, based on the value of our proved oil and natural gas reserves, in accordance with the lenders' customary procedures and practices. We and the lenders each have a right to one additional redetermination each year. On October 22, 2013, we entered into a Sixth Amendment to our credit facility, which amended certain terms of the credit facility. See Note 12 to the Condensed Financial Statements.

The credit facility contains certain covenants, which, among other things, require the maintenance of (i) an interest coverage ratio of at least 2.75 to 1.0 and (ii) a minimum current ratio of 1.0 to 1.0. The credit facility also contains other customary covenants, subject to certain agreed exceptions, including covenants restricting our ability to, among other things, owe or be liable for indebtedness; create, assume or permit to exist liens; be a party to or be liable on any hedging contract; engage in mergers or consolidations; transfer, lease, exchange, alienate or dispose of our material assets or properties; declare dividends on or redeem or repurchase our capital stock; make any acquisitions of, capital contributions to or other investments in any entity or property; extend credit or make advances or loans; engage in transactions with affiliates; and enter into, create or allow to exist contractual obligations limiting our ability to grant liens on our assets to the lenders under the credit facility. As of September 30, 2013, we were in compliance with all financial covenants and have complied with all financial covenants for all prior periods presented.

Outstanding Indebtedness. As of September 30, 2013 we had the following senior notes outstanding:

- $205.3 million aggregate principal amount of our 2014 Notes;

- $300 million aggregate principal amount of our 6.75% Senior notes due 2020; and

- $600 million aggregate principal amount of our 2022 Notes.

The indentures governing our senior notes contain provisions that limit our ability to incur, assume or guarantee additional indebtedness; issue redeemable stock and preferred stock; pay dividends or distributions or redeem or repurchase capital stock; prepay, redeem or repurchase debt that is junior in right of payment to our senior and subordinated notes; make loans and other types of investments; incur liens; restrict dividends, loans or asset transfers from our subsidiaries; sell or otherwise dispose of assets, including capital stock of subsidiaries; consolidate or merge with or into, or sell substantially all of our assets to, another person; enter into transactions with affiliates; and enter into new lines of business. Upon specified change in control events, we will be required to make offers to repurchase our senior notes at amounts specified in the indentures governing such notes.

Maturity of 2014 Notes. Our 2014 Notes are scheduled to mature on June 1, 2014. As a result, all $205.3 million aggregate principal amount of the 2014 Notes is classified as a current obligation on our Condensed Balance Sheet as of September 30, 2013. Our ability to repay or refinance the aggregate principal amount of the 2014 Notes is subject to restrictions contained in the Merger Agreement. See Note 11 to the Condensed Financial Statements. While we have not yet determined how we will repay or refinance the 2014 Notes, we may do so through multiple methods which we may pursue separately or in combination, including (i) issuing new debt or equity securities and (ii) borrowing under our credit facility. Although we believe we will be able to complete a refinancing transaction prior to the maturity of the 2014 Notes, if we are unable to complete a refinancing or otherwise repay such debt using cash on hand and borrowings under our credit facility, we would be in default under the indenture governing the 2014 Notes, which would also cause us to be in default under our credit facility and the indentures governing our other senior notes, and would result in indebtedness outstanding under those agreements to be declared immediately due and payable.

Credit Ratings. Our credit risk is evaluated by two independent rating agencies based on publicly available information and information obtained during our ongoing discussions with the rating agencies. Moody's Investor Services and Standard & Poor's Rating Services currently rate our senior notes and have assigned us a credit rating. We do not have any contractual rights or obligations affected by our credit ratings, nor do we have any credit rating triggers that would accelerate the maturity of amounts due under our current outstanding debt. However, our ability to raise funds and the costs of any financing activities will be affected by our credit rating at the time any such financing activities are conducted.

Historical Cash Flows.

(in thousands)	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Net cash provided by operating activities	$ 405,306	$ 391,616
Net cash used in investing activities	(442,460)	(599,725)
Net cash provided by financing activities	60,897	207,915
Net increase (decrease) in cash and cash equivalents	$ 23,743	$ (194)

Operating Activities. Net cash provided by operating activities is primarily affected by the price of oil and natural gas, production volumes and changes in working capital. The increase in net cash provided by operating activities of $13.7 million in the first nine months of 2013 compared to the first nine months of 2012 was primarily due to changes in current assets and liabilities (including bank overdraft but excluding cash), which decreased cash provided by operating activities by $82.7 million. This decrease was partially offset by a 21% increase in average oil production and an 8% increase in average sales price between periods.

Investing Activities. Net cash used in investing activities is primarily comprised of acquisition, exploration and development of oil and natural gas properties net of dispositions of oil and natural gas properties. The decrease of $157.3 million in net cash used in investing activities in the first nine months of 2013 compared to the first nine months of 2012 was primarily due to decreases in development and exploration activity, property acquisitions and capitalized interest.

Financing Activities. Net cash provided by financing activities in the first nine months of 2013 included net borrowings of $73.1 million under our credit facility. Net cash provided by financing activities in the first nine months of 2012 included net proceeds of $589.5 million from the issuance of $600 million aggregate principal amount of our 2022 Notes, partially offset by the repurchase of $150 million aggregate principal amount of our 2014 Notes for an aggregate purchase price of $181.5 million, the repurchase of all $200 million aggregate principal amount of our 2016 Notes for an aggregate purchase price of $215.5 million and net repayments of $21.5 million of borrowings under our credit facility.

Capital Expenditures.

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

We believe that our cash flow provided by operating activities and funds available under our credit facility will be sufficient to fund our operating and capital expenditures budget and our short-term contractual operations for the remainder of 2013. However, if our revenue and cash flow decrease as a result of deterioration in economic conditions or an adverse change in commodity prices, we may have to reduce our spending levels. As we have operational control of substantially all of our assets and we have limited drilling commitments, we believe that we have the financial flexibility to adjust our spending levels, if necessary, to meet our financial obligations.

Recent Accounting Standards and Updates.

For further information on the potential effects of new accounting pronouncements see Note 1 to the Condensed Financial Statements.

Reconciliation of Non-GAAP Measures.

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

(in thousands)	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2013
Net cash provided by operating activities	$ 173,346	$ 405,306
Net increase in current assets	13,243	29,519
Net (increase) decrease in current liabilities, including book overdraft	(13,645)	16,988
Discretionary cash flow	$ 172,944	$ 451,813

Operating Margin per BOE. Operating margin per BOE is a non-GAAP performance measure. Operating margin per BOE consists of average sale price including cash derivative settlements less operating costs—oil and natural and production taxes, each on a per BOE basis. Management uses operating margin per BOE as a measure of profitability and believes it provides useful information to investors because it relates our oil and natural gas revenue and oil and natural gas operating expenses to our total units of production, providing a gross margin per unit of production and allowing investors to evaluate how our profitability varies on a per unit basis each period.

(per BOE)	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2013
Average sales price including cash derivative settlements	$ 78.34	$ 76.66
Operating costs—oil and natural gas production	23.99	24.49
Production taxes	2.90	2.99
Operating margin	$ 51.45	$ 49.18

Item 3. Quantitative and Qualitative Disclosures About Market Risk

As discussed in Note 8 to the Condensed Financial Statements, to minimize the effect of a downturn in oil and natural gas prices and protect our profitability and the economics of our development plans, we enter into crude oil and natural gas derivative contracts from time to time. The terms of the contracts depend on various factors, including management's view of future crude oil and natural gas prices, acquisition economics on purchased assets and our future financial commitments. This price hedging program is designed to moderate the effects of a severe crude oil and natural gas price downturn while allowing us to participate in some commodity price increases. In California, we benefit from lower natural gas pricing, as we are a consumer of natural gas in our operations, and elsewhere we benefit from higher natural gas pricing. We have hedged, and may hedge in the future, both natural gas purchases and sales as determined appropriate by management. Management regularly monitors the crude oil and natural gas markets and our financial commitments to determine if, when, and at what level some form of crude oil and/or natural gas hedging and/or basis adjustments or other price protection is appropriate and in accordance with policy established by our board of directors. Currently, our derivatives are in the form of swaps and collars. However, we may use a variety of derivative instruments in the future to hedge WTI or the index natural gas price. A three-way collar is a combination of three options. The base structure is a normal collar. A short option is added to fund the improvement of the long strike in the base collar. For oil sales three way collars, a purchased put and a sold call comprise the base collar. A sold put below is added to fund the raising of the strike on the purchased put. The purchased put establishes a minimum price unless the market price falls below the sold put, at which point the minimum price would be NYMEX plus the difference between the purchased put and the sold put strike price. The sold call establishes a maximum price (the ceiling) we will receive for the volumes under contract. For natural gas purchase three-way collars, a purchased call and a sold put comprise the base collar. A sold call above is added to fund the lowering of the strike on the purchased call. The purchased call establishes a maximum price unless the market price rises above the sold call, at which point the maximum price would be NYMEX plus the difference between the purchased call and the sold call strike price. The sold put establishes a minimum price (the floor) we will pay for the volumes under contract.

As of September 30, 2013, we had approximately 60% and 55% of our expected 2013 and 2014 oil production hedged, respectively. A hypothetical $10 increase in the oil prices used and $1 increase in the natural gas prices used to calculate the fair values of our derivative instruments at September 30, 2013 would decrease the fair value of our crude oil derivative instruments by $81.2 million and would increase the fair value of our natural gas derivative instruments by $0.6 million. A hypothetical $10 decrease in the oil prices used and $1 decrease in the natural gas prices used to calculate the fair values of our derivative instruments at September 30, 2013 would increase the fair value of our crude oil derivative instruments by $74.8 million and would decrease the fair value of our natural gas derivative instruments by $0.3 million.

The following table summarizes our commodity derivative position as of September 30, 2013:

Term	Average Barrels Per Day	Sold Put / Purchased Put / Sold Call
Crude Oil Sales (NYMEX WTI) Three-Way Collars		
Full year 2013	1,000	$65.00/$85.00/$95.00
Full year 2013	1,000	$65.00/$85.00/$97.25
Full year 2013	1,000	$70.00/$87.00/$105.00
Full year 2013	1,000	$70.00/$88.00/$106.00
Full year 2013	1,000	$60.00/$80.00/$103.30
Full year 2013	1,000	$70.00/$88.15/$100.00
Full year 2013	1,000	$70.00/$86.85/$100.00
Full year 2013	1,000	$69.70/$85.00/$100.00
Full year 2013	1,000	$70.00/$87.00/$108.50
Full year 2013	1,000	$70.00/$90.00/$116.50
Full year 2013	1,000	$70.00/$95.00/$120.10
Full year 2013	500	$70.00/$90.00/$100.00
Full year 2013	500	$70.00/$90.00/$100.00
Full year 2013	1,000	$75.00/$90.00/$101.85
Full year 2013	800	$75.00/$95.00/$101.70
Full year 2013 and 2014	1,000	$70.00/$90.00/$100.00
Full year 2013 and 2014	1,000	$70.00/$90.00/$120.00
Full year 2013 and 2014	1,000	$77.95/$105.00/$115.00
Full year 2013 and 2014	1,000	$80.00/$107.00/$119.60
Full year 2014	1,000	$70.00/$90.00/$102.00
Full year 2014	1,000	$70.00/$90.00/$121.80
Full year 2014	1,500	$70.00/$90.00/$100.00
Full year 2014 and 2015	1,000	$70.00/$90.00/$104.85
Full year 2015	2,000	$70.00/$90.00/$100.00
Crude Oil Sales (ICE Brent) Three-Way Collars		
Full Year 2013	1,000	$80.00/$100.00/$115.00
Full year 2013 and 2014	1,000	$80.00/$100.00/$114.05

Term	Average MMBtu/D or MMTCDE	Average Prices
Crude Oil Sales (NYMEX WTI) Swaps(1)		
Full year 2014	4,700	$90.00
Full year 2014	1,800	$90.06
Full year 2014	2,000	$90.10
Full year 2014	1,000	$90.17
Full year 2014	1,000	$90.50
Full year 2014	1,000	$90.59
Crude Oil Sales (NYMEX WTI to ICE Brent) Basis Swaps(1)		
Full year 2014	1,500	$11.40
Full year 2014	1,500	$11.52
Full year 2014	1,500	$11.55
Full year 2014	2,250	$11.60
Full year 2014	500	$11.65
Full year 2014	500	$11.70
Full year 2014	2,250	$11.80
Full year 2015	1,200	$11.40
Full year 2015	1,200	$11.52
Full year 2015	1,200	$11.55
Full year 2015	1,800	$11.60
Full year 2015	400	$11.65
Full year 2015	400	$11.70
Full year 2015	1,800	$11.80
Crude Oil Sales (NYMEX WTI to Midland) Basis Swaps		
April - Dec 2013	2,000	$1.20
April - Dec 2013	2,000	$1.75
Natural Gas Purchases (NYMEX SoCal Border) Purchased Calls		
Full year 2013	5,000	$3.50
Natural Gas Purchases (NYMEX SoCal Border) Three-Way Collars		
Full year 2013	1,000	$2.90 / $4.00 / $5.00
Full year 2013	1,000	$2.96 / $4.25 / $5.25
Full year 2013	1,000	$2.70 / $4.00 / $5.00
Full year 2013	2,000	$3.03 / $4.25 / $5.25

(1) Derivative transactions we entered into with respect to our production following the execution of the Merger Agreement. The total fair value of these derivative instruments resulted in a net asset of $3.5 million on our September 30, 2013 Condensed Balance Sheet. The Merger Agreement provides that, in general, LinnCo and LINN will bear all of the benefits and burdens of these derivative transactions if the Merger Agreement is terminated. However, if the Merger Agreement is terminated because (1) our board of directors changes its recommendation for the merger or (2) we terminate the Merger Agreement to accept a “company superior proposal,” then we and LinnCo will each bear half of the burdens and receive half of the benefits associated with the derivative transactions. In addition, if one party willfully breaches its obligations under the merger agreement, then the breaching party will bear all of the losses associated with the derivative transactions and, if the derivative transactions resulted in a gain, then the non-breaching party will receive all of such gain.

Excluded from the table above are our calendar month average swaps, which protect us from variances in market pricing conditions of certain of our sales contracts. These derivative contracts protect 5,000 BOE/D of our Permian sales volumes and have differentials of $0.07 to $0.075 during 2013 and $0.32 during 2014.

Interest Rate Risk

Our credit facility allows us to fix the interest rate for all or a portion of the principal balance for a period up to 12 months. To the extent the interest rate is fixed, interest rate changes affect the instrument's fair market value but do not impact results of operations or cash flows. Conversely, for the portion of the credit facility that has a floating interest rate, interest rate changes will not affect the fair market value but will impact future results of operations and cash flows. Changes in interest rates do not affect the amount of interest we pay on our fixed-rate debt. At September 30, 2013, our outstanding principal balance under our credit facility was $636.0 million and the weighted average interest rate on the outstanding principal balance was 2.19%. At September 30, 2013, the carrying amount approximated fair market value. Assuming a constant debt level of $1.7 billion, the cash flow impact resulting from a 100 basis point change in interest rates during periods when the interest rate is not fixed would be $4.0 million over a 12-month time period.

Item 4. Controls and Procedures

As of September 30, 2013, 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 (the Exchange Act).

Our Chief Executive Officer and Chief Financial Officer have concluded that, as of September 30, 2013, 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 Securities and Exchange Commission (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 were no changes in our internal controls over financial reporting that occurred during the three months ended September 30, 2013 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. We may make changes in our internal control procedures from time to time in the future.

Forward Looking Statements

Any statements in this Form 10-Q that are not historical facts, including with respect to expected future production, are forward-looking statements that involve risks and uncertainties. Words such as "plan," "will," "intend," "continue," "target(s)," "expect," "achieve," "future," "may," "could," "goal(s)," "anticipate," "estimate" or other comparable words or phrases, or the negative of those words, and other words of similar meaning indicate forward-looking statements and important factors which could affect actual results. Forward-looking statements are made based on management's current expectations and beliefs concerning future developments and their potential effects upon Berry Petroleum Company. These items are discussed at length in Part I, Item 1A. of our Annual Report on Form 10-K for the year ended December 31, 2012, filed with the SEC on February 28, 2013, under the heading "Risk Factors".

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

The information set forth under "Legal Matters" in Note 10 of our Notes to Condensed Financial Statements included in Item 1 of Part I of this quarterly report is incorporated by reference in response to this item.

Item 1A. Risk Factors

Our business has many risks. Factors that could materially and adversely affect our financial condition, results of operations and operating cash flows are described in Item 1A. of our Annual Report on Form 10-K for the year ended December 31, 2012 filed with the SEC on February 28, 2013, and Item 1A. of our Quarterly Report on Form 10-Q filed on May 8, 2013. Except as set forth below, as of the date of this report, these risk factors have not significantly changed. This information should be considered carefully, together with other information in this report and other reports and materials we file with the United States Securities and Exchange Commission.

The LinnCo merger will not be completed on or prior to October 31, 2013 (the End Date). After the End Date, any of the Company, Linn, or LinnCo may unilaterally terminate the merger agreement at any time prior to completion of the merger. The closing will not occur on or prior to the End Date, and any of the Company, Linn, or LinnCo may unilaterally terminate the Merger Agreement after the End Date. There can be no assurances as to whether the parties will agree to extend the End Date or that the parties will refrain from exercising their rights to terminate the Merger Agreement.

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

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosure

Not applicable.

Item 5. Other Information

On October 22, 2013, as part of the semi-annual borrowing base redetermination process, we entered into the Sixth Amendment to our Second Amended and Restated Credit Agreement by and among the Company, Wells Fargo Bank, N.A., as administrative agent, and the lenders party thereto (the Sixth Amendment). Among other things, the Sixth Amendment eliminates the requirement that the maturity date for borrowings under our credit facility would be accelerated to February 28, 2014 if our 2014 Notes have not been refinanced by such date. In addition, the Sixth Amendment eliminates the leverage and pro forma liquidity tests that we would otherwise be required to meet under the credit facility in order to refinance the 2014 Notes. The amendment did not result in any changes to our borrowing base or lender commitments under the credit facility.

Table of Contents

Item 6. Exhibits

Exhibit No.	Description of Exhibit
10.1*	Fifth Amendment to its Second Amended and Restated Credit Agreement, dated May 21, 2012, by and among the Company, Wells Fargo Bank, N.A., as administrative agent, and the lenders party thereto
10.2*	Sixth Amendment to its Second Amended and Restated Credit Agreement, dated October 22, 2013, by and among the Company, Wells Fargo Bank, N.A., as administrative agent, and the lenders party thereto
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
101*	Interactive data files

* Filed herewith.

** Furnished herewith.

SIGNATURE

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

BERRY PETROLEUM COMPANY

/s/ JAMIE L. WHEAT

Jamie L. Wheat
Vice President and Controller
(Principal Accounting Officer)

Date: October 24, 2013

Exhibit 10.1

FIFTH AMENDMENT TO SECOND AMENDED AND RESTATED
CREDIT AGREEMENT

THIS FIFTH AMENDMENT TO SECOND AMENDED AND RESTATED CREDIT AGREEMENT (this "Amendment") is made as of May 21, 2012 by and among BERRY PETROLEUM COMPANY, a Delaware corporation ("Borrower"), WELLS FARGO BANK, N.A., individually and as administrative agent ("Administrative Agent"), and the Lenders party to the Original Credit Agreement defined below ("Lenders").

W I T N E S S E T H:

WHEREAS, Borrower, Administrative Agent and Lenders entered into that certain Second Amended and Restated Credit Agreement dated as of November 15, 2010 (as amended, supplemented, or restated to the date hereof, the "Original Credit Agreement"), for the purpose and consideration therein expressed, whereby Lenders became obligated to make loans and other extensions of credit to Borrower as therein provided; and

WHEREAS, Borrower, Administrative Agent and Lenders desire to amend the Original Credit Agreement upon the terms and conditions as set forth herein;

NOW, THEREFORE, in consideration of the premises and the mutual covenants and agreements contained herein and in the Original Credit Agreement, in consideration of the loans and other extensions of credit that may hereafter be made by Lenders to Borrower, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto do hereby agree as follows:

ARTICLE I.

Definitions and References

§1.1 Terms Defined in the Original Credit Agreement. Unless the context otherwise requires or unless otherwise expressly defined herein, the terms defined in the Original Credit Agreement shall have the same meanings whenever used in this Amendment.

§1.2 Other Defined Terms. Unless the context otherwise requires, the following terms when used in this Amendment shall have the meanings assigned to them in this Section 1.2.

"Amendment" means this Fifth Amendment to Second Amended and Restated Credit Agreement.

"Credit Agreement" means the Original Credit Agreement as amended hereby.

"Original Omnibus Certificate" means the Omnibus Certificate dated November 15, 2010 executed and delivered by officers of Borrower pursuant to the Original Credit Agreement.

ARTICLE II.

AGREEMENTS

§2.1 Definitions. The following definition in Section 1.1 of the Original Credit Agreement is hereby amended in its entirety to read as follows:

"Lender Counterparties" means (a) each Lender and each Affiliate of a Lender to whom Lender Hedging Obligations are owed and (b) each Person that entered into any Hedging Contract with the Borrower or any Guarantor prior to the time, or during the time, that such Person was a Lender or an Affiliate of a Lender, even if such Person ceases to be a Lender or an Affiliate of a Lender for any reason.

§2.2 Hedging Contracts. Section 7.3 of the Original Credit Agreement is hereby amended to add a new subsection (h) thereto immediately following subsection (g) thereof to read as follows:

(h) GHG. Contracts entered into with the purpose and effect of fixing prices on greenhouse gasses (GHG) that are expected to be emitted from the Restricted Persons' steam generation and co-generation facilities located in the State of California, provided that at all times: (i) no such contract fixes a price for a term of more than 60 months; (ii) the aggregate monthly notional amounts covered by all such contracts (determined, in the case of contracts that are not settled on a monthly basis, by a monthly proration reasonably acceptable to Administrative Agent) for any single month does not in the aggregate exceed 100% of Restricted Persons' aggregate projected GHG emissions from such facilities for such month, (iii) except for letters of credit and the Collateral under the Security Documents with respect to Lender Hedging Obligations, no such contract requires any Restricted Person to put up money, assets or other security against the event of its nonperformance prior to actual default by such Restricted Person in performing its obligations thereunder, and (iv) each such contract is with a counterparty or has a guarantor of the obligation of the counterparty who (unless such counterparty is a Lender or one of its Affiliates) at the time the contract is made has long-term obligations rated A1 by Moody's or A+ by S & P, or better, respectively, by either Rating Agency.

ARTICLE III.

CONDITIONS OF EFFECTIVENESS

§3.1 Effective Date. This Amendment shall become effective as of the date first above written when and only when:

(a) Amendment Documentation. Administrative Agent shall have received all of the following, at Administrative Agent's office, duly executed and delivered and in form and substance satisfactory to Administrative Agent, all of the following:

(i) this Amendment;

(ii) a certificate of the Secretary of Borrower dated the date of this Amendment certifying: (i) that resolutions attached thereto previously adopted by the Board of Directors of the Borrower authorize the execution, delivery and performance of this Amendment by Borrower; (ii) the names and true signatures of the officers of the Borrower authorized to execute and deliver Loan Documents; (iii) that the certificate of incorporation and bylaws of Borrower are in effect on the date hereof and no modifications have been made to them; and (iv) that all of the representations and warranties set forth in Article IV hereof are true and correct on and as of the date hereof, except to the extent that such representation or warranty was made as of a specific date or updated, modified or supplemented as of a subsequent date with the consent of Required Lenders and Administrative Agent, in which cases such representations and warranties shall have been true and correct in all material respects on and of such date; and

(iii) such other supporting documents as Administrative Agent may reasonably request.

(b) No Default. No event shall have occurred and be continuing that would constitute an Event of Default or a Default.

(c) Fees & Expenses. Borrower shall have paid, in connection with such Loan Documents, all other fees and reimbursements to be paid to Administrative Agent pursuant to any Loan Documents, or otherwise due Administrative Agent and including fees and disbursements of Administrative Agent's attorneys.

ARTICLE IV.

Representations and Warranties

§4.1 Representations and Warranties of Borrower. In order to induce each Lender to enter into this Amendment, Borrower represents and warrants to each Lender that:

(a) The representations and warranties contained in Article V of the Original Credit Agreement and the other Loan Documents are true and correct in all material respects on and as of the date hereof as if such representations and warranties have been made as of the date hereof, except to the extent that such representations or warranties were made as of a specific date or updated, modified or supplemented as of a subsequent date with the consent of Required Lenders and Administrative Agent, in which case such representations and warranties shall have been true and correct in all material respects on and of such date.

(b) Borrower is duly authorized to execute and deliver this Amendment and is and will continue to be duly authorized to borrow monies and to perform its obligations under the Credit Agreement. Borrower has duly taken all corporate action necessary to authorize the execution and delivery of this Amendment and to authorize the performance of the obligations of Borrower hereunder.

(c) The execution and delivery by Borrower of this Amendment, the performance by Borrower of its obligations hereunder and the consummation of the transactions contemplated

hereby do not and will not (a) conflict with (i) any Law, (ii) the Organizational Documents of Borrower, or (iii) any agreement, judgment, license, order or permit applicable to or binding upon Borrower in any material respect, (b) result in the acceleration of any Indebtedness owed by Borrower, or (c) result in the creation of any Lien upon any assets or properties of Borrower. Except for those which have been obtained, no consent, approval, authorization or order of, and no notice to or filing with, any Governmental Authority or third party is required in connection with the execution, delivery or performance by Borrower of this Amendment or to consummate any transactions contemplated hereby.

(d) When duly executed and delivered, each of this Amendment and the Credit Agreement will be a legal and binding obligation of Borrower, enforceable in accordance with its terms, except as limited by bankruptcy, insolvency or similar laws of general application relating to the enforcement of creditors' rights and by equitable principles of general application.

(e) The most recent financial statements of Borrower delivered to Lenders pursuant to Sections 6.2(a) and (b) of the Credit Agreement fairly present Borrower's financial position as of the respective dates thereof. Copies of such financial statements have heretofore been delivered to each Lender. Since such date no Material Adverse Change has occurred in the financial condition or businesses or in the Consolidated financial condition or businesses of Borrower.

ARTICLE V.

Miscellaneous

§5.1 Ratification of Agreements. The Original Credit Agreement as hereby amended is hereby ratified and confirmed in all respects. The Loan Documents, as they may be amended or affected by this Amendment, are hereby ratified and confirmed in all respects. Any reference to the Credit Agreement in any Loan Document shall be deemed to be a reference to the Original Credit Agreement as hereby amended. The execution, delivery and effectiveness of this Amendment shall not, except as expressly provided herein, operate as a waiver of any right, power or remedy of Lenders under the Credit Agreement, the Notes, or any other Loan Document nor constitute a waiver of any provision of the Credit Agreement, the Notes or any other Loan Document.

§5.2 Survival of Agreements. All representations, warranties, covenants and agreements of Borrower herein shall survive the execution and delivery of this Amendment and the performance hereof, including without limitation the making or granting of the Loans, and shall further survive until all of the Obligations are paid in full. All statements and agreements contained in any certificate or instrument delivered by Borrower hereunder or under the Credit Agreement to any Lender shall be deemed to constitute representations and warranties by, and/or agreements and covenants of, Borrower under this Amendment and under the Credit Agreement.

§5.3 Loan Documents. This Amendment is a Loan Document, and all provisions in the Credit Agreement pertaining to Loan Documents apply hereto.

§5.4 Interpretive Provisions. Section 1.4 of the Credit Agreement is incorporated herein by reference herein as if fully set forth.

§5.5 Governing Law. This Amendment shall be governed by and construed in accordance with and governed by the laws of the State of California and the laws of the United States of America without regard to principles of conflicts of law.

§5.6 Counterparts; Fax. This Amendment may be separately executed in counterparts and by the different parties hereto in separate counterparts, each of which when so executed shall be deemed to constitute one and the same Amendment. This Amendment may be validly executed by facsimile or other electronic transmission.

THIS AMENDMENT AND THE OTHER LOAN DOCUMENTS REPRESENT THE FINAL AGREEMENT BETWEEN THE PARTIES AND MAY NOT BE CONTRADICTED BY EVIDENCE OF PRIOR, CONTEMPORANEOUS, OR SUBSEQUENT ORAL AGREEMENTS OF THE PARTIES. THERE ARE NO UNWRITTEN ORAL AGREEMENTS OF THE PARTIES.

[*The remainder of this page has been intentionally left blank.*]

IN WITNESS WHEREOF, this Amendment is executed as of the date first above written.

BERRY PETROLEUM COMPANY,
Borrower

By: /s/ SHAWN M. CANADAY

Shawn M. Canaday
Vice President of Finance, Treasurer, and
Assistant Secretary

WELLS FARGO BANK, N.A.,
as Administrative Agent, LC Issuer, Swing Line
Lender, and a Lender

By: /s/ TIM GREEN

Tim Green
Director

BANK OF MONTREAL, as a Lender

By: /s/ GUMARO TIJERINA

Gumaro Tijerina
Director

JPMORGAN CHASE BANK, N.A., as a Lender

By: /s/ DAVID MORRIS

David Morris
Authorized Officer

THE ROYAL BANK OF SCOTLAND plc, as a Lender

By: /s/ SANJAY REMOND

Sanjay Remond
Director

Société Générale, as a Lender

By: /s/ ELENA ROBCIUC

Elena Robciuc
Director

CITIBANK, N.A., as a Lender

By: /s/ JOHN F. MILLER

John F. Miller
Attorney-In-Fact

CREDIT SUISSE AG, CAYMAN ISLANDS
BRANCH, as a Lender

By: /s/ SHAHEEN MALIK

Shaheen Malik
Vice President

By: /s/ MICHAEL D. SPAIGHT

Michael D. Spaight
Associate

ROYAL BANK OF CANADA, as a Lender

By: /s/ MARK LUMPKIN, JR.

Mark Lumpkin, Jr.
Authorized Signatory

UNION BANK, N.A., as a Lender

By: /s/ LAUREN TRUSSELL

Lauren Trussell
Assistant Vice President

U.S. BANK NATIONAL ASSOCIATION, as a Lender

By: /s/ JUSTIN M. ALEXANDER

Justin M. Alexander
Vice President

BOKF, NA dba BANK OF OKLAHOMA
(successor to Bank of Oklahoma, N.A.), as a Lender

By: /s/ GUY C. EVANGELISTA
Guy C. Evangelista
Senior Vice President

BANK OF SCOTLAND plc, as a Lender

By: /s/ JULIA R. FRANKLIN

Julia R. Franklin
Vice President

COMPASS BANK, as a Lender

By: /s/ DOROTHY MARCHAND

Dorothy Marchand
Senior Vice President

KEYBANK, NATIONAL ASSOCIATION, as a Lender

By: /s/ CRAIG HANSELMAN

Craig Hanselman
Vice President

NATIXIS, as a Lender

By: /s/ KENYATTA GIBBS

Kenyatta Gibbs
Director

By: /s/ CARLOS QUINTEROS

Carlos Quinteros
Managing Director

REGIONS BANK, as a Lender

By: /s/ DANIEL G. STEELE

Daniel G. Steele
Regions Bank

THE BANK OF NOVA SCOTIA, as a Lender

By: /s/ TERRY DONOVAN

Terry Donovan
Managing Director

BNP PARIBAS, as a Lender

By: /s/ MYLENE DAO

Mylene Dao
Managing Director

By: /s/ PJ DE FILIPPIS

PJ De Filippis
Managing Director

SIXTH AMENDMENT TO SECOND AMENDED AND RESTATED CREDIT AGREEMENT

THIS SIXTH AMENDMENT TO SECOND AMENDED AND RESTATED CREDIT AGREEMENT (this "Amendment") is made as of October 22, 2013 by and among BERRY PETROLEUM COMPANY, a Delaware corporation ("Borrower"), WELLS FARGO BANK, N.A., individually and as administrative agent ("Administrative Agent"), and the Lenders party to the Original Credit Agreement defined below ("Lenders").

W I T N E S S E T H:

WHEREAS, Borrower, Administrative Agent and Lenders entered into that certain Second Amended and Restated Credit Agreement dated as of November 15, 2010 (as amended, supplemented, or restated to the date hereof, the "Original Credit Agreement"), for the purpose and consideration therein expressed, whereby Lenders became obligated to make loans and other extensions of credit to Borrower as therein provided; and

WHEREAS, Borrower, Administrative Agent and Lenders desire to amend the Original Credit Agreement upon the terms and conditions as set forth herein;

NOW, THEREFORE, in consideration of the premises and the mutual covenants and agreements contained herein and in the Original Credit Agreement, in consideration of the loans and other extensions of credit that may hereafter be made by Lenders to Borrower, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto do hereby agree as follows:

ARTICLE I.

DEFINITIONS AND REFERENCES

§1.1 Terms Defined in the Original Credit Agreement. Unless the context otherwise requires or unless otherwise expressly defined herein, the terms defined in the Original Credit Agreement shall have the same meanings whenever used in this Amendment.

§1.2 Other Defined Terms. Unless the context otherwise requires, the following terms when used in this Amendment shall have the meanings assigned to them in this Section 1.2.

"Amendment" means this Sixth Amendment to Second Amended and Restated Credit Agreement.

"Credit Agreement" means the Original Credit Agreement as amended hereby.

"Original Omnibus Certificate" means the Omnibus Certificate dated November 15, 2010 executed and delivered by officers of Borrower pursuant to the Original Credit Agreement.

ARTICLE II.

AGREEMENTS

§2.1 Definitions.

(a) The following definition in Section 1.1 of the Original Credit Agreement is hereby amended in its entirety to read as follows:

"Maturity Date" means May 13, 2016.

(b) The definitions of "Leverage Test" and "Liquidity Test" in Section 1.1 of the Original Credit Agreement are hereby deleted in their entirety.

§2.2 Reports. Section 6.2 of the Original Credit Agreement is hereby amended to delete subsection (k) thereof in its entirety.

§2.3 Indebtedness. The last sentence of Section 7.1 of the Original Credit Agreement is hereby amended in its entirety to read as follows:

> No Restricted Person will make any prepayment, redemption, sinking fund payment, refinancing, or renewal of any Indebtedness described in Section 7.1(g), (h), (i), or (j), except for (a) a Permitted Refinancing thereof, and (b) with respect to the 2014 Notes only, cash payments at any time and from time to time to prepay, redeem, or retire the 2014 Notes (including deposits of cash to a sinking fund or other similar deposit in a sufficient amount to pay the outstanding principal of, and all accrued interest on, the 2014 Notes).

§2.4 Borrowing Base Redetermination. Pursuant to Section 2.9(a) of the Credit Agreement, Administrative Agent and Lenders hereby notify Borrower that from the date hereof until the next Determination Date the Borrowing Base shall be $1,400,000,000, and by its execution hereof, Borrower accepts the foregoing Borrowing Base.

§2.5 Post Closing. Within 30 days after the date hereof, Borrower will deliver to Administrative Agent Security Documents and title opinions (or other title information satisfactory to Administrative Agent in its sole discretion) in form, substance and authorship reasonably satisfactory to Administrative Agent, with respect to Restricted Persons' Proved Reserves representing not less than the Minimum Collateral Amount.

ARTICLE III.

CONDITIONS OF EFFECTIVENESS

§3.1 Effective Date. This Amendment shall become effective as of the date first above written when and only when:

(a) Amendment Documentation. Administrative Agent shall have received all of the following, at Administrative Agent's office, duly executed and delivered and in form and substance satisfactory to Administrative Agent, all of the following:

(i) this Amendment;

(ii) a certificate of the Secretary of Borrower dated the date of this Amendment certifying: (i) that resolutions attached thereto previously adopted by the Board of Directors of the Borrower authorize the execution, delivery and performance of this Amendment by Borrower; (ii) the names and true signatures of the officers of the Borrower authorized to execute and deliver Loan Documents; (iii) that the certificate of incorporation and bylaws of Borrower are in effect on the date hereof and no modifications have been made to them; and (iv) that all of the representations and warranties set forth in Article IV hereof are true and correct on and as of the date hereof, except to the extent that such representation or warranty was made as of a specific date or updated, modified or supplemented as of a subsequent date with the consent of Required Lenders and Administrative Agent, in which cases such representations and warranties shall have been true and correct in all material respects on and of such date; and

(iii) such other supporting documents as Administrative Agent may reasonably request.

(b) No Default. No event shall have occurred and be continuing that would constitute an Event of Default or a Default.

(c) Fees & Expenses. Borrower shall have paid, in connection with such Loan Documents, all other fees and reimbursements to be paid to Administrative Agent pursuant to any Loan Documents, or otherwise due Administrative Agent and including fees and disbursements of Administrative Agent's attorneys.

ARTICLE IV.

REPRESENTATIONS AND WARRANTIES

§4.1 Representations and Warranties of Borrower. In order to induce each Lender to enter into this Amendment, Borrower represents and warrants to each Lender that:

(a) The representations and warranties contained in Article V of the Original Credit Agreement and the other Loan Documents are true and correct in all material respects on and as of the date hereof as if such representations and warranties have been made as of the date hereof, except to the extent that such representations or warranties were made as of a specific date or updated, modified or supplemented as of a subsequent date with the consent of Required Lenders and Administrative Agent, in which case such representations and warranties shall have been true and correct in all material respects on and of such date.

(b) Borrower is duly authorized to execute and deliver this Amendment and is and will continue to be duly authorized to borrow monies and to perform its obligations under the Credit Agreement. Borrower has duly taken all corporate action necessary to authorize the execution and delivery of this Amendment and to authorize the performance of the obligations of Borrower hereunder.

(c) The execution and delivery by Borrower of this Amendment, the performance by Borrower of its obligations hereunder and the consummation of the transactions contemplated hereby do not and will not (a) conflict with (i) any Law, (ii) the Organizational Documents of Borrower, or (iii) any agreement, judgment, license, order or permit applicable to or binding upon Borrower in any material respect, (b) result in the acceleration of any Indebtedness owed by Borrower, or (c) result in the creation of any Lien upon any assets or properties of Borrower. Except for those which have been obtained, no consent, approval, authorization or order of, and no notice to or filing with, any Governmental Authority or third party is required in connection with the execution, delivery or performance by Borrower of this Amendment or to consummate any transactions contemplated hereby.

(d) When duly executed and delivered, each of this Amendment and the Credit Agreement will be a legal and binding obligation of Borrower, enforceable in accordance with its terms, except as limited by bankruptcy, insolvency or similar laws of general application relating to the enforcement of creditors' rights and by equitable principles of general application.

(e) The most recent financial statements of Borrower delivered to Lenders pursuant to Sections 6.2(a) and (b) of the Credit Agreement fairly present Borrower's financial position as of the respective dates thereof. Copies of such financial statements have heretofore been delivered to each Lender. Since such date no Material Adverse Change has occurred in the financial condition or businesses or in the Consolidated financial condition or businesses of Borrower.

ARTICLE V.

MISCELLANEOUS

§5.1 Ratification of Agreements. The Original Credit Agreement as hereby amended is hereby ratified and confirmed in all respects. The Loan Documents, as they may be amended or affected by this Amendment, are hereby ratified and confirmed in all respects. Any reference to the Credit Agreement in any Loan Document shall be deemed to be a reference to the Original Credit Agreement as hereby amended. The execution, delivery and effectiveness of this Amendment shall not, except as expressly provided herein, operate as a waiver of any right, power or remedy of Lenders under the Credit Agreement, the Notes, or any other Loan Document nor constitute a waiver of any provision of the Credit Agreement, the Notes or any other Loan Document.

§5.2 Survival of Agreements. All representations, warranties, covenants and agreements of Borrower herein shall survive the execution and delivery of this Amendment and the performance hereof, including without limitation the making or granting of the Loans, and shall further survive until all of the Obligations are paid in full. All statements and agreements contained in any certificate

or instrument delivered by Borrower hereunder or under the Credit Agreement to any Lender shall be deemed to constitute representations and warranties by, and/or agreements and covenants of, Borrower under this Amendment and under the Credit Agreement.

§5.3 Loan Documents. This Amendment is a Loan Document, and all provisions in the Credit Agreement pertaining to Loan Documents apply hereto.

§5.4 Interpretive Provisions. Section 1.4 of the Credit Agreement is incorporated herein by reference herein as if fully set forth.

§5.5 Governing Law. This Amendment shall be governed by and construed in accordance with and governed by the laws of the State of California and the laws of the United States of America without regard to principles of conflicts of law.

§5.6 Counterparts; Fax. This Amendment may be separately executed in counterparts and by the different parties hereto in separate counterparts, each of which when so executed shall be deemed to constitute one and the same Amendment. This Amendment may be validly executed by facsimile or other electronic transmission.

THIS AMENDMENT AND THE OTHER LOAN DOCUMENTS REPRESENT THE FINAL AGREEMENT BETWEEN THE PARTIES AND MAY NOT BE CONTRADICTED BY EVIDENCE OF PRIOR, CONTEMPORANEOUS, OR SUBSEQUENT ORAL AGREEMENTS OF THE PARTIES. THERE ARE NO UNWRITTEN ORAL AGREEMENTS OF THE PARTIES.

[*The remainder of this page has been intentionally left blank.*]

IN WITNESS WHEREOF, this Amendment is executed as of the date first above written.

BERRY PETROLEUM COMPANY,
Borrower

By: /s/ SHAWN M. CANADAY

Shawn M. Canaday
Vice President of Finance, Treasurer, and
Assistant Secretary

WELLS FARGO BANK, N.A.,
as Administrative Agent, LC Issuer, Swing Line
Lender, and a Lender

By: /s/ MICHAELA BRAUN

Michaela Braun
Director

BANK OF MONTREAL, as a Lender

By: /s/ JOSEPH A. BLISS

Joseph A. Bliss
Managing Director

JPMORGAN CHASE BANK, N.A., as a Lender

By: /s/ MARK OLSON

Mark Olson
Authorized Officer

THE ROYAL BANK OF SCOTLAND plc, as a Lender

By: /s/ JAMES L. MOYES

James L. Moyes
Managing Director

Société Générale, as a Lender

By: /s/ DAVID M. BORNSTEIN

David M. Bornstein
Director

CITIBANK, N.A., as a Lender

By: /s/ EAMON BAQUI

Eamon Baqui
Vice President

CREDIT SUISSE AG, CAYMAN ISLANDS
BRANCH, as a Lender

By: /s/ CHRISTOPER DAY

Christoper Day
Authorized Signatory

By: /s/ MICHAEL SPAIGHT

Michael Spaight
Authorized Signatory

ROYAL BANK OF CANADA, as a Lender

By: /s/ MARK LUMPKIN, JR.

Mark Lumpkin, Jr.
Authorized Signatory

UNION BANK, N.A., as a Lender

By: /s/ JOSH PATTERSON

Josh Patterson
Vice President

U.S. BANK NATIONAL ASSOCIATION, as a Lender

By: /s/ JOHN C. LOZANO

John C. Lozano
Vice President

BOKF, NA dba BANK OF OKLAHOMA
(successor to Bank of Oklahoma, N.A.), as a Lender

By: /s/ SONJA BORODKO

Sonja Borodko
Vice President

COMPASS BANK, as a Lender

By: /s/ JAMES NEBLETT

James Neblett
Vice President

KEYBANK, NATIONAL ASSOCIATION, as a Lender

By: /s/ PAUL J. PACE

Paul J. Pace
Senior Vice President

NATIXIS, as a Lender

By: /s/ STUART MURRAY

Stuart Murray
Managing Director

By: /s/ KENYATTA GIBBS

Kenyatta Gibbs
Director

REGIONS BANK, as a Lender

By: /s/ KELLY L. ELMORE III

Kelly L. Elmore III
Senior Vice President

THE BANK OF NOVA SCOTIA, as a Lender

By: /s/ TERRY DONOVAN

Terry Donovan
Managing Director

Exhibit 12.1

COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES

(in thousands, except ratios)

	Nine Months Ended 09/30/2013	12/31/2012	12/31/2011	12/31/2010	12/31/2009	12/31/2008
Pre-tax income from continuing operations	$ 194,789	$ 259,660	$ (370,291)	$ 136,492	$ 67,888	$ 190,193
Interest expense	74,562	83,136	72,807	66,541	50,738	26,209
Amortization of capitalized interest	2,229	2,116	1,813			
Capitalized interest	4,978	17,915	29,117	28,321	30,107	23,209
Earnings	$ 271,580	$ 344,912	$ (295,671)	$ 203,033	$ 118,626	$ 216,402
Ratio of earnings to fixed charges	**3.4x**	**3.4x**	**—** (1)	**2.1x**	**1.5x**	**4.4x**

(1) For the year ended December 31, 2011, earnings were deficient by $397.6 million, which was due primarily to a pre-tax, non-cash charge to earnings of $625.0 million related to the impairment of our E. Texas natural gas properties.

For purposes of this table, “earnings” consists of earnings before income taxes plus interest expense and amortization of capitalized interest. “Fixed charges” consists of interest expensed and capitalized.

Exhibit 31.1

Certification of Chief Executive Officer
Pursuant to Section 302 of Sarbanes Oxley Act of 2002

I, Robert F. Heinemann, certify that:

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

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

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

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

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

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

   c) evaluated the effectiveness of the Company's disclosure controls and procedures and presented in this report our conclusions 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/ ROBERT F. HEINEMANN
Robert F. Heinemann
President, Chief Executive Officer and Director

October 24, 2013

Exhibit 31.2

Certification of Chief Financial Officer
Pursuant to Section 302 of Sarbanes Oxley Act of 2002

I, David D. Wolf, certify that:

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

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

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

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

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

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

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

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

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

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

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

/s/ DAVID D. WOLF

David D. Wolf
Executive Vice President and Chief Financial Officer

October 24, 2013

Exhibit 32.1

Certification of Chief Executive Officer
Pursuant to Section 906 of Sarbanes Oxley Act of 2002

In Connection with the Quarterly Report of Berry Petroleum Company (the “Company”) on Form 10-Q for the period ending September 30, 2013 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Robert F. Heinemann, President, Chief Executive Officer and Director of the Company, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

/s/ ROBERT F. HEINEMANN

Robert F. Heinemann
President, Chief Executive Officer and Director

October 24, 2013

Exhibit 32.2

Certification of Chief Financial Officer
Pursuant to Section 906 of Sarbanes Oxley Act of 2002

In Connection with the Quarterly Report of Berry Petroleum Company (the “Company”) on Form 10-Q for the period ending September 30, 2013 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

October 24, 2013