BERRY PETROLEUM CO
Form 10-Q
August 07, 2013
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q
T Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the quarterly period ended June 30, 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 August 5, 2013 the registrant had 52,674,211 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 August 5, 2013, all of which is held by a single holder.

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June 30, 2013

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PART I. FINANCIAL INFORMATION

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

	June 30, 2013	December 31, 2012
ASSETS		
Current assets:		
Cash and cash equivalents	$8,914	$312
Restricted short-term investments	125	125
Accounts receivable	138,649	122,159
Deferred income taxes	185	703
Derivative instruments	18,377	14,661
Prepaid expenses and other	19,005	19,065
Total current assets	185,255	157,025
Oil and natural gas properties (successful efforts basis), buildings and equipment, net	3,240,447	3,128,502
Derivative instruments	34,867	10,891
Other assets	25,933	28,984
	$3,486,502	$3,325,402
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$105,912	$175,893
Revenue and royalties payable	42,618	57,021
Accrued liabilities	46,166	51,151
Derivative instruments	—	1,111
Deferred income taxes	6,598	1,456
10.25% Senior notes due 2014, net of unamortized discount of $1,553	203,704	—
Total current liabilities	404,998	286,632
Long-term liabilities:		
Deferred income taxes	311,449	255,471
Senior secured revolving credit facility	646,000	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	94,424	82,316
Derivative instruments	—	1,239
Other long-term liabilities	23,127	19,136
	1,975,000	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; 52,672,162 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	371,425	364,710

Retained earnings	734,534	649,539
Total shareholders' equity	1,106,504	1,014,791
	$3,486,502	$3,325,402

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

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BERRY PETROLEUM COMPANY
Condensed Statements of Operations
(Unaudited)
(In Thousands, Except Per Share Data)

	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
REVENUES				
Oil and natural gas sales	$274,715	$221,781	$541,487	$455,434
Electricity sales	9,513	5,860	17,102	11,840
Natural gas marketing	2,255	1,580	4,282	3,439
(Loss) gain on sale of assets	—	(163)	23	1,600
Interest and other income, net	374	645	849	1,392
	286,857	229,703	563,743	473,705
EXPENSES				
Operating costs—oil and natural gas production	91,277	62,426	177,425	116,647
Operating costs—electricity generation	6,337	4,256	11,633	9,273
Production taxes	11,004	9,690	21,788	20,348
Depreciation, depletion & amortization—oil and natural gas production	69,839	52,026	137,923	99,982
Depreciation, depletion & amortization—electricity generation	433	455	827	921
Natural gas marketing	2,198	1,387	4,076	3,164
General and administrative	19,430	17,965	41,708	35,706
Interest	24,879	20,789	49,566	40,893
Dry hole, abandonment, impairment and exploration	872	1,582	1,834	4,621
Impairment of oil and natural gas properties	—	38	2,467	66
Extinguishment of debt	—	41,526	—	41,526
Realized and unrealized gain on derivatives, net	(35,622)	(113,082)	(34,885)	(84,601)
	190,647	99,058	414,362	288,546
Earnings before income taxes	96,210	130,645	149,381	185,159
Income tax provision	34,846	49,629	55,583	70,245
Net earnings	$61,364	$81,016	$93,798	$114,914
Basic net earnings per share	$1.11	$1.47	$1.69	$2.08
Diluted net earnings per share	$1.10	$1.46	$1.68	$2.07
Dividends per share	$0.08	$0.08	$0.16	$0.16

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

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BERRY PETROLEUM COMPANY
Condensed Statements of Comprehensive Earnings
(Unaudited)
(In Thousands)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Net earnings	$61,364	$81,016	$93,798	$114,914
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, $618, $0 and $1,394, respectively	—	1,009	—	2,276
Other comprehensive earnings	$—	$1,009	$—	$2,276
Comprehensive earnings	$61,364	$82,025	$93,798	$117,190

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

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BERRY PETROLEUM COMPANY
Condensed Statements of Cash Flows
(Unaudited)
(In Thousands)

	Six Months Ended June 30, 2013	2012
Cash flows from operating activities:		
Net earnings	$93,798	$114,914
Depreciation, depletion and amortization	138,749	100,903
Gain on sale of assets	(23)	(1,600)
Extinguishment of debt	—	6,842
Amortization of debt issuance costs and net discount	3,438	3,688
Impairment of oil and natural gas properties	2,467	66
Dry hole and impairment	713	211
Derivatives	(30,041)	(66,901)
Stock-based compensation expense	5,903	5,426
Deferred income taxes	61,639	66,782
Other, net	2,226	(524)
Allowance for bad debt	—	315
Change in book overdraft	(14,885)	(2,628)
Changes in operating assets and liabilities:		
Accounts receivable	(16,518)	9,063
Inventories, prepaid expenses, and other current assets	242	(4,702)
Accounts payable and revenue and royalties payable	(10,741)	7,755
Accrued interest and other accrued liabilities	(5,007)	8,457
Net cash provided by operating activities	231,960	248,067
Cash flows from investing activities:		
Development and exploration of oil and natural gas properties	(303,228)	(328,968)
Property acquisitions	(3,080)	(24,851)
Capitalized interest	(3,450)	(9,723)
Proceeds from sale of assets	11,511	15,722
Deposits on asset sales	—	(3,300)
Net cash used in investing activities	(298,247)	(351,120)
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	490,700	858,700
Repayments of long-term borrowings under credit facility	(407,600)	(989,700)
Financing obligation	(223)	(202)
Debt issuance costs	—	(11,424)
Dividends paid	(8,803)	(8,771)
Stock options and restricted stock issued	65	3,497
Excess income tax benefit	750	735
Net cash provided by financing activities	74,889	102,836
Net increase (decrease) in cash and cash equivalents	8,602	(217)
Cash and cash equivalents at beginning of period	312	298
Cash and cash equivalents at end of period	$8,914	$81

Noncash investing activities:		
Accrued capital expenditures	$40,607	$55,311
Asset retirement obligations	10,607	15,012

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

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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	—	62	—	65
Stock based compensation expense	—	—	5,903	—	5,903
Income tax effect of stock option exercises	—	—	750	—	750
Dividends ($0.16 per share)	—	—	—	(8,803)	(8,803)
Net earnings	—	—	—	93,798	93,798
Balances at June 30, 2013	$527	$18	$371,425	$734,534	$1,106,504

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

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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 June 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 June 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 assets related to 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 (loss) gain on sale of assets.

3. Debt

Senior Secured Revolving Credit Facility

As of June 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 June 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 June 30, 2013, there were $646.0 million in outstanding borrowings under the credit facility and $23.2 million in outstanding letters of credit, leaving $530.8 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. The semi-annual redetermination in April 2013 did not result in any changes to the borrowing base, lender commitments, or other terms of the credit facility.

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 June 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, which may require seeking additional availability under the credit facility. If the Company is unable to complete a refinancing, 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. In addition, failure to comply with any of the indentures or covenants under the senior notes and credit facility could adversely affect the Company's ability to fund ongoing operations and future capital expenditures, as well as the ability to pay distributions to shareholders.

4. Income Taxes

The effective income tax rate for the three months ended June 30, 2013 and 2012 was 36.2% and 38.0%, respectively. The effective income tax rate for the six months ended June 30, 2013 and 2012 was 37.2% 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. The decrease in the effective income tax rate for the three months ended June 30, 2013 was primarily due to a reduction in uncertain income tax positions recognized for closing statutes.

As of June 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 June 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 calculated by dividing net earnings available to common shareholders by the weighted average shares outstanding-basic during each period. Diluted earnings per share is calculated by dividing earnings available to common shareholders by the weighted average shares outstanding-dilutive, which includes the effect of potentially dilutive securities. Potentially dilutive securities consist of unvested restricted stock awards and outstanding stock options. No potential shares of common stock are included in the computation of any diluted per share amount when a net loss exists.

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BERRY PETROLEUM COMPANY
Notes to Condensed Financial Statements (Continued)
(Unaudited)
5. Earnings Per Share (Continued)

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. Unvested restricted shares issued subsequent to January 1, 2010 under the Company's equity incentive plans do not participate in dividends. Stock options issued under the Company's equity incentive plans do not participate in dividends.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands, except per share data)	2013	2012	2013	2012
Net earnings	$61,364	$81,016	$93,798	$114,914
Less: net earnings allocable to participating securities	112	399	194	556
Net earnings available for common shareholders	$61,252	$80,617	$93,604	$114,358
Basic net earnings per share	$1.11	$1.47	$1.69	$2.08
Diluted net earnings per share	$1.10	$1.46	$1.68	$2.07
Basic weighted average shares outstanding	55,302	54,942	55,245	54,851
Add: Dilutive effects of stock options and RSUs	417	352	406	451
Dilutive weighted average shares outstanding	55,719	55,294	55,651	55,302

Not included in the diluted earnings per share calculation were 0.3 million and 0.7 million stock options and RSUs, for the three and six months ended June 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 0.3 million stock options and RSUs, for the three and six months ended June 30, 2012, respectively, because their effect would have been anti-dilutive.

6. Asset Retirement Obligations

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

	Six Months Ended June 30,	
(in thousands)	2013	2012
Beginning balance at January 1	$86,746	$64,019
Liabilities incurred	4,700	4,024
Liabilities settled	(2,007)	(1,668)
Liabilities assumed	—	1,626
Disposition of assets	(40)	(705)
Accretion expense	3,548	2,596
Revisions in estimated cash flows	5,907	10,988
Ending balance at June 30	$98,854	$80,880

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 $2.6 million and $2.2 million during the three months ended June 30, 2013 and 2012, respectively, and $5.6 million and $5.2 million during the six months ended June 30, 2013 and 2012, respectively.

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BERRY PETROLEUM COMPANY
Notes to Condensed Financial Statements (Continued)
(Unaudited)

Stock Options

The following table summarizes stock option activity for the six months ended June 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	
Granted	—	—		
Exercised	(3,000)	21.58	76	
Canceled/expired	—	—		
Outstanding at June 30, 2013	1,384,592	$33.74	$13,465	3.59
Vested and expected to vest at June 30, 2013	1,383,778	$33.73	$13,465	3.59
Exercisable at June 30, 2013	1,278,372	$32.29	$13,465	3.20

(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 June 30, 2013, there were $2.0 million of total unrecognized compensation costs related to outstanding stock options. These costs are expected to be recognized over 2.8 years.

Restricted Stock Units

The following table summarizes restricted stock unit (RSU) activity for the six months ended June 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	(176,724)	24.68	$6,884
Canceled/expired	(13,707)	43.85	
Outstanding at June 30, 2013(1)(2)	1,055,479	$32.02	

(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 June 30, 2013, there were $18.9 million of total unrecognized compensation costs related to RSUs granted. These costs are expected to be recognized over 3.8 years.

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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 six months ended June 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 June 30, 2013	122,923	$57.61	

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

As of June 30, 2013, there were $1.5 million of total unrecognized compensation costs related to performance shares granted. These costs are expected to be recognized over 1.5 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 June 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 six months ended June 30, 2013:

Crude Oil Sales Three-Way Collars

Term	Index	Average Barrels	Sold Put / Purchased Put / Sold Call

		Per Day	
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

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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 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)		June 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	$23.8	$(5.5)	$18.3
Commodity derivative instruments	Long-term	35.0	(0.1)	34.9
Total assets		$58.8	$(5.6)	$53.2
Liabilities				
Commodity derivative instruments	Current	$5.4	$(5.4)	$—
Commodity derivative instruments	Long-term	0.2	(0.2)	—
Total liabilities		$5.6	$(5.6)	$—

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BERRY PETROLEUM COMPANY
Notes to Condensed Financial Statements (Continued)
(Unaudited)
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)	Location of Loss (Gain)	Three Months Ended June 30,		Six Months Ended June 30,	
Description 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	$—	$2.5	$—	$5.2
Gain recognized in earnings (cash settlements and mark-to-market movements)	Realized and unrealized gain on derivatives, net	(35.6)	(113.1)	(34.9)	(84.6)
Interest rate					
Gain reclassified from AOCL into earnings (amortization of frozen amounts)	Interest	$—	$(0.9)	$—	$(1.5)

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 June 30, 2013 was $53.2 million.

As of June 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 in default under the credit facility. As of June 30, 2013, the Company was not in a net liability position with any of the counterparties to the Company's derivative instruments. As of June 30, 2013, the Company's largest three counterparties accounted for 52% 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 June 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				
June 30, 2013	$53.2	$—	$53.2	$—
December 31, 2012	$23.2	$—	$23.2	$—

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BERRY PETROLEUM COMPANY
Notes to Condensed Financial Statements (Continued)
(Unaudited)
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:

June 30, 2013	Carrying Amount	Estimated Fair Value			
(in millions)		Level 1	Level 2	Level 3	Total
Cash and cash equivalents	$9	$9	$—	$—	$9
Senior secured revolving credit facility(1)	646	—	646	—	646
10.25% Senior notes due 2014(2)	205	221	—	—	221
6.75% Senior notes due 2020	300	311	—	—	311
6.375% Senior notes due 2022	600	599	—	—	599
	$1,760	$1,140	$646	$—	$1,786

(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 $1.6 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
	$1,668	$1,179	$563	$—	$1,742

(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 June 30, 2013 and 2012, the Company incurred net costs of $0.5 million and $0.6 million, respectively, under the agreements. For the six months ended June 30, 2013 and 2012, the Company incurred net costs of $1.0 million and $1.4 million, respectively, under the agreements.

BERRY PETROLEUM COMPANY
Notes to Condensed Financial Statements (Continued)
(Unaudited)

Carry and Earning Agreement

On January 14, 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 the amendment, if by June 30, 2013, the Company did not expend $9.0 million on the construction of either the extension of the road or a new road, then the Company was 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. The Company agreed in principal with the third party to extend such deadline until September 30, 2013. Such 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, 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 is proposing 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 third 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.

BERRY PETROLEUM COMPANY
Notes to Condensed Financial Statements (Continued)
(Unaudited)
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.

On March 1, 2013, a purported stockholder class action captioned Nancy P. Assad Trust v. Berry Petroleum Company, et al. was filed in the United States District Court for the District of Colorado. The case was dismissed by the Court on March 20, 2013 for lack of subject matter jurisdiction, and refiled in the District Court for the City and County of Denver, Colorado on March 21, 2013, Case No. 2013CV031365. On April 5, 2013, the plaintiff filed an amended complaint alleging that the individual Company director defendants breached their fiduciary duties in connection with the proposed merger transaction with Linn and LinnCo by engaging in an unfair sales process that resulted in an unfair price for the Company, and that the entity defendants aided and abetted those breaches of fiduciary duty. The amended complaint seeks a declaration that the proposed merger transactions are unlawful and unenforceable, an order directing the individual director defendants to comply with their fiduciary duties, an injunction against consummation of the merger transactions or, in the event they are so completed, rescission of the transactions, an award of fees and costs, including attorneys' and experts' fees and expenses, and other relief.
On April 12, 2013, a second purported stockholder class action captioned David S. Hall v. Berry Petroleum Company, et al. was filed in the Court of Chancery of the State of Delaware, C.A. No. 8476-VCG. The plaintiff in this case makes allegations, and seeks relief similar to the allegations made and relief sought in the Assad case.
In response to a motion filed by the defendants, on May 20, 2013, after conferring with the Delaware judge in the Hall case, the Colorado judge stayed the Assad case, allowing the parties to proceed with one case, the Hall case, in one jurisdiction, Delaware. On July 19, 2013, the plaintiffs in the Assad case voluntarily dismissed the case without prejudice. After expedited discovery, the plaintiffs in the Hall case made a settlement proposal and the parties are currently engaged in settlement discussions. The Company believes the claims relating to the merger are without merit, and intends to defend such actions vigorously.

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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.

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.

On March 1, 2013, a purported stockholder class action captioned Nancy P. Assad Trust v. Berry Petroleum Company, et al. was filed in the United States District Court for the District of Colorado. The case was dismissed by the Court on March 20, 2013 for lack of subject matter jurisdiction, and refiled in the District Court for the City and County of Denver, Colorado on March 21, 2013, Case No. 2013CV031365. On April 5, 2013, the plaintiff filed an amended complaint alleging that the individual Company director defendants breached their fiduciary duties in connection with the proposed merger transaction with Linn and LinnCo by engaging in an unfair sales process that resulted in an unfair price for the Company, and that the entity defendants aided and abetted those breaches of fiduciary duty. The amended complaint seeks a declaration that the proposed merger transactions are unlawful and unenforceable, an order directing the individual director defendants to comply with their fiduciary duties, an injunction against consummation of the merger transactions or, in the event they are so completed, rescission of the transactions, an award of fees and costs, including attorneys' and experts' fees and expenses, and other relief.
On April 12, 2013, a second purported stockholder class action captioned David S. Hall v. Berry Petroleum Company, et al. was filed in the Court of Chancery of the State of Delaware, C.A. No. 8476-VCG. The plaintiff in this case makes allegations, and seeks relief similar to the allegations made and relief sought in the Assad case.
In response to a motion filed by the defendants, on May 20, 2013, after conferring with the Delaware judge in the Hall case, the Colorado judge stayed the Assad case, allowing the parties to proceed with one case, the Hall case, in one jurisdiction, Delaware. On July 19, 2013, the plaintiffs in the Assad case voluntarily dismissed the case without prejudice. After expedited discovery, the plaintiffs in the Hall case made a settlement proposal and the parties are currently engaged in settlement discussions. The Company believes the claims relating to the merger are without merit, and intends to defend such actions vigorously.
Notable Second Quarter 2013 Items

- Increased total production by 12% and oil production by 20% from the second quarter of 2012
- Generated discretionary cash flow of $145.0 million from production of 39,529 BOE/D, of which 80% was oil[(1)]
- Generated an operating margin of $47.15 per BOE, supported by sales of our California heavy oil at a $5.05 average premium to WTI during the quarter[(1)]

- Diatomite production averaged 4,735 BOE/D, a 15% increase from the first quarter of 2013
- Production from our North Midway-Sunset—New Steam Floods (NMWSS—NSF) properties, which include McKittrick, averaged 2,645 BOE/D, a 12% increase from the first quarter of 2013
- Drilled 26 Diatomite wells, 22 Uinta wells, 13 Permian wells and ten South Midway-Sunset—Steam Floods (SMWSS—Steam Floods) wells

(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.

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Results of Operations.

In the second quarter of 2013, we reported net earnings of $61.4 million, or $1.10 per diluted share, and net cash flows from operations of $140.3 million. Net earnings in the second quarter of 2013 included a gain on derivatives of $21.2 million, net of income taxes, resulting from non-cash changes in fair values. For the first six months of 2013, we reported net earnings of $93.8 million, or $1.68 per diluted share, and net cash flows from operations of $232.0 million. Net earnings for the first six months of 2013 included a gain on derivatives of $18.9 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:

	June 30, 2013	%	June 30, 2012	%	March 31, 2013	%
Heavy oil production (BOE/D)	19,775	50	17,395	49	19,566	50
Light oil production (BOE/D)	11,681	30	8,901	25	11,588	29
Total oil production (BOE/D)	31,456	80	26,296	74	31,154	79
Natural gas production (Mcf/D)	48,436	20	54,271	26	51,132	21
Total (BOE/D)(1)	39,529	100	35,341	100	39,676	100
Oil and natural gas, per BOE:						
Average realized sales price	$74.91		$69.07		$75.27	
Average sales price including cash derivative settlements	$75.58		$70.40		$75.95	
Oil, per BOE:						
Average WTI price	$94.17		$93.35		$94.36	
Price sensitive royalties(2)	(2.64	)	(3.55	)	(2.81	)
Location differential and other(3)	(4.00	)	(0.51	)	(1.25	)
Oil derivatives non-cash amortization(4)	—		(1.12	)	—	
Oil revenue	$87.53		$88.17		$90.30	
Add: Oil derivatives non-cash amortization(4)	—		1.12		—	
Oil derivative cash settlements(5)	0.70		0.79		0.89	
Average realized oil price	$88.23		$90.08		$91.19	
Natural gas price:						
Average Henry Hub price per MMBtu	$4.10		$2.21		$3.34	
Conversion to Mcf	0.28		0.15		0.22	
Natural gas derivatives non-cash amortization(4)	—		0.03		—	
Location differential and other	(0.29	)	(0.11	)	(0.09	)
Natural gas revenue per Mcf	$4.09		$2.28		$3.47	
Add: Natural gas derivatives non-cash amortization(4)	—		(0.03	)	—	
Natural gas derivative cash settlements(5)	0.09		(0.03	)	(0.01	)
Average realized natural gas price per Mcf	$4.18		$2.22		$3.46	

(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 second 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 June 30, 2013 was $1.58, ranged from $1.58 to $8.98 during the second quarter of 2013 and averaged $5.05 during the second quarter of 2013. In Utah, the per barrel oil posting differential during the second 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 gain on derivatives, net.

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

	June 30, 2013	%	June 30, 2012	%
Heavy oil production (BOE/D)	19,672	50	17,201	49
Light oil production (BOE/D)	11,634	29	8,495	25
Total oil production (BOE/D)	31,306	79	25,696	74
Natural gas production (Mcf/D)	49,777	21	55,188	26
Total (BOE/D)(1)	39,602	100	34,894	100
Oil and natural gas, per BOE:				
Average realized sales price	$75.09		$71.68	
Average sales price including cash derivative settlements	$75.76		$72.40	
Oil, per BOE:				
Average WTI price	$94.26		$98.15	
Price sensitive royalties(2)	(2.73	)	(3.89	)
Location differential and other(3)	(2.65	)	(1.04	)
Oil derivatives non-cash amortization(4)	—		(1.13	)
Oil revenue	$88.88		$92.09	
Add: Oil derivatives non-cash amortization(4)	—		1.13	
Oil derivative cash settlements(5)	0.79		(1.11	)
Average realized oil price	$89.67		$92.11	
Natural gas price:				
Average Henry Hub price per MMBtu	$3.72		$2.47	
Conversion to Mcf	0.26		0.17	
Natural gas derivatives non-cash amortization(4)	—		0.01	
Location differential and other	(0.20	)	(0.21	)
Natural gas revenue per Mcf	$3.78		$2.44	
Add: Natural gas derivatives non-cash amortization(4)	—		(0.01	)
Natural gas derivative cash settlements(5)	0.03		0.45	
Average realized natural gas price per Mcf	$3.81		$2.88	

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(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 second 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 June 30, 2013 was $1.58, ranged from $1.58 to $11.02 during the first six months of 2013 and averaged $7.53 during the first six months of 2013. In Utah, the per barrel oil posting differential at June 30, 2013 was ($16.50), ranged from ($14.50) to ($16.50) during the first six months of 2013 and averaged ($16.09) during the first six 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 gain on derivatives, net.

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

	June 30, 2013	June 30, 2012	2Q12 to 2Q13 Change	March 31, 2013	1Q13 to 2Q13 Change
Oil sales	$256,682	$210,562	22 %	$250,777	2 %
Natural gas sales	18,033	11,219	61 %	15,995	13 %
Total oil and natural gas sales	$274,715	$221,781	24 %	$266,772	3 %
Electricity sales	9,513	5,860	62 %	7,589	25 %
Natural gas marketing	2,255	1,580	43 %	2,027	11 %
(Loss) gain on sale of assets	—	(163)	(100)%	23	(100)%
Interest and other income, net	374	645	(42)%	475	(21)%
Total revenues and other income	$286,857	$229,703	25 %	$276,886	4 %
Net earnings	$61,364	$81,016	(24)%	$32,434	89 %
Diluted earnings per share	$1.10	$1.46	(25)%	$0.58	90 %

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

	June 30, 2013	June 30, 2012	% Change
Oil sales	$507,459	$431,015	18 %
Natural gas sales	34,028	24,419	39 %
Total oil and natural gas sales	$541,487	$455,434	19 %
Electricity sales	17,102	11,840	44 %
Natural gas marketing	4,282	3,439	25 %
Gain on sale of assets	23	1,600	(99)%
Interest and other income, net	849	1,392	(39)%
Total revenues and other income	$563,743	$473,705	19 %
Net earnings	$93,798	$114,914	(18)%
Diluted earnings per share	$1.68	$2.07	(19)%

Oil and Natural Gas Sales.

Oil and natural gas sales increased $52.9 million, or 24%, to $274.7 million in the second 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 volume increased 23% in the second quarter of 2013 compared to the same period in 2012, while our natural gas sales volumes decreased 11%. 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. Permian oil production in the second quarter of 2013 increased 1,200 BOE/D, or 22%, from the same period in 2012, Uinta oil production increased 1,660 BOE/D, or 52%, Diatomite oil production in the second quarter of 2013 increased 1,765 BOE/D, or 60%, and NMWSS—NSF oil production increased 900 BOE/D, or 52%. 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, an 8% increase in the average sales price, primarily due to a 79% increase in realized natural gas prices, partially offset by a decrease in realized oil prices, contributed to the increase in oil and natural gas sales in the second quarter of 2013 from the second quarter of 2012.

Oil and natural gas sales increased $7.9 million, or 3%, to $274.7 million in the second quarter of 2013 compared to the first quarter of 2013. The increase was primarily due to a 6% increase in oil sales volumes between periods and an 18% increase in realized natural gas prices, partially offset by a 4% decrease in natural gas sales volumes between periods. 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, and the Permian, which was impacted by curtailment issues. Diatomite oil production in the second quarter of 2013 increased 615 BOE/D, or 15%, from the first quarter of 2013, NMWSS

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—NSF oil production increased 290 BOE/D, or 12%, and Uinta oil production increased 235 BOE/D, or 5%. 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 $86.1 million, or 19%, to $541.5 million in the six months ended June 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 10%. 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. Permian oil production in the six months ended June 30, 2013 increased 1,630 BOE/D, or 33%, from the same period in 2012, Uinta oil production increased 1,595 BOE/D, or 50%, Diatomite oil production increased 1,600 BOE/D, or 57%, and oil production for NMWSS—NSF increased 875 BOE/D, or 54%. 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, a 5% increase in the average sales price, primarily due to a 55% increase in realized natural gas prices, partially offset by a decrease in realized oil prices, contributed to the increase in oil and natural gas sales in the six months ended June 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			Six Months Ended	
	June 30, 2013	June 30, 2012	March 31, 2013	June 30, 2013	June 30, 2012
Electricity					
Electricity sales (in thousands)	$9,513	$5,860	$7,589	$17,102	$11,840
Operating costs (in thousands)	$6,337	$4,256	$5,296	$11,633	$9,273
Electric power produced (MWh/D)	1,957	2,061	2,036	1,996	2,075
Electric power sold (MWh/D)	1,772	1,882	1,851	1,812	1,908
Average sales price per MWh	$58.98	$34.22	$44.77	$51.76	$34.09
Fuel gas cost per MMBtu (including transportation)	$3.95	$2.36	$3.55	$3.75	$2.52
Estimated natural gas volumes consumed to produce electricity (MMBtu/D)(1)	14,612	14,924	14,726	14,684	15,069

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

Electricity sales in the second quarter of 2013 increased 62% compared to the second quarter of 2012 primarily due to a 72% increase in the average sales price of electricity, partially offset by a 6% decrease in electric power sold. Electricity operating costs in the second quarter of 2013 increased 49% compared to the second quarter of 2012 largely due to a 67% increase in fuel gas cost, partially offset by a 5% decrease in electric power produced.

Electricity sales increased 25% in the second quarter of 2013 compared to the first quarter of 2013, primarily due to a 32% increase in the average sales price of electricity partially offset by a 4% decrease in electric power sold. Electricity operating costs in the second quarter of 2013 increased 20% compared to the first quarter of 2013 largely due to a 11% increase in fuel gas cost, partially offset by a 4% decrease in electric power produced.

Electricity sales increased 44% in the six months ended June 30, 2013 compared to the six months ended June 30, 2012 primarily due to a 52% increase in the average sales price of electricity, partially offset by a 5% decrease in electric power sold. Electricity operating costs in the six months ended June 30, 2013 increased 25% compared to the six months ended June 30, 2012 primarily due to a 49% increase in fuel gas cost, partially offset by a 4% 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.

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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 June 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 June 30, 2013 and 2012 were $0.1 million and $0.2 million, respectively. The pre-tax net earnings of natural gas marketing operations for the six months ended June 30, 2013 and 2012 was $0.2 million and $0.3 million, respectively.

(Loss) Gain on Sale of Assets.

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 (loss) gain on sale of assets.

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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)		
	June 30, 2013	June 30, 2012	March 31, 2013	June 30, 2013	June 30, 2012	March 31, 2013
Operating costs—oil and natural gas production(1)	$25.37	$19.41	$24.13	$91,277	$62,426	$86,148
Production taxes	3.06	3.01	3.02	11,004	9,690	10,784
DD&A—oil and natural gas production	19.42	16.18	19.07	69,839	52,026	68,084
General and administrative	5.40	5.59	6.24	19,430	17,965	22,278
Interest expense	6.92	6.46	6.91	24,879	20,789	24,687
Total	$60.17	$50.65	$59.37	$216,429	$162,896	$211,981

(1) Operating costs—oil and natural gas production includes firm transportation costs of $8.3 million and $7.0 million for the three months ended June 30, 2013 and 2012, respectively, and $7.7 million for the three months ended March 31, 2013.

- Operating costs—oil and natural gas production in the second quarter of 2013 were $91.3 million, or $25.37 per BOE, compared to $62.4 million, or $19.41 per BOE, in the second quarter of 2012 and $86.1 million, or $24.13 per BOE, in the first quarter of 2013. The increase in the second quarter of 2013 compared to the second quarter of 2012 was primarily due to an increase of approximately $15.6 million in steam costs, largely due to a 67% increase in the price of natural gas used in steam generation and a 14% increase in the average volume of steam injected. In addition, $3.2 million of emissions expense related to California greenhouse gas regulatory compliance in the second quarter of 2013 contributed to the increase in steam costs between periods. Also increasing over the same time period were contract services, primarily due to our Permian and Uinta wells added in the last 12 months, transportation costs associated with rail car rental costs in the Uinta and workover costs in the Permian.

The increase in operating costs—oil and natural gas production in the second quarter of 2013 compared to the first quarter of 2013 was primarily due to a $2.8 million increase in steam costs, largely due to an 11% increase in the price of natural gas used to produce steam. Also increasing over the same time period were natural gas processing costs in the Uinta and workover costs in the Permian.

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

	June 30, 2013	June 30, 2012	2Q12 to 2Q13 Change	March 31, 2013	1Q13 to 2Q13 Change
Average net volume of steam injected (Bbl/D)	190,085	167,004	14 %	197,829	(4)%
Fuel gas cost per MMBtu (including transportation)	$3.95	$2.36	67 %	$3.55	11 %
Approximate net fuel gas volume consumed in steam generation (MMBtu/D)	65,313	55,532	18 %	66,171	(1)%

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Production taxes in the second quarter of 2013 were $11.0 million, or $3.06 per BOE, compared to $9.7 million, or $3.01 per BOE, in the second quarter of 2012 and $10.8 million, or $3.02 per BOE, in the first quarter of 2013. Our production taxes may vary depending on production from each area, the assessed values of our reserves and the production tax rate in effect. The increase in production taxes per BOE in the second quarter of 2013 compared to the second quarter of 2012 was primarily due to increased severance taxes in the Permian largely related to an increase in our average realized sales price in the Permian. The increase in production taxes in the second quarter of 2013 compared to the first quarter of 2013 was primarily due to increased severance taxes related to a shift in Uinta production to tribal properties, which experience higher severance tax rates, and an increase in our average realized sales price in the Permian.

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Depreciation, depletion and amortization—oil and natural gas production (DD&A—oil and natural gas production) in the second quarter of 2013 was $69.8 million, or $19.42 per BOE, compared to $52.0 million, or $16.18 per BOE, in the second quarter of 2012 and $68.1 million, or $19.07 per BOE, in the first quarter of 2013. The increase in the second quarter of 2013 compared to the second quarter of 2012 and the first quarter of 2013 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 second quarter of 2013 was 20% higher than the second quarter of 2012 and 2% higher than the first quarter of 2013. The higher DD&A rate in the second quarter of 2013 compared to the second quarter of 2012 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. The higher DD&A rate in the second quarter of 2013 compared to the first quarter of 2013 was primarily due to our development expenditures, which were partially offset by reserve additions, during the second quarter of 2013.

General and administrative expense (G&A) in the second quarter of 2013 was $19.4 million, or $5.40 per BOE, compared to $18.0 million, or $5.59 per BOE, in the second quarter of 2012 and $22.3 million, or $6.24 per BOE, in the first quarter of 2013. The increase in the second quarter of 2013 compared to the second quarter of 2012 was primarily due to an increase in employee compensation and benefits resulting from new personnel hired during the previous twelve months, as well as general pay increases. In addition, in the second quarter of 2013, we recorded an additional $0.4 million of professional fees associated with the pending LinnCo merger. The decrease in the second quarter of 2013 compared to the first quarter of 2013 was primarily due to $2.1 million recorded in the first quarter of 2013 related to professional fees associated with the pending LinnCo merger and director compensation of $1.1 million recorded in the first quarter of 2013.

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

(in thousands)	June 30, 2013	June 30, 2012	March 31, 2013
Senior subordinated notes	$—	$367	$—
Senior notes	19,884	19,970	19,885
Credit facility	4,588	2,905	4,412
Amortization of debt issuance costs and net discount	1,729	1,651	1,709
Amortization of AOCL	—	(918)	—
Other	329	1,347	480
Capitalized interest	(1,651)	(4,533)	(1,799)
	$24,879	$20,789	$24,687

Interest expense in the second quarter of 2013 was $24.9 million, or $6.92 per BOE, compared to $20.8 million, or $6.46 per BOE, in the second quarter of 2012 and $24.7 million, or $6.91 per BOE, in the first quarter of 2013. The increase in the second quarter of 2013 compared to the second 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 six months ended:

	Amount Per BOE		Amount (in thousands)	
	June 30, 2013	June 30, 2012	June 30, 2013	June 30, 2012
Operating costs—oil and natural gas production(1)	$24.75	$18.37	$177,425	$116,647
Production taxes	3.04	3.20	21,788	20,348
DD&A—oil and natural gas production	19.24	15.74	137,923	99,982
General and administrative	5.82	5.62	41,708	35,706

Interest expense	6.91	6.44	49,566	40,893
Total	$ 59.76	$ 49.37	$ 428,410	$ 313,576

(1) Operating costs—oil and natural gas production includes firm transportation costs of $16.0 million and $14.1 million for the six months ended June 30, 2013 and 2012, respectively.

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- Operating costs in the six months ended June 30, 2013 were $177.4 million, or $24.75 per BOE, compared to $116.6 million, or $18.37 per BOE, in the six months ended June 30, 2012. The increase was primarily due to an increase of approximately $30.2 million in steam costs, largely related to a 49% increase in the price of natural gas used in steam generation and a 29% increase in the average volume of steam injected. In addition, $6.4 million of emissions expense related to California greenhouse gas regulatory compliance in the six months ended June 30, 2013 contributed to the increase in steam costs between periods. Also increasing over the same time period were well workover costs and contract labor costs associated with new wells and increased production in the Diatomite, Uinta, and Permian. We also incurred increased oil storage and transportation costs in the Uinta related to refinery constraints experienced during the fourth quarter of 2012, as well as rail car rental costs associated with transporting our Uinta crude to markets outside of Utah.

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

	June 30, 2013	June 30, 2012	% Change	
Average net volume of steam injected (Bbl/D)	193,936	150,757	29	%
Fuel gas cost per MMBtu (including transportation)	$3.75	$2.52	49	%
Approximate net fuel gas volume consumed in steam generation (MMBtu/D)	65,724	50,553	30	%

- Production taxes in the six months ended June 30, 2013 were $21.8 million, or $3.04 per BOE, compared to $20.3 million, or $3.20 per BOE, in the six months ended June 30, 2012. The decrease in production tax per BOE was primarily due to certain severance tax exemptions related to new Uinta wells.

- DD&A—oil and natural gas production in the six months ended June 30, 2013 was $137.9 million, or $19.24 per BOE, compared to $100.0 million, or $15.74 per BOE, in the six months ended June 30, 2012. The increase was primarily due to an increase in our DD&A—oil and natural gas production rate per BOE (DD&A rate), which was 22% higher in the six months ended June 30, 2013 than in the six months ended June 30, 2012. The higher DD&A rate in the six months ended June 30, 2013 compared to the six months ended June 30, 2012 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 12% in the six months ended June 30, 2013 from the six months ended June 30, 2012 contributed to higher DD&A—oil and natural gas production costs.

- G&A in the six months ended June 30, 2013 was $41.7 million, or $5.82 per BOE, compared to $35.7 million, or $5.62 per BOE, in the six months ended June 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 six months of 2013 associated with the pending LinnCo merger.

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

(in thousands)	June 30, 2013	June 30, 2012
Senior subordinated notes	$—	$4,492
Senior notes	39,769	36,367
Credit facility	9,000	5,062
Amortization of debt issuance costs and net discount	3,438	4,469

Amortization of AOCL	—	(1,564)
Other	809	1,790
Capitalized interest	(3,450)	(9,723)
	$49,566	$40,893

Interest expense in the six months ended June 30, 2013 was $49.6 million, or $6.91 per BOE, compared to $40.9 million, or $6.44 per BOE, in the six months ended June 30, 2012. The increase was primarily due to a decrease in capitalized

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interest, an increase in the amount outstanding under our credit facility, the issuance of our 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 2014 Notes and related to the redemption of our 2016 Notes.

Dry Hole, Abandonment, Impairment and Exploration. For the three and six months ended June 30, 2013, we incurred dry hole, abandonment, impairment and exploration expense of $0.9 million and $1.8 million, respectively. The cost recognized in the first six 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 six months ended June 30, 2012, we incurred dry hole, abandonment, impairment and exploration expense of $1.6 million and $4.6 million. The cost recognized in the first six months of 2012 was primarily for 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 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 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			Six Months Ended	
(in thousands)	June 30, 2013	June 30, 2012	March 31, 2013	June 30, 2013	June 30, 2012
Cash (receipts) payments:					
Commodity derivatives—oil	$(2,051)	$(1,865)	$(2,470)	$(4,521)	$5,204
Commodity derivatives—natural gas(1)	(384)	147	61	(323)	(19,234)
Total cash (receipts) payments	$(2,435)	$(1,718)	$(2,409)	$(4,844)	$(14,030)
Mark-to-market (gain) loss:					
Commodity derivatives—oil	$(34,248)	$(111,056)	$3,693	$(30,555)	$(86,693)
Commodity derivatives—natural gas(1)	1,061	(308)	(547)	514	16,122
Total mark-to-market (gain) loss	$(33,187)	$(111,364)	$3,146	$(30,041)	$(70,571)
Total realized and unrealized (gain) loss on derivatives, net	$(35,622)	$(113,082)	$737	$(34,885)	$(84,601)

(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 gain on derivatives, net.

Income Tax Expense. The effective income tax rate for the three months ended June 30, 2013 and 2012 was 36.2% and 38.0%, respectively. The effective income tax rate for the six months ended June 30, 2013 and 2012 was 37.2% 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. The decrease in the effective income tax rate for the three months ended June 30, 2013 was primarily due to a reduction of $1.9 million in uncertain tax positions recognized for closing statutes.

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Drilling Activity.

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

Asset Team	Three Months Ended June 30, 2013 Gross Production Wells		Net Production Wells	Six Months Ended June 30, 2013 Gross Production Wells		Net Production Wells
SMWSS—Steam Floods	10		10	10		10
NMWSS—Diatomite	26		26	70		70
NMWSS—New Steam Floods	—		—	—		—
Permian	18	(1)	13	34	(2)	23
Uinta	24	(3)	21	44	(3)	39
E. Texas	—		—	—		—
Piceance	—		—	—		—
Total	78		70	158		142

(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 13 gross operated wells.

(2) Includes 11 non-operated wells in which we have an average interest of approximately 0.68% each, or approximately 0.08 total net wells, and 23 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 (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 second quarter of 2013, we drilled seven new producing wells, one replacement producing well and four new steam injection wells at Ethel D. At Formax, we drilled two new horizontal producing wells during the second quarter of 2013 as we continued the infill program there. In the third quarter of 2013, we plan to drill one new productive well at Ethel D, nine new productive wells at Placerita, one new productive well and two steam injection wells at Homebase and five new productive wells and two replacement productive wells at Poso Creek. Average daily production in the second quarter of 2013 from all of our SMWSS—Steam Floods assets was approximately 12,395 BOE/D, a 5% decrease from 13,095 BOE/D in the first 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, we have seen success in our recent Diatomite development programs. We have also seen positive responses in the redevelopment of certain Diatomite areas, and plan to continue those redevelopment efforts. In the second quarter of 2013, we drilled 14 wells in our redevelopment areas and 12 wells in our newer development areas. In the third quarter of 2013, we expect to drill approximately 35 wells in our newer development areas. Average daily production from our NMWSS—Diatomite assets in the second quarter of 2013 was approximately 4,735 BOE/D, a 15% increase from 4,115 BOE/D in the first 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 second quarter of 2013, we drilled 45 steam injection wells and three thermal observation wells at McKittrick, in our continuing effort to expand the steam flood development. In the third quarter of 2013, we plan to build out our infrastructure at McKittrick, Main Camp and Pan. This includes commissioning a pipeline from Main Camp to Fairfield to support the current operations and in preparation for our planned development in the fourth quarter. We also plan to commission a steam flood pilot at Pan during the third quarter of 2013. Average daily production from all of our NMWSS—NSF assets in the second quarter of 2013 was approximately 2,645 BOE/D, a 12% increase from 2,355 BOE/D in the first quarter of 2013.

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Permian. During the second quarter of 2013, we drilled 13 net wells using a three-rig program, and we plan to continue at this pace, drilling approximately ten additional net wells in the third 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 third quarter of 2013. Average daily production in the second quarter of 2013 from our Permian assets was approximately 8,000 BOE/D, a 1% decrease from 8,105 BOE/D in the first quarter of 2013.

Uinta. During the second quarter of 2013, we drilled 22 gross (21 net) wells at our Uinta properties utilizing a two-rig drilling program. All wells we drilled in the second quarter of 2013 were Wasatch/Green River commingled wells; 10 were in Brundage Canyon, four were in Ashley National Forest and eight were in Lake Canyon. Delayed completion activity, which negatively affected production in the first quarter, continued into the beginning of the second quarter. In the second quarter of 2013, we continued shipping crude oil via rail to markets outside of Utah, and now have over 100 rail cars in service. In the third quarter of 2013, we plan to drill 24 gross wells utilizing a two-rig program, including 21 in Ashley National Forest and three in Lake Canyon. Average daily production from our Uinta assets was approximately 7,315 BOE/D in the second quarter of 2013 compared to 7,305 BOE/D in the first 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 second quarter of 2013 from the E. Texas assets was approximately 12 MMcf/D compared to 13 MMcf/D in the first 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 second quarter of 2013 from the Piceance assets was approximately 14 MMcf/D compared to 15 MMcf/D in the first 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 June 30, 2013, we had a working capital deficit of approximately $219.7 million. This deficit included $203.7 million, net of unamortized discount of $1.6 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 June 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 June 30, 2013, our credit facility, which matures on May 13, 2016, had a borrowing base of $1.4 billion, subject to lender commitments. At June 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.

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As of June 30, 2013, there were $646.0 million in outstanding borrowings under the credit facility and $23.2 million in outstanding letters of credit, leaving $530.8 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. The semi-annual redetermination in April 2013 did not result in any changes to the borrowing base, lender commitments, or other terms of the credit facility.

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 June 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 June 30, 2013 we had the following senior notes outstanding:

• $205.3 million aggregate principal amount of our 10.25% Senior notes due 2014 (2014 Notes);

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

• $600 million aggregate principal amount of our 6.375% Senior notes due 2022.

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 June 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, which may require seeking additional availability under the credit facility. If we are unable to complete a refinancing, 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. In addition, failure to comply with any of the indentures or covenants under the senior notes and credit facility could adversely affect our ability to fund ongoing operations and future capital expenditures, as well as the ability to pay distributions to shareholders.We have not currently determined if or when we will refinance the 2014 Notes. 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. 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

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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.

	Six Months Ended	
(in thousands)	June 30, 2013	June 30, 2012
Net cash provided by operating activities	$231,960	$248,067
Net cash used in investing activities	(298,247)	(351,120)
Net cash provided by financing activities	74,889	102,836
Net increase (decrease) in cash and cash equivalents	$8,602	$(217)

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 decrease in net cash provided by operating activities of $16.1 million in the first six months of 2013 compared to the first six 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 $64.9 million. This decrease was partially offset by a 22% increase in average oil production and an 5% 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 $52.9 million in net cash used in investing activities in the first six months of 2013 compared to the first six 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 six months of 2013 included net borrowings of $83.1 million under our credit facility. Net cash provided by financing activities in the first six 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 $131.0 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.

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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 June 30, 2013	Six Months Ended June 30, 2013
Net cash provided by operating activities	$140,262	$231,960
Net increase in current assets	3,712	16,276
Net decrease in current liabilities, including book overdraft	1,011	30,633
Discretionary cash flow	$144,985	$278,869

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 June 30, 2013	Six Months Ended June 30, 2013
Average sales price including cash derivative settlements	$75.58	$75.76
Operating costs—oil and natural gas production	25.37	24.75
Production taxes	3.06	3.04
Operating margin	$47.15	$47.97

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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 June 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 June 30, 2013 would decrease the fair value of our crude oil derivative instruments by $88.2 million and would increase the fair value of our natural gas derivative instruments by $1.2 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 June 30, 2013 would increase the fair value of our crude oil derivative instruments by $85.1 million and would decrease the fair value of our natural gas derivative instruments by $0.6 million.

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

Term	Average Barrels Per Day	Sold Put / Purchased Put / Sold Call	Term	Average MMBtu/D or MMTCDE	Average Prices
Crude Oil Sales (NYMEX WTI) Three-Way Collars			Crude Oil Sales (NYMEX WTI) Swaps(1)		
Full year 2013	1,000	$65.00/$85.00/$95.00	Full year 2014	4,700	$90.00
Full year 2013	1,000	$65.00/$85.00/$97.25	Full year 2014	1,800	$90.06
Full year 2013	1,000	$70.00/$87.00/$105.00	Full year 2014	2,000	$90.10
Full year 2013	1,000	$70.00/$88.00/$106.00	Full year 2014	1,000	$90.17
Full year 2013	1,000	$60.00/$80.00/$103.30	Full year 2014	1,000	$90.50
Full year 2013	1,000	$70.00/$88.15/$100.00	Full year 2014	1,000	$90.59
Full year 2013	1,000	$70.00/$86.85/$100.00	Crude Oil Sales (NYMEX WTI to ICE Brent) Basis Swaps(1)		
Full year 2013	1,000	$69.70/$85.00/$100.00	Full year 2014	1,500	$11.40
Full year 2013	1,000	$70.00/$87.00/$108.50	Full year 2014	1,500	$11.52
Full year 2013	1,000	$70.00/$90.00/$116.50	Full year 2014	1,500	$11.55
Full year 2013	1,000	$70.00/$95.00/$120.10	Full year 2014	2,250	$11.60
Full year 2013	500	$70.00/$90.00/$100.00	Full year 2014	500	$11.65
Full year 2013	500	$70.00/$90.00/$100.00	Full year 2014	500	$11.70
Full year 2013	1,000	$75.00/$90.00/$101.85	Full year 2014	2,250	$11.80
Full year 2013	800	$75.00/$95.00/$101.70	Full year 2015	1,200	$11.40
Full year 2013 and 2014	1,000	$70.00/$90.00/$100.00	Full year 2015	1,200	$11.52
Full year 2013 and 2014	1,000	$70.00/$90.00/$120.00	Full year 2015	1,200	$11.55
Full year 2013 and 2014	1,000	$77.95/$105.00/$115.00	Full year 2015	1,800	$11.60
Full year 2013 and 2014	1,000	$80.00/$107.00/$119.60	Full year 2015	400	$11.65
Full year 2014	1,000	$70.00/$90.00/$102.00	Full year 2015	400	$11.70
Full year 2014	1,000	$70.00/$90.00/$121.80	Full year 2015	1,800	$11.80
Full year 2014	1,500	$70.00/$90.00/$100.00	Crude Oil Sales (NYMEX WTI to Midland) Basis Swaps		
Full year 2014 and 2015	1,000	$70.00/$90.00/$104.85	April - Dec 2013	2,000	$1.20
Full year 2015	2,000	$70.00/$90.00/$100.00	April - Dec 2013	2,000	$1.75
Crude Oil Sales (ICE Brent) Three-Way Collars			Natural Gas Purchases (NYMEX SoCal Border) Purchased Calls		
Full Year 2013	1,000	$80.00/$100.00/$115.00	Full year 2013	5,000	$3.50
Full year 2013 and 2014	1,000	$80.00/$100.00/$114.05	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 $24.0 million on our

June 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.

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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 June 30, 2013, our outstanding principal balance under our credit facility was $646.0 million and the weighted average interest rate on the outstanding principal balance was 2.20%. At June 30, 2013, the carrying amount approximated fair market value. Assuming a constant debt level of $1.8 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 $4.1 million over a 12-month time period.

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Item 4. Controls and Procedures

As of June 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 June 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 June 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".

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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.

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

None.

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Item 6. Exhibits

Exhibit No.	Description of Exhibit
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.

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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: August 7, 2013