BERRY PETROLEUM CO
Form 10-Q
May 08, 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 March 31, 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 May 6, 2013 the registrant had 52,671,706 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 May 6, 2013, all of which is held by a single holder.

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March 31, 2013

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

	March 31, 2013	December 31, 2012
ASSETS		
Current assets:		
Cash and cash equivalents	$105	$312
Restricted short-term investments	125	125
Accounts receivable	131,632	122,159
Deferred income taxes	6,093	703
Derivative instruments	7,622	14,661
Prepaid expenses and other	22,205	19,065
Total current assets	167,782	157,025
Oil and natural gas properties (successful efforts basis), buildings and equipment, net	3,177,892	3,128,502
Derivative instruments	17,491	10,891
Other assets	27,468	28,984
	$3,390,633	$3,325,402
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$108,713	$175,893
Revenue and royalties payable	31,564	57,021
Accrued liabilities	47,183	51,151
Derivative instruments	5,057	1,111
Deferred income taxes	—	1,456
Total current liabilities	192,517	286,632
Long-term liabilities:		
Deferred income taxes	281,925	255,471
Senior secured revolving credit facility	653,600	562,900
10.25% Senior notes due 2014, net of unamortized discount of $1,950 and $2,340, respectively	203,307	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	90,237	82,316
Derivative instruments	—	1,239
Other long-term liabilities	22,241	19,136
	2,151,310	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; 52,669,614 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	368,688	364,710
Retained earnings	677,573	649,539
Total shareholders' equity	1,046,806	1,014,791

	$3,390,633	$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 March 31,	
	2013	2012
REVENUES		
Oil and natural gas sales	$266,772	$233,653
Electricity sales	7,589	5,980
Natural gas marketing	2,027	1,859
Gain on sale of assets	23	1,763
Interest and other income, net	475	747
	276,886	244,002
EXPENSES		
Operating costs—oil and natural gas production	86,148	54,221
Operating costs—electricity generation	5,296	5,017
Production taxes	10,784	10,658
Depreciation, depletion & amortization—oil and natural gas production	68,084	47,956
Depreciation, depletion & amortization—electricity generation	394	466
Natural gas marketing	1,878	1,777
General and administrative	22,278	17,741
Interest	24,687	20,104
Dry hole, abandonment, impairment and exploration	962	3,067
Impairment of oil and natural gas properties	2,467	—
Realized and unrealized loss on derivatives, net	737	28,481
	223,715	189,488
Earnings before income taxes	53,171	54,514
Income tax provision	20,737	20,616
Net earnings	$32,434	$33,898
Basic net earnings per share	$0.59	$0.62
Diluted net earnings per share	$0.58	$0.61
Dividends per share	$0.08	$0.08

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 March 31,	
	2013	2012
Net earnings	$32,434	$33,898
Other comprehensive earnings, net of income taxes:		
Amortization of accumulated other comprehensive loss related to de-designated hedges, net of income tax benefits of $0 and $777, respectively	—	1,267
Other comprehensive earnings	—	1,267
Comprehensive earnings	$32,434	$35,165

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)

	Three Months Ended March 31, 2013	2012
Cash flows from operating activities:		
Net earnings	$32,434	$33,898
Depreciation, depletion and amortization	68,478	48,422
Gain on sale of assets	(23)	(1,763)
Amortization of debt issuance costs and net discount	1,709	2,037
Impairment of oil and natural gas properties	2,467	—
Dry hole and impairment	449	28
Derivatives	3,146	42,837
Stock-based compensation expense	3,195	3,104
Deferred income taxes	19,648	16,567
Other, net	2,381	683
Allowance for bad debt	—	315
Change in book overdraft	(232)	(509)
Changes in operating assets and liabilities:		
Accounts receivable	(9,507)	(7,835)
Inventories, prepaid expenses, and other current assets	(3,057)	(2,686)
Accounts payable and revenue and royalties payable	(25,411)	(674)
Accrued interest and other accrued liabilities	(3,979)	20,982
Net cash provided by operating activities	91,698	155,406
Cash flows from investing activities:		
Development and exploration of oil and natural gas properties	(174,663)	(167,758)
Property acquisitions	(2,897)	(8,529)
Capitalized interest	(1,799)	(5,190)
Proceeds from sale of assets	480	15,700
Deposits on asset sales	—	(3,300)
Net cash used in investing activities	(178,879)	(169,077)
Cash flows from financing activities:		
Proceeds from issuance of 6.375% Senior notes due 2022	—	600,000
Long-term borrowings under credit facility	299,200	102,700
Repayments of long-term borrowings under credit facility	(208,500)	(634,200)
Financing obligation	(112)	(101)
Debt issuance costs	—	(10,569)
Dividends paid	(4,400)	(4,381)
Stock options and restricted stock issued	65	3,498
Excess income tax benefit	721	422
Net cash provided by financing activities	86,974	57,369
Net (decrease) increase in cash and cash equivalents	(207)	43,698
Cash and cash equivalents at beginning of period	312	298
Cash and cash equivalents at end of period	$105	$43,996
Noncash investing activities:		
Accrued capital expenditures	$32,379	$41,339
Asset retirement obligations	7,022	4,994

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	—	—	3,195	—	3,195
Income tax effect of stock option exercises	—	—	721	—	721
Dividends ($0.08 per share)	—	—	—	(4,400)	(4,400)
Net earnings	—	—	—	32,434	32,434
Balances at March 31, 2013	$527	$18	$368,688	$677,573	$1,046,806

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 March 31, 2013 and December 31, 2012 was $14.7 million and $14.9 million, respectively, representing outstanding checks in excess of the bank balance (book overdraft).

Recent Accounting Standards

There are no material new accounting pronouncements that have been issued but not yet adopted by the Company as of March 31, 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 gain on sale of assets.

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

3. Debt

Senior Secured Revolving Credit Facility

As of March 31, 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 March 31, 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 March 31, 2013, there were $653.6 million in outstanding borrowings under the credit facility and $23.2 million in outstanding letters of credit, leaving $523.2 million in borrowing capacity available under the credit facility. The maximum amount available under the credit facility is subject to semi-annual redeterminations of the borrowing base in April and October of each year, based on the value of the Company's proved oil and natural gas reserves, in accordance with the lenders' customary procedures and practices. The Company and the lenders each have the right to one additional redetermination each year. 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.

4. Income Taxes

The effective income tax rate for the three months ended March 31, 2013 and 2012 was 39.0% and 37.8%, respectively. The Company's provision for income taxes differed from the U.S. statutory rate of 35% primarily due to state income taxes, domestic production activities deduction, percentage depletion, nondeductible employee compensation and other permanent differences.

As of March 31, 2013, the Company had a gross liability for uncertain income tax benefits of $22.6 million, $17.5 million of which, if recognized, would impact the effective income tax rate. There have been no significant changes to the calculation of uncertain income tax benefits during 2013. 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 March 31, 2013 could decrease by a maximum of $6.7 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.

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.

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

The following table shows the computation of basic and diluted net earnings per share for the three months ended March 31, 2013 and 2012:

	Three Months Ended March 31,	
(in thousands, except per share data)	2013	2012
Net earnings	$32,434	$33,898
Less: net earnings allocable to participating securities	81	171
Net earnings available for common shareholders	$32,353	$33,727
Basic net earnings per share	$0.59	$0.62
Diluted net earnings per share	$0.58	$0.61
Basic weighted average shares outstanding	55,186	54,759
Add: Dilutive effects of stock options and RSUs	379	504
Dilutive weighted average shares outstanding	55,565	55,263

Not included in the diluted earnings per share calculation were 0.8 million and 0.3 million stock options and RSUs, for the three months ended March 31, 2013 and March 31, 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 three months ended March 31, 2013 and 2012:

	Three Months Ended March 31,	
(in thousands)	2013	2012
Beginning balance at January 1	$86,746	$64,019
Liabilities incurred	2,711	2,993
Liabilities settled	(805)	(467)
Disposition of assets	—	(705)
Accretion expense	1,704	1,223
Revisions in estimated cash flows	4,311	2,001
Ending balance at March 31	$94,667	$69,064

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 $3.0 million and $3.0 million during the three months ended March 31, 2013 and 2012, respectively.

Stock Options

The following table summarizes stock option activity for the three months ended March 31, 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 March 31, 2013	1,384,592	$33.74	$17,939	3.84
Vested and expected to vest at March 31, 2013	1,384,293	$33.73	$17,939	3.84
Exercisable at March 31, 2013	1,278,372	$32.29	$17,939	3.45

(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 March 31, 2013, there were $2.3 million of total unrecognized compensation costs related to outstanding stock options. These costs are expected to be recognized over 3.0 years.

Restricted Stock Units

The following table summarizes restricted stock unit (RSU) activity for the three months ended March 31, 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	(175,269)	24.68	$6,817
Canceled/expired	(1,445)	49.29	
Outstanding at March 31, 2013(1)(2)	1,069,196	$32.16	

(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.

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BERRY PETROLEUM COMPANY
Notes to Condensed Financial Statements (Continued)
(Unaudited)
7. Equity Incentive Compensation Plans (Continued)

As of March 31, 2013, there were $20.3 million of total unrecognized compensation costs related to RSUs granted. These costs are expected to be recognized over 4.0 years.

Performance Share Program

The following table summarizes performance share award activity for the three months ended March 31, 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 March 31, 2013	122,923	$57.61	

(1) Reflects the maximum number of performance shares that can be issued.

As of March 31, 2013, there were $1.8 million of total unrecognized compensation costs related to performance shares granted. These costs are expected to be recognized over 1.8 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 March 31, 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 three months ended March 31, 2013:

Crude Oil Sales Three-Way Collars

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

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

Crude Oil Sales (NYMEX WTI) Swaps

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

Crude Oil Sales (NYMEX WTI to ICE Brent) Basis Swaps

Term	Average Barrels Per Day	Weighted Average Price
Full year 2014	10,000	$11.60
Full year 2015	8,000	$11.60

Crude Oil Sales (NYMEX WTI to Midland) Basis Swaps

Term	Average Barrels Per Day	Weighted Average Price
April 2013 - December 2013	4,000	$1.48

In March 2012, the Company terminated certain of its natural gas derivative instruments, which were associated with a total of 15,000 MMBtu/D for the remainder of 2012. The termination resulted in a net loss of $1.9 million, including cash settlements and non-cash fair value losses, and was recorded in the Condensed Statements of Operations under the caption realized and unrealized loss 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)		March 31, 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	$12.4	$(4.8)	$7.6
Commodity derivative instruments	Long-term	24.0	(6.5)	17.5
Total assets		$36.4	$(11.3)	$25.1
Liabilities				
Commodity derivative instruments	Current	$9.9	$(4.8)	$5.1

Commodity derivative instruments	Long-term	6.5	(6.5	) —
Total liabilities		$16.4	$(11.3	) $5.1

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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 March 31,	
Description of Loss (Gain)	Recognized in Earnings	2013	2012
Commodity			
Loss reclassified from AOCL into earnings (amortization of frozen amounts)	Oil and natural gas sales	$—	$2.7
Loss recognized in earnings (cash settlements and mark-to-market movements)	Realized and unrealized loss on derivatives, net	0.7	28.5
Interest rate			
Gain reclassified from AOCL into earnings (amortization of frozen amounts)	Interest	$—	$(0.6)

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 March 31, 2013 was $20.8 million.

As of March 31, 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 March 31, 2013, the Company was in a net liability position with two of the counterparties to the Company's derivative instruments, totaling $0.8 million. As of March 31, 2013, the Company's largest two counterparties accounted for 69% 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 March 31, 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				
March 31, 2013	$20.1	$—	$20.1	$—
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:

March 31, 2013	Carrying Amount	Estimated Fair Value			
(in millions)		Level 1	Level 2	Level 3	Total
Cash and cash equivalents	$—	$—	$—	$—	$—
Senior secured revolving credit facility(1)	654	—	654	—	654
10.25% Senior notes due 2014(2)	205	224	—	—	224
6.75% Senior notes due 2020	300	324	—	—	324
6.375% Senior notes due 2022	600	639	—	—	639
	$1,759	$1,187	$654	$—	$1,841

(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 $2.0 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 a portion as interest expense, with the balance being recorded as a reduction to the financing obligation. There are no minimum payments required under these agreements. For the three months ended March 31, 2013 and 2012, the Company incurred costs of $0.7 million and $0.9 million, respectively, under the agreements. These amounts are recorded in the Condensed Financial Statements under the caption operating costs—oil and natural gas production.

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. If by June 30, 2013 (which date is subject to extension to no later than December 31, 2014 under the terms of the amendment), the Company has not expended $9.0 million on the construction of either the extension of the road or a new road, then the Company will be 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. 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 June 30, 2013 (or the extended date), 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 intends to contest the proposed debarment and believes the matter is without merit; nevertheless, the Company has reached an agreement in principle with the DOI to resolve the matter administratively.

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.

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

BERRY PETROLEUM COMPANY
Notes to Condensed Financial Statements (Continued)
(Unaudited)
11. LinnCO, LLC Merger (Continued)

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 of LinnCo and Linn, 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.

A response has not yet been filed with respect to either complaint. However, 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.

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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 of LinnCo and Linn, 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.

A response has not yet been filed with respect to either complaint. However, the Company believes the claims relating to the merger are without merit, and intends to defend such actions vigorously.

Notable First Quarter 2013 Items

- Increased oil production by 2% from the fourth quarter of 2012
- Generated discretionary cash flow of $133.9 million from production of 39,676 BOE/D, of which 79% was oil(1)
- Generated an operating margin of $48.80 per BOE, supported by sales of our California heavy oil at a $10.18 average premium to WTI during the quarter(1)
- Average daily production from our Diatomite properties increased 7% from the fourth quarter of 2012
-

- Production from our North Midway-Sunset—New Steam Floods (NMWSS—NSF) properties, which include McKittrick, averaged 2,355 BOE/D, an 11% increase from the fourth quarter of 2012
- Production from our Permian properties averaged 8,105 BOE/D, a 2% increase from the fourth quarter of 2012
- Drilled 20 Uinta wells, 10 Permian wells and 44 Diatomite wells

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(1) Discretionary cash flow and operating margin are considered non-GAAP performance 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 first quarter of 2013, we reported net earnings of $32.4 million, or $0.58 per diluted share, and net cash flows from operations of $91.7 million. Net earnings in the first quarter of 2013 included a loss on derivatives of $1.9 million resulting from non-cash changes in fair values, lease write offs of $1.5 million and $1.3 million of professional fees 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:

	March 31, 2013	%	March 31, 2012	%	December 31, 2012	%
Heavy oil production (BOE/D)	19,566	50	17,005	49	19,058	48
Light oil production (BOE/D)	11,588	29	8,091	24	11,591	30
Total oil production (BOE/D)	31,154	79	25,096	73	30,649	78
Natural gas production (Mcf/D)	51,132	21	56,105	27	53,106	22
Total (BOE/D)(1)	39,676	100	34,447	100	39,500	100
Oil and natural gas, per BOE:						
Average realized sales price	$75.27		$74.33		$ 70.51	
Average sales price including cash derivative settlements	$75.95		$74.44		$ 72.47	
Oil, per BOE:						
Average WTI price	$94.36		$103.03		$ 88.23	
Price sensitive royalties(2)	(2.81)		(4.24)		(2.65)	
Location differential and other(3)	(1.25)		(1.48)		0.79	
Oil derivatives non-cash amortization(4)	0.89		(1.14)		(1.03)	
Oil revenue	$91.19		$96.17		$ 85.34	
Add: Oil derivatives non-cash amortization(4)	—		1.14		1.03	
Oil derivative cash settlements(5)	(0.89)		(3.08)		1.57	
Average realized oil price	$90.30		$94.23		$ 87.94	
Natural gas price:						
Average Henry Hub price per MMBtu	$3.34		$2.72		$ 3.41	
Conversion to Mcf	0.22		0.18		0.24	
Natural gas derivatives non-cash amortization(4)	—		(0.01)		—	
Location differential and other	(0.09)		(0.30)		(0.14)	
Natural gas revenue per Mcf	$3.47		$2.59		$ 3.51	
Add: Natural gas derivatives non-cash amortization(4)	—		0.01		—	
Natural gas derivative cash settlements(5)	(0.01)		0.92		(0.03)	
Average realized natural gas price per Mcf	$3.46		$3.52		$ 3.48	

(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 first 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 March 31, 2013 was $9.10, ranged from $9.10 to $11.02 during the first quarter of 2013 and averaged $10.18 during the first quarter of 2013. In Utah, the per barrel oil posting differential at March 31, 2013 was ($16.50), ranged from ($14.50) to ($16.50) during the first quarter of 2013 and averaged ($15.65) during the first quarter of 2013.

Non-cash amortization of AOCL resulting from discontinuing hedge accounting effective January 1, 2010.

(4) Recorded in the Condensed Statements of Operations under the caption oil and natural gas sales. At December 31, 2012, the entire balance of AOCL had been reclassified into earnings.

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

	March 31, 2013	March 31, 2012	1Q12 to 1Q13 Change		December 31, 2012	4Q12 to 1Q13 Change	
Oil sales	$250,777	$220,452	14	%	$231,766	8	%
Natural gas sales	15,995	13,201	21	%	17,145	(7	)%
Total oil and natural gas sales	$266,772	$233,653	14	%	$248,911	7	%
Electricity sales	7,589	5,980	27	%	8,586	(12	)%
Natural gas marketing	2,027	1,859	9	%	2,253	(10	)%
Gain on sale of assets	23	1,763	(99	)%	12	92	%
Interest and other income, net	475	747	(36	)%	307	55	%
Total revenues and other income	$276,886	$244,002	13	%	$260,069	6	%
Net earnings	$32,434	$33,898	(4	)%	$38,499	(16	)%
Diluted earnings per share	$0.58	$0.61	(5	)%	$0.69	(16	)%

Oil and Natural Gas Sales.

Oil and natural gas sales increased $33.1 million, or 14%, to $266.8 million in the first 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 21% in the first quarter of 2013 compared to the first quarter of 2012, while our natural gas sales volumes decreased 10%. The oil sales volume increase was primarily due to increased oil production from each of our oil properties. Permian oil production in the first quarter of 2013 increased 2,065 BOE/D, or 44%, from the same period in 2012, Uinta oil production increased 1,525 BOE/D, or 49%, between periods, Diatomite oil production in the first quarter of 2013 increased 1,430 BOE/D, or 53%, from the same period in 2012, oil production for NMWSS—NSF increased 845 BOE/D, or 56%, between periods and South Midway-Sunset—Steam Floods (SMWSS—Steam Floods) oil production increased 285 BOE/D, or 2%, between periods. 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 Permian and Uinta properties.

Oil and natural gas sales increased $17.9 million, or 7%, to $266.8 million in the first quarter of 2013 compared to the fourth quarter of 2012. The increase was primarily due to a 7% increase in the average realized sales price between periods, primarily due to an increase in oil sales volumes as a percentage of total sales volumes. In addition, oil sales volumes increased 2% in the first quarter of 2013 compared to the fourth quarter of 2012, while natural gas sales volumes decreased 6% 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 Uinta, which was impacted by refinery constraints in the Utah region. Diatomite oil production increased 260 BOE/D, or 7%, between periods, NMWSS—NSF oil production increased 225 BOE/D, or 11%, from the fourth quarter of 2012, and Permian oil production increased 175 BOE/D, or 3%, between periods. The decrease in natural gas sales volumes was primarily due to expected field decline in E. Texas and the Piceance.

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Electricity Sales.

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

	Three Months Ended		
	March 31, 2013	March 31, 2012	December 31, 2012
Electricity			
Electricity sales (in thousands)	$7,589	$5,980	$ 8,586
Operating costs (in thousands)	$5,296	$5,017	$ 5,975
Electric power produced (MWh/D)	2,036	2,089	2,112
Electric power sold (MWh/D)	1,851	1,935	1,917
Average sales price per MWh	$44.77	$33.96	$ 41.30
Fuel gas cost per MMBtu (including transportation)	$3.55	$2.71	$ 3.51
Estimated natural gas volumes consumed to produce electricity (MMBtu/D)(1)	14,726	15,197	15,987

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

Electricity sales in the first quarter of 2013 increased 27% compared to the first quarter of 2012 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 first quarter of 2013 increased 6% compared to the first quarter of 2012 largely due to a 31% increase in fuel gas cost, partially offset by a 3% decrease in electric power produced. Electricity sales decreased 12% in the first quarter of 2013 compared to the fourth quarter of 2012. Electricity sales in the fourth quarter of 2012 included a retroactive payment adjustment for capacity of $1.3 million from one of our electricity customers. As a result of our previously disclosed global settlement with various parties that became effective on November 23, 2011, we received retroactive payments for firm capacity that had been originally paid at "as available" capacity rates, and these payments represent the difference in rates over the disputed period. Excluding the retroactive payment adjustments, electricity sales in the first quarter of 2013 would have increased 5% compared to the fourth quarter of 2012 primarily due to an 8% increase in the average sales price of electricity partially offset by a 3% decrease in electric power sold. Electricity operating costs in the first quarter of 2013 decreased 11% compared to the fourth quarter of 2012 largely due to an 8% decrease in fuel gas volumes purchased.

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

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

Our legacy PPA for our Cogen 38 facility expired in March 2012, at which time a transition PPA with PG&E became effective. We intend to participate in future CHP 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.

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The following table summarizes our cogeneration facilities and related contract information as of March 31, 2013:

Facility	Type of Contract(1)	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 7-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 March 31, 2013 and 2012 were $0.1 million and $0.1 million, respectively.

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 gain on sale of assets.

Oil and Natural Gas Operating and Other Expenses.

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

	Amount Per BOE			Amount (in thousands)		
	March 31, 2013	March 31, 2012	December 31, 2012	March 31, 2013	March 31, 2012	December 31, 2012
Operating costs—oil and natural gas production(1)	$24.13	$17.30	$ 23.35	$86,148	$54,221	$ 84,862
Production taxes	3.02	3.40	2.57	10,784	10,658	9,326
DD&A—oil and natural gas production	19.07	15.30	18.44	68,084	47,956	67,023
General and administrative	6.24	5.66	5.03	22,278	17,741	18,293
Interest expense	6.91	6.41	5.97	24,687	20,104	21,690
Total	$59.37	$48.07	$ 55.36	$211,981	$150,680	$ 201,194

(1) Operating costs—oil and natural gas production includes firm transportation costs of $7.7 million and $7.0 million for the three months ended March 31, 2013 and 2012, respectively, and $7.1 million for the three months ended December 31, 2012.

Operating costs—oil and natural gas production in the first quarter of 2013 were $86.1 million, or $24.13 per BOE, compared to $54.2 million, or $17.30 per BOE, in the first quarter of 2012 and $84.9 million, or $23.35 per BOE, in the fourth quarter of 2012. The increase in the first quarter of 2013 compared to the first quarter of 2012 was primarily due to an increase of approximately $14.6 million in steam costs, due to a 47% increase in the average volume of steam injected and a 31% increase in the price of natural gas used in steam generation. Also contributing to the increase in steam costs was $3.2 million of emissions expense related to California greenhouse gas regulatory compliance in the first quarter of 2013. Also increasing over the same time period were well workover costs and contract services primarily related to Permian wells added in the last 12 months, well servicing and maintenance costs in the Uinta and contract labor in the Diatomite.

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The increase in operating costs—oil and natural gas production in the first quarter of 2013 compared to the fourth quarter of 2012 was primarily due to an increase in steam costs primarily due to $3.2 million of emissions expense related to California greenhouse gas regulatory compliance. Also increasing over the same time period were well servicing and maintenance costs and transportation costs, partly related to refinery constraints in the Utah region during the fourth quarter of 2012. These increases were partially offset by a decrease in well workover costs in the Permian between periods.

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

	March 31, 2013	March 31, 2012	1Q12 to 1Q13 Change		December 31, 2012	4Q12 to 1Q13 Change	
Average net volume of steam injected (Bbl/D)	197,829	134,510	47	%	197,950	—	%
Fuel gas cost per MMBtu (including transportation)	$3.55	$2.71	31	%	$ 3.51	1	%
Approximate net fuel gas volume consumed in steam generation (MMBtu/D)	66,171	45,591	45	%	61,998	7	%

- Production taxes in the first quarter of 2013 were $10.8 million, or $3.02 per BOE, compared to $10.7 million, or $3.40 per BOE, in the first quarter of 2012 and $9.3 million, or $2.57 per BOE, in the fourth quarter of 2012. 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 decrease in production taxes per BOE in the first quarter of 2013 compared to the first quarter of 2012 was primarily due to a decrease in Utah severance taxes related to increased new well deductions associated with increased drilling in the first quarter of 2013. The increase in production taxes in the first quarter of 2013 compared to the fourth quarter of 2012 was primarily due to increases in estimated 2013 ad valorem taxes associated with development in the Permian and in Utah.

- Depreciation, depletion and amortization—oil and natural gas production (DD&A—oil and natural gas production) in the first quarter of 2013 was $68.1 million, or $19.07 per BOE, compared to $48.0 million, or $15.30 per BOE, in the first quarter of 2012 and $67.0 million, or $18.44 per BOE, in the fourth quarter of 2012. The increase in the first quarter of 2013 compared to the first quarter of 2012 and the fourth quarter of 2012 was primarily due to an increase in our DD&A rate. Our DD&A rate per BOE can fluctuate as a result of changes in the mix of our production, impairments, and changes in our proved reserves. Our DD&A rate per BOE in the first quarter of 2013 was 25% higher than in the first quarter of 2012 and 3% higher than in the fourth quarter of 2012. The higher DD&A rate per BOE in the first quarter of 2013 compared to the first quarter of 2012 was primarily due to our development expenditures during the past twelve months 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 15% from the first quarter of 2013 to the first quarter of 2012 contributed to higher DD&A costs. The higher DD&A rate per BOE in the first quarter of 2013 compared to the fourth quarter of 2012 was primarily due to converting part of our Piceance proved reserves to unproved at December 31, 2012 as a result of the SEC's five year development limitation on proved undeveloped reserves.

- General and administrative expense (G&A) in the first quarter of 2013 was $22.3 million, or $6.24 per BOE, compared to $17.7 million, or $5.66 per BOE, in the first quarter of 2012 and $18.3 million, or $5.03 per BOE, in the fourth quarter of 2012. The increase in the first quarter of 2013 compared to the first quarter of 2012 was primarily due to $2.1 million of professional fees associated with the pending LinnCo merger, an increase in employee compensation and benefits resulting from new personnel hired during the previous twelve months, as well as general pay increases. The increase in the first quarter of 2013 compared to the fourth quarter of 2012 was primarily due to

$2.1 million related to professional fees associated with the pending LinnCo merger, director compensation of $1.1 million recorded in the first quarter of 2013 and new personnel hired and general pay increases during the first quarter of 2013.

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•The following table sets forth components of interest expense for the periods presented:

	Three Months Ended		
(in thousands)	March 31, 2013	March 31, 2012	December 31, 2012
Senior subordinated notes	$—	$4,125	$—
Senior notes	19,885	16,397	19,885
Credit facility	4,412	2,938	3,639
Amortization of debt issuance costs and net discount	1,709	2,038	1,680
Amortization of AOCL	—	(647)	—
Other	480	443	423
Capitalized interest	(1,799)	(5,190)	(3,937)
	$24,687	$20,104	$21,690

Interest expense in the first quarter of 2013 was $24.7 million, or $6.91 per BOE, compared to $20.1 million, or $6.41 per BOE, in the first quarter of 2012 and $21.7 million, or $5.97 per BOE, in the fourth quarter of 2012. The increase in the first quarter of 2013 compared to the first quarter of 2012 was primarily due to the issuance of our 2022 Notes in March 2012, a decrease in capitalized interest and an increase in the amount outstanding under our credit facility. 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. The increase in the first quarter of 2013 compared to the fourth quarter of 2012 was primarily due a decrease in capitalized interest and an increase in the amount outstanding under our credit facility.

Dry Hole, Abandonment, Impairment and Exploration. For the three months ended March 31, 2013, we incurred dry hole, abandonment, impairment and exploration expense of $1.0 million, primarily related to plugging and abandonment activities, primarily 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 months ended March 31, 2012, we incurred dry hole, abandonment, impairment and exploration expense of $3.1 million primarily for the purchase of seismic data and plugging and abandonment activities.

Impairment of Oil and Natural Gas Properties. In the three months ended March 31, 2013, we wrote off $2.5 million related to the expiration of certain leases in the Permian.

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Realized and Unrealized Loss (Gain) on Derivatives, Net. The following table sets forth the derivative cash settlements and non-cash derivative contract fair value gains and losses recorded in the Condensed Statements of Operations under the caption realized and unrealized loss 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		
(in thousands)	March 31, 2013	March 31, 2012	December 31, 2012
Cash (receipts) payments:			
Commodity derivatives—oil	$(2,470)	$7,069	$(4,280)
Commodity derivatives—natural gas(1)	61	(19,381)	149
Total cash (receipts) payments	$(2,409)	$(12,312)	$(4,131)
Mark-to-market loss (gain):			
Commodity derivatives—oil	$3,693	$24,363	$(4,660)
Commodity derivatives—natural gas(1)	(547)	16,430	485
Total mark-to-market loss (gain)	$3,146	$40,793	$(4,175)
Total realized and unrealized loss (gain) on derivatives, net	$737	$28,481	$(8,306)

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

Income Tax Expense. The effective income tax rate for the three months ended March 31, 2013 and 2012 was 39.0% and 37.8%, 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.

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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 March 31, 2013 Gross Production Wells		Net Production Wells
SMWSS—Steam Floods	—		—
NMWSS—Diatomite	44		44
NMWSS—New Steam Floods	—		—
Permian	16	(1)	10
Uinta	20		18
E. Texas	—		—
Piceance	—		—
Total	80		72

(1) Includes six non-operated wells in which we have an average interest of approximately 0.68% each, or approximately 0.04 total net wells, and 10 gross operated 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 plan to continue development at Ethel D, where we plan to drill seven new producing wells and four steam injection wells, as well as redrill one producing well. Also during the second quarter of 2013, we plan to drill two horizontal producing wells at Formax, as well as seven new producing wells and seven recompletions at Placerita. Average daily production in the first quarter of 2013 from all of our SMWSS—Steam Floods assets was approximately 13,095 BOE/D compared to 13,070 BOE/D in the fourth quarter of 2012.

NMWSS—Diatomite. Our NMWSS—Diatomite asset team includes our Diatomite properties in the San Joaquin Valley. We are continuing to refine our development approach by using real-time performance monitoring and surveillance, and have increased our focus on redevelopment areas. We expect these efforts to increase the number of active completions and improve the recovery of the resource in leases with existing production and infrastructure. In the first quarter of 2013, we drilled 27 new producing wells and 17 replacement wells, and plan to drill an additional 12 new producing wells and 14 replacement wells in the second quarter of 2013. Average daily production from our NMWSS—Diatomite assets in the first quarter of 2013 was approximately 4,115 BOE/D, a 7% increase from 3,855 BOE/D in the fourth quarter of 2012.

NMWSS—New Steam Floods. 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 first quarter of 2013, we drilled the first seven of the 50 steam injection wells we plan to drill at McKittrick during 2013, and we plan to drill the remaining 43 steam injection wells in the second quarter of 2013. We also added an additional steam generator at

McKittrick in the first quarter of 2013, increasing the steam capacity at McKittrick to approximately 25,000 barrels of steam per day. In addition, during the first quarter of 2013, we began expanding our Main Camp oil processing facility, and expect to complete the expansion in the second quarter of 2013. Average daily production from all of our NMWSS—NSF assets in the first quarter of 2013 was approximately 2,355 BOE/D, a 11% increase from 2,130 BOE/D in the fourth quarter of 2012.

Permian. During the first quarter of 2013, we drilled ten net wells using a three-rig program, and we plan to continue at this pace, drilling ten additional net wells in the second quarter of 2013. While our Permian production continues to increase, 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. Average daily production in the first quarter of 2013 from our Permian assets was approximately 8,105 BOE/D, a 2% increase from 7,965 BOE/D in the fourth quarter of 2012.

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Uinta. During the first quarter of 2013, we drilled 20 gross (18 net) wells at our Uinta properties utilizing a three-rig drilling program. Of the 20 wells drilled, 19 were Wasatch/Green River commingled wells. Our Uinta production in the first quarter of 2013 was impacted by delayed completion activity as we worked off inventory in the field resulting from refinery turnarounds. In the first quarter of 2013, we began shipping crude oil via rail to markets outside of Utah. In the second quarter of 2013, we plan to drill 20 gross wells utilizing a two-rig program, including five in Brundage Canyon, four in Lake Canyon, and 11 in Ashley National forest. Average daily production from our Uinta assets was approximately 7,305 BOE/D in the first quarter of 2013, a 3% decrease from 7,500 BOE/D in the fourth quarter of 2012.

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 first quarter of 2013 from the E. Texas assets was approximately 13 MMcf/D compared to 14 MMcf/D in the fourth quarter of 2012.

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 first quarter of 2013 from the Piceance assets was approximately 15 MMcf/D compared to 16 MMcf/D in the fourth quarter of 2012.

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 March 31, 2013, we had a working capital deficit of approximately $24.7 million. We generally maintain a working capital deficit because we use excess cash to reduce borrowings under our credit facility. 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 March 31, 2013, we had approximately 65% and 60% 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 March 31, 2013, our credit facility, which matures on May 13, 2016, had a borrowing base of $1.4 billion, subject to lender commitments. At March 31, 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 March 31, 2013, there were $653.6 million in outstanding borrowings under the credit facility and $23.2 million in outstanding letters of credit, leaving $523.2 million in borrowing capacity available under the credit facility. The maximum amount available under the credit facility is subject to semi-annual redeterminations of the borrowing base in April and October of each year, based on the value of our proved oil and natural gas reserves, in accordance with the lenders' customary procedures and practices. We and the lenders each have a right to one additional redetermination each year. 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 March 31, 2013, we were in compliance with all financial covenants and have complied with all financial covenants for all prior periods presented.

Outstanding Long-Term Indebtedness. As of March 31, 2013 we had the following senior notes outstanding:

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

- $300 million aggregate principal amount of our 2020 Notes; and

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

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

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

Historical Cash Flows.

	Three Months Ended	
(in thousands)	March 31, 2013	March 31, 2012
Net cash provided by operating activities	$91,698	$155,406
Net cash used in investing activities	(178,879)	(169,077)
Net cash provided by financing activities	86,974	57,369
Net (decrease) increase in cash and cash equivalents	$(207)	$43,698

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 $63.7 million in the first three months of 2013 compared to the first three 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 $51.5 million.

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 increase of $9.8 million in net cash used in investing activities in the first three months of 2013 compared to the first three months of 2012 was primarily due to an increase in development and exploration activity partially offset by decreases in acquisitions, capitalized interest and divestitures. Investing activities in the first three months of 2012 included proceeds from the sale of our Nevada assets.

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Financing Activities. Net cash provided by financing activities in the first three months of 2013 included net borrowings of $90.7 million under our credit facility. Net cash provided by financing activities in the first three months of 2012 included net proceeds of $589.5 million from the issuance of $600 million aggregate principal amount of our 2022 Notes, offset by net repayments of $531.5 million of borrowings under our credit facility.

Capital Expenditures.

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

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

Recent Accounting Standards and Updates.

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

Reconciliation of Non-GAAP Measures.

Discretionary Cash Flow. Discretionary cash flow is a non-GAAP liquidity measure. Discretionary cash flow consists of cash provided by operating activities before changes in working capital items, cash settlements from the early termination of natural gas derivatives and cash premiums to repurchase debt. 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 March 31, 2013
Net cash provided by operating activities	$91,698
Net increase in current assets	12,564
Net decrease in current liabilities, including book overdraft	29,622
Discretionary cash flow	$133,884

Operating Margin per BOE. Operating margin per BOE consists of oil and natural gas revenues less oil and natural gas operating expenses and production taxes divided by the total BOEs produced during the period. 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 March 31, 2013

Average sales price including cash derivative settlements	$75.95
Average operating costs—oil and natural gas production	24.13
Average production taxes	3.02
Average operating margin	$48.80

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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 March 31, 2013, we had approximately 65% and 60% 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 March 31, 2013 would decrease the fair value of our crude oil derivative instruments by \$102.4 million and would increase the fair value of our natural gas derivative instruments by \$2.0 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 March 31, 2013 would increase the fair value of our crude oil derivative instruments by \$92.4 million and would decrease the fair value of our natural gas derivative instruments by \$1.3 million.

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The following table summarizes our commodity derivative position as of March 31, 2013:

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

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

(1) Derivative transactions we entered into with respect to our production following the execution of the merger agreement. The 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 March 31, 2013, our outstanding principal balance under our credit facility was $653.6 million and the weighted average interest rate on the outstanding principal balance was 2.30%. At March 31, 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 $4.0 million over a 12-month time period.

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Item 4. Controls and Procedures

As of March 31, 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 March 31, 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 March 31, 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. Except as set forth below, as of the date of this report, these risk factors have not significantly changed. This information should be considered carefully, together with other information in this report and other reports and materials we file with the United States Securities and Exchange Commission.

Failure to complete or delays in completing the merger could have an adverse impact on our stock price and our business. If the merger is not completed, or there are delays in completing the merger, our stock price and our business could be adversely affected and we would be subject to a number of risks, including the following:

- the current trading price of our common stock may reflect a market assumption that the merger will be completed and a failure to complete or delays in completing the merger could result in a decline in the price of our common stock;
- we may not realize the benefits expected from the merger, including cost savings, enhanced financial and competitive position and diversification of customer base, operating locations and assets;
- we will be required to pay certain costs relating to the merger, including certain investment banking, financing, legal and accounting fees and expenses, whether or not the merger is completed, and we may be required to pay LinnCo a termination fee of up to $83.7 million under certain circumstances;
- the merger agreement places certain restrictions on the conduct of our business prior to completion of the merger or termination of the merger agreement, and such restrictions prevent us from making certain acquisitions or taking certain other specified actions during the pendency of the merger; and
- we may be responsible for the net losses resulting from the termination of the derivative transactions entered into by us on or after the date of the merger agreement, which net losses could be significant.

There can be no assurance that these risks will not materialize, and if any of them do, they may have an adverse effect on our financial position, results of operations and operating cash flows.

The proposed merger with LinnCo and related transactions are subject to approval by our stockholders, LinnCo shareholders and LINN Energy unitholders, and are subject to the receipt of consents and approvals from governmental entities that may impose conditions that could have an adverse effect on LinnCo. In order for the merger to be completed, the our stockholders must adopt the merger agreement and approve the merger and the other transactions contemplated by the merger agreement, which requires approval by a majority of the votes entitled to be cast by all outstanding shares of our common stock. In addition, the completion of the merger is subject to a vote of holders of LinnCo common shares LINN Energy unitholders. We can make no assurance as to the outcome of such shareholder or unitholder votes.

Before the merger may be completed, various waivers, approvals, clearances or consents must be obtained from the Federal Trade Commission, Federal Energy Regulatory Commission and the Antitrust Division of the Department of Justice and other authorities in the United States. These governmental entities may impose conditions on the completion of the merger or require changes to the terms of the merger. Although we do not currently expect that any such conditions or changes will be imposed, there can be no assurance that they will not be, and such conditions or changes could have the effect of delaying completion of the merger or imposing additional costs on or limiting the revenues of LinnCo and LINN Energy following the merger.

Pending litigation against Berry, LinnCo and LINN Energy could result in an injunction preventing completion of the merger, the payment of damages in the event that the merger is completed and/or may adversely affect the combined company's business, financial condition or results of operations following the merger. Purported stockholder class actions have been filed against, among others, us, LinnCo, LINN Energy and the members of the our board of directors. The actions generally seek injunctions barring or rescinding the merger and damages in connection with the proposed transactions. If a final settlement is not reached, or if dismissal of such actions is not obtained, such lawsuits could prevent or delay the completion of the merger, and result in substantial costs, including costs associated with the indemnification of our directors. Additional lawsuits related to the merger may be filed. The defense or settlement of any lawsuit or claim that remains unresolved at the time the merger is completed may adversely affect the combined company's business, financial condition or results of operations.

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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
2.1*	Agreement and Plan of Merger, dated as of February 20, 2013, by and among Berry Petroleum Company, Bacchus HoldCo, Inc., Bacchus Merger Sub, Inc., LinnCo, LLC, Linn Acquisition Company, LLC and Linn Energy, LLC (incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed on February 21, 2013, File No. 1-09735).
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

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*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: May 8, 2013