

BERRY PETROLEUM CO

Form 10-Q

August 02, 2012

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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2012

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

(State of incorporation or organization)

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 July 16, 2012 the registrant had 52,381,865 shares of Class A Common Stock (\$.01 par value) outstanding. The registrant also had 1,763,866 shares of Class B Stock (\$.01 par value) outstanding on July 16, 2012, all of which is held by a single holder.

BERRY PETROLEUM COMPANY

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June 30, 2012

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BERRY PETROLEUM COMPANY

Condensed Balance Sheets

(Unaudited)

(In Thousands, Except Share Information)

	June 30, 2012	December 31, 2011
ASSETS		
Current assets:		
Cash and cash equivalents	\$81	\$298
Restricted short-term investments	65	65
Accounts receivable	106,537	115,952
Deferred income taxes	—	13,779
Derivative instruments	28,650	6,117
Assets held for sale	—	14,622
Prepaid expenses and other	17,631	16,801
Total current assets	152,964	167,634
Oil and natural gas properties (successful efforts basis), buildings and equipment, net	2,810,963	2,531,393
Derivative instruments	20,092	7,027
Other assets	32,035	28,898
	\$3,016,054	\$2,734,952
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	\$138,104	\$126,489
Revenue and royalties payable	36,941	49,253
Accrued liabilities	41,138	35,066
Derivative instruments	2	20,365
Deferred income taxes	9,111	—
Total current liabilities	225,296	231,173
Long-term liabilities:		
Deferred income taxes	230,736	185,450
Senior secured revolving credit facility	400,500	531,500
8.25% Senior subordinated notes due 2016	—	200,000
10.25% Senior notes due 2014, net of unamortized discount of \$3,083 and \$6,564, respectively	202,174	348,692
6.75% Senior notes due 2020	300,000	300,000
6.375% Senior notes due 2022	600,000	—
Asset retirement obligation	80,880	64,019
Derivative instruments	—	15,505
Other long-term liabilities	17,662	17,884
	1,831,952	1,663,050
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; 52,381,865 and 52,067,994 shares issued and outstanding, respectively	524	521
Class B Stock, 3,000,000 shares authorized; 1,763,866 and 1,797,784 shares issued and outstanding, respectively (liquidation preference of \$0.50 per share)	18	18
Capital in excess of par value	359,813	350,158

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Accumulated other comprehensive loss	(3,241) (5,517)
Retained earnings	601,692	495,549	
Total shareholders' equity	958,806	840,729	
	\$3,016,054	\$2,734,952	

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		Six Months Ended	
	June 30,		June 30,	
	2012	2011	2012	2011
REVENUES				
Oil and natural gas sales	\$221,781	\$230,760	\$455,434	\$418,149
Electricity sales	5,860	7,964	11,840	14,376
Natural gas marketing	1,580	3,985	3,439	7,670
(Loss) gain on sale of assets	(163) —	1,600	—
Interest and other income, net	645	803	1,392	931
	229,703	243,512	473,705	441,126
EXPENSES				
Operating costs—oil and natural gas production	62,461	58,780	116,713	115,863
Operating costs—electricity generation	4,256	6,891	9,273	13,004
Production taxes	9,690	8,350	20,348	15,741
Depreciation, depletion & amortization—oil and natural gas production	52,026	51,967	99,982	104,076
Depreciation, depletion & amortization—electricity generation	455	491	921	992
Natural gas marketing	1,387	3,674	3,164	7,190
General and administrative	17,965	15,910	35,706	32,201
Interest	20,789	17,712	40,893	33,367
Impairment of oil and natural gas properties	38	—	66	—
Dry hole, abandonment, impairment and exploration	1,547	310	4,555	423
Gain on purchase	—	—	—	(1,046
Extinguishment of debt	41,526	—	41,526	—
Realized and unrealized (gain) loss on derivatives, net	(113,082) (91,808) (84,601) 35,708
	99,058	72,277	288,546	357,519
Earnings before income taxes	130,645	171,235	185,159	83,607
Income tax provision	49,629	66,069	70,245	30,938
Net earnings	\$81,016	\$105,166	\$114,914	\$52,669
Basic net earnings per share	\$1.47	\$1.93	\$2.08	\$0.97
Diluted net earnings per share	\$1.46	\$1.90	\$2.07	\$0.95
Dividends per share	\$0.080	\$0.075	\$0.160	\$0.150

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		Six Months Ended	
	June 30,		June 30,	
	2012	2011	2012	2011
Net earnings	\$81,016	\$105,166	\$114,914	\$52,669
Other comprehensive earnings, net of income taxes:				
Amortization of accumulated other comprehensive loss related to de-designated hedges, net of income tax benefits of \$618, \$5,837, \$1,394 and \$11,673, respectively	1,009	9,522	2,276	19,045
Other comprehensive earnings	1,009	9,522	\$2,276	\$19,045
Comprehensive earnings	\$82,025	\$114,688	\$117,190	\$71,714

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

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

	Six Months Ended	
	June 30,	
	2012	2011
Cash flows from operating activities:		
Net earnings	\$ 114,914	\$ 52,669
Depreciation, depletion and amortization	100,903	105,068
Gain on sale of assets	(1,600) —
Gain on purchase	—	(1,046
Extinguishment of debt	6,842	—
Amortization of debt issuance costs and net discount	3,688	4,205
Impairment of oil and natural gas properties	66	—
Dry hole and impairment	211	298
Derivatives	(66,901) 19,496
Stock-based compensation expense	5,426	5,439
Deferred income taxes	66,782	19,572
Other, net	(524) (190
Allowance for bad debt	315	—
Change in book overdraft	(2,628) 4,022
Changes in operating assets and liabilities:		
Accounts receivable	9,063	(18,543
Inventories, prepaid expenses, and other current assets	(4,702) (1,813
Accounts payable and revenue and royalties payable	7,755	24,044
Accrued interest and other accrued liabilities	8,457	(6,699
Net cash provided by operating activities	248,067	206,522
Cash flows from investing activities:		
Exploration and development of oil and natural gas properties	(328,968) (271,433
Property acquisitions	(24,851) (145,461
Capitalized interest	(9,723) (18,664
Proceeds from sale of assets	15,722	—
Deposits on asset sales	(3,300) —
Net cash used in investing activities	(351,120) (435,558
Cash flows from financing activities:		
Proceeds from issuances on line of credit	—	243,300
Repayments of borrowings under line of credit	—	(235,900
Proceeds from issuance of 6.375% Senior notes due 2022	600,000	—
Repurchase of 8.25% Senior subordinated notes due 2016	(200,000) —
Repurchase of 10.25% Senior notes due 2014	(149,999) —
Long-term borrowings under credit facility	858,700	357,500
Repayments of long-term borrowings under credit facility	(989,700) (132,500
Financing obligation	(202) (185
Debt issuance costs	(11,424) (677
Dividends paid	(8,771) (8,124
Stock options and restricted stock issued	3,497	3,415
Excess income tax benefit	735	2,177
Net cash provided by financing activities	102,836	229,006

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Net decrease in cash and cash equivalents	(217) (30)
Cash and cash equivalents at beginning of period	298	278	
Cash and cash equivalents at end of period	\$81	\$248	
Noncash investing activities:			
Accrued capital expenditures	\$55,311	\$20,809	
Asset retirement obligation	15,012	1,642	

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	Accumulated Other Comprehensive Loss	Total Shareholders' Equity
Balances at December 31, 2011	\$521	\$18	\$350,158	\$495,549	\$ (5,517)	\$840,729
Stock options and restricted stock issued	3	—	3,494	—	—	3,497
Stock based compensation expense	—	—	5,426	—	—	5,426
Income tax effect of stock option exercises	—	—	735	—	—	735
Dividends (\$0.160 per share)	—	—	—	(8,771)	—	(8,771)
Net earnings	—	—	—	114,914	—	114,914
Amortization of Accumulated other comprehensive loss related to de-designated hedges, net of income taxes	—	—	—	—	2,276	2,276
Balances at June 30, 2012	\$524	\$18	\$359,813	\$601,692	\$ (3,241)	\$958,806

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 the Company's 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, 2011, previously filed with the Securities and Exchange Commission (SEC).

All adjustments, consisting of normal and recurring accruals, which are, in the opinion of management, necessary to fairly state Berry Petroleum Company's (the Company) 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 June 30, 2012 and December 31, 2011 were \$13.5 million and \$16.1 million, respectively, representing outstanding checks in excess of the bank balance (book overdraft).

Recent Accounting Standards

In December 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2011-11 which requires that an entity disclose both gross and net information about instruments and transactions that are either eligible for offset in the balance sheet or subject to an agreement similar to a master netting agreement, including derivative instruments. ASU 2011-11 was issued in order to facilitate comparison between GAAP and IFRS financial statements by requiring enhanced disclosures, but does not change existing GAAP that permits balance sheet offsetting. This authoritative guidance is effective for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods. The Company is currently evaluating the provisions of ASU 2011-11 and assessing the impact, if any, it may have on the Company's financial position or results of operations.

2. Acquisitions and Divestures

2012 Acquisition

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 the acquisition of this one well 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 (Nevada Assets), which closed on January 31, 2012, for total cash consideration of \$15.6 million. The Company recorded a \$1.6 million gain in conjunction with the sale. The gain was recorded in the Condensed Statements of Operations under the caption (loss) gain on sale of assets.

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BERRY PETROLEUM COMPANY

Notes to Condensed Financial Statements (Continued)

(Unaudited)

2. Acquisitions and Divestures (Continued)

2011 Acquisition

On May 25, 2011, the Company acquired interests in producing properties on approximately 6,000 net acres in the Wolfberry trend in the Permian for an aggregate purchase price of \$128.4 million. The acquisition was financed using the Company's credit facility. Disclosures of pro forma revenues and net earnings for the wells acquired in this transaction are not material and have not been presented.

3. Debt

Issuance and Sale of 6.375% Senior Notes Due 2022

On March 9, 2012, the Company issued \$600 million aggregate principal amount of its 6.375% Senior notes due 2022 (2022 Notes) for net proceeds of \$589.5 million. Interest is payable in arrears semi-annually in March and September of each year, beginning September 2012. The 2022 Notes are senior unsecured obligations of the Company, which rank effectively junior to all of the Company's existing and any future secured debt, to the extent of the value of the collateral securing that debt, equally in right of payment with the Company's 10.25% Senior notes due 2014 (2014 Notes) and 6.75% Senior notes due 2020 (2020 Notes), and senior in right of payment to all of the Company's existing and any future subordinated debt.

On and after March 15, 2017, the Company may redeem all or, from time to time, a part of the 2022 Notes upon not less than 30 nor more than 60 days' notice, at the following redemption prices (expressed as a percentage of principal amount of notes to be redeemed), plus accrued and unpaid interest, if any, to the applicable redemption date (subject to the right of holders of record on the relevant record date to receive interest due on the relevant interest payment date), if redeemed during the 12-month period beginning on March 15 of the years indicated below:

2017	103.188	%
2018	102.125	%
2019	101.063	%
2020 and thereafter	100.000	%

In addition, before March 15, 2015, the Company may, at its option, on any one or more occasions redeem up to 35% of the aggregate principal amount of the 2022 Notes with the net cash proceeds of certain equity offerings and if certain conditions are met as described in the indenture governing the 2022 Notes, at a redemption price of 106.375% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date. At any time prior to March 15, 2017, the Company may also redeem all or part of the 2022 Notes at a redemption price equal to 100% of the principal amount of the notes redeemed plus a "make-whole" premium described in the indenture, plus accrued and unpaid interest, if any, to the redemption date.

Tender Offer and Redemption of Notes

On April 3, 2012, pursuant to the terms of the Offer to Purchase dated March 6, 2012, the Company repurchased \$150.0 million aggregate principal amount of its 2014 Notes for an aggregate purchase price of \$181.5 million, including accrued and unpaid interest. A related loss of \$30.9 million was recorded in the second quarter of 2012, consisting of \$26.4 million for premiums paid over par and \$4.5 million for write-offs of net discounts and debt issuance costs. The 2014 Notes were repurchased using net proceeds from the issuance of the Company's 2022 Notes.

Following the closing of the tender offer on April 3, 2012, \$205.3 million aggregate principal amount of 2014 Notes was outstanding.

On April 9, 2012, the Company redeemed all \$200 million aggregate principal amount of its 8.25% Senior subordinated notes due 2016 (2016 Notes) for an aggregate purchase price of \$215.5 million, including accrued and unpaid interest. A related loss of \$10.6 million was recorded in the second quarter of 2012 consisting of \$8.3 million for premiums paid over par and \$2.3 million for write-offs of debt issuance costs. The 2016 Notes were redeemed using net proceeds from the issuance of the Company's 2022 Notes.

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BERRY PETROLEUM COMPANY

Notes to Condensed Financial Statements (Continued)

(Unaudited)

3. Debt (Continued)

Senior Secured Revolving Credit Facility

On April 13, 2012, as part of the semi-annual borrowing base redetermination process, the Company entered into a fourth amendment to its credit facility. Among other things, the fourth amendment increased the borrowing base to \$1.4 billion. Total lender commitments remained unchanged at \$1.2 billion.

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

As of June 30, 2012, there were \$400.5 million in outstanding borrowings under the credit facility and \$23.2 million in outstanding letters of credit, leaving \$776.3 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.

4. Income Taxes

The effective income tax rate for the three months ended June 30, 2012 and 2011 was 38.0% and 38.6%, respectively. The effective income tax rate for the six months ended June 30, 2012 and 2011 was 37.9% and 37.0%, 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 June 30, 2012, the Company had a gross liability for uncertain income tax benefits of \$2.9 million, which, if recognized, would affect the effective income tax rate. There have been no significant changes to the calculation of uncertain income tax benefits during 2012. Consistent with the Company's policy, interest and penalties on income taxes have been recorded as a component of the income tax provision. The Company estimates that it is reasonably possible that the balance of unrecognized income tax benefits as of June 30, 2012 could decrease by a maximum of \$2.7 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 and six months ended June 30, 2012 and 2011:

(in thousands, except per share data)	Three Months Ended		Six Months Ended	
	June 30, 2012	2011	June 30, 2012	2011
Net earnings	\$81,016	\$105,166	\$114,914	\$52,669
Less: net earnings allocable to participating securities	399	1,012	556	544
Net earnings available for common shareholders	\$80,617	\$104,154	\$114,358	\$52,125
Basic net earnings per share	\$1.47	\$1.93	\$2.08	\$0.97
Diluted net earnings per share	\$1.46	\$1.90	\$2.07	\$0.95
Weighted average shares outstanding—basic	54,942	54,004	54,851	53,936
Add: Dilutive effects of stock options and RSUs	352	704	451	755
Weighted average shares outstanding—dilutive	55,294	54,708	55,302	54,691

0.7 million and 0.3 million stock options and RSUs were not included in the diluted earnings per share calculation for the three and six months ended June 30, 2012, respectively, because their effect would have been anti-dilutive. There were no stock options or RSUs excluded from the diluted earnings per share calculation for the three and six months ended June 30, 2011.

6. Asset Retirement Obligation

The following table summarizes the activity for the Company's asset retirement obligation (ARO) for the six months ended June 30, 2012 and 2011:

(in thousands)	Six Months Ended	
	June 30, 2012	2011
Beginning balance at January 1	\$64,019	\$53,443
Liabilities incurred	4,024	1,642
Liabilities settled	(1,668)	(864)
Liabilities assumed	1,626	119
Disposition of assets	(705)	—
Accretion expense	2,596	2,545
Revisions in estimated cash flows	10,988	—
Ending balance at June 30	\$80,880	\$56,885

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).

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BERRY PETROLEUM COMPANY

Notes to Condensed Financial Statements (Continued)

(Unaudited)

7. Equity Incentive Compensation Plans (Continued)

Total compensation cost recognized in the Condensed Statements of Operations for the grants under the Company's equity incentive compensation plans was \$2.2 million and \$2.2 million during the three months ended June 30, 2012 and 2011, respectively, and \$5.2 million and \$5.1 million during the six months ended June 30, 2012 and 2011, respectively.

Stock Options

The following table summarizes stock option activity for the six months ended June 30, 2012:

	Number of Shares	Weighted Average Exercise Price	Aggregate Intrinsic Value (in thousands)(1)	Number of Shares Exercisable
Outstanding at January 1, 2012	1,520,689	\$30.32	\$17,798	1,434,020
Granted	82,262	53.02	—	—
Exercised	(197,209)	17.73	6,779	—
Cancelled/expired	—	—	—	—
Outstanding at June 30, 2012	1,405,742	\$33.41	\$10,893	1,257,883

(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.

In March 2012, 82,262 stock options were granted under the 2010 Equity Incentive Plan to certain executive officers and other officers of the Company with exercise prices equal to the closing market price of the Company's common stock on the grant date. These stock options generally vest ratably over a four-year service period from the grant date and are exercisable immediately upon vesting through the tenth anniversary of the grant date.

The grant date fair value of each option granted was estimated using the Black-Scholes option pricing model. Expected volatility was calculated based on the historical volatility of the Company's common stock, and the risk-free interest rate was based on U.S. Treasury yield curve rates with maturities consistent with the expected life of each option. The key assumptions used in computing the weighted average fair market value of stock options granted were as follows:

	2012	
Expected volatility	50.00	%
Risk-free interest rate	0.95	%
Dividend yield	0.57	%
Expected term (in years)	5.2	

As of June 30, 2012, there were \$3.0 million of total unrecognized compensation costs related to outstanding stock options. These costs are expected to be recognized over 3.8 years.

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Notes to Condensed Financial Statements (Continued)

(Unaudited)

7. Equity Incentive Compensation Plans (Continued)

Restricted Stock Units

The following table summarizes restricted stock unit (RSU) activity for the six months ended June 30, 2012:

	RSUs	Weighted Average Grant Date Fair Value	Vest Date Fair Value (in thousands)
Outstanding at January 1, 2012	915,022	\$23.88	
Granted	154,130	51.40	
Issued	(50,660)	42.94	\$2,446
Canceled/expired	(12,649)	38.44	
Outstanding at June 30, 2012(1)(2)	1,005,843	\$27.52	

(1) The balance outstanding includes 43,554 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 469,165 RSUs granted to executive officers and other officers that have vested in accordance with the RSU agreement, but are subject to deferral elections delaying the date on which the corresponding shares are issued.

As of June 30, 2012, there were \$14.2 million of total unrecognized compensation costs related to RSUs granted. These costs are expected to be recognized over 3.8 years.

Performance Share Program

The following table summarizes performance share award activity for the six months ended June 30, 2012:

	Performance Share Awards(1)	Weighted Average Grant Date Fair Value	Vest Date Fair Value (in thousands)
Outstanding at January 1, 2012	162,849	\$39.00	
Granted	59,738	63.69	
Issued	—	—	\$—
Canceled/expired	—	—	
Outstanding at June 30, 2012	222,587	\$44.58	

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

In March 2012, 59,738 RSUs that are subject to performance metrics and a three-year service condition (performance shares) were granted to executive officers and certain other officers. The vesting of the performance share awards is contingent upon satisfying certain performance criteria. No performance shares will vest unless, from January 1, 2012 to December 31, 2014, the Company maintains an interest coverage ratio of at least 2.5 to 1.0, achieves a defined total shareholder return as compared to the Company's defined peer group and achieves a defined level of compounded

annual production growth as measured by average annual barrels of oil equivalent per day (excluding acquisitions and divestitures). If such thresholds are met, the number of performance shares that vest is based on the excess total shareholder return and compounded annual production growth over the thresholds.

For the portion of the performance shares subject to a performance-based vesting condition based on the Company's annual production growth, the grant date fair value was determined by reference to the closing price of the Company's common stock on the date of grant. The Company recognizes compensation expense when it becomes probable that these conditions will be achieved. However, any such compensation expense recognized is reversed if vesting does not actually occur.

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BERRY PETROLEUM COMPANY

Notes to Condensed Financial Statements (Continued)

(Unaudited)

7. Equity Incentive Compensation Plans (Continued)

For the portion of the performance shares subject to a market performance-based vesting condition based on the Company's total shareholder return, the grant date fair value was estimated using a Monte Carlo simulation method. The Monte Carlo model is based on random projections of stock price paths and must be repeated numerous times to achieve a probabilistic assessment. Expected volatility was calculated based on the historical volatility of the Company's common stock, and the risk-free interest rate is based on U.S. Treasury yield curve rates with maturities consistent with the three-year vesting period. The key assumptions used in valuing the market-based restricted shares were as follows:

	2012	
Number of simulations	100,000	
Expected volatility	50	%
Risk-free interest rate	0.42	%

All compensation expense related to the market performance-based awards will be recognized if the requisite service period is fulfilled, even if the market condition is not achieved.

As of June 30, 2012, there were \$3.0 million of total unrecognized compensation costs related to performance share awards granted. These costs are expected to be recognized over 2.5 years.

8. Derivative Instruments

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

As of June 30, 2012, the Company had commodity derivatives associated with the following volumes:

	2012	2013	2014
Oil, Bbl/D:	21,000	15,000	4,000
Natural Gas, MMBtu/D:	—	8,000	—

The Company entered into the following derivative instruments during the six months ended June 30, 2012:

Crude Oil Sales (NYMEX WTI) Three-Way Collars

Term	Average Barrels Per Day	Sold Put / Purchased Put / Sold Call
Full year 2014	1,000	\$70.00 / \$90.00 / \$120.00

Full year 2014

1,000

\$70.00 / \$90.00 / \$121.80

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BERRY PETROLEUM COMPANY

Notes to Condensed Financial Statements (Continued)

(Unaudited)

8. Derivative Instruments (Continued)

Natural Gas Purchases (NYMEX SoCal Border) Three-Way Collars

Term	Average MMBtus Per Day	Sold Put / Purchased Call / Sold Call
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

Natural Gas Purchases (NYMEX SoCal Border) Purchased Calls

Term	Average MMBtus Per Day	Strike Price	Deferred Premium per MMBtu
Full year 2013	1,000	\$3.50	\$0.43
Full year 2013	1,000	\$3.50	\$0.46
Full year 2013	1,000	\$3.50	\$0.4975
Full year 2013	2,000	\$3.50	\$0.5325

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

Discontinuance of Cash Flow Hedge Accounting

Effective January 1, 2010, the Company elected to de-designate all of its commodity and interest rate derivative contracts that had been previously designated as cash flow hedges as of December 31, 2009. As a result, subsequent to December 31, 2009, the Company recognizes all gains and losses from changes in commodity derivative fair values immediately in earnings rather than deferring any such amounts in accumulated other comprehensive loss (AOCL). As a result of discontinuing hedge accounting, the changes in fair values of the Company's derivative contracts designated as cash flow hedges as of December 31, 2009 were frozen in AOCL and are reclassified into earnings as the original hedge transactions settle.

At December 31, 2011, AOCL consisted of \$8.9 million (\$5.5 million, net of income tax) of net unrealized losses on commodity and interest rate contracts that had been previously designated as cash flow hedges. At June 30, 2012, AOCL consisted of \$5.2 million (\$3.2 million net of income tax) of net unrealized losses on commodity and interest rate contracts that had been previously designated as cash flow hedges. During the three and six months ended June 30, 2012, \$1.6 million (\$1.0 million, net of income tax) and \$3.7 million (\$2.3 million, net of income tax), respectively, of non-cash amortization of AOCL related to de-designated hedges was reclassified from AOCL into earnings. The Company expects to reclassify into earnings from AOCL the remaining after-tax net losses of \$3.2 million related to de-designated commodity and interest rate derivative contracts during the remainder of 2012.

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BERRY PETROLEUM COMPANY

Notes to Condensed Financial Statements (Continued)

(Unaudited)

8. Derivative Instruments (Continued)

The following tables detail the fair value of derivatives recorded on the Company's Condensed Balance Sheets, by category:

(in millions)	June 30, 2012		Derivative Liabilities	
	Derivative Assets Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
Current:				
Commodity	Derivative assets	\$28.6	Derivative liabilities	\$—
Long term:				
Commodity	Derivative assets	20.1	Derivative liabilities	—
Total derivatives		\$48.7		\$—

(in millions)	December 31, 2011		Derivative Liabilities	
	Derivative Assets Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
Current:				
Commodity	Derivative assets	\$6.1	Derivative liabilities	\$20.4
Long term:				
Commodity	Derivative assets	7.0	Derivative liabilities	15.5
Total derivatives		\$13.1		\$35.9

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

(in millions)	Location of (Gain) Loss Recognized in Earnings	Three Months Ended		Six Months Ended	
		June 30, 2012	2011	June 30, 2012	2011
Commodity					
Loss reclassified from AOCL into earnings (amortization of frozen amounts)	Oil and natural gas sales	\$2.5	\$14.9	\$5.2	\$29.5
(Gain) loss recognized in earnings (cash settlements and mark-to-market movements)	Realized and unrealized (gain) loss on derivatives, net	(113.1) (91.8) (84.6) 35.7
Interest rate					
(Gain) loss reclassified from AOCL into earnings (amortization of frozen amounts)	Interest	\$(0.9) \$0.4	\$(1.5) \$1.2

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BERRY PETROLEUM COMPANY

Notes to Condensed Financial Statements (Continued)

(Unaudited)

8. Derivative Instruments (Continued)

Credit Risk

The Company does not require collateral or other security from counterparties to support derivative instruments. However, the agreements with those counterparties typically contain netting provisions such that if a default occurs, the non-defaulting party can offset the amount payable to the defaulting party under the derivative contract with the amount due from the defaulting party. As a result of the netting provisions, the Company's maximum amount of loss due to credit risk is limited to the net amounts due to and from the counterparties under the derivative contracts. The maximum amount of loss due to credit risk that the Company would have incurred if all counterparties to its derivative contracts failed to perform at June 30, 2012 was \$48.7 million.

As of June 30, 2012, 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, potentially, its derivative agreements, the Company would be in default under the credit facility. As of June 30, 2012, the Company was not in a net liability position with any of the counterparties to the Company's derivative instruments. As of June 30, 2012, the Company's largest three 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 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. The Company recognizes transfers between levels at the end of the reporting period for which the transfer has occurred.

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BERRY PETROLEUM COMPANY

Notes to Condensed Financial Statements (Continued)

(Unaudited)

9. Fair Value Measurements (Continued)

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

The following table presents information about the Company's financial assets and liabilities measured at fair value on a recurring basis as of June 30, 2012 and December 31, 2011, 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 (liability), net				
June 30, 2012	\$48.7	\$—	\$48.7	\$—
December 31, 2011	\$(22.7)) \$—	\$(22.7)) \$—

Changes in Level 3 Fair Value Measurements

The table below includes a rollforward of the Condensed Balance Sheet amounts (including the change in fair value) for financial instruments classified by the Company within Level 3 of the fair value hierarchy. When a determination is made to classify a financial instrument within Level 3, the determination is based upon the significance of the unobservable factors to the overall fair value measurement. Level 3 financial instruments typically include, in addition to the unobservable or Level 3 components, observable components (that is, components that are actively quoted and can be validated to external sources).

(in millions)	Three Months Ended		Six Months Ended	
	June 30, 2012	2011	June 30, 2012	2011
Fair value liability, beginning of period	\$—	\$—	\$—	\$(101.8)
Transfers out of Level 3(1)	—	—	—	101.8
Realized and unrealized (gain) loss included in earnings	—	—	—	—
Settlements	—	—	—	—
Fair value liability, end of period	\$—	\$—	\$—	\$—
Total unrealized (gain) loss included in earnings related to financial assets and liabilities still on the Condensed Balance Sheets at June 30, 2012 and 2011	\$—	\$—	\$—	\$—

(1) During the first quarter of 2011, the inputs used to value oil collars, natural gas collars and natural gas basis swaps were directly or indirectly observable, and these instruments were transferred to Level 2.

For further discussion related to the Company's derivatives, see Note 8 to the Condensed Financial Statements.

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BERRY PETROLEUM COMPANY

Notes to Condensed Financial Statements (Continued)

(Unaudited)

9. Fair Value Measurements (Continued)

Fair Market Value of Financial Instruments

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

June 30, 2012 (in millions)	Carrying Amount	Estimated Fair Value			Total
		Level 1	Level 2	Level 3	
Cash and cash equivalents	\$—	\$—	\$—	\$—	\$—
Senior secured revolving credit facility(1)	401	—	401	—	401
10.25% Senior notes due 2014(2)	205	228	—	—	228
6.75% Senior notes due 2020	300	314	—	—	314
6.375% Senior notes due 2022	600	621	—	—	621
	\$1,506	\$1,163	\$401	\$—	\$1,564

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 (1)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 \$3.1 million.

December 31, 2011

(in millions)	Carrying Amount	Estimated Fair Value
Credit facility(1)	532	532
8.25% Senior subordinated notes due 2016	200	209
10.25% Senior notes due 2014(2)	355	402
6.75% Senior notes due 2020	300	302
	\$1,387	\$1,445

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 (1)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 \$6.6 million.

10. Commitments and Contingencies

Uinta Crude Oil Sales Contract

The Company is a party to a crude oil sales contract through June 30, 2013 with a refiner for the purchase of a minimum of 5,000 Bbl/D of its Uinta crude oil. Pricing under the contract, which includes transportation and gravity

adjustments, is at a fixed percentage of WTI. Gross operated oil production from the Company's Uinta properties averaged approximately 3,900 Bbl/D in the first six months of 2012. Due to the possibility of refinery constraints in the Utah region, it is possible that the loss of the Company's crude oil sales customer in Utah could impact the marketability of a portion of the Company's Uinta crude oil volumes. See Item 1A. Risk Factors of the Company's Annual Report on Form 10-K for the year ended 2011 filed with the SEC on February 28, 2012.

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BERRY PETROLEUM COMPANY

Notes to Condensed Financial Statements (Continued)

(Unaudited)

10. Commitments and Contingencies (Continued)

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. The transaction was treated as a financing obligation. 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 June 30, 2012 and 2011, the Company incurred \$0.8 million and \$1.4 million, respectively, under the agreements. For the six months ended June 30, 2012 and 2011, the Company incurred \$1.7 million and \$3.1 million, respectively, under the agreements. These amounts are recorded in the Condensed Financial Statements under the caption operating costs—oil and natural gas production.

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 may be extended until December 31, 2014 if road construction has commenced by June 30, 2013), the Company has not expended \$9.0 million (\$4.5 million of which would otherwise be such third party's responsibility) in road construction costs, then it 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, 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. The Company is currently engaged in discussions with the DOI to resolve the matter.

COGCC Order. On April 21, 2011, the Company received a proposed Order Finding Violation from the Colorado Oil and Gas Conservation Commission (COGCC) alleging that certain releases in late 2007 from a lined reserve pit

located on a well pad in western Colorado violated COGCC regulations. Shortly thereafter, the Company entered into negotiations with the COGCC. While the Company denies that it violated any COGCC regulations in connection with the releases, on June 27, 2011, the COGCC approved and the Company later signed an Administrative Order on Consent under which the Company would pay \$100,000, and fund a mutually acceptable public project in the amount of \$73,000, in full satisfaction of the matter. The Company recorded these amounts in the second quarter of 2011 and paid \$100,000 in July 2011. The Company expects to fund the mutually acceptable project in the third quarter of 2012.

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BERRY PETROLEUM COMPANY

Notes to Condensed Financial Statements (Continued)

(Unaudited)

10. Commitments and Contingencies (Continued)

Royalty Payments. Certain of the Company's royalty payment calculations are being disputed. The Company believes that its royalty calculations are in accordance with applicable leases and other agreements, as well as applicable law. On July 26, 2012, the Company received a federal court jury verdict that the Company had underpaid certain disputed royalty payments. While a judgment has not yet been entered on the matter, the Company believes its liability to the royalty owner pursuant to the verdict will be approximately \$4.2 million, inclusive of statutory interest, of which approximately \$1.3 million had been previously recorded in compression, gathering, and dehydration expense. The Company recorded \$2.0 million in compression, gathering and dehydration expense and \$0.9 million in interest expense in the second quarter of 2012 in conjunction with the verdict. The Company has not yet determined whether to appeal the verdict. As of June 30, 2012, the Company may be required to pay amounts of up to approximately \$3.9 million with respect to other royalty disputes.

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 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.

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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, 2011, included in our Annual Report on Form 10-K and the Condensed Financial Statements included elsewhere herein.

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

Notable Second Quarter 2012 Items

- Generated discretionary cash flow of \$118.7 million from production of 35,341 BOE/D, of which 74% was oil⁽¹⁾
- Generated operating margin of \$47.97 per BOE, supported by sales of our California heavy oil at a \$9.19 average premium to WTI during the quarter⁽¹⁾
- Production from our Permian properties averaged 6,500 BOE/D, a 16% increase from the first quarter of 2012
 - Production from our North Midway-Sunset New Steam Floods properties, which include McKittrick, averaged 1,745 BOE/D, a 16% increase from the first quarter of 2012
- Production from our Diatomite properties increased 11% from the first quarter of 2012
- Drilled 38 NMWSS New Steam Flood wells, 25 Permian wells, 22 Uinta wells, and 10 Diatomite wells
- Received final US Forest Service approval on our Environmental Impact Study for the Ashley Forest in the Uinta
- Purchased an additional 10,000 net acres in the Lake Canyon area and 3,000 net acres in the Permian

Notable Items and Expectations for the Third Quarter and Full Year 2012

- Executed an amendment to our ExxonMobil crude purchase contract covering the sale of oil production from our California properties other than Placerita and Poso Creek through August 2014
- Expect to drill approximately 57 additional Uinta wells during the remainder of 2012
- Continuing to evaluate acquisition opportunities that fit into our core areas of operation
- Expect full-year production to average 37,000 BOE/D

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

Results of Operations.

In the second quarter of 2012, we reported net earnings of \$81.0 million, or \$1.46 per diluted share, and net cash flows from operations of \$92.7 million. Net earnings in the second quarter of 2012 included a \$25.8 million loss on extinguishment of debt associated with repurchasing all \$200 million aggregate principal amount of our 8.25% Senior subordinated notes due 2016 (2016 Notes) and \$150 million aggregate principal amount of our 10.25% Senior notes due 2014 (2014 Notes), a gain on derivatives of \$68.1 million resulting from non-cash changes in fair values and amortization of AOCL related to de-designated hedges and \$1.8 million related to disputed royalty payments, in each case net of income taxes.

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For the first six months of 2012, we reported net earnings of \$114.9 million, or \$2.07 per diluted share, and net cash flows from operations of \$248.1 million. Net earnings for the first six months of 2012 included a \$25.8 million loss on extinguishment of debt, a \$1.0 million gain associated with the sale of properties in Elko, Eureka and Nye Counties, Nevada (Nevada Assets), a \$9.1 million cash settlement related to the early termination of our natural gas derivatives and a gain on derivatives of \$41.5 million resulting from non-cash changes in fair values and amortization of AOCL related to de-designated hedges and \$1.8 million related to disputed royalty payments, in each case net of income taxes.

Operating Data.

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

	June 30, 2012	%	June 30, 2011	%	March 31, 2012	%
Heavy oil production (BOE/D)	17,395	49	17,670	50	17,005	49
Light oil production (BOE/D)	8,901	25	6,959	19	8,091	24
Total oil production (BOE/D)	26,296	74	24,629	69	25,096	73
Natural gas production (Mcf/D)	54,271	26	65,859	31	56,105	27
Total (BOE/D)(1)	35,341	100	35,606	100	34,447	100
Oil and natural gas, per BOE:						
Average realized sales price	\$69.07		\$71.07		\$74.33	
Average sales price including cash derivative settlements	\$70.40		\$66.90		\$74.44	
Oil, per BOE:						
Average WTI price	\$93.35		\$102.34		\$103.03	
Price sensitive royalties(2)	(3.55)		(3.85)		(4.24)	
Quality differential and other(3)	(0.51)		(0.83)		(1.48)	
Oil derivatives non-cash amortization(4)	(1.12)		(6.72)		(1.14)	
Oil revenue	\$88.17		\$90.94		\$96.17	
Add: Oil derivatives non-cash amortization(4)	1.12		6.72		1.14	
Oil derivative cash settlements(5)	0.79		(13.71)		(3.08)	
Average realized oil price	\$90.08		\$83.95		\$94.23	
Natural gas price:						
Average Henry Hub price per MMBtu	\$2.21		\$4.32		\$2.72	
Conversion to Mcf	0.15		0.21		0.18	
Natural gas derivatives non-cash amortization(4)	0.03		0.03		(0.01)	
Location, quality differentials and other	(0.11)		(0.17)		(0.30)	
Natural gas revenue per Mcf	\$2.28		\$4.39		\$2.59	
Add: Natural gas derivatives non-cash amortization(4)	(0.03)		(0.03)		0.01	
Natural gas derivative cash settlements(5)	(0.03)		0.39		0.92	
Average realized natural gas price per Mcf	\$2.22		\$4.75		\$3.52	

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

Our Formax property in S. Midway is subject to a price-sensitive royalty burden. The royalty is 53% of the amount of the heavy oil posted price above the 2012 base price of \$17.43 per barrel as long as we maintain a minimum

(2) steam injection level. We met the steam injection level in the second quarter of 2012 and expect to meet the requirement going forward. The base price escalates at 2% annually and will be \$17.78 in 2013.

(3) In California, the per barrel oil posting differential at June 30, 2012 was \$8.35, ranged from \$8.22 to \$11.52 during the second quarter of 2012 and averaged \$9.19 during the second quarter of 2012. In Utah, the per barrel oil

posting differential at June 30, 2012 was (\$16.50), ranged from (\$16.00) to (\$16.50) during the second quarter of 2012 and averaged (\$16.43) during the second quarter of 2012.

- (4) Non-cash amortization of AOCL resulting from discontinuing hedge accounting effective January 1, 2010. Recorded in the Condensed Statements of Operations under the caption oil and natural gas sales.
- (5) Cash settlements on derivatives are recorded in the Condensed Statements of Operations under the caption realized and unrealized (gain) loss on derivatives, net.

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

	June 30, 2012	%	June 30, 2011	%
Heavy oil production (BOE/D)	17,201	49	16,951	49
Light oil production (BOE/D)	8,495	25	6,714	19
Total oil production (BOE/D)	25,696	74	23,665	68
Natural gas production (Mcf/D)	55,188	26	68,188	32
Total (BOE/D)(1)	34,894	100	35,030	100
Oil and natural gas, per BOE:				
Average realized sales price	\$71.68		\$65.78	
Average sales price including cash derivative settlements	\$72.40		\$63.04	
Oil, per BOE:				
Average WTI price	\$98.15		\$98.50	
Price sensitive royalties(2)	(3.89))	(3.71))
Quality differential and other(3)	(1.04))	(3.00))
Oil derivatives non-cash amortization(4)	(1.13))	(6.89))
Oil revenue	\$92.09		\$84.90	
Add: Oil derivatives non-cash amortization(4)	1.13		6.89	
Oil derivative cash settlements(5)	(1.11))	(12.06))
Average realized oil price	\$92.11		\$79.73	
Natural gas price:				
Average Henry Hub price per MMBtu	\$2.47		\$4.21	
Conversion to Mcf	0.17		0.21	
Natural gas derivatives non-cash amortization(4)	0.01		0.01	
Location, quality differentials and other	(0.21))	(0.13))
Natural gas revenue per Mcf	\$2.44		\$4.30	
Add: Natural gas derivatives non-cash amortization(4)	(0.01))	(0.01))
Natural gas derivative cash settlements(5)	0.45		0.40	
Average realized natural gas price per Mcf	\$2.88		\$4.69	

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

(2) Our Formax property in S. Midway is subject to a price-sensitive royalty burden. The royalty is 53% of the amount of the heavy oil posted price above the 2012 base price of \$17.43 per barrel as long as we maintain a minimum steam injection level. We met the steam injection level in the first six months of 2012 and expect to meet the requirement going forward. The base price escalates at 2% annually and will be \$17.78 in 2013.

(3) In California, the per barrel oil posting differential at June 30, 2012 was \$8.35, ranged from \$2.18 to \$11.52 during the first six months of 2012 and averaged \$8.41 during the first six months of 2012. In Utah, the per barrel oil posting differential at June 30, 2012 was (\$16.50), ranged from (\$12.49) to (\$16.50) during the first six months of 2012 and averaged (\$15.69) during the first six months of 2012.

(4) Non-cash amortization of AOCL resulting from discontinuing hedge accounting effective January 1, 2010. Recorded in the Condensed Statements of Operations under the caption oil and natural gas sales.

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

	June 30, 2012	June 30, 2011	2Q11 to 2Q12 Change	March 31, 2012	1Q12 to 2Q12 Change		
Oil sales	\$210,562	\$204,441	3	% \$220,452	(4)%	
Natural gas sales	11,219	26,319	(57)%	13,201	(15)%
Total oil and natural gas sales	\$221,781	\$230,760	(4)%	\$233,653	(5)%
Electricity sales	5,860	7,964	(26)%	5,980	(2)%
Natural gas marketing	1,580	3,985	(60)%	1,859	(15)%
(Loss) gain on sale of assets	(163) —	(100)%	1,763	(109)%
Interest and other income, net	645	803	(20)%	747	(14)%
Total revenues and other income	\$229,703	\$243,512	(6)%	\$244,002	(6)%
Net earnings	\$81,016	\$105,166	—		\$33,898	—	
Diluted earnings per share	\$1.46	\$1.90	—		\$0.61	—	

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

	June 30, 2012	June 30, 2011	% Change	
Oil sales	\$431,015	\$365,066	18	%
Natural gas sales	24,419	53,083	(54)%
Total oil and natural gas sales	\$455,434	\$418,149	9	%
Electricity Sales	11,840	14,376	(18)%
Natural gas marketing	3,439	7,670	(55)%
Gain on sale of assets	1,600	—	100	%
Interest and other income, net	1,392	931	50	%
Total revenues and other income	\$473,705	\$441,126	7	%
Net earnings	\$114,914	\$52,669	—	
Diluted earnings per share	\$2.07	\$0.95	—	

Oil and Natural Gas Sales.

Oil and natural gas sales decreased \$9.0 million, or 4%, to \$221.8 million in the second quarter of 2012 compared to the same period in 2011. The decrease was primarily due to a 3% decrease in the average realized sales price in the second quarter of 2012 compared to the same period in 2011, as a result of decreases in commodity prices between periods. Our oil sales volume increased 6% in the second quarter of 2012 compared to the second quarter of 2011, while our natural gas sales volumes decreased 18%. The oil sales volume increase was primarily due to increased oil production from our Permian and NWMSS-New Steam Floods properties. Permian oil production in the second quarter of 2012 increased 2,070 BOE/D, or 62%, from the same period in 2011 and oil production for North Midway Sunset - New Steam Floods (NMWSS-NSF) increased 785 BOE/D, or 82%, between periods. These increases in oil production were partially offset by a decrease in production from our South Midway Sunset (SMWSS) properties due to expected production declines. 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 Uinta and Permian properties.

Oil and natural gas sales decreased \$11.9 million, or 5%, to \$221.8 million in the second quarter of 2012 compared to the first quarter of 2012. The decrease was primarily due to a 7% decrease in the average realized sales price in the

second quarter of 2012 compared to the first quarter of 2012, as a result of lower commodity price between periods. Our oil sales volume in the second quarter of 2012 increased 4% compared to the first quarter of 2012, while our natural gas sales volume decreased 3% between periods. The oil sales volume increase was primarily due to increased production

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from all of our oil properties except our legacy SMWSS properties. The decrease in natural gas sales volumes was primarily due to expected field decline in E. Texas and the Piceance, partially offset by increased natural gas production in the Uinta and Permian.

Oil and natural gas sales increased \$37.3 million, or 9%, to \$455.4 million in the six months ended June 30, 2012 compared to the six months ended June 30, 2011. The increase was primarily due to a 9% increase in the realized sales price over the same period, primarily due to an increase in the average realized oil price between periods. Our oil sales volume in the six months ended June 30, 2012 increased 9% from the same period in 2011, while our natural gas sales volume decreased 19% between periods. The oil volume increase was primarily due to increased production from our properties in the Permian and NMWSS-New Steam Floods. Permian oil production in the six months ended June 30, 2012 increased 2,020 BOE/D, or 67%, from the same period in 2011 and oil production for NMWSS-NSF increased 711 BOE/D, or 78%, between periods. These increases in oil production were partially offset by a decrease in production from our SMWSS properties due to expected production declines. The decrease in natural gas volumes was primarily due to expected production declines from our E. Texas and Piceance properties, partially offset by increased natural gas production from our Uinta and Permian properties.

Electricity Sales.

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

	Three Months Ended			Six Months Ended	
	June 30, 2012	June 30, 2011	March 31, 2012	June 30, 2012	June 30, 2011
Electricity					
Electricity Sales (in thousands)	\$5,860	\$7,964	\$5,980	\$11,840	\$14,376
Operating costs (in thousands)	\$4,256	\$6,891	\$5,017	\$9,273	\$13,004
Electric power produced—MWh/D	2,061	1,969	2,089	2,075	1,912
Electric power sold—MWh/D	1,882	1,810	1,935	1,908	1,750
Average sales price/MWh	\$34.22	\$48.34	\$33.96	\$34.09	\$45.38
Fuel gas cost/MMBtu (including transportation)	\$2.36	\$4.53	\$2.71	\$2.52	\$4.43
Fuel gas purchased (MMBtu/D)	26,000	25,000	27,000	27,000	24,000

Electricity sales in the second quarter of 2012 decreased 26% compared to the second quarter of 2011 primarily due to a 29% decrease in the average sales price of electricity, partially offset by a 4% increase in electric power sold.

Electricity operating costs in the second quarter of 2012 decreased 38% compared to the second quarter of 2011 primarily due to a 48% decrease in fuel gas cost, partially offset by a 4% increase in fuel gas volumes purchased.

Electricity sales decreased 2% in the second quarter of 2012 compared to the first quarter of 2012 primarily due to a 3% decrease in electric power sold, partially offset by a 1% increase in the average sales price of electricity.

Electricity operating costs in the second quarter of 2012 decreased 15% compared to the first quarter of 2012 primarily due to a 13% decrease in fuel gas cost and a 4% decrease in fuel gas volumes purchased.

Electricity sales decreased 18% in the six months ended June 30, 2012 compared to the six months ended June 30, 2011 primarily due to a 25% decrease in the average sales price of electricity, partially offset by an 9% increase in electric power sold period over period primarily due to the shutdown of one of our three cogeneration facilities in March 2011 for scheduled maintenance. Electricity operating costs decreased 29% in the six months ended June 30, 2012 compared to the six months ended June 30, 2011 primarily due to a 43% decrease in fuel gas cost, partially offset by a 9% increase in electric power produced.

Electricity Sales Contracts. We sell electricity produced by our cogeneration (also referred to as Combined Heat and Power or CHP) 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). These contracts have historically been referred to as standard offer (SO) power purchase agreement (PPA) contracts, under which 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 will be based on market prices for electricity.

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At December 31, 2011, we sold energy and capacity from all Cogen units under interim extensions of legacy SO PPAs. Our legacy PPA for our Cogen 38 facility expired in March 2012, at which time a transition PPA with PG&E became effective. Our legacy PPAs for our Cogen 42 facilities expired in May 2012, at which time a transition PPA with Edison for the combined output of the two units became effective. Transition PPAs are intended to be bridge agreements to allow qualifying cogeneration facilities, such as our cogeneration facilities, to bid against other CHP facilities for long-term contracts with the IOUs and are similar to our prior SO contracts, but with updated regulatory requirements and more stringent scheduling and performance requirements. Transition PPAs are to terminate no later than June 30, 2015, but may be terminated earlier in the event we elect to bid into a competitive CHP solicitation and are awarded a long-term contract based on our bid. Our Cogen facilities are eligible to bid into one or more of the competitive CHP solicitations that are expected to be issued over the next two to three years. For existing facilities, such as ours, the maximum term of a PPA awarded in a competitive CHP solicitation is seven years. Effective July 2, 2012, Berry and Edison executed a seven-year contract for our Cogen 42 facilities pursuant to a competitive solicitation. Subject to CPUC approval, the seven-year term will commence on July 1, 2014, at which time the Transition PPA for Cogen 42 will terminate.

Our current legacy extension PPA with PG&E for our Cogen 18 facility was recently extended and is now scheduled to terminate on the earlier of September 30, 2012 or the date the CPUC approves a new Public Utility Regulatory Policy Act (PURPA) PPA for a term of seven years. Because the rated capacity of our Cogen 18 facility is less than 20 MW, it will continue to be eligible for a PURPA PPA, under which it will be paid the prevailing CPUC-determined SRAC price and either a firm or "as available" capacity payment, at our discretion.

The following table summarizes our cogeneration facilities and related contract information as of June 30, 2012:

Facility	Type of Contract(1)	Purchaser	Contract Expiration
Cogen 42	Transition	Edison	Jun 2012(2)
Cogen 18	SO2	PG&E	Sept 2012(3)
Cogen 38	Transition	PG&E	Jun 2015(4)

(1) Transition and SO2 contracts pay firm capacity rates.

(2) Subject to CPUC approval, we have executed a seven-year contract with Edison that will commence on July 1, 2014 and which will replace the current Transition contract.

(3) Subject to CPUC approval, the current contract will be replaced by a PURPA contract with a term of seven years.

(4) We anticipate the current contract will be replaced by a long-term contract with a term of up to seven years pursuant to a competitive solicitation.

Natural Gas Marketing.

We have long-term firm transportation contracts on the Rockies Express, Wyoming Interstate Company, and Ruby pipelines, each with a total average capacity of 35,000 MMBtu/D. Demand charges for our capacity are reflected in operating costs—oil and natural gas production in our Condensed Statements of Operations. Our current production is insufficient to fully utilize this capacity. To optimize our remaining capacity, we purchase third-party natural gas at the market rate in our producing areas and utilize FERC-approved asset management agreements. Sales and purchases of third-party natural gas are recorded under natural gas marketing in the revenues and expenses sections of the Condensed Statements of Operations, respectively. The pre-tax net earnings of natural gas marketing operations for the three months ended June 30, 2012 and 2011 was \$0.2 million and \$0.3 million, respectively. The pre-tax net earnings of natural gas marketing operations for the six months ended June 30, 2012 and 2011 was \$0.3 million and \$0.5 million, respectively.

(Loss) Gain on Sale of Assets.

For the three months ended March 31, 2012, we recorded a \$1.6 million gain in conjunction with the sale of assets related to proved developed properties in Elko, Eureka and Nye Counties, Nevada (Nevada Assets). The gain was recorded in the Condensed Statements of Operations under the caption (loss) gain on sale of assets.

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Oil and Natural Gas Operating and Other Expenses.

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

	Amount Per BOE			Amount (in thousands)		
	June 30, 2012	June 30, 2011	March 31, 2012	June 30, 2012	June 30, 2011	March 31, 2012
Operating costs—oil and natural gas production	\$19.42	\$18.14	\$17.31	\$62,461	\$58,780	\$54,252
Production taxes	3.01	2.58	3.40	9,690	8,350	10,658
DD&A—oil and natural gas production	16.18	16.04	15.30	52,026	51,967	47,956
General and administrative	5.59	4.91	5.66	17,965	15,910	17,741
Interest expense	6.46	5.47	6.41	20,789	17,712	20,104
Total	\$50.66	\$47.14	\$48.08	\$162,931	\$152,719	\$150,711

Operating costs—oil and natural gas production in the second quarter of 2012 were \$62.5 million, or \$19.42 per BOE, compared to \$58.8 million, or \$18.14 per BOE, in the second quarter of 2011 and \$54.3 million, or \$17.31 per BOE, in the first quarter of 2012. The increase in the second quarter of 2012 compared to the second quarter of 2011 was primarily due to increased transportation costs associated with the commencement of Ruby Pipeline operations in July 2011, increased compression, gathering, and dehydration costs of \$2.0 million related to disputed royalty payments, increases in chemicals, labor and other contract services associated with net wells added during the last twelve months and higher levels of well maintenance and workovers, primarily in our Permian and SMWSS properties. These increases were partially offset by a \$5.4 million decrease in steam costs, primarily due to a decrease in the price of natural gas used in steam generation. The increase in operating costs—oil and natural gas production in the second quarter of 2012 compared to the first quarter of 2012 was primarily due to an increase in lease operating expenses associated with a higher level of workover activity, increased compression, gathering, and dehydration costs of \$2.0 million related to disputed royalty payments and increased steam costs. The increase in steam costs was due to an increase in steam volumes injected, partially offset by a decrease in the cost of natural gas used in steam generation.

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

	June 30, 2012	June 30, 2011	2Q11 to 2Q12 Change	March 31, 2012	1Q12 to 2Q12 Change
Average volume of steam injected (Bbl/D)	167,004	141,334	18	% 134,510	24
Fuel gas cost/MMBtu (including transportation)	\$2.36	\$4.53	(48))% \$2.71	(13
Approximate net fuel gas volume consumed in steam generation (MMBtu/D)	55,532	46,940	18	% 45,591	22

Included in operating costs are firm transportation costs, which totaled \$7.0 million and \$4.1 million for the three months ended June 30, 2012 and 2011, respectively.

Production taxes in the second quarter of 2012 were \$9.7 million, or \$3.01 per BOE, compared to \$8.4 million, or \$2.58 per BOE, in the second quarter of 2011 and \$10.7 million, or \$3.40 per BOE, in the first quarter of 2012. The increase in production taxes in the second quarter of 2012 compared to the second quarter of 2011 was primarily due

to an increase in the assessed ad valorem values attributable to our California properties, increased ad valorem and severance taxes related to new wells drilled in our Permian and Utah properties and the expiration of certain severance tax exemptions in Utah. The increase in ad valorem taxes was partially offset by a decrease in severance taxes attributable to a decrease in oil prices. The decrease in production taxes in the second quarter of 2012 compared to the first quarter of 2012 was primarily due to a decrease in oil prices in the second quarter of 2012, which resulted in a decrease in severance taxes over the same period.

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Depreciation, depletion and amortization—oil and natural gas production (DD&A—oil and natural gas production) in the second quarter of 2012 was \$52.0 million, or \$16.18 per BOE, compared to \$52.0 million, or \$16.04 per BOE, in the second quarter of 2011 and \$48.0 million, or \$15.30 per BOE, in the first quarter of 2012. The increase in the second quarter of 2012 compared to the second quarter of 2011 and the first quarter of 2012 was primarily due to the development of our properties with higher drilling and leasehold acquisition costs.

General and administrative expense (G&A) in the second quarter of 2012 was \$18.0 million, or \$5.59 per BOE, compared to \$15.9 million, or \$4.91 per BOE, in the second quarter of 2011 and \$17.7 million, or \$5.66 per BOE, in the first quarter of 2012. The increase in the second quarter of 2012 compared to the second quarter of 2011 was primarily due to an increase in employee compensation and benefits resulting from new personnel hired, general pay increases and higher consulting costs directly attributable to our growing capital program and production levels.

Interest expense in the second quarter of 2012 was \$20.8 million, or \$6.46 per BOE, compared to \$17.7 million, or \$5.47 per BOE, in the second quarter of 2011 and \$20.1 million, or \$6.41 per BOE, in the first quarter of 2012. The increase in the second quarter of 2012 compared to the second quarter of 2011 was primarily due to additional interest of \$0.9 million related to disputed royalty payments and a decrease in capitalized interest. These increases were partially offset by a decrease in non-cash derivative losses of \$1.3 million related to the de-designated interest rate hedges reclassified from AOCL into interest expense.

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

	Amount Per BOE		Amount (in thousands)	
	June 30, 2012	June 30, 2011	June 30, 2012	June 30, 2011
Operating costs—oil and natural gas production	\$18.38	\$18.27	\$116,713	\$115,863
Production taxes	3.20	2.48	20,348	15,741
DD&A—oil and natural gas production	15.74	16.41	99,982	104,076
General and administrative	5.62	5.08	35,706	32,201
Interest expense	6.44	5.26	40,893	33,367
Total	\$49.38	\$47.50	\$313,642	\$301,248

Operating costs in the six months ended June 30, 2012 were \$116.7 million, or \$18.38 per BOE, compared to \$115.9 million, or \$18.27 per BOE, in the six months ended June 30, 2011. The increase was primarily due to increases in transportation, chemicals, labor and other contract services associated with net wells added during the last twelve months and a higher level of workovers, primarily in the Permian. These increases were partially offset by a decrease in steam costs due to a reduction in the cost of natural gas used in steam generation. Compression, gathering, and dehydration costs also decreased over the same period primarily due to expected production declines from our natural gas properties, partially offset by an increase in compression, gathering, and dehydration costs of \$2.0 million related to disputed royalty payments.

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

	June 30, 2012	June 30, 2011	% Change	
Average volume of steam injected (Bbl/D)	150,757	130,250	16	%
Fuel gas cost/MMBtu (including transportation)	\$2.52	\$4.43	(43))%
Approximate net fuel gas volume consumed in steam generation (MMBtu/D)	50,553	43,786	15	%

Included in operating costs are firm transportation costs, which totaled \$14.1 million and \$8.1 million for the six months ended June 30, 2012 and 2011, respectively.

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Production taxes in the six months ended June 30, 2012 were \$20.3 million, or \$3.20 per BOE, compared to \$15.7 million, or \$2.48 per BOE, in the six months ended June 30, 2011. The increase was primarily due to an increase in the assessed ad valorem values attributable to our California properties, increased ad valorem taxes related to new wells drilled in our Permian and Utah properties and the expiration of certain tax exemptions in Utah.

DD&A—oil and natural gas production in the six months ended June 30, 2012 was \$100.0 million, or \$15.74 per BOE, compared to \$104.1 million, or \$16.41 per BOE, in the six months ended June 30, 2011. The decrease was primarily due to the impairment of our E. Texas natural gas assets in the fourth quarter of 2011.

G&A in the six months ended June 30, 2012 was \$35.7 million, or \$5.62 per BOE, compared to \$32.2 million, or \$5.08 per BOE, in the six months ended June 30, 2011. The increase in G&A was primarily due to an increase in employee compensation and benefits resulting from new personnel hired, general pay increases and higher consulting costs directly attributable to our growing capital program and production levels.

Interest expense in the six months ended June 30, 2012 was \$40.9 million, or \$6.44 per BOE, compared to \$33.4 million, or \$5.26 per BOE, in the six months ended June 30, 2011. The increase was primarily due to additional interest of \$0.9 million related to disputed royalty payments and a decrease of \$8.9 million in capitalized interest. These increases were partially offset by non-cash derivative losses of \$2.8 million related to the de-designated interest rate hedges reclassified from AOCL into interest expense.

Dry Hole, Abandonment, Impairment and Exploration. For the three and six months ended June 30, 2012, we incurred dry hole, abandonment, impairment and exploration expense of \$1.5 million and \$4.6 million, respectively. For the three and six months ended June 30, 2011, we incurred dry hole, abandonment, impairment and exploration expense of \$0.3 million and \$0.4 million, respectively. The cost recognized in the first six months of 2012 was primarily related to the purchase of seismic data and plugging and abandonment activities.

Gain on Purchase. For the three months ended March 31, 2011, we recorded a \$1.0 million gain (net of deferred income taxes of \$0.7 million) in conjunction with usual and customary post-closing adjustments to the purchase price of a November 2010 acquisition in the Permian. The gain was recorded in the Condensed Statements of Operations under the caption gain on purchase.

Extinguishment of Debt. For the three and six months ended June 30, 2012, we incurred debt extinguishment expense of \$41.5 million related to the redemption of the entire \$200 million aggregate principal amount our 2016 Notes and the repurchase of \$150 million aggregate principal amount of our 2014 Notes for a total aggregate purchase price of \$397.0 million, including accrued and unpaid interest. The loss of \$41.5 million, recorded in the second quarter of 2012, consists of \$34.7 million for premiums paid over par and \$6.8 million for write-offs of net discounts and debt issuance costs.

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Realized and Unrealized (Gain) Loss 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 (gain) 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.

(in thousands)	Three Months Ended			Six Months Ended	
	June 30, 2012	June 30, 2011	March 31, 2012	June 30, 2012	June 30, 2011
Cash payments (receipts):					
Commodity derivatives—oil	\$(1,865)	\$30,831	\$7,069	\$5,204	\$51,840
Commodity derivatives—natural gas(1)	147	(2,319)	(19,381)	(19,234)	(4,911)
Total cash (receipts) payments	\$(1,718)	\$28,512	\$(12,312)	\$(14,030)	\$46,929
Mark-to-market (gain) loss:					
Commodity derivatives—oil	\$(111,056)	\$(121,013)	\$24,363	\$(86,693)	\$(13,924)
Commodity derivatives—natural gas(1)	(308)	693	16,430	16,122	2,703
Total mark-to-market (gain) loss	\$(111,364)	\$(120,320)	\$40,793	\$(70,571)	\$(11,221)
Total realized and unrealized (gain) loss on derivatives, net	\$(113,082)	\$(91,808)	\$28,481	\$(84,601)	\$35,708

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

Income Tax Expense. The effective income tax rate for the three months ended June 30, 2012 and 2011 was 38.0% and 38.6%, respectively. The effective income tax rate for the six months ended June 30, 2012 and 2011 was 37.9% and 37.0%, respectively. Our provision for income taxes differed from the U.S. statutory rate of 35% primarily due to state income taxes, domestic production activities deduction, percentage depletion, nondeductible employee compensation and other permanent differences.

Drilling Activity.

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

Asset Team	Three Months Ended June 30, 2012		Six Months Ended June 30, 2012	
	Gross Production Wells	Net Production Wells	Gross Production Wells	Net Production Wells
SMWSS—Steam Floods	24	24	32	32
NMWSS—Diatomite	10	10	82	82
NMWSS—New Steam Floods	38	38	50	50
Permian	33	(1) 25	54	(2) 40
Uinta	22	15	37	27
E. Texas	—	—	—	—
Piceance	—	—	—	—
Totals	127	112	255	231

- (1) Includes eight non-operated wells in which we have an average interest of approximately 0.59% each, or approximately 0.05 total net wells, and 25 gross operated wells.
- (2) Includes 14 non-operated wells in which we have an average interest of approximately 0.61% each, or approximately 0.09 total net wells, and 40 gross operated wells.

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Properties.

We currently have seven asset teams, as follows: South Midway-Sunset (SMWSS)—Steam Floods, North Midway-Sunset (NMWSS)—Diatomite, NMWSS—New Steam Floods, 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 2012, we drilled five new Placerita producing wells in the Upper Kraft zone, successfully recompleted eight Placerita producing wells in the Kraft zone and drilled 17 Ethel D producing wells, all of which are currently on steam or production. During the second quarter of 2012, we also began expanding our Poso Creek steam flood, drilling two of the 10 producing wells scheduled to be drilled there. For the remainder of 2012, we plan to continue development of the steam floods at our Ethel D and Poso Creek properties, drilling approximately 32 additional producing wells and seven additional steam injection wells. Average daily production in the second quarter of 2012 from all of our SMWSS—Steam Floods assets was approximately 12,675 BOE/D compared to 12,810 BOE/D in the first quarter of 2012.

NMWSS—Diatomite. Our NMWSS—Diatomite asset team includes our Diatomite properties in the San Joaquin Valley. Our Diatomite wells that were completed in the first quarter of 2012 all received their first steam injection in the second quarter of 2012, and they have begun contributing to production. Diatomite production has grown consistently since March 2012. Our revised development approach, which includes modified injection methods and real-time performance monitoring, has started successfully, with our new wells performing on the type curve. We are encouraged that we have not experienced any wellbore failures in our 2012 Diatomite development areas over the last four months, although we are continuously monitoring the integrity of our wells. Implementing this strategy of maximizing the number of active completions by optimizing injection will enhance the long-term value of the Diatomite and support the ultimate recovery of our resource. Average daily production from our NMWSS—Diatomite assets in the second quarter of 2012 was approximately 2,970 BOE/D, an 11% increase from 2,685 BOE/D in the first quarter of 2012.

NMWSS—New Steam Floods. Our NMWSS—New Steam Floods asset team includes our non-Diatomite North Midway-Sunset assets including our McKittrick, Main Camp, Fairfield, Pan, and USL-12 properties. In the second quarter of 2012, we drilled 13 productive wells at our Main Camp property, seven at our Pan property and three at our Fairfield property. At our McKittrick property, we drilled 15 producing wells in the second quarter of 2012 and plan to drill another 39 during the remainder of 2012. We also plan to drill 30 steam injection wells at McKittrick during the remainder of 2012 in order to accelerate our steam flood recovery. Average daily production from all of our NMWSS—New Steam Floods assets in the second quarter of 2012 was approximately 1,745 BOE/D, a 16% increase from 1,510 BOE/D in the first quarter of 2012.

Permian. During the second quarter of 2012, our Permian drilling program averaged six rigs, and we drilled 25 gross (25 net) wells. While our secondary outlets in key operating areas reduced our natural gas curtailments from first quarter levels, we continue to experience processing issues along with drilling delays across our asset base, which has impacted the Permian's full-year production goal. In the second quarter of 2012, we drilled one well on our prospective acreage outside the Wolfberry fairway and plan to drill three more during the remainder of 2012. We expect to determine the development potential of this area by the end of 2012. In April 2012, we acquired approximately 3,000 additional net acres in the Permian. Average daily production in the second quarter of 2012 from our Permian assets was approximately 6,500 BOE/D, a 16% increase from 5,600 BOE/D in the first quarter of 2012.

Uinta. During the second quarter of 2012, we drilled 22 gross (15 net) wells at our Uinta properties utilizing a three-rig drilling program. All wells drilled targeted higher oil potential areas, with 15 wells drilled in Lake Canyon, five in the Ashley Forest, one in Brundage Canyon and one near Lake Canyon. All 15 Lake Canyon wells and the

Brundage Canyon well were Green River/Wasatch commingled wells. The Ashley Forest wells consisted of three Green River wells and two Green River/Wasatch commingled wells. During the second quarter of 2012, we continued the implementation of our second Brundage Canyon waterflood pilot by converting seven production wells to water injection wells surrounding our 20 acre infill waterflood production wells. We also purchased approximately 10,000 additional net acres in the Lake Canyon area during the second quarter of 2012. In June 2012, the Environmental Impact Study for our Ashley Forest property, where we have an inventory of 375 drilling locations on approximately 25,000 net acres with 100% working interest, was approved by the US Forest Service. In the remainder of 2012, we plan to drill approximately 57 Uinta wells, including 33 in Lake Canyon, 17 in Ashley Forest, five in Brundage Canyon and two near Lake Canyon. Average daily production from our Uinta assets was approximately 5,650 BOE/D in the second quarter of 2012, a 4% increase from to 5,430 BOE/D in the first 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 second quarter of 2012 from the E. Texas assets was approximately 17 MMcf/D compared to 18 MMcf/D in the first quarter of 2012.

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Piceance. We have deferred drilling activities in the Piceance while we focus on higher return oil development opportunities at our other properties. Average daily production in the second quarter of 2012 from the Piceance assets was approximately 18 MMcf/D compared to 20 MMcf/D in the first 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 June 30, 2012, we had a working capital deficit of approximately \$72.3 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 June 30, 2012, we had approximately 70% and 45% of our expected 2012 and 2013 oil production, respectively, hedged with collars. 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 2012 and 2013. 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.

Tender Offer and Redemption of Notes. On April 3, 2012, pursuant to the terms of the Offer to Purchase dated March 6, 2012, we repurchased \$150 million aggregate principal amount of our 2014 Notes for an aggregate purchase price of \$181.5 million, including accrued and unpaid interest. The 2014 Notes were repurchased using net proceeds from the issuance of \$600 million aggregate principal amount of our 6.375% Senior notes due 2022 (2022 Notes). Following the closing of the tender offer on April 3, 2012, \$205.3 million aggregate principal amount of 2014 Notes were outstanding. Pursuant to the terms of our credit facility, the repurchase of \$150.0 million of 2014 Notes in the tender offer increased the borrowing base of the credit facility by 25 cents per dollar of the 2014 Notes repurchased.

On April 9, 2012, we redeemed all \$200 million aggregate principal amount of our 2016 Notes for an aggregate purchase price of \$215.5 million, including accrued and unpaid interest. The 2016 Notes were redeemed using net proceeds from the issuance of our 2022 Notes. Pursuant to the terms of our credit facility, the redemption of subordinated notes did not affect our borrowing base.

Senior Secured Revolving Credit Facility. On April 13, 2012, as part of the semi-annual borrowing base redetermination process, we entered into a fourth amendment to our credit facility. Among other things, the fourth amendment increased the borrowing base to \$1.4 billion. Total lender commitments remained unchanged at \$1.2 billion.

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

As of June 30, 2012, there were \$400.5 million in outstanding borrowings under the credit facility and \$23.2 million in outstanding letters of credit, leaving \$776.3 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.

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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 the our material assets or properties; declare dividends on or redeem or repurchase our capital stock; make any acquisitions of, capital contributions to or other investments in any entity or property; extend credit or make advances or loans; engage in transactions with affiliates; and enter into, create or allow to exist contractual obligations limiting our ability to grant liens on our assets to the lenders under the credit facility. As of June 30, 2012, 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 June 30, 2012 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.

(in thousands)	Six Months Ended	
	June 30, 2012	June 30, 2011
Net cash provided by operating activities	248,067	206,522
Net cash used in investing activities	(351,120)	(435,558)
Net cash provided by financing activities	102,836	229,006
Net decrease in cash and cash equivalents	(217)	(30)

Operating Activities. Net cash provided by operating activities is primarily affected by the price of oil and natural gas, production volumes and changes in working capital. The increase in net cash provided by operating activities of \$41.5 million in the first six months of 2012 compared to the first six months of 2011 was primarily due to a 9% increase in average oil production and a 9% increase in the average realized sales price over the same time period.

Investing Activities. Net cash used in investing activities is primarily comprised of acquisition, exploration and development of oil and natural gas properties net of dispositions of oil and natural gas properties. The decrease of \$84.4 million in net cash used in investing activities in the first six months of 2012 compared to the first six months of 2011 was primarily due to a decrease in acquisition costs in the first six months of 2012 compared to the first six months of 2011, which included our acquisition of approximately 6,000 net acres in the Wolfberry trend in the Permian in May 2011. This decrease was partially offset by increased exploration and development activity in the first six months of 2012 compared to the first six months of 2011 and proceeds from the sale of our Nevada Assets during the first six months of 2012.

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Financing Activities. Net cash provided by financing activities in the first six months of 2012 included net proceeds of \$589.5 million from the issuance of \$600 million aggregate principal amount of our 2022 Notes, partially offset by the repurchase of \$150 million aggregate principal amount of our 2014 Notes for an aggregate purchase price of \$181.5 million, the repurchase of all \$200 million aggregate principal amount of our 2016 Notes for an aggregate purchase price of \$215.5 million and net repayments of \$131.0 million of borrowings under our credit facility. Net cash provided by financing activities in the first six months of 2011 included net borrowings under our credit facility and money market line of credit of \$232.4 million.

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 2012. 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.

Regulatory Matters.

On April 17, 2012, the Environmental Protection Agency (EPA) issued final rules that subject all oil and natural gas operations (production, processing, transmission, and storage) to regulation under the New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPS) programs. The EPA rules include NSPS standards for completions of hydraulically fractured natural gas wells. Before January 1, 2015, these standards require owners/operators to reduce VOC emissions from natural gas not sent to the gathering line during well completion either by flaring using a completion combustion device or by capturing the gas using green completions with a completion combustion device. Beginning January 1, 2015, operators must capture the gas and make it available for use or sale, which can be done through the use of green completions. The standards are applicable to newly fractured wells as well as existing wells that are refractured. Further, the finalized regulations under NESHAPS include emissions limitations for certain glycol dehydrators and storage vessels at major sources of hazardous air pollutants. We are currently evaluating the effect these rules will have on our business.

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:

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(in thousands)	Three Months Ended June 30, 2012	Six Months Ended June 30, 2012
Net cash provided by operating activities	\$92,661	\$248,067
Net decrease in current assets	(14,882) (4,361
Net decrease (increase) in current liabilities, including book overdraft	6,215	(13,584
Cash premiums for repurchases of notes	34,700	\$34,700
Cash settlements from early termination of natural gas derivatives	—	\$(14,700
Discretionary cash flow	\$118,694	\$250,122

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Operating Margin per BOE. Operating margin per barrel 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 barrel as a measure of profitability and believes it provides useful information to investors because it relates our oil and natural gas revenue and oil and natural gas operating expenses to our total units of production, providing a gross margin per unit of production and allowing investors to evaluate how our profitability varies on a per unit basis each period.

(per BOE)	Three Months Ended June 30, 2012	Six Months Ended June 30, 2012
Average sales price including cash derivative settlements	\$70.40	\$72.40
Average operating costs—oil and natural gas production	19.42	18.38
Average production taxes	3.01	3.20
Average operating margin	\$47.97	\$50.82

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Item 3. Quantitative and Qualitative Disclosures About Market Risk

As discussed in Note 8 to the Condensed Financial Statements, to minimize the effect of a downturn in oil and natural gas prices and protect our profitability and the economics of our development plans, we enter into crude oil and natural gas derivative contracts from time to time. The terms of the contracts depend on various factors, including management's view of future crude oil and natural gas prices, acquisition economics on purchased assets and our future financial commitments. This price hedging program is designed to moderate the effects of a severe crude oil and natural gas price downturn while allowing us to participate in some commodity price increases. In California, we benefit from lower natural gas pricing, as we are a consumer of natural gas in our operations, and elsewhere we benefit from higher natural gas pricing. We have hedged, and may hedge in the future, both natural gas purchases and sales as determined appropriate by management. Management regularly monitors the crude oil and natural gas markets and our financial commitments to determine if, when, and at what level some form of crude oil and/or natural gas hedging and/or basis adjustments or other price protection is appropriate and in accordance with policy established by our board of directors. Currently, our derivatives are in the form of swaps and collars. However, we may use a variety of derivative instruments in the future to hedge WTI or the index natural gas price. A three-way collar is a combination of three options. The base structure is a normal collar. A short option is added to fund the improvement of the long strike in the base collar. For oil sales three way collars, a purchased put and a sold call comprise the base collar. A sold put below is added to fund the raising of the strike on the purchased put. The purchased put establishes a minimum price unless the market price falls below the sold put, at which point the minimum price would be NYMEX plus the difference between the purchased put and the sold put strike price. The sold call establishes a maximum price (the ceiling) we will receive for the volumes under contract. For natural gas purchase three-way collars, a purchased call and a sold put comprise the base collar. A sold call above is added to fund the lowering of the strike on the purchased call. The purchased call establishes a maximum price unless the market price rises above the sold call, at which point the maximum price would be NYMEX plus the difference between the purchased call and the sold call strike price. The sold put establishes a minimum price (the floor) we will pay for the volumes under contract. As of June 30, 2012, we had approximately 70% and 45% of our expected 2012 and 2013 oil production, respectively, hedged with collars. A hypothetical \$10 increase in the oil prices used and \$1 increase in the natural gas prices used to calculate the fair values of our derivative instruments at June 30, 2012 would decrease the fair value of our crude oil derivative instruments by \$61.6 million and would increase the fair value of our natural gas derivative instruments by \$1.6 million. A hypothetical \$10 decrease in the oil prices used and \$1 decrease in the natural gas prices used to calculate the fair values of our derivative instruments at June 30, 2012 would increase the fair value of our crude oil derivative instruments by \$59.9 million and would decrease the fair value of our natural gas derivative instruments by \$1.2 million.

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The following table summarizes our commodity derivative position as of June 30, 2012:

Term	Average Barrels Per Day	Sold Put / Purchased Put / Sold Call	Term	Average MMBtu/D or MMTCDE	Average Prices
Crude Oil Sales (NYMEX WTI) Three-Way Collars			Natural Gas Purchases (NYMEX SoCal Border)		
Full year 2012	1,000	\$65.00/\$85.00/\$97.25	Purchased Calls		
Full year 2012	1,000	\$70.00/\$87.00/\$105.00	Full year 2013	5,000	\$3.50
Full year 2012	1,000	\$70.00/\$88.00/\$106.00	Natural Gas Purchases (NYMEX SoCal Border) 3-Way Collars		
Full year 2012	1,000	\$60.00/\$80.00/\$96.92	Full year 2013	1,000	\$2.90 / \$4.00 / \$5.00
Full year 2012	1,000	\$60.00/\$80.00/\$120.00	Full year 2013	1,000	\$2.96 / \$4.25 / \$5.25
Full year 2012	1,000	\$70.00/\$88.15/\$100.00	Full year 2013	1,000	\$2.70 / \$4.00 / \$5.00
Full year 2012	1,000	\$70.00/\$86.85/\$100.00	Natural Gas Sales (NYMEX HH to NGPL-Tex OK)		
Full year 2012	1,000	\$69.70/\$85.00/\$100.00	Basis Swaps		
Full year 2012	1,000	\$70.00/\$87.00/\$108.50	Full year 2012	2,500	\$0.44
Full year 2012	1,000	\$70.00/\$90.00/\$116.50	Natural Gas Sales (NYMEX HH TO HSC) Basis Swaps		
Full year 2012	1,000	\$70.00/\$90.00/\$120.00	Full year 2012	2,500	\$0.32
Full year 2012	1,000	\$70.00/\$95.00/\$120.10			
Full Year 2012	1,000	\$77.95/\$105.00/\$115.00			
Full Year 2012	1,000	\$80.00/\$107.00/\$119.60			
Full year 2012	500	\$70.00/\$90.00/\$100.00			
Full year 2012	500	\$70.00/\$90.00/\$100.00			
Full year 2012	1,000	\$75.00/\$90.00/\$101.85			
Full year 2012	1,000	\$70.00/\$85.00/\$92.00			
Full year 2012	2,000	\$70.00/\$80.00/\$83.00			
Full year 2012	1,500	\$75.00/\$90.00/\$97.50			
Full year 2012	500	\$75.00/\$90.00/\$106.90			
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/\$90.00/\$120.00			
Full year 2013	1,000	\$70.00/\$95.00/\$120.10			
Full year 2013	1,000	\$77.95/\$105.00/\$115.00			
Full year 2013	1,000	\$80.00/\$107.00/\$119.60			
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 2014	1,000	\$77.95/\$105.00/\$115.00			
Full year 2014	1,000	\$80.00/\$107.00/\$119.60			
Full year 2014	1,000	\$70.00/\$90.00/\$120.00			

Full year 2014	1,000	\$70.00/\$90.00/\$121.80
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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 \$0.075 to \$0.08 during 2012 and \$0.07 to \$0.075 during 2013.

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Interest Rate Risk

Our credit facility allows us to fix the interest rate for all or a portion of the principal balance for a period up to 12 months. To the extent the interest rate is fixed, interest rate changes affect the instrument's fair market value but do not impact results of operations or cash flows. Conversely, for the portion of the credit facility that has a floating interest rate, interest rate changes will not affect the fair market value but will impact future results of operations and cash flows. Changes in interest rates do not affect the amount of interest we pay on our fixed-rate debt. At June 30, 2012, our outstanding principal balance under our credit facility was \$400.5 million and the weighted average interest rate on the outstanding principal balance was 2.1%. At June 30, 2012, the carrying amount approximated fair market value. Assuming a constant debt level of \$1.5 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 \$2.5 million over a 12-month time period.

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Item 4. Controls and Procedures

As of June 30, 2012, we have carried out an evaluation under the supervision of, and with the participation of, our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15 under the Securities Exchange Act of 1934, as amended (the Exchange Act).

Our Chief Executive Officer and Chief Financial Officer have concluded that, as of June 30, 2012, our disclosure controls and procedures are effective to ensure that the information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission (SEC) rules and forms, and that information required to be disclosed by us in such reports is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure.

There were no changes in our internal controls over financial reporting that occurred during the three months ended June 30, 2012 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, 2011, filed with the SEC on February 28, 2012, 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

For additional information about our risk factors, see Item 1A. of our Annual Report on Form 10-K for the year ended December 31, 2011 filed with the SEC on February 28, 2012.

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
4.1	Fourth Amendment to the Second Amended and Restated Credit Agreement dated April 13, 2012 by and among the Registrant and Wells Fargo Bank, N.A. and other lenders (filed as exhibit 4.1 to the Registrant's Current Report on form 8-K filed on April 17, 2012, File No. 1-9735)
12.1*	Computation of Ratio of Earnings to Fixed Charges
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1**	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2**	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101**	Interactive data files

* Filed herewith.

* * Furnished herewith.

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SIGNATURE

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

BERRY PETROLEUM COMPANY

/s/ JAMIE L. WHEAT

Jamie L. Wheat

Controller

(Principal Accounting Officer)

Date: August 2, 2012