BERRY PETROLEUM CO
Form 10-Q
November 01, 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 September 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	77-0079387
(State of incorporation or organization)	(I.R.S. Employer Identification Number)

1999 Broadway, Suite 3700
Denver, Colorado 80202
(Address of principal executive offices, including zip code)
Registrant's telephone number, including area code: (303) 999-4400
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. YES T NO £
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). YES T NO £
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer T	Accelerated filer £	Non-accelerated filer £ (Do not check if a smaller reporting company)	Smaller reporting company £

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). YES £ NO T
As of October 26, 2012 the registrant had 52,386,165 shares of Class A Common Stock ($0.01 par value) outstanding. The registrant also had 1,763,866 shares of Class B Stock ($0.01 par value) outstanding on October 26, 2012, all of which is held by a single holder.

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September 30, 2012

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

	September 30, 2012	December 31, 2011
ASSETS		
Current assets:		
Cash and cash equivalents	$ 104	$ 298
Restricted short-term investments	125	65
Accounts receivable	114,916	115,952
Deferred income taxes	—	13,779
Derivative instruments	10,573	6,117
Assets held for sale	—	14,622
Prepaid expenses and other	15,503	16,801
Total current assets	141,221	167,634
Oil and natural gas properties (successful efforts basis), buildings and equipment, net	3,010,126	2,531,393
Derivative instruments	11,122	7,027
Other assets	30,891	28,898
	$ 3,193,360	$ 2,734,952
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 155,766	$ 126,489
Revenue and royalties payable	44,405	49,253
Accrued liabilities	48,392	35,066
Derivative instruments	1,309	20,365
Deferred income taxes	3,486	—
Total current liabilities	253,358	231,173
Long-term liabilities:		
Deferred income taxes	248,018	185,450
Senior secured revolving credit facility	510,000	531,500
8.25% Senior subordinated notes due 2016	—	200,000
10.25% Senior notes due 2014, net of unamortized discount of $2,715 and $6,564, respectively	202,542	348,692
6.75% Senior notes due 2020	300,000	300,000
6.375% Senior notes due 2022	600,000	—
Asset retirement obligation	84,257	64,019
Derivative instruments	1,358	15,505
Other long-term liabilities	17,541	17,884
	1,963,716	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; 52,385,165 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	362,051	350,158

Accumulated other comprehensive loss	(1,736)	(5,517)
Retained earnings	615,429	495,549
Total shareholders' equity	976,286	840,729
	$3,193,360	$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 September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
REVENUES				
Oil and natural gas sales	$232,916	$225,325	$688,350	$643,474
Electricity sales	9,514	9,826	21,354	24,202
Natural gas marketing	1,939	3,612	5,378	11,282
Gain on sale of assets	170	—	1,770	—
Interest and other income, net	286	463	1,678	1,394
	244,825	239,226	718,530	680,352
EXPENSES				
Operating costs—oil and natural gas production	70,778	61,979	187,491	177,842
Operating costs—electricity generation	4,727	6,965	14,000	19,969
Production taxes	9,700	9,185	30,048	24,926
Depreciation, depletion & amortization—oil and natural gas production	58,887	54,581	158,869	158,657
Depreciation, depletion & amortization—electricity generation	461	487	1,382	1,479
Natural gas marketing	1,753	3,285	4,917	10,475
General and administrative	17,767	14,922	53,473	47,123
Interest	20,572	19,928	61,446	53,295
Impairment of oil and natural gas properties	—	—	67	—
Dry hole, abandonment, impairment and exploration	2,729	196	7,283	619
Gain on purchase	—	—	—	(1,046)
Extinguishment of debt	—	14,391	41,545	14,391
Realized and unrealized loss (gain) on derivatives, net	28,287	(162,145)	(56,314)	(126,437)
	215,661	23,774	504,207	381,293
Earnings before income taxes	29,164	215,452	214,323	299,059
Income tax provision	11,038	81,451	81,283	112,389
Net earnings	$18,126	$134,001	$133,040	$186,670
Basic net earnings per share	$0.33	$2.45	$2.41	$3.42
Diluted net earnings per share	$0.33	$2.42	$2.39	$3.38
Dividends per share	$0.08	$0.08	$0.24	$0.23

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 September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Net earnings	$18,126	$134,001	$133,040	$186,670
Other comprehensive earnings, net of income taxes:				
Amortization of accumulated other comprehensive loss related to de-designated hedges, net of income tax benefits of $924, $5,886, $2,318 and $17,559, respectively	1,505	9,604	3,781	28,649
Other comprehensive earnings	1,505	9,604	$3,781	$28,649
Comprehensive earnings	$19,631	$143,605	$136,821	$215,319

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)

	Nine Months Ended September 30, 2012	2011
Cash flows from operating activities:		
Net earnings	$133,040	$186,670
Depreciation, depletion and amortization	160,251	160,136
Gain on sale of assets	(1,770)	—
Gain on purchase	—	(1,046)
Extinguishment of debt	6,842	3,377
Amortization of debt issuance costs and net discount	5,350	6,261
Impairment of oil and natural gas properties	67	—
Dry hole and impairment	2,515	316
Derivatives	(34,760)	(139,683)
Stock-based compensation expense	7,589	7,451
Deferred income taxes	77,511	105,096
Other, net	(1,620)	(275)
Allowance for bad debt	450	—
Change in book overdraft	7,573	5,359
Changes in operating assets and liabilities:		
Accounts receivable	504	(24,614)
Inventories, prepaid expenses, and other current assets	(2,634)	(2,263)
Accounts payable and revenue and royalties payable	15,097	48,438
Accrued interest and other accrued liabilities	15,611	16,667
Net cash provided by operating activities	391,616	371,890
Cash flows from investing activities:		
Exploration and development of oil and natural gas properties	(524,036)	(424,144)
Property acquisitions	(75,706)	(155,443)
Capitalized interest	(13,977)	(24,236)
Proceeds from sale of assets	17,294	—
Deposits on asset sales	(3,300)	—
Net cash used in investing activities	(599,725)	(603,823)
Cash flows from financing activities:		
Proceeds from issuances on line of credit	—	368,100
Repayments of borrowings under line of credit	—	(355,900)
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)	(91,044)
Long-term borrowings under credit facility	1,215,500	529,400
Repayments of long-term borrowings under credit facility	(1,237,000)	(214,400)
Financing obligation	(309)	(281)
Debt issuance costs	(11,424)	(1,176)
Dividends paid	(13,160)	(12,480)
Stock options and restricted stock issued	3,551	7,333
Excess income tax benefit	756	2,197
Net cash provided by financing activities	207,915	231,749

Net decrease in cash and cash equivalents	(194)	(184)
Cash and cash equivalents at beginning of period	298	278
Cash and cash equivalents at end of period	$104	$94
Noncash investing activities:		
Accrued capital expenditures	$61,044	$19,162
Asset retirement obligation	16,854	6,477

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	—	3,548	—	—	3,551
Stock based compensation expense	—	—	7,589	—	—	7,589
Income tax effect of stock option exercises	—	—	756	—	—	756
Dividends ($0.24 per share)	—	—	—	(13,160)	—	(13,160)
Net earnings	—	—	—	133,040	—	133,040
Amortization of Accumulated other comprehensive loss related to de-designated hedges, net of income taxes	—	—	—	—	3,781	3,781
Balances at September 30, 2012	$524	$18	$362,051	$615,429	$ (1,736)	$976,286

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

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BERRY PETROLEUM COMPANY
Notes to Condensed Financial Statements
(Unaudited)

1. Basis of Presentation

These Condensed Financial Statements have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP) for interim financial reporting. Pursuant to the rules and regulations of the Securities and Exchange Commission (SEC), the unaudited Condensed Financial Statements do not include all disclosures required by GAAP. For a more complete understanding of Berry Petroleum Company's (the Company) operations, financial position and accounting policies, the unaudited Condensed Financial Statements and notes thereto should be read in conjunction with the Company's Annual Report on Form 10-K for the year ended December 31, 2011, previously filed with the SEC.

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

The Company's cash management process provides for the daily funding of checks as they are presented to the bank. Included in accounts payable at September 30, 2012 and December 31, 2011 were $23.7 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 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 Divestitures

2012 Acquisitions

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

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

2012 Divestiture

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

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BERRY PETROLEUM COMPANY
Notes to Condensed Financial Statements (Continued)
(Unaudited)
2. Acquisitions and Divestiture (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 this acquisition 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 any of the Company's 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.

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 September 30, 2012, there were $510.0 million in outstanding borrowings under the credit facility and $23.2 million in outstanding letters of credit, leaving $666.8 million in borrowing capacity available under the credit facility. The maximum amount available under the credit facility is subject to semi-annual redeterminations of the borrowing base in April and October of each year, based on the value of the Company's proved oil and natural gas reserves, in accordance with the lenders' customary procedures and practices. The Company and the lenders each have the right to one additional redetermination each year. The semi-annual redetermination in October 2012 did not result in any changes to the borrowing base, lender commitments, or other terms of the credit facility.

4. Income Taxes

The effective income tax rate for the three months ended September 30, 2012 and 2011 was 37.8% and 37.8%, respectively. The effective income tax rate for the nine months ended September 30, 2012 and 2011 was 37.9% and 37.6%, respectively. The Company's provision for income taxes differed from the U.S. statutory rate of 35% primarily due to state income taxes, domestic production activities deduction, percentage depletion, nondeductible employee compensation and other permanent differences.

As of September 30, 2012, the Company had a gross liability for uncertain income tax benefits of $2.8 million, which, if recognized, would impact the effective income tax rate. There have been no significant changes to the calculation of uncertain income tax benefits during 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 September 30, 2012 could decrease by a maximum of $2.6 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 nine months ended September 30, 2012 and 2011:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands, except per share data)	2012	2011	2012	2011
Net earnings	$18,126	$134,001	$133,040	$186,670
Less: net earnings allocable to participating securities	118	1,207	709	1,797
Net earnings available for common shareholders	$18,008	$132,794	$132,331	$184,873
Basic net earnings per share	$0.33	$2.45	$2.41	$3.42
Diluted net earnings per share	$0.33	$2.42	$2.39	$3.38
Basic weighted average shares outstanding	54,945	54,211	54,883	54,029
Add: Dilutive effects of stock options and RSUs	336	654	395	743
Dilutive weighted average shares outstanding	55,281	54,865	55,278	54,772

Not included in the diluted earnings per share calculation were 0.7 million and 0.6 million stock options and RSUs, for the three and nine months ended September 30, 2012, respectively, because their effect would have been anti-dilutive. There were no stock options or RSUs excluded from the diluted earnings per share calculation for the three and nine months ended September 30, 2011.

6. Asset Retirement Obligation

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

	Nine Months Ended September 30,	
(in thousands)	2012	2011
Beginning balance at January 1	$64,019	$53,443
Liabilities incurred	5,862	2,169
Liabilities settled	(2,763)	(1,921)
Liabilities assumed	2,651	119
Disposition of assets	(705)	—
Accretion expense	4,201	3,593
Revisions in estimated cash flows	10,992	4,308
Ending balance at September 30	$84,257	$61,711

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.

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7. Equity Incentive Compensation Plans

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

Total compensation cost recognized in the Condensed Statements of Operations for the grants under the Company's equity incentive compensation plans was $2.0 million and $1.9 million during the three months ended September 30, 2012 and 2011, respectively, and $7.2 million and $7.0 million during the nine months ended September 30, 2012 and 2011, respectively.

Stock Options

The following table summarizes stock option activity for the nine months ended September 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	(200,509)	17.71	6,859	
Canceled/expired	—	—		
Outstanding at September 30, 2012	1,402,442	$33.45	$11,900	1,254,583

(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 September 30, 2012, there were $2.7 million of total unrecognized compensation costs related to outstanding stock options. These costs are expected to be recognized over 3.5 years.

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BERRY PETROLEUM COMPANY
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 nine months ended September 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	162,612	50.71	
Issued	(50,660)	42.94	$2,446
Canceled/expired	(14,956)	40.53	
Outstanding at September 30, 2012(1)(2)	1,012,018	$27.12	

(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 September 30, 2012, there were $12.8 million of total unrecognized compensation costs related to RSUs granted. These costs are expected to be recognized over 3.5 years.

Performance Share Program

The following table summarizes performance share award activity for the nine months ended September 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 September 30, 2012	222,587	$45.79	

(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 shares 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 September 30, 2012, there were $2.5 million of total unrecognized compensation costs related to performance shares granted. These costs are expected to be recognized over 2.3 years.

8. Derivative Instruments

The Company uses financial derivative instruments as part of its price risk management program to achieve a more predictable, economic cash flow from its oil production by reducing its exposure to price fluctuations. The Company has historically entered into financial commodity swap and collar contracts to fix the floor and ceiling prices received for a portion of the Company's oil and natural gas production. During the second quarter of 2012, the Company began entering into derivative contracts to fix the floor and ceiling prices paid for a portion of its natural gas consumption. The terms of the Company's derivative contracts depend on various factors, including management's view of future crude oil and natural gas prices, acquisition economics on purchased assets 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 September 30, 2012, the Company had commodity derivatives associated with the following volumes:

	2012	2013	2014	2015
Oil sales, Bbl/D:	21,000	16,800	7,500	3,000
Natural gas purchases, MMBtu/D:	—	10,000	—	—

The Company entered into the following derivative instruments during the nine months ended September 30, 2012:

Crude Oil Sales (NYMEX WTI) Three-Way Collars

Term	Average Barrels Per Day	Sold Put / Purchased Put / Sold Call
Full year 2013	800	$75.00 / $95.00 / $101.70

Full year 2013 and 2014	1,000	$70.00 / $90.00 / $100.00
Full year 2014	1,000	$70.00 / $90.00 / $120.00
Full year 2014	1,000	$70.00 / $90.00 / $121.80
Full year 2014	1,500	$70.00 / $90.00 / $100.00
Full year 2014 and 2015	1,000	$70.00 / $90.00 / $104.85
Full year 2015	2,000	$70.00 / $90.00 / $100.00

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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
Full year 2013	2,000	$3.03 / $4.25 / $5.25

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 loss (gain) 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 September 30, 2012, AOCL consisted of $2.8 million ($1.7 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 nine months ended September 30, 2012, $2.4 million ($1.5 million, net of income tax) and $6.1 million ($3.8 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 the remaining after-tax net losses of $1.7 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)
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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)	September 30, 2012 Derivative Assets Balance Sheet Classification	Fair Value	Derivative Liabilities Balance Sheet Classification	Fair Value
Current:				
Commodity	Derivative assets	$10.6	Derivative liabilities	$1.3
Long term:				
Commodity	Derivative assets	11.1	Derivative liabilities	1.4
Total derivatives		$21.7		$2.7

(in millions)	December 31, 2011 Derivative Assets Balance Sheet Classification	Fair Value	Derivative Liabilities 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 losses (gains) before income taxes reported in the Condensed Statements of Operations for the periods indicated:

(in millions) Description of Loss (Gain)	Location of Loss (Gain) Recognized in Earnings	Three Months Ended September 30, 2012	 2011	Nine Months Ended September 30, 2012	 2011
Commodity					
Loss reclassified from AOCL into earnings (amortization of frozen amounts)	Oil and natural gas sales	$2.7	$15.5	$7.9	$45.0
Loss (gain) recognized in earnings (cash settlements and mark-to-market movements)	Realized and unrealized loss (gain) on derivatives, net	28.3	(162.1)	(56.3)	(126.4)
Interest rate					
(Gain) loss reclassified from AOCL into earnings (amortization of frozen amounts)	Interest	$(0.3)	$—	$(1.8)	$1.2

Credit Risk

The Company does not require collateral or other security from counterparties to support derivative instruments. However, the agreements with those counterparties typically contain netting provisions such that if a default occurs, the non-defaulting party can offset the amount payable to the defaulting party under the derivative contract with the amount due from the defaulting party. As a result of the netting provisions, the Company's maximum amount of loss due to credit risk is limited to the net amounts due to and from the counterparties under the derivative contracts. The maximum amount of loss due to credit risk that the Company would have incurred if all counterparties to its derivative contracts failed to perform at September 30, 2012 was $19.8 million.

As of September 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 its derivative agreements, the Company would be in default under the credit facility. As of September 30, 2012, the Company was in a net liability position with three of the counterparties to the Company's derivative instruments. As of September 30, 2012, the Company's largest two counterparties accounted for 80% of the value of its total net derivative positions.

9. Fair Value Measurements

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

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

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

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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 September 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				
September 30, 2012	$19.0	$—	$19.0	$—
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).

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2012	2011	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 September 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)
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9. Fair Value Measurements (Continued)

Fair Market Value of Financial Instruments

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

September 30, 2012	Carrying Amount	Estimated Fair Value			
(in millions)		Level 1	Level 2	Level 3	Total
Cash and cash equivalents	$—	$—	$—	$—	$—
Senior secured revolving credit facility(1)	510	—	510	—	510
10.25% Senior notes due 2014(2)	205	229	—	—	229
6.75% Senior notes due 2020	300	324	—	—	324
6.375% Senior notes due 2022	600	632	—	—	632
	$1,615	$1,185	$510	$—	$1,695

(1) The Company's credit facility can be repaid at any time without penalty. Interest is generally fixed for 30-day increments at the prime rate or LIBOR plus a stipulated margin for the amount utilized and at a stipulated percentage as a commitment fee for the portion not utilized. The carrying amount of the credit facility approximated fair value due to the short-term maturities of the borrowings and because the borrowings bear interest at variable market rates.
(2) Carrying amount does not include unamortized discount of $2.7 million.

December 31, 2011

(in millions)	Carrying Amount	Estimated Fair Value
Senior secured revolving 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

(1) The Company's credit facility can be repaid at any time without penalty. Interest is generally fixed for 30-day increments at the prime rate or LIBOR plus a stipulated margin for the amount utilized and at a stipulated percentage as a commitment fee for the portion not utilized. The carrying amount of the credit facility approximated fair value due to the short-term maturities of the borrowings and because the borrowings bear interest at variable market rates.
(2) Carrying amount does not include unamortized discount of $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 subject to the terms of this contract averaged approximately 4,035 Bbl/D in the first nine months of 2012. The Company anticipates the crude oil sales customer will be conducting maintenance on its refinery during the fourth quarter of 2012, resulting on a reduction of the volumes of the Company's Uinta crude oil purchased by such customer during periods of maintenance. Such volumes will either have to be stored or sold into alternative markets to be identified. 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. 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 September 30, 2012 and 2011, the Company incurred costs of $0.8 million and $1.2 million, respectively, under the agreements. For the nine months ended September 30, 2012 and 2011, the Company incurred costs of $2.5 million and $4.3 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 in certain circumstances), 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; nevertheless, the Company is currently engaged in discussions with the DOI to resolve the matter administratively.

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, paid the $100,000 in July 2011 and paid the $73,000 to fund the public project in the third quarter of 2012, settling its obligation under the COGCC order.

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BERRY PETROLEUM COMPANY
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10. Commitments and Contingencies (Continued)

Royalty Payments. Certain of the Company's royalty payment calculations are being disputed. On August 1, 2012, a federal court entered a judgment against the Company that the Company had inappropriately taken certain post-wellhead deductions against royalty payments. The Company is in the process of negotiating a settlement of the judgment under which the Company's liability to the royalty owner will be approximately $3.9 million, inclusive of statutory interest, of which approximately $1.3 million had been previously recorded under the caption operating costs—oil and natural gas production. The Company recorded $1.9 million in operating costs—oil and natural gas production and $0.7 million in interest expense in the nine months ended September 30, 2012 in conjunction with the verdict. As of September 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 some of the uncertainties associated with environmental assessment and remediation activities, future expense to remediate the currently identified sites, and sites identified in the future, if any, could be incurred. Management believes, based upon current site assessments, that the ultimate resolution of any matters will not result in material costs incurred.

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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 the volume of electricity generated and the results of development, exploitation, acquisition, exploration and derivative activities. The realized prices for natural gas and electricity fluctuate from one period to another due to regional market conditions and other factors, while oil prices are 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 Third Quarter 2012 Items

- Increased oil production by 5% from the second quarter of 2012
- Generated discretionary cash flow of $125.3 million from production of 36,286 BOE/D, of which 76% was oil(1)
- Generated operating margin of $47.34 per BOE, supported by sales of our California heavy oil at a $8.50 average premium to WTI during the quarter(1)
- Average daily production from our Diatomite properties increased 18% from the second quarter of 2012
- Production from our North Midway-Sunset—New Steam Floods (NMWSS—NSF) properties, which include McKittrick, averaged 1,925 BOE/D, a 10% increase from the second quarter of 2012
- Production from our Permian properties averaged 6,860 BOE/D, a 6% increase from the second quarter of 2012
- Production from our Uinta properties averaged 5,940 BOE/D, a 5% increase from the second quarter of 2012
- Drilled 38 Uinta wells, 23 Permian wells, 17 Diatomite wells and 15 NMWSS—NSF wells
- Acquired approximately18,000 net acres in our core operating areas in the Uinta, 14,000 of which are contiguous to Brundage Canyon

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

- Expect to drill approximately 33 Diatomite wells, 25 additional Uinta wells, 17 additional McKittrick wells and 16 Permian wells during the fourth quarter of 2012
- Expect full-year 2012 development capital of approximately $675 million and production of approximately 36,200 BOE/D

Expectations for 2013

- Expect full-year 2013 development capital to be between $500 million and $600 million
- Expect full-year 2013 total production growth of between 5% and 10% over 2012

• Expect full-year 2013 oil production growth of between 10% and 15% over 2012

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

Results of Operations.

In the third quarter of 2012, we reported net earnings of $18.1 million, or $0.33 per diluted share, and net cash flows from operations of $143.5 million. Net earnings in the third quarter of 2012 included a loss on derivatives of $20.0 million resulting from non-cash changes in fair values and amortization of accumulated other comprehensive loss (AOCL) related to de-designated hedges as well as dry hole expense of $1.4 million, in each case net of income taxes.

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For the first nine months of 2012, we reported net earnings of $133.0 million, or $2.39 per diluted share, and net cash flows from operations of $391.6 million. Net earnings for the first nine months 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 $21.6 million resulting from non-cash changes in fair values and amortization of AOCL related to de-designated hedges, $1.7 million of principal and interest related to a settlement of disputed royalty payments, dry hole expense of $1.4 million, a $9.1 million cash settlement related to the early termination of our natural gas derivatives and a $1.0 million gain associated with the sale of assets related to proved developed properties in Elko, Eureka and Nye Counties, Nevada (Nevada Assets), in each case net of income taxes.

Operating Data.

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

	September 30, 2012	%	September 30, 2011	%	June 30, 2012	%
Heavy oil production (BOE/D)	18,149	50	18,173	49	17,395	49
Light oil production (BOE/D)	9,344	26	7,918	22	8,901	25
Total oil production (BOE/D)	27,493	76	26,091	71	26,296	74
Natural gas production (Mcf/D)	52,758	24	64,950	29	54,271	26
Total (BOE/D)(1)	36,286	100	36,916	100	35,341	100
Oil and natural gas, per BOE:						
Average realized sales price	$ 70.22		$ 66.74		$69.07	
Average sales price including cash derivative settlements	$ 71.45		$ 67.62		$70.40	
Oil, per BOE:						
Average WTI price	$ 92.20		$ 89.48		$93.35	
Price sensitive royalties(2)	(3.12	)	(3.37	)	(3.55	)
Location differential and other(3)	(0.68	)	4.45		(0.51	)
Oil derivatives non-cash amortization(4)	(1.10	)	(6.56	)	(1.12	)
Oil revenue	$ 87.30		$ 84.00		$88.17	
Add: Oil derivatives non-cash amortization(4)	1.10		6.56		1.12	
Oil derivative cash settlements(5)	0.64		(6.32	)	0.79	
Average realized oil price	$ 89.04		$ 84.24		$90.08	
Natural gas price:						
Average Henry Hub price per MMBtu	$ 2.80		$ 4.20		$2.21	
Conversion to Mcf	0.19		0.21		0.15	
Natural gas derivatives non-cash amortization(4)	0.02		0.02		0.03	
Location differential and other	(0.13	)	(0.18	)	(0.11	)
Natural gas revenue per Mcf	$ 2.88		$ 4.25		$2.28	
Add: Natural gas derivatives non-cash amortization(4)	(0.02	)	(0.02	)	(0.03	)
Natural gas derivative cash settlements(5)	(0.04	)	0.42		(0.03	)
Average realized natural gas price per Mcf	$ 2.82		$ 4.65		$2.22	

(1) Oil equivalents are determined using the ratio of six Mcf of natural gas to one barrel of oil.
(2) Our Formax property in SMWSS—Steam Floods is subject to a price-sensitive royalty burden. The royalty is 53% of the amount of the heavy oil posted price above the 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 third 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 September 30, 2012 was $9.88, ranged from $7.76 to $9.93 during the third quarter of 2012 and averaged $8.50 during the third quarter of 2012. In Utah, the per barrel oil posting differential at September 30, 2012 was ($15.00), ranged from ($15.00) to ($16.52) during the third quarter of 2012 and averaged ($15.91) during the third 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 loss (gain) on derivatives, net.

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

	September 30, 2012	%	September 30, 2011	%
Heavy oil production (BOE/D)	17,519	50	17,363	49
Light oil production (BOE/D)	8,781	24	7,106	20
Total oil production (BOE/D)	26,300	74	24,469	69
Natural gas production (Mcf/D)	54,372	26	67,097	31
Total (BOE/D)(1)	35,362	100	35,652	100
Oil and natural gas, per BOE:				
Average realized sales price	$71.18		$66.11	
Average sales price including cash derivative settlements	$72.08		$64.63	
Oil, per BOE:				
Average WTI price	$96.16		$95.42	
Price sensitive royalties(2)	(3.62)		(3.59)	
Location differential and other(3)	(1.00)		(0.48)	
Oil derivatives non-cash amortization(4)	(1.12)		(6.77)	
Oil revenue	$90.42		$84.58	
Add: Oil derivatives non-cash amortization(4)	1.12		6.77	
Oil derivative cash settlements(5)	(0.50)		(10.01)	
Average realized oil price	$91.04		$81.34	
Natural gas price:				
Average Henry Hub price per MMBtu	$2.58		$4.21	
Conversion to Mcf	0.17		0.21	
Natural gas derivatives non-cash amortization(4)	0.01		0.01	
Location differential and other	(0.18)		(0.15)	
Natural gas revenue per Mcf	$2.58		$4.28	
Add: Natural gas derivatives non-cash amortization(4)	(0.01)		(0.01)	
Natural gas derivative cash settlements(5)	0.29		0.41	
Average realized natural gas price per Mcf	$2.86		$4.68	

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

(2) Our Formax property in SMWSS—Steam Floods is subject to a price-sensitive royalty burden. The royalty is 53% of the amount of the heavy oil posted price above the 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 nine 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 September 30, 2012 was $9.88, ranged from $2.18 to $11.52 during the first nine months of 2012 and averaged $8.44 during the first nine months of 2012. In Utah, the per barrel oil posting differential at September 30, 2012 was ($15.00), ranged from ($12.49) to ($16.52) during the first nine months of 2012 and averaged ($15.76) during the first nine 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 loss (gain) on derivatives, net.

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

	September 30, 2012	September 30, 2011	3Q11 to 3Q12 Change	June 30, 2012	2Q12 to 3Q12 Change
Oil sales	$218,952	$199,930	10 %	$210,517	4 %
Natural gas sales	13,964	25,395	(45)%	11,264	24 %
Total oil and natural gas sales	$232,916	$225,325	3 %	$221,781	5 %
Electricity sales	9,514	9,826	(3)%	5,860	62 %
Natural gas marketing	1,939	3,612	(46)%	1,580	23 %
Gain (loss) on sale of assets	170	—	100 %	(163)	204 %
Interest and other income, net	286	463	(38)%	645	(56)%
Total revenues and other income	$244,825	$239,226	2 %	$229,703	7 %
Net earnings	$18,126	$134,001	—	$81,016	—
Diluted earnings per share	$0.33	$2.42	—	$1.46	—

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

	September 30, 2012	September 30, 2011	% Change
Oil sales	$649,922	$564,996	15 %
Natural gas sales	38,428	78,478	(51)%
Total oil and natural gas sales	$688,350	$643,474	7 %
Electricity Sales	21,354	24,202	(12)%
Natural gas marketing	5,378	11,282	(52)%
Gain on sale of assets	1,770	—	100 %
Interest and other income, net	1,678	1,394	20 %
Total revenues and other income	$718,530	$680,352	6 %
Net earnings	$133,040	$186,670	—
Diluted earnings per share	$2.39	$3.38	—

Oil and Natural Gas Sales.

Oil and natural gas sales increased $7.6 million, or 3%, to $232.9 million in the third quarter of 2012 compared to the same period in 2011. The increase was primarily due to a 5% increase in the average realized sales price in the third quarter of 2012 compared to the same period in 2011, largely as a result of an increase in oil sales volumes as a percentage of total sales volumes. Our oil sales volume increased 5% in the third quarter of 2012 compared to the third quarter of 2011, while our natural gas sales volumes decreased 19%. The oil sales volume increase was primarily due to increased oil production from all of our oil properties except our legacy South Midway-Sunset—Steam Floods (SMWSS—Steam Floods) properties. Permian oil production in the third quarter of 2012 increased 1,250 BOE/D, or 29%, from the same period in 2011, Uinta oil production increased 320 BOE/D, or 10%, between periods, Diatomite oil production in the third quarter of 2012 increased 315 BOE/D, or 10%, from the same period in 2011 and oil production for NMWSS—NSF increased 170 BOE/D, or 10%, between periods. These increases in oil production were partially offset by a decrease in production from our SMWSS—Steam Floods 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 Permian and Uinta properties.

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Oil and natural gas sales increased $11.1 million, or 5%, to $232.9 million in the third quarter of 2012 compared to the second quarter of 2012. The increase was primarily due to a 3% increase in the overall sales volumes in the third quarter of 2012 compared to the second quarter of 2012. Additionally, there was a 2% increase in the average realized sales price between periods, primarily due to an increase in oil sales volumes as a percentage of total sales volumes. Oil sales volumes increased 5% in the third quarter of 2012 compared to the second quarter of 2012, while natural gas sales volumes decreased 2% between periods. The oil sales volume increase was primarily due to increased oil production from all of our oil properties, most notably in the Diatomite, which increased 530 BOE/D, or 18%, between periods. Additionally, NMWSS—NSF oil production in the third quarter of 2012 increased 180 BOE/D, or 10%, from the second quarter of 2012. 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 the Permian.

Oil and natural gas sales increased $44.9 million, or 7%, to $688.4 million in the nine months ended September 30, 2012 compared to the nine months ended September 30, 2011. The increase was primarily due to an 8% increase in the realized sales price over the same period, largely due to an increase in oil sales volumes as a percentage of total sales volumes. Oil sales volumes in the nine months ended September 30, 2012 increased 8% from the same period in 2011, while our natural gas sales volume decreased 19% between periods. The oil sales volume increase was primarily due to increased oil production from all of our oil properties except our legacy SMWSS—Steam Floods properties, most notably in the Permian, which increased 1,760 BOE/D, or 51%, between periods. Additionally, Diatomite oil production in the nine months ended September 30, 2012 increased 375 BOE/D, or 14%, from the nine months ended September 30, 2011 and NMWSS—NSF increased 210 BOE/D or 14% between periods. The increases in oil production were partially offset by a decrease in production from our SMWSS—Steam Floods 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			Nine Months Ended	
	September 30, 2012	September 30, 2011	June 30, 2012	September 30, 2012	September 30, 2011
Electricity					
Electricity sales (in thousands)	$9,514	$ 9,826	$5,860	$21,354	$ 24,202
Operating costs (in thousands)	$4,727	$ 6,965	$4,256	$14,000	$ 19,969
Electric power produced—MWh/D	2,146	2,114	2,061	2,099	1,980
Electric power sold—MWh/D	1,939	1,949	1,882	1,919	1,817
Average sales price/MWh	$53.34	$ 55.47	$34.22	$40.62	$ 49.07
Fuel gas cost/MMBtu (including transportation)	$2.97	$ 4.38	$2.36	$2.68	$ 4.42
Fuel gas purchased (MMBtu/D)	27,000	27,000	26,000	27,000	25,000

Electricity sales in the third quarter of 2012 decreased 3% compared to the third quarter of 2011 primarily due to a 4% decrease in the average sales price of electricity and a 1% decrease in electric power sold. Electricity operating costs in the third quarter of 2012 decreased 32% compared to the third quarter of 2011 largely due to a 32% decrease in fuel gas cost. Electricity sales increased 62% in the third quarter of 2012 compared to the second quarter of 2012 primarily due to a 56% increase in the average sales price of electricity and a 3% increase in electric power sold. Electricity operating costs in the third quarter of 2012 increased 11% compared to the second quarter of 2012 largely due to a 26% increase in fuel gas cost and a 4% increase in fuel gas volumes purchased.

Electricity sales decreased 12% in the nine months ended September 30, 2012 compared to the nine months ended September 30, 2011 primarily due to a 17% decrease in the average sales price of electricity, partially offset by a 6% increase in electric power sold. Electricity operating costs decreased 30% in the nine months ended September 30, 2012 compared to the nine months ended September 30, 2011 primarily due to a 39% decrease in fuel gas cost, partially offset by a 6% increase in electric power produced.

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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 under these contracts will be based on market prices for electricity.

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

Under the PURPA PPA for our Cogen 18 facility and the transition PPAs for our Cogen 38 and Cogen 42 facilities, we will be paid the CPUC-determined SRAC energy price and a combination of firm and "as-available" capacity payments. Under the RFO PPA for our Cogen 42 facility, which will commence July 1, 2014, we will be paid a negotiated energy and capacity price stipulated in the contract.

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

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

(1) 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.

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

Natural Gas Marketing.

We have long-term firm transportation contracts on the Rockies Express, Wyoming Interstate Company, and Ruby pipelines, each with a total average capacity of 35,000 MMBtu/D. Demand charges for our capacity are reflected in operating costs—oil and natural gas production in our Condensed Statements of Operations. Our current production is insufficient to fully utilize this capacity. To optimize our remaining capacity, we purchase third-party natural gas at the market rate in our producing areas and utilize FERC-approved asset management agreements. Sales and purchases of third-party natural gas are recorded under natural gas marketing in the revenues and expenses sections of the Condensed Statements of Operations, respectively. The pre-tax net earnings of natural gas marketing operations for the three months ended September 30, 2012 and 2011 was $0.2 million and $0.3 million, respectively. The pre-tax net earnings of natural gas marketing operations for the nine months ended September 30, 2012 and 2011 was $0.5 million and $0.8 million, respectively.

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Gain on Sale of Assets.

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

Oil and Natural Gas Operating and Other Expenses.

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

	Amount Per BOE			Amount (in thousands)		
	September 30, 2012	September 30, 2011	June 30, 2012	September 30, 2012	September 30, 2011	June 30, 2012
Operating costs—oil and natural gas production	$21.20	$18.25	$19.42	$70,778	$61,979	$62,461
Production taxes	2.91	2.70	3.01	9,700	9,185	9,690
DD&A—oil and natural gas production	17.64	16.07	16.18	58,887	54,581	52,026
General and administrative	5.32	4.39	5.59	17,767	14,922	17,965
Interest expense	6.16	5.87	6.46	20,572	19,928	20,789
Total	$53.23	$47.28	$50.66	$177,704	$160,595	$162,931

• Operating costs—oil and natural gas production in the third quarter of 2012 were $70.8 million, or $21.20 per BOE, compared to $62.0 million, or $18.25 per BOE, in the third quarter of 2011 and $62.5 million, or $19.42 per BOE, in the second quarter of 2012. The increase in the third quarter of 2012 compared to the third quarter of 2011 was primarily due to increased well workover costs in the Permian and increased transportation costs due to the commencement of Ruby Pipeline operations in July 2011. Also increasing over the same time period were contract services, contract labor, chemicals, electricity, well maintenance costs and internal labor costs associated with net wells added during the last 12 months. These increases were partially offset by a $2.6 million decrease in steam costs, primarily due to decreases in the price of natural gas used in steam generation and a decrease in compression, gathering, and dehydration costs due to the natural decline in production from our natural gas properties.

The increase in operating costs—oil and natural gas production in the third quarter of 2012 compared to the second quarter of 2012 was primarily due to an increase in steam costs. Steam costs increased due to a 26% increase in the price of natural gas used in steam generation and a 7% increase in the volume of steam used in oil production over the same period. Also increasing over the same time period were well workover costs in the Permian, contract services, contract labor, chemicals, and facility costs associated with net wells added during the last 12 months. These increases were partially offset by a decrease in compression, gathering, and dehydration costs related to $2.0 million of disputed royalty deductions recorded in the second quarter of 2012.

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

	September 30, 2012	September 30, 2011	3Q11 to 3Q12 Change	June 30, 2012	2Q12 to 3Q12 Change
Average volume of steam injected (Bbl/D)	178,545	137,762	30 %	167,004	7 %
	$2.97	$4.38	(32)%	$2.36	26 %

Fuel gas cost/MMBtu (including transportation)						
Approximate net fuel gas volume consumed in steam generation (MMBtu/D)	54,911	45,488	21	%	55,532	(1)%

Included in operating costs are firm transportation costs, which totaled $7.4 million and $6.2 million for the three months ended September 30, 2012 and 2011, respectively.

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Production taxes in the third quarter of 2012 were $9.7 million, or $2.91 per BOE, compared to $9.2 million, or $2.70 per BOE, in the third quarter of 2011 and $9.7 million, or $3.01 per BOE, in the second quarter of 2012. The increase in production taxes in the third quarter of 2012 compared to the third quarter of 2011 was primarily due to an increase in the assessed ad valorem values attributable to our California and Utah properties. The decrease in production taxes per BOE in the third quarter of 2012 compared to the second quarter of 2012 was largely due to a decrease in the assessed ad valorem values of our Permian properties as a result of our successful appraisal disputes. The decrease was partially offset by an increase to ad valorem taxes attributed to increased California reserves.

Depreciation, depletion and amortization—oil and natural gas production (DD&A—oil and natural gas production) in the third quarter of 2012 was $58.9 million, or $17.64 per BOE, compared to $54.6 million, or $16.07 per BOE, in the third quarter of 2011 and $52.0 million, or $16.18 per BOE, in the second quarter of 2012. The increase in the third quarter of 2012 compared to the third quarter of 2011 and the second quarter of 2012 was primarily due to an increase in our DD&A rate. Our DD&A rate per BOE can fluctuate as a result of changes in the mix of our production, impairments, and changes in our proved reserves. Our DD&A rate per BOE in the third quarter of 2012 was 10% higher than in the third quarter of 2011 and 9% higher than in the second quarter of 2012. The higher DD&A rate per BOE was primarily due to our development expenditures during the past twelve months, which were partially offset by reserve additions during the same period.

General and administrative expense (G&A) in the third quarter of 2012 was $17.8 million, or $5.32 per BOE, compared to $14.9 million, or $4.39 per BOE, in the third quarter of 2011 and $18.0 million, or $5.59 per BOE, in the second quarter of 2012. The increase in the third quarter of 2012 compared to the third quarter of 2011 was primarily due to an increase in employee compensation and benefits resulting from new personnel hired and general pay increases directly attributable to our growing capital program and production levels. Employee travel, employee relocation, legal and accounting costs also increased over the same period.

Interest expense in the third quarter of 2012 was $20.6 million, or $6.16 per BOE, compared to $19.9 million, or $5.87 per BOE, in the third quarter of 2011 and $20.8 million, or $6.46 per BOE, in the second quarter of 2012. The increase in the third quarter of 2012 compared to the third quarter of 2011 was primarily due to a decrease in capitalized interest. The decrease in the third quarter of 2012 compared to the second quarter of 2012 was primarily due to additional interest of $0.7 million recorded in the second quarter of 2012 related to disputed royalty deductions partially offset by a decrease in non-cash derivative losses of $0.7 million related to the de-designated interest rate hedges reclassified from AOCL into interest expense and a decrease in capitalized interest.

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

	Amount Per BOE		Amount (in thousands)	
	September 30, 2012	September 30, 2011	September 30, 2012	September 30, 2011
Operating costs—oil and natural gas production	$19.35	$18.27	$187,491	$177,842
Production taxes	3.10	2.56	30,048	24,926
DD&A—oil and natural gas production	16.40	16.30	158,869	158,657
General and administrative	5.52	4.84	53,473	47,123
Interest expense	6.34	5.48	61,446	53,295
Total	$50.71	$47.45	$491,327	$461,843

Operating costs in the nine months ended September 30, 2012 were $187.5 million, or $19.35 per BOE, compared to $177.8 million, or $18.27 per BOE, in the nine months ended September 30, 2011. The increase was primarily due to an increase in transportation due to the commencement of Ruby Pipeline operations in July 2011 and increased well maintenance costs in California. Also increasing over the period were Permian well workover costs, contract services, contract labor, chemicals, electricity and internal labor costs associated with net wells added during the last 12 months. 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 increased costs of $1.9 million related to disputed royalty deductions.

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

	September 30, 2012	September 30, 2011	% Change	
Average volume of steam injected (Bbl/D)	160,087	132,781	21	%
Fuel gas cost/MMBtu (including transportation)	$ 2.68	$ 4.42	(39	)%
Approximate net fuel gas volume consumed in steam generation (MMBtu/D)	52,015	44,355	17	%

Included in operating costs are firm transportation costs, which totaled $21.5 million and $14.3 million for the nine months ended September 30, 2012 and 2011, respectively.

- Production taxes in the nine months ended September 30, 2012 were $30.0 million, or $3.10 per BOE, compared to $24.9 million, or $2.56 per BOE, in the nine months ended September 30, 2011. The increase was primarily due to an increase in the assessed ad valorem values attributable to our California properties and increased ad valorem and severance taxes related to new wells drilled and acquisitions, primarily in the Permian. This increase in Permian ad valorem severance taxes was partially offset by a decrease in the assessed ad valorem values of our Permian properties as a result of our successful appraisal disputes during the third quarter of 2012.

- DD&A—oil and natural gas production in the nine months ended September 30, 2012 was $158.9 million, or $16.40 per BOE, compared to $158.7 million, or $16.30 per BOE, in the nine months ended September 30, 2011.

- G&A in the nine months ended September 30, 2012 was $53.5 million, or $5.52 per BOE, compared to $47.1 million, or $4.84 per BOE, in the nine months ended September 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. Employee travel and relocation costs also increased over the same time period.

- Interest expense in the nine months ended September 30, 2012 was $61.4 million, or $6.34 per BOE, compared to $53.3 million, or $5.48 per BOE, in the nine months ended September 30, 2011. The increase was primarily due to a decrease of $10.3 million in capitalized interest, as well as additional interest of $0.7 million related to disputed royalty payments. These increases were partially offset by a decrease in non-cash derivative losses of $3.0 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 nine months ended September 30, 2012, we incurred dry hole, abandonment, impairment and exploration expense of $2.7 million and $7.3 million, respectively. For the three and nine months ended September 30, 2011, we incurred dry hole, abandonment, impairment and exploration expense of $0.2 million and $0.6 million, respectively. In the third quarter of 2012, we recorded dry hole expense of $2.3 million associated with mechanical failure encountered on one well near Lake Canyon, which was abandoned in favor of drilling a nearby replacement well. In the first nine months of 2012 the remaining amounts recorded in dry hole, abandonment, impairment, and exploration were primarily related to the purchase of seismic data and plugging and abandonment activities.

Gain on Purchase. In the first quarter of 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. In the second quarter of 2012, we incurred debt extinguishment expense of $41.5 million related to the redemption of the entire $200 million aggregate principal amount of 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 Loss (Gain) on Derivatives, Net. The following table sets forth the derivative cash settlements and non-cash derivative contract fair value gains and losses recorded in the Condensed Statements of Operations under the caption realized and unrealized loss (gain) on derivatives, net for the periods indicated. See Notes 8 and 9 to the Condensed Financial Statements for more information on our derivative instruments.

(in thousands)	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Three Months Ended June 30, 2012	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Cash (receipts) payments:					
Commodity derivatives—oil	$(1,595)	$15,016	$(1,865)	$3,609	$66,856
Commodity derivatives—natural gas(1)	170	(2,491)	147	(19,064)	(7,402)
Total cash (receipts) payments	$(1,425)	$12,525	$(1,718)	$(15,455)	$59,454
Mark-to-market loss (gain):					
Commodity derivatives—oil	$30,228	$(172,875)	$(111,056)	$(56,465)	$(186,799)
Commodity derivatives—natural gas(1)	(516)	(1,795)	(308)	15,606	908
Total mark-to-market loss (gain)	$29,712	$(174,670)	$(111,364)	$(40,859)	$(185,891)
Total realized and unrealized loss (gain) on derivatives, net	$28,287	$(162,145)	$(113,082)	$(56,314)	$(126,437)

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

Income Tax Expense. The effective income tax rate for the three months ended September 30, 2012 and 2011 was 37.8% and 37.8%, respectively. The effective income tax rate for the nine months ended September 30, 2012 and 2011 was 37.9% and 37.6%, respectively. Our provision for income taxes differed from the U.S. statutory rate of 35% primarily due to state income taxes, domestic production activities deduction, percentage depletion, nondeductible employee compensation and other permanent differences.

Drilling Activity.

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

Asset Team	Three Months Ended September 30, 2012 Gross Production Wells		Three Months Ended September 30, 2012 Net Production Wells	Nine Months Ended September 30, 2012 Gross Production Wells		Nine Months Ended September 30, 2012 Net Production Wells
SMWSS—Steam Floods	31		31	63		63
NMWSS—Diatomite	17		17	99		99
NMWSS—New Steam Floods	15		15	65		65
Permian	26	(1)	23	79	(2)	63
Uinta	38		31	75		58
E. Texas	—		—	—		—
Piceance	—		—	—		—
Total	127		117	381		348

(1) Includes three non-operated wells in which we have an average interest of approximately 0.59% each, or approximately 0.02 total net wells, and 23 gross operated wells.

(2) Includes 16 non-operated wells in which we have an average interest of approximately 0.60% each, or approximately 0.10 total net wells, and 63 gross operated wells.

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Properties.

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

SMWSS—Steam Floods. Our SMWSS—Steam Floods asset team includes our Homebase, Formax, Ethel D, Placerita and Poso Creek properties. These are our legacy assets in California, and we expect total average production to slowly decline over time. In the third quarter of 2012, we continued the drilling program at Ethel D, drilling 23 producing wells and two steam injection wells, all of which are operational. The program will continue in the fourth quarter of 2012, with additional steam injection wells. During the third quarter of 2012, we also completed the expansion of our Poso Creek steam flood, drilling an additional eight producing wells and two steam injection wells. During the remainder of 2012, we plan to drill one additional production well at Poso Creek and two additional production wells at Formax. Average daily production in the third quarter of 2012 from all of our SMWSS—Steam Floods assets was approximately 12,720 BOE/D compared to 12,675 BOE/D in the second quarter of 2012.

NMWSS—Diatomite. Our NMWSS—Diatomite asset team includes our Diatomite properties in the San Joaquin Valley. Between the third and fourth quarters of 2012 we expect to drill approximately 50 producing wells in the Diatomite. These wells are being drilled as part of our accelerated 2013 development program. We are continuing to refine our development approach, which includes modified high-frequency, reduced-temperature injection cycles, continuous development utilizing advanced drilling techniques and real-time performance monitoring. As a result of these efforts, reservoir dilation had decreased, which has reduced wellbore stresses. This strategy will increase the number of active completions, improve the recovery of the resource and enhance the long-term value of the Diatomite. Average daily production from our NMWSS—Diatomite assets in the third quarter of 2012 was approximately 3,500 BOE/D, an 18% increase from 2,970 BOE/D in the second quarter of 2012.

NMWSS—New Steam Floods. Our NWMSS—NSF asset team includes our non-Diatomite North Midway-Sunset assets including our McKittrick, Main Camp, Fairfield, Pan, and USL-12 properties. In the third quarter of 2012, we drilled 15 productive wells and 30 steam injector wells at McKittrick to accelerate our steam flood recovery. In the remainder of 2012, we plan to drill 17 additional productive wells at McKittrick. Average daily production from all of our NMWSS—NSF assets in the third quarter of 2012 was approximately 1,925 BOE/D, a 10% increase from 1,745 BOE/D in the second quarter of 2012.

Permian. During the third quarter of 2012, our Permian drilling program averaged six rigs, and we drilled 23 wells, including 20 wells on our core development properties. Additionally, we drilled three wells on our prospective acreage outside the Wolfberry fairway. Appraisal of this area is progressing on schedule, and we expect to determine its development potential by the end of 2012. While our Permian production continues to increase, we are still experiencing higher line pressure, periodic gas plant downtime and ethane rejection as a result of record activity levels in the area. Average daily production in the third quarter of 2012 from our Permian assets was approximately 6,860 BOE/D, a 6% increase from 6,500 BOE/D in the second quarter of 2012.

Uinta. During the third quarter of 2012, we drilled 38 wells at our Uinta properties utilizing a four-rig drilling program. All wells drilled targeted higher oil potential areas, with 16 wells drilled in Lake Canyon, 17 in the Ashley Forest and five in Brundage Canyon. All of the Uinta wells drilled during the third quarter of 2012 were Green River/Wasatch commingled wells, with the exception of one Green River only well in Lake Canyon. Early test results from the Ashley Forest commingled wells have been encouraging. To date, we have approximately 350 remaining locations in the Ashley Forest on approximately 25,000 net acres with 100% working interest. During the third quarter of 2012, we acquired approximately18,000 net acres in our core operating areas in the Uinta, 14,000 of which are contiguous to Brundage Canyon. In the remainder of 2012, we plan to drill approximately 25 additional wells, including ten in Lake Canyon, nine in Brundage Canyon and six in Ashley Forest. Average daily production from our

Uinta assets was approximately 5,940 BOE/D in the third quarter of 2012, a 5% increase from 5,650 BOE/D in the second 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 third quarter of 2012 from the E. Texas assets was approximately 15 MMcf/D compared to 17 MMcf/D in the second quarter of 2012.

Piceance. We have deferred drilling activities in the Piceance while we focus on higher return oil development opportunities at our other properties. Average daily production in the third quarter of 2012 from the Piceance assets was approximately 17 MMcf/D compared to 18 MMcf/D in the second quarter of 2012.

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Financial Condition, Liquidity and Capital Resources.

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

At September 30, 2012, we had a working capital deficit of approximately $112.1 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 September 30, 2012, we had approximately 70% and 50% of our expected 2012 and 2013 oil production, respectively, hedged. 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.

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.

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 September 30, 2012, there were $510.0 million in outstanding borrowings under the credit facility and $23.2 million in outstanding letters of credit, leaving $666.8 million in borrowing capacity available under the credit facility. The maximum amount available under the credit facility is subject to semi-annual redeterminations of the borrowing base in April and October of each year, based on the value of our proved oil and natural gas reserves, in accordance with the lenders' customary procedures and practices. We and the lenders each have a right to one additional redetermination each year. The semi-annual redetermination in October 2012 did not result in any changes to the borrowing base, lender commitments, or other terms of the credit facility.

The credit facility contains certain covenants, which, among other things, require the maintenance of (i) an interest coverage ratio of at least 2.75 to 1.0 and (ii) a minimum current ratio of 1.0 to 1.0. The credit facility also contains other customary covenants, subject to certain agreed exceptions, including covenants restricting our ability to, among other things, owe or be liable for indebtedness; create, assume or permit to exist liens; be a party to or be liable on any hedging contract; engage in mergers or consolidations; transfer, lease, exchange, alienate or dispose of our material assets or properties; declare dividends on or redeem or repurchase our capital stock; make any acquisitions of, capital contributions to or other investments in any entity or property; extend credit or make advances or loans; engage in transactions with affiliates; and enter into, create or allow to exist contractual obligations limiting our ability to grant liens on our assets to the lenders under the credit facility. As of September 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 September 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)	Nine Months Ended September 30, 2012	September 30, 2011
Net cash provided by operating activities	$391,616	$371,890
Net cash used in investing activities	(599,725)	(603,823)
Net cash provided by financing activities	207,915	231,749
Net decrease in cash and cash equivalents	$(194)	$(184)

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 $19.7 million in the first nine months of 2012 compared to the first nine months of 2011 was primarily due to an 8% 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 $4.1 million in net cash used in investing activities in the first nine months of 2012 compared to the first nine months of 2011 was primarily due to a decrease in acquisition costs in the first nine months of 2012 compared to the first nine months of 2011, which included our acquisition of approximately 6,000 net acres in the Wolfberry trend in the Permian in May 2011. The proceeds from the sale of our Nevada Assets during the first nine months of 2012 also contributed to the decrease. This decrease was partially offset by increased exploration and development activity in the first nine months of 2012 compared to the first nine months of 2011.

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Financing Activities. Net cash provided by financing activities in the first nine months of 2012 included net proceeds of $589.5 million from the issuance of $600 million aggregate principal amount of our 2022 Notes, partially offset by the repurchase of $150 million aggregate principal amount of our 2014 Notes for an aggregate purchase price of $181.5 million, the repurchase of all $200 million aggregate principal amount of our 2016 Notes for an aggregate purchase price of $215.5 million and net repayments of $21.5 million of borrowings under our credit facility. Net cash provided by financing activities in the first nine months of 2011 included net borrowings under our credit facility and money market line of credit of $327.2 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 volatile organic compound 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.

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Reconciliation of Non-GAAP Measures.

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

(in thousands)	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2012
Net cash provided by operating activities	$143,549	$391,616
Net decrease in current assets	6,491	2,130
Net increase in current liabilities, including book overdraft	(24,697)	(38,281)
Cash premiums for repurchases of notes	—	34,700
Cash settlements from early termination of natural gas derivatives	—	(14,700)
Discretionary cash flow	$125,343	$375,465

Operating Margin per BOE. Operating margin per BOE consists of oil and natural gas revenues less oil and natural gas operating expenses and production taxes divided by the total BOEs produced during the period. Management uses operating margin per BOE as a measure of profitability and believes it provides useful information to investors because it relates our oil and natural gas revenue and oil and natural gas operating expenses to our total units of production, providing a gross margin per unit of production and allowing investors to evaluate how our profitability varies on a per unit basis each period.

(per BOE)	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2012
Average sales price including cash derivative settlements	$71.45	$72.08
Average operating costs—oil and natural gas production	21.20	19.35
Average production taxes	2.91	3.10
Average operating margin	$47.34	$49.63

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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 September 30, 2012, we had approximately 70% and 50% of our expected 2012 and 2013 oil production, respectively, hedged. A hypothetical $10 increase in the oil prices used and $1 increase in the natural gas prices used to calculate the fair values of our derivative instruments at September 30, 2012 would decrease the fair value of our crude oil derivative instruments by $74.6 million and would increase the fair value of our natural gas derivative instruments by $2.1 million. A hypothetical $10 decrease in the oil prices used and $1 decrease in the natural gas prices used to calculate the fair values of our derivative instruments at September 30, 2012 would increase the fair value of our crude oil derivative instruments by $66.8 million and would decrease the fair value of our natural gas derivative instruments by $1.6 million.

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

Term	Average Barrels Per Day	Sold Put / Purchased Put / Sold Call
Crude Oil Sales (NYMEX WTI) Three-Way Collars		
Full year 2012	1,000	$65.00/$85.00/$97.25
Full year 2012	1,000	$70.00/$87.00/$105.00
Full year 2012	1,000	$70.00/$88.00/$106.00
Full year 2012	1,000	$60.00/$80.00/$96.92
Full year 2012	1,000	$60.00/$80.00/$120.00
Full year 2012	1,000	$70.00/$88.15/$100.00
Full year 2012	1,000	$70.00/$86.85/$100.00
Full year 2012	1,000	$69.70/$85.00/$100.00
Full year 2012	1,000	$70.00/$87.00/$108.50
Full year 2012	1,000	$70.00/$90.00/$116.50
Full year 2012	1,000	$70.00/$90.00/$120.00
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 2013	800	$75.00/$95.00/$101.70
	1,000	$70.00/$90.00/$100.00

Term	Average MMBtu/D or MMTCDE	Average Prices
Natural Gas Purchases (NYMEX SoCal Border) Purchased Calls		
Full year 2013	5,000	$3.50
Natural Gas Purchases (NYMEX SoCal Border) 3-Way Collars		
Full year 2013	1,000	$2.90 / $4.00 / $5.00
Full year 2013	1,000	$2.96 / $4.25 / $5.25
Full year 2013	1,000	$2.70 / $4.00 / $5.00
Full year 2013	2,000	$3.03 / $4.25 / $5.25
Natural Gas Sales (NYMEX HH to NGPL-Tex OK) Basis Swaps		
Full year 2012	2,500	$0.44
Natural Gas Sales (NYMEX HH TO HSC) Basis Swaps		
Full year 2012	2,500	$0.32

Full year 2013 and 2014		
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
Full year 2014	1,500	$70.00/$90.00/$100.00
Full year 2014 and 2015	1,000	$70.00/$90.00/$104.85
Full year 2015	2,000	$70.00/$90.00/$100.00

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 September 30, 2012, our outstanding principal balance under our credit facility was $510.0 million and the weighted average interest rate on the outstanding principal balance was 2.0%. At September 30, 2012, the carrying amount approximated fair market value. Assuming a constant debt level of $1.6 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 $3.2 million over a 12-month time period.

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Item 4. Controls and Procedures

As of September 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 September 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 September 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
10.1†**	Crude Oil Purchase Contract dated July 9, 2012 between the Registrant and ExxonMobil Oil Corporation.
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

† Portions of this exhibit have been omitted pursuant to a request for confidential treatment.
** 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: November 1, 2012