

Diamondback Energy, Inc.
Form 10-Q
August 08, 2013
Table of Contents

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

✓ QUARTERLY REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF
1934
FOR THE QUARTERLY PERIOD ENDED June 30, 2013
OR
.. TRANSITION REPORT UNDER SECTION 13 OR 15(d) OF SECURITIES EXCHANGE ACT OF 1934
Commission File Number 001-35700

Diamondback Energy, Inc.
(Exact Name of Registrant As Specified in Its Charter)

Delaware 45-4502447
(State or Other Jurisdiction of (IRS Employer
Incorporation or Organization) Identification Number)

500 West Texas, Suite 1225 79701
Midland, Texas (Zip Code)
(Address of Principal Executive Offices)
(432) 221-7400
(Registrant Telephone Number, Including Area Code)

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 past 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 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 during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes 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 the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check One):

Large Accelerated Filer .. Accelerated Filer ..

Edgar Filing: Diamondback Energy, Inc. - Form 10-Q

Non-Accelerated Filer

Smaller Reporting Company

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes No

As of July 24, 2013, 42,161,532 shares of the registrant's common stock were outstanding.

DIAMONDBACK ENERGY, INC.
TABLE OF CONTENTS

	Page
<u>PART I. FINANCIAL INFORMATION</u>	
ITEM 1.	<u>1</u>
	<u>1</u>
	<u>2</u>
	<u>4</u>
	<u>5</u>
	<u>7</u>
ITEM 2.	<u>22</u>
ITEM 3.	<u>32</u>
ITEM 4.	<u>33</u>
<u>PART II OTHER INFORMATION</u>	
ITEM 1.	<u>35</u>
ITEM 1A.	<u>35</u>
ITEM 2.	<u>35</u>
ITEM 3.	<u>35</u>
ITEM 4.	<u>35</u>
ITEM 5.	<u>35</u>
ITEM 6.	<u>36</u>
<u>Signatures</u>	<u>38</u>

GLOSSARY OF OIL AND NATURAL GAS TERMS

The following is a description of the meanings of some of the oil and natural gas industry terms used throughout this report:

3-D seismic. Geophysical data that depict the subsurface strata in three dimensions. 3-D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2-D, or two-dimensional, seismic.

Bbl. Stock tank barrel, or 42 U.S. gallons liquid volume, used in this report in reference to crude oil or other liquid hydrocarbons.

Bbls/d. Bbls per day.

BOE. Barrels of oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil.

BOE/d. BOE per day.

Completion. The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Condensate. Liquid hydrocarbons associated with the production of a primarily natural gas reserve.

Developed acreage. The number of acres that are allocated or assignable to productive wells or wells capable of production.

Development well. A well drilled within the proved area of a natural gas or oil reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Exploratory well. A well drilled to find and produce natural gas or oil reserves not classified as proved, to find a new reservoir in a field previously found to be productive of natural gas or oil in another reservoir or to extend a known reservoir.

Field. An area consisting of either a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Finding and Development Costs. Capital costs incurred in the acquisition, exploitation and exploration of proved oil and natural gas reserves divided by proved reserve additions and revisions to proved reserves.

Fracturing. The process of creating and preserving a fracture or system of fractures in a reservoir rock typically by injecting a fluid under pressure through a wellbore and into the targeted formation.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

Horizontal drilling. A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle with a specified interval.

MBbls. Thousand barrels of crude oil or other liquid hydrocarbons.

MBOE. One thousand barrels of crude oil equivalent, determined using a ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Mcf. Thousand cubic feet of natural gas.

Mcf/d. Mcf per day.

MMcf. Million cubic feet of natural gas.

Net acres or net wells. The sum of the fractional working interest owned in gross acres or gross wells, as the case may be.

Net revenue interest. An owner's interest in the revenues of a well after deducting proceeds allocated to royalty and overriding interests.

PDP. Proved developed producing.

Play. A set of discovered or prospective oil and/or natural gas accumulations sharing similar geologic, geographic and temporal properties, such as source rock, reservoir structure, timing, trapping mechanism and hydrocarbon type.

Plugging and abandonment. Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of all states require plugging of abandoned wells.

PUD. Proved undeveloped.

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

Proved developed reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved reserves. The estimated quantities of oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved undeveloped reserves. Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

Recompletion. The process of re-entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is separate from other reservoirs.

Stratigraphic play. An oil or natural gas formation contained within an area created by permeability and porosity changes characteristic of the alternating rock layer that result from the sedimentation process.

Structural play. An oil or natural gas formation contained within an area created by earth movements that deform or rupture (such as folding or faulting) rock strata.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production and requires the owner to pay a share of the costs of drilling and production operations.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Various statements contained in this report that express a belief, expectation, or intention, or that are not statements of historical fact, are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, or the Securities Act, and Section 21E of the Securities Exchange Act of 1934, or the Exchange Act. These forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond our control. All statements, other than statements of historical fact, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this quarterly report, the words “could,” “believe,” “anticipate,” “intend,” “estimate,” “expect,” “may,” “continue,” “predict,” “potential,” “project,” and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. In particular, the factors discussed in this quarterly report on Form 10-Q and detailed under Part II, Item 1A. Risk Factors in this report and our Annual Report on Form 10-K for the year ended December 31, 2012 could affect our actual results and cause our actual results to differ materially from expectations, estimates or assumptions expressed, forecasted or implied in such forward-looking statements.

Forward-looking statements may include statements about our:

- business strategy;
- exploration and development drilling prospects, inventories, projects and programs;
- oil and natural gas reserves;
- identified drilling locations;
- ability to obtain permits and governmental approvals;
- technology;
- financial strategy;
- realized oil and natural gas prices;
- production;
 - lease operating expenses, general and administrative costs and finding and development costs;
- future operating results; and
- plans, objectives, expectations and intentions.

All forward-looking statements speak only as of the date of this quarterly report. You should not place undue reliance on these forward-looking statements. These forward-looking statements are subject to a number of risks, uncertainties and assumptions. Moreover, we operate in a very competitive and rapidly changing environment. New risks emerge from time to time. It is not possible for our management to predict all risks, nor can we assess the impact of all factors on our business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements we may make. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this quarterly report are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved or occur, and actual results could differ materially and adversely from those anticipated or implied in the forward-looking statements.

Table of ContentsDiamondback Energy, Inc. and Subsidiaries
Consolidated Balance Sheets
(Unaudited)

	June 30, 2013	December 31, 2012
Assets		
Current assets:		
Cash and cash equivalents	\$81,898,000	\$26,358,000
Accounts receivable:		
Joint interest and other	7,347,000	5,959,000
Oil and natural gas sales	16,374,000	8,081,000
Related party	648,000	772,000
Inventories	6,271,000	6,195,000
Deferred income taxes	—	1,857,000
Derivative instruments	3,191,000	—
Prepaid expenses and other	807,000	1,053,000
Total current assets	116,536,000	50,275,000
Property and equipment		
Oil and natural gas properties, based on the full cost method of accounting (\$118,893,000 and \$121,245,000 excluded from amortization at June 30, 2013 and December 31, 2012, respectively)	847,732,000	697,742,000
Other property and equipment	4,749,000	2,337,000
Accumulated depletion, depreciation, amortization and impairment	(171,309,000)	(145,837,000)
	681,172,000	554,242,000
Other assets	931,000	2,184,000
Total assets	\$798,639,000	\$606,701,000
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable trade	\$22,630,000	\$12,141,000
Accounts payable-related party	724,000	18,813,000
Accrued capital expenditures	50,042,000	29,397,000
Other accrued liabilities	16,065,000	10,649,000
Revenues and royalties payable	5,020,000	3,270,000
Derivative instruments	2,679,000	4,817,000
Deferred income taxes	182,000	—
Note payable-short term	145,000	145,000
Total current liabilities	97,487,000	79,232,000
Note payable—long term	121,000	193,000
Derivative instruments-long term	—	388,000
Asset retirement obligations-long term	2,324,000	2,125,000
Deferred income taxes-noncurrent	71,098,000	62,695,000
Total liabilities	171,030,000	144,633,000
Contingencies (Note 13)		
Stockholders' equity:		

Edgar Filing: Diamondback Energy, Inc. - Form 10-Q

Common stock, \$0.01 par value, 100,000,000 shares authorized, 42,161,532 issued and outstanding at June 30, 2013; 36,986,532 issued and outstanding at December 31, 2012	422,000	370,000
Additional paid-in capital	659,394,000	513,772,000
Accumulated deficit	(32,207,000) (52,074,000)
Total stockholders' equity	627,609,000	462,068,000
Total liabilities and stockholders' equity	\$798,639,000	\$606,701,000

See accompanying notes to combined consolidated financial statements.

Table of ContentsDiamondback Energy, Inc. and Subsidiaries
Combined Consolidated Statements of Operations
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Revenues:				
Oil sales	\$41,034,000	\$14,366,000	\$66,287,000	\$29,012,000
Natural gas sales	988,000	205,000	1,727,000	397,000
Natural gas sales - related party	680,000	106,000	1,092,000	261,000
Natural gas liquid sales	1,649,000	841,000	3,471,000	1,575,000
Natural gas liquid sales - related party	1,043,000	512,000	1,726,000	1,136,000
Total revenues	45,394,000	16,030,000	74,303,000	32,381,000
Costs and expenses:				
Lease operating expenses	5,695,000	3,523,000	10,928,000	5,744,000
Lease operating expenses - related party	392,000	6,000	594,000	574,000
Production taxes	2,080,000	738,000	3,431,000	1,479,000
Production taxes - related party	116,000	44,000	192,000	100,000
Gathering and transportation	31,000	35,000	106,000	52,000
Gathering and transportation - related party	216,000	44,000	274,000	94,000
Depreciation, depletion and amortization	14,815,000	5,659,000	25,553,000	10,416,000
General and administrative expenses	2,355,000	1,005,000	4,540,000	1,480,000
General and administrative expenses - related party	266,000	648,000	552,000	1,357,000
Asset retirement obligation accretion expense	45,000	21,000	88,000	41,000
Total costs and expenses	26,011,000	11,723,000	46,258,000	21,337,000
Income from operations	19,383,000	4,307,000	28,045,000	11,044,000
Other income (expense)				
Interest income	—	1,000	—	2,000
Interest expense	(535,000)	(1,173,000)	(1,020,000)	(2,054,000)
Other income - related party	388,000	586,000	777,000	1,011,000
Gain on derivative instruments, net	3,037,000	9,957,000	3,029,000	5,165,000
Loss from equity investment	—	(54,000)	—	(67,000)
Total other income, net	2,890,000	9,317,000	2,786,000	4,057,000
Income before income taxes	22,273,000	13,624,000	30,831,000	15,101,000
Provision for income taxes				
Deferred income tax provision	7,802,000	—	10,964,000	—
Net income	\$14,471,000	\$13,624,000	\$19,867,000	\$15,101,000
Earnings per common share				
Basic	\$0.37		\$0.52	
Diluted	\$0.36		\$0.52	
Weighted average common shares outstanding				
Basic	39,402,282		38,237,149	
Diluted	39,718,574		38,476,719	

See accompanying notes to combined consolidated financial statements.

Table of Contents

Diamondback Energy, Inc. and Subsidiaries

Combined Consolidated Statements of Operations - Continued

(Unaudited)

	Three Months Ended June 30, 2012	Six Months Ended June 30, 2012
Pro forma information		
Income before income taxes, as reported	\$13,624,000	\$15,101,000
Pro forma provision for income taxes	4,857,000	5,384,000
Pro forma net income	\$8,767,000	\$9,717,000
Pro forma earnings per common share - basic and diluted	\$0.60	\$0.66
Pro forma weighted average common shares outstanding - basic and diluted	14,697,496	14,697,496

See accompanying notes to combined consolidated financial statements.

Table of ContentsDiamondback Energy, Inc. and Subsidiaries
Consolidated Statement of Stockholders' Equity
(Unaudited)

	Common Stock		Additional	Accumulated	Total
	Shares	Amount	Paid-in Capital	Deficit	
Balance December 31, 2012	36,986,532	\$370,000	\$513,772,000	\$(52,074,000)) \$462,068,000
Stock-based compensation	—	—	1,183,000	—	1,183,000
Common shares issued in public offering, net of offering costs	5,175,000	52,000	144,439,000	—	144,491,000
Net income	—	—	—	19,867,000	19,867,000
Balance June 30, 2013	42,161,532	\$422,000	\$659,394,000	\$(32,207,000)) \$627,609,000

See accompanying notes to combined consolidated financial statements.

Table of ContentsDiamondback Energy, Inc. and Subsidiaries
Combined Consolidated Statements of Cash Flows
(Unaudited)

	Six Months Ended June 30,	
	2013	2012
Cash flows from operating activities:		
Net income	\$ 19,867,000	\$ 15,101,000
Adjustments to reconcile net income to net cash provided by operating activities:		
Provision for deferred income taxes	10,964,000	—
Asset retirement obligation accretion expense	88,000	41,000
Depreciation, depletion, and amortization	25,553,000	10,416,000
Amortization of debt issuance costs	318,000	212,000
Change in fair value of derivative instruments	(5,429,000) (5,165,000
Loss from equity investment	—	67,000
Equity-based compensation expense	936,000	582,000
Gain on sale of assets	(30,000) (10,000
Changes in operating assets and liabilities:		
Accounts receivable	(12,185,000) (2,915,000
Accounts receivable-related party	5,110,000	7,111,000
Inventories	(96,000) 181,000
Prepaid expenses and other	(1,517,000) (1,590,000
Accounts payable and accrued liabilities	4,543,000	2,058,000
Accounts payable and accrued liabilities-related party	(74,000) (1,484,000
Revenues and royalties payable	1,750,000	(349,000
Revenues and royalties payable-related party	—	(1,595,000
Net cash provided by operating activities	49,798,000	22,661,000
Cash flows from investing activities:		
Additions to oil and natural gas properties	(108,977,000) (50,576,000
Additions to oil and natural gas properties-related party	(9,298,000) (4,629,000
Acquisition of Gulfport properties	(18,550,000) —
Purchase of other property and equipment	(1,615,000) (637,000
Proceeds from sale of property and equipment	54,000	10,000
Settlement of non-hedge derivative instruments	(289,000) (5,263,000
Receipt on derivative margins	—	1,479,000
Net cash used in investing activities	(138,675,000) (59,616,000
Cash flows from financing activities:		
Proceeds from borrowings on credit facility	49,000,000	15,000,000
Repayment on credit facility	(49,000,000) —
Proceeds from note payable - related party	—	14,100,000
Debt issuance costs	(72,000) (42,000
Public offering costs	(447,000) (729,000
Proceeds from public offering	144,936,000	—
Contributions by members	—	4,008,000
Net cash provided by financing activities	144,417,000	32,337,000
Net increase (decrease) in cash and cash equivalents	55,540,000	(4,618,000
Cash and cash equivalents at beginning of period	26,358,000	6,959,000
Cash and cash equivalents at end of period	\$ 81,898,000	\$ 2,341,000

See accompanying notes to combined consolidated financial statements.

5

Table of Contents

Diamondback Energy, Inc. and Subsidiaries
 Combined Consolidated Statements of Cash Flows - Continued
 (Unaudited)

	Six Months Ended June 30,	
	2013	2012
Supplemental disclosure of cash flow information:		
Interest paid, net of capitalized interest	\$383,000	\$876,000
Supplemental disclosure of non-cash transactions:		
Asset retirement obligation incurred	\$111,000	\$95,000
Distribution of equity method investments	\$—	\$10,504,000
Note payable exchanged for equipment	\$—	\$411,000

See accompanying notes to combined consolidated financial statements.

Table of Contents

Diamondback Energy, Inc. and Subsidiaries
Notes to Combined Consolidated Financial Statements
(Unaudited)

1. DESCRIPTION OF THE BUSINESS AND BASIS OF PRESENTATION

Organization and Description of the Business

Diamondback Energy, Inc. (“Diamondback” or the “Company”) together with its subsidiaries, is an independent oil and gas company currently focused on the acquisition, development, exploration and exploitation of unconventional, onshore oil and natural gas reserves in the Permian Basin in West Texas. Diamondback was incorporated in Delaware on December 30, 2011, and did not conduct any material business operations until October 11, 2012 when Diamondback merged with its parent entity, Diamondback Energy LLC, with Diamondback continuing as the surviving entity (the “Merger”). Prior to the Merger, Diamondback Energy LLC was a holding company and did not conduct any material business operations other than its ownership of the Diamondback’s common stock and the membership interests in Diamondback O&G LLC (formerly known as Windsor Permian LLC, or “Windsor Permian”). As a result of the Merger, Windsor Permian became a wholly-owned subsidiary of Diamondback. Also on October 11, 2012, Wexford Capital LP (“Wexford”), our equity sponsor, caused all of the outstanding equity interests in Windsor UT LLC (“Windsor UT”) to be contributed to Windsor Permian prior to the Merger in a transaction referred to as the “Windsor UT Contribution”. The Windsor UT Contribution was treated as a combination of entities under common control with assets and liabilities transferred at their carrying amounts in a manner similar to a pooling of interests. We refer to the historical results of Windsor Permian and Windsor UT prior to October 11, 2012 as our “Predecessors”. Immediately after the Merger on October 11, 2012, Diamondback acquired from Gulfport Energy Corporation (“Gulfport”) all of its oil and natural gas interests in the Permian Basin (the “Gulfport properties”) in exchange for shares of Diamondback common stock and a promissory note in a transaction referred to as the Gulfport transaction. The Gulfport transaction was treated as a business combination accounted for under the acquisition method of accounting with the identifiable assets and liabilities recognized at fair value on the date of transfer. See Note 3—Acquisitions for information regarding the acquisition.

On October 17, 2012, the Company completed its initial public offering (“IPO”) of 14,375,000 shares of common stock, which included 1,875,000 shares of common stock issued pursuant to an option to purchase additional shares granted to the underwriters. The stock was sold to the public at \$17.50 per share and the Company received net proceeds of approximately \$234.1 million from the sale of these shares of common stock, net of offering expenses and underwriting discounts and commissions.

In the first quarter of 2013, Windsor UT merged with and into Windsor Permian and Windsor Permian, the surviving entity in the merger, was renamed Diamondback O&G LLC, or Diamondback O&G.

On May 22, 2013, the Company completed an underwritten primary public offering of 5,175,000 shares of common stock, which included 675,000 shares of common stock issued pursuant to an option to purchase additional shares granted to the underwriters. The stock was sold to the public at \$29.25 per share and the Company received net proceeds of approximately \$144.4 million from the sale of these shares of common stock, net of offering expenses and underwriting discounts and commissions.

On June 24, 2013, Gulfport and certain entities controlled by Wexford completed an underwritten secondary public offering of 6,000,000 shares of the Company’s common stock and, on July 5, 2013, the underwriters purchased an additional 869,222 shares of the Company’s common stock from these selling stockholders pursuant to an option to purchase such additional shares granted to the underwriters. The shares were sold to the public at \$34.75 per share and the selling stockholders received all proceeds from this offering.

Basis of Presentation

These financial statements have been prepared by the Company without audit, pursuant to the rules and regulations of the Securities and Exchange Commission (“SEC”). They reflect all adjustments that are, in the opinion of management, necessary for a fair statement of the results for interim periods, on a basis consistent with the annual audited financial statements. All such adjustments are of a normal recurring nature. Certain information, accounting policies and footnote disclosures normally included in financial statements prepared in accordance with accounting principles

generally accepted in the United States (“GAAP”) have been omitted pursuant to such rules and regulations, although the Company believes the disclosures are adequate to make the information presented not misleading. This Quarterly Report on Form 10-Q should be read in conjunction with the Company’s most recent

Table of Contents

Diamondback Energy, Inc. and Subsidiaries

Notes to Combined Consolidated Financial Statements-(Continued)

(Unaudited)

Annual Report on Form 10-K for the fiscal year ended December 31, 2012, which contains a summary of the Company's significant accounting policies and other disclosures.

Transfers of a business between entities under common control are accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information. As discussed above, the Windsor UT Contribution was accounted for as a transaction between entities under common control. Thus, the accompanying combined consolidated financial statements and related notes of the Company have been retrospectively adjusted to include the historical results of Windsor UT at historical carrying values and its operations prior to October 11, 2012, the effective date of the Windsor UT Contribution. The accompanying financial statements and related notes presented herein represent the combined results of operations and cash flows of our Predecessors through October 11, 2012, and the Company and its wholly-owned subsidiaries consolidated financial position, results of operations, cash flows and equity subsequent to October 11, 2012. All intercompany balances and transactions are eliminated in consolidation.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

Certain amounts included in or affecting the Company's combined consolidated financial statements and related disclosures must be estimated by management, requiring certain assumptions to be made with respect to values or conditions that cannot be known with certainty at the time the combined consolidated financial statements are prepared. These estimates and assumptions affect the amounts the Company reports for assets and liabilities and the Company's disclosure of contingent assets and liabilities at the date of the combined consolidated financial statements. Actual results could differ from those estimates.

The Company evaluates these estimates on an ongoing basis, using historical experience, consultation with experts and other methods the Company considers reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from the Company's estimates. Any effects on the Company's business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known. Significant items subject to such estimates and assumptions include estimates of proved oil and natural gas reserves and related present value estimates of future net cash flows therefrom, the carrying value of oil and natural gas properties, asset retirement obligations, the fair value determination of acquired assets and liabilities, stock-based compensation, fair value estimates of commodity derivatives and estimates of income taxes.

Unaudited Pro Forma Income Taxes

Diamondback was formed as a holding company on December 30, 2011, and did not conduct any material business operations prior to the Merger. Diamondback is a C-Corporation under the Internal Revenue Code and is subject to income taxes. The Company computed a pro forma income tax provision as if the Company and our Predecessors were subject to income taxes since December 31, 2011. The pro forma tax provision has been calculated at a rate based upon a federal corporate level tax rate and a state tax rate, net of federal benefit, incorporating permanent differences.

Unaudited Pro Forma Earnings per Share

The Company's pro forma basic earnings per share amounts have been computed based on the weighted-average number of shares of common stock outstanding for the period, as if the common shares issued upon the Merger were outstanding for the entire year. Diluted earnings per share reflects the potential dilution, using the treasury stock method, which assumes that options were exercised and restricted stock awards and units were fully vested. During periods in which the Company realizes a net loss, options and restricted stock awards would not be dilutive to net loss per share and conversion into common stock is assumed not to occur.

3. ACQUISITIONS

On October 11, 2012, the Company completed the acquisition of Gulfport's oil and natural gas interests in the Permian Basin. The following unaudited summary pro forma combined consolidated statement of operations data of Diamondback for the three months and six months ended June 30, 2012 has been prepared to give effect to the

acquisition as if it had occurred on January 1, 2011. The pro forma data are not necessarily indicative of financial results that would have been attained had the acquisition occurred on January 1, 2011. The pro forma data also

8

Table of Contents

Diamondback Energy, Inc. and Subsidiaries

Notes to Combined Consolidated Financial Statements-(Continued)

(Unaudited)

necessarily exclude various operation expenses related to the Gulfport properties and the financial statements should not be viewed as indicative of operations in future periods.

	Three Months Ended June 30, 2012 (Pro Forma)	Six Months Ended June 30, 2012 (Pro Forma)
Pro forma total revenues	\$22,951,000	\$46,572,000
Pro forma income from operations	6,405,000	15,691,000
Pro forma net income	15,722,000	(1) 19,748,000 (1)

(1) This amount does not include a pro forma income tax provision relating to becoming subject to income taxes as a result of the Merger.

Table of Contents

Diamondback Energy, Inc. and Subsidiaries
Notes to Combined Consolidated Financial Statements-(Continued)
(Unaudited)

4. PROPERTY AND EQUIPMENT

Property and equipment includes the following:

	June 30, 2013	December 31, 2012
Oil and natural gas properties:		
Subject to depletion	\$728,839,000	\$576,497,000
Not subject to depletion-acquisition costs		
Incurred in 2013	5,984,000	—
Incurred in 2012	109,059,000	117,395,000
Incurred in 2011	1,670,000	1,670,000
Incurred in 2010	1,647,000	1,647,000
Incurred in 2009	533,000	533,000
Total not subject to depletion	118,893,000	121,245,000
Gross oil and natural gas properties	847,732,000	697,742,000
Less accumulated depreciation, depletion, amortization and impairment	(170,286,000)	(145,102,000)
Oil and natural gas properties, net	677,446,000	552,640,000
Other property and equipment	4,749,000	2,337,000
Less accumulated depreciation	(1,023,000)	(735,000)
Other property and equipment, net	3,726,000	1,602,000
Property and equipment, net of accumulated depreciation, depletion, amortization and impairment	\$681,172,000	\$554,242,000

The average depletion rate per barrel equivalent unit of production was \$24.42 and \$24.44 for the three months and six months ended June 30, 2013, respectively, and \$24.26 and \$23.70 for the three months and six months ended June 30, 2012, respectively. Internal costs capitalized to the full cost pool represent management's estimate of costs incurred directly related to exploration and development activities such as geological and other administrative costs associated with overseeing the exploration and development activities. All internal costs not directly associated with exploration and development activities were charged to expense as they were incurred. Capitalized internal costs were approximately \$843,000 and \$1,640,000 for the three months and six months ended June 30, 2013, respectively, and \$1,083,000 and \$1,775,000 for the three months and six months ended June 30, 2012, respectively. Costs associated with unevaluated properties are excluded from the full cost pool until the Company has made a determination as to the existence of proved reserves. The inclusion of the Company's unevaluated costs into the amortization base is expected to be completed within three to five years.

5. ASSET RETIREMENT OBLIGATIONS

The following table describes the changes to the Company's asset retirement obligation liability for the following periods:

	Six Months Ended	
	June 30, 2013	2012
Asset retirement obligation, beginning of period	\$2,145,000	\$1,104,000
Additional liability incurred	111,000	95,000
Accretion expense	88,000	41,000
Asset retirement obligation, end of period	2,344,000	1,240,000

Edgar Filing: Diamondback Energy, Inc. - Form 10-Q

Less current portion	20,000	19,000
Asset retirement obligations - long-term	\$2,324,000	\$1,221,000

The Company's asset retirement obligations primarily relate to the future plugging and abandonment of wells and related facilities. The Company estimates the future plugging and abandonment costs of wells, the ultimate productive life of the properties, a risk-adjusted discount rate and an inflation factor in order to determine the current

Table of Contents

Diamondback Energy, Inc. and Subsidiaries

Notes to Combined Consolidated Financial Statements-(Continued)

(Unaudited)

present value of this obligation. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligation liability, a corresponding adjustment is made to the oil and natural gas property balance.

6. EQUITY METHOD INVESTMENTS

Bison Drilling and Field Services LLC

On November 15, 2010, the Company formed a wholly owned subsidiary, Bison Drilling and Field Services LLC (“Bison”), formerly known as Windsor Drilling LLC. In addition, on March 2, 2010, the Company formed a wholly owned subsidiary, West Texas Field Services LLC, which, on January 1, 2011, contributed all of its assets and liabilities to Bison and West Texas Field Services LLC was subsequently dissolved on June 12, 2012. Bison owns and operates drilling rigs and various oil and natural gas well servicing equipment.

Beginning on March 31, 2011, various related party investors contributed capital to Bison diluting the Company’s ownership interest. The Company assessed its ability to exercise financial control over Bison and based on the results of its assessment, the Company concluded it maintained significant influence but it no longer had the ability to exercise control over Bison. The Company deconsolidated Bison for financial reporting purposes as of March 31, 2011 and the previously consolidated amounts were removed from the consolidated balance sheet and reflected as an equity method investment. The Company eliminated intercompany profits or losses in relation to its continuing involvement with Bison, proportionate to its equity interest. Under the equity method, generally the Company’s share of investees’ earnings or loss is recognized in the combined consolidated statements of operations. However, because substantially all of Bison’s earnings were generated by performing services on properties owned and operated by the Company, the Company’s share of Bison’s earnings have been credited to oil and natural gas properties.

An entity is required to deconsolidate a subsidiary when the entity ceases to have a controlling financial interest in the subsidiary. Upon deconsolidation of a subsidiary, an entity recognizes a gain or loss on the transaction and measures any retained investment in the subsidiary at fair value. The gain or loss includes any gain or loss associated with the difference between the fair value of the retained investment in the subsidiary and its carrying amount at the date the subsidiary is deconsolidated.

The Company internally reviewed the balance sheet of Bison to determine its fair value. At the time of the transaction Bison was still a recently formed company and had not yet built value in its operations. Bison’s assets consisted primarily of four recently purchased drilling rigs. Two of the drilling rigs were purchased at market price from a third party in December 2010 and the second two were purchased from the same third party in April 2011. The Company also reviewed pricing of similar rigs in the market through retail and auction transactions. Because the rigs had just recently been purchased and this purchase price was in line with other outside transactions the Company determined that Bison’s book value equaled fair value. There was no gain or loss recorded and the retained investment was recorded at fair value which equaled book value.

In September 2011, the Company completed the sale of 25% of its membership interest in Bison to a related party. The Company internally reviewed the fair value of Bison and because the effective date of this transaction was May 1, 2011 and was within thirty days of the above valuation the Company concluded the value of Bison had not changed. The Company determined that fair value equaled book value at the date of this transaction. There was no gain or loss recorded and the retained investment was recorded at fair value which equaled book value.

As of June 15, 2012, the Company distributed its remaining interest in Bison to an entity which is controlled and managed by Wexford. As the transaction was between entities under common control, the Company recognized the distribution of \$6,437,000 as an equity transaction. Bison continues to be a related party with the Company.

Muskie Holdings LLC

During 2011, the Company paid approximately \$4,200,000 for land and various other capital items related to the land. On October 7, 2011, the Company contributed these assets to a newly formed entity, Muskie Holdings LLC (“Muskie”), a Delaware limited liability company now known as Muskie Proppant LLC, for a 48.6% equity interest. Through additional contributions to Muskie from a related party and various Wexford portfolio companies, the Company’s

interest in Muskie decreased to 33% as of June 15, 2012. Muskie generated a loss during the period from January 1, 2012 through June 15, 2012 and the Company recorded its share of this loss.

Table of Contents

Diamondback Energy, Inc. and Subsidiaries

Notes to Combined Consolidated Financial Statements-(Continued)

(Unaudited)

As of June 15, 2012, the Company distributed its remaining interest in Muskie to an entity which is controlled and managed by Wexford. As the transaction was between entities under common control, the Company recognized the distribution of \$4,067,000 as an equity transaction. Muskie continues to be a related party with the Company.

7. DEBT**Credit Facility-Wells Fargo Bank**

On October 15, 2010, the Company entered into a secured loan agreement with BNP Paribas (“BNP”) as the administrative agent, sole book runner and lead arranger providing for a revolving credit facility. On May 10, 2012, the revolving credit agreement was amended to provide for the resignation of BNP, and the appointment of Wells Fargo Bank, National Association, as administrative agent for the lenders. The loan agreement, as amended, provides for a \$250.0 million revolving credit facility subject to scheduled semi-annual and other elective collateral borrowing base redeterminations based on our oil and natural gas reserves (the “borrowing base”). The outstanding borrowings bear interest at a rate elected by the Company that is based on the prime, LIBOR or federal funds rate plus margins ranging from 1.25% to 3.50% depending on the base rate used and the amount of the loan outstanding in relation to the borrowing base.

Principal may be optionally repaid from time to time and is required to be paid (i) if the loan amount exceeds the borrowing base and (ii) at the maturity date of October 15, 2014. The Company is obligated to pay, quarterly, a commitment fee equal to 0.5% per year of the unused portion of the borrowing base. The loan is secured by substantially all of the Company’s assets. The borrowing base is re-determined semi-annually with effective dates of April 1st and October 1st (a “scheduled redetermination”). In addition, the Company may request an additional three redeterminations of the borrowing base during any 12 months period. The borrowing base was \$100.0 million at December 31, 2011. The borrowing base increased throughout 2012 and 2013 through various redeterminations and at December 31, 2012 and June 30, 2013, the borrowing base was \$135.0 million and \$180.0 million, respectively. In connection with the IPO, the Company repaid all outstanding borrowings under its revolving credit facility and, as of December 31, 2012, had no outstanding borrowings. In connection with the public offering of the Company’s common stock in May 2013, the Company repaid all outstanding borrowings under its revolving credit facility and, as of June 30, 2013, had no outstanding borrowings under this facility.

The revolving credit agreement contains various affirmative and restrictive covenants. These covenants, among other things, prohibit additional indebtedness, sales of assets, mergers and consolidations, dividends and distributions, and changes in management and require the maintenance of various financial ratios defined below.

The current lenders and their percentage commitments in the revolving credit facility are Wells Fargo Bank, N.A. (45%), Amegy Bank, N.A. (25%), U.S. Bank, N.A. (25%) and West Texas National Bank (5%).

As of July 24, 2012, the revolving credit agreement was amended and restated to include Diamondback Energy LLC and its subsidiaries as additional guarantors to the facility. The covenant prohibiting additional indebtedness was also amended to allow the issuance of unsecured debt of up to \$250.0 million and, in connection with any such issuance, the reduction of the borrowing base by 25% of the principal amount of such issuance. A borrowing base reduction in connection with such issuance may require a portion of the outstanding principal of the loan to be repaid. The amendment also provided that redemptions of any unsecured debt will be restricted unless certain liquidity requirements are met. Further, the amendment modified certain financial ratios, the current requirements of which are described below.

Financial Covenant

	Required Ratio
Ratio of EBITDAX to interest expense, as defined in the credit agreement	Not less than 2.5 to 1.0
Ratio of total debt to EBITDAX	Not greater than 4.0 to 1.0
Ratio of debt under revolving credit agreement to EBITDAX	Not greater than 3.0 to 1.0
Ratio of current assets to liabilities, as defined in the credit agreement	Not less than 1.0 to 1.0

The revolving credit agreement defines EBITDAX, for any period, as the sum of consolidated net income for such period plus the following expenses or charges to the extent deducted from consolidated net income for such period: interest; income taxes; depreciation, depletion, amortization and exploration expenses; extraordinary items and other similar non-cash charges, including expenses related to stock-based compensation and hedging, minus all non-cash income added to consolidated net income.

Table of Contents

Diamondback Energy, Inc. and Subsidiaries

Notes to Combined Consolidated Financial Statements-(Continued)

(Unaudited)

As of September 28, 2012, the second amendment to the amended and restated credit agreement was executed, which among other things provided for an increase in permitted subordinated debt in a maximum principal amount not to exceed \$45.0 million, waived compliance with the Company's current ratio covenant for the quarter ending September 30, 2012 and increased the aggregate limitation on lease payments during any period of 12 months consecutive calendar months from \$250,000 to \$550,000.

As of June 30, 2013, the Company was in compliance with all financial covenants under the revolving credit facility. The lenders may accelerate all of the indebtedness under the revolving credit facility upon the occurrence of any event of default unless the Company cures any such default within any applicable grace period. For payments of principal and interest under the revolving credit facility, the Company generally has a three business day grace period, and a 30-day cure period for most covenant defaults, but not for defaults of certain specific covenants, including the financial covenants and negative covenants.

Note Payable

The Company entered into an installment payment contract with EMC Corporation for the purchase of computer equipment. The contract is payable in equal installments over a period of 36 months. As of June 30, 2013 and December 31, 2012, the Company had amounts outstanding under this note of \$266,000 and \$338,000, respectively.

Subordinated Note

Effective May 14, 2012, the Company issued a subordinated note to an affiliate of Wexford pursuant to which, as amended, the Wexford affiliate could, from time to time, advance up to an aggregate of \$45.0 million. These advances were solely at the lender's discretion and neither Wexford nor any of its affiliates had any commitment or obligation to provide further capital support to the Company. The note bore interest at a rate equal to LIBOR plus 0.28% or 8% per annum, whichever was lower. Interest was due quarterly in arrears beginning on July 1, 2012. Interest payments were payable in kind by adding such amounts to the principal balance of the note. The unpaid principal balance and all accrued interest on the note was due and payable in full on January 31, 2015 or the earlier completion of an initial public offering. Any indebtedness evidenced by this note was subordinate in the right of payment to any indebtedness outstanding under the Company's revolving credit facility. As of June 30, 2012, there was \$14.1 million in aggregate principal amount outstanding under this note. In connection with the IPO, the Company repaid all outstanding borrowings under the subordinated note and the subordinated note was canceled.

8. EARNINGS PER SHARE & PRO FORMA EARNINGS PER SHARE**Earnings Per Share**

The Company's basic earnings per share amounts have been computed based on the weighted-average number of shares of common stock outstanding for the period. A reconciliation of the components of basic and diluted earnings per common share is presented in the table below:

	Three Months Ended June 30, 2013		
	Income	Shares	Per Share
Basic:			
Net income attributable to common stock	\$14,471,000	39,402,282	\$0.37
Effect of Dilutive Securities:			
Dilutive effect of potential common shares issuable	\$—	316,292	
Diluted:			

Edgar Filing: Diamondback Energy, Inc. - Form 10-Q

Net income attributable to common stock	\$ 14,471,000	39,718,574	\$0.36
---	---------------	------------	--------

13

Table of Contents

Diamondback Energy, Inc. and Subsidiaries
 Notes to Combined Consolidated Financial Statements-(Continued)
 (Unaudited)

	Six Months Ended June 30, 2013		Per Share
	Income	Shares	
Basic:			
Net income attributable to common stock	\$ 19,867,000	38,237,149	\$0.52
Effect of Dilutive Securities:			
Dilutive effect of potential common shares issuable	\$—	239,570	
Diluted:			
Net income attributable to common stock	\$ 19,867,000	38,476,719	\$0.52

Pro Forma Earnings Per Share

The Company's pro forma basic earnings per share amounts have been computed based on the weighted-average number of shares of common stock outstanding for the period, as if the common shares issued upon the Merger were outstanding for the entire year. A reconciliation of the components of pro forma basic and diluted earnings per common share is presented in the table below:

	Three Months Ended June 30, 2012		Per Share
	Income	Shares	
Basic:			
Pro forma net income attributable to common stock	\$ 8,767,000	14,697,496	\$0.60
Effect of Dilutive Securities:			
Dilutive effect of potential common shares issuable	\$—	—	
Diluted:			
Pro forma net income attributable to common stock	\$ 8,767,000	14,697,496	\$0.60

	Six Months Ended June 30, 2012		Per Share
	Income	Shares	
Basic:			
Pro forma net income attributable to common stock	\$ 9,717,000	14,697,496	\$0.66
Effect of Dilutive Securities:			
Dilutive effect of potential common shares issuable	\$—	—	
Diluted:			
Pro forma net income attributable to common stock	\$ 9,717,000	14,697,496	\$0.66

9. STOCK AND EQUITY BASED COMPENSATION

For the three months and six months ended June 30, 2013, the Company incurred \$700,000 and \$1,356,000, respectively, of stock based compensation, of which the Company capitalized \$223,000 and \$420,000, respectively, pursuant to the full cost method of accounting for oil and natural gas properties. For the three months and six months ended June 30, 2012, the Company incurred \$291,000 and \$582,000, respectively, of equity based compensation, of which the Company capitalized \$116,000 and \$223,000, respectively, pursuant to the full cost method of accounting

for oil and natural gas properties.

The following table presents the Company's stock option activity under the 2012 Plan for the six months ended June 30, 2013.

14

Table of Contents

Diamondback Energy, Inc. and Subsidiaries

Notes to Combined Consolidated Financial Statements-(Continued)

(Unaudited)

	Options	Weighted Average Exercise Price	Remaining Term (In years)	Intrinsic Value
Outstanding at December 31, 2012	850,000	\$ 17.50		
Granted	63,000	\$ 22.72		
Exercised	—	\$ —		
Expired/Forfeited	—	\$ —		
Outstanding at June 30, 2013	913,000	\$ 17.86	3.28	\$ 14,115,000
Vested and Expected to vest at June 30, 2013	913,000	\$ 17.86	3.28	\$ 14,115,000
Exercisable at June 30, 2013	287,500	\$ 17.50	2.99	\$ 4,548,000

As of June 30, 2013, the unrecognized compensation cost related to unvested stock options was \$2,347,000. Such cost is expected to be recognized over a weighted-average period of 2.3 years.

The following table presents the Company's restricted stock awards and units activity under the 2012 Plan for the six months ended June 30, 2013.

	Restricted Stock Awards & Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2012	206,507	\$ 17.50
Granted	—	\$ —
Vested	14,286	\$ 17.50
Forfeited	—	\$ —
Unvested at June 30, 2013	192,221	\$ 17.50

As of June 30, 2013, the Company's unrecognized compensation cost related to unvested restricted stock awards and units was \$2,574,000. Such cost is expected to be recognized over a weighted-average period of 2.0 years.

10. RELATED PARTY TRANSACTIONS**Administrative Services**

An entity under common management provided technical, administrative and payroll services to the Company under a shared services agreement which began March 1, 2008. Through December 31, 2011, amounts charged to the Company included those costs directly attributable to the Company as well as indirect costs allocated to the Company. The reimbursement amount for indirect costs is determined by the affiliate's management based on estimates of time devoted to the Company. The initial term of this shared service agreement was two years. Since the expiration of such two-year period on March 1, 2010, the agreement by its terms, continued on a month-to-month basis. For the three months and six months ended June 30, 2013, the Company incurred total costs of \$51,000 and \$109,000, respectively. For the three months and six months ended June 30, 2012, the Company incurred total costs of \$1,673,000 and \$4,123,000, respectively. Costs incurred unrelated to drilling activities are expensed and costs incurred in the acquisition, exploration and development of proved oil and natural gas properties have been capitalized. The expensed costs were partially offset in general and administrative expenses by overhead reimbursements of \$613,000 and \$1,152,000 for the three months and six months ended June 30, 2012, respectively. As of June 30, 2013 and December 31, 2012, the Company owed the administrative services affiliate \$16,000 and \$13,000, respectively. These amounts are included in accounts payable-related party in the accompanying consolidated balance sheets.

Effective January 1, 2012, the Company entered into an additional shared services agreement with this entity. Under this agreement, the Company provides this entity and, at its request, certain affiliates, with consulting, technical and administrative services. The initial term of the additional shared services agreement is two years. Upon expiration of

15

Table of Contents

Diamondback Energy, Inc. and Subsidiaries

Notes to Combined Consolidated Financial Statements-(Continued)

(Unaudited)

the initial term the agreement will continue on a month-to-month basis until canceled by either party upon thirty days prior written notice. Costs that are attributable to and billed to other affiliates are reported as other income-related party. For the three months and six months ended June 30, 2013, the affiliate reimbursed the Company \$388,000 and \$777,000, respectively, and for the three months and six months ended June 30, 2012, the affiliate reimbursed the Company \$586,000 and \$1,011,000, respectively for services under the shared services agreement. As of June 30, 2013 and December 31, 2012, the affiliate owed the Company no amounts and \$1,000, respectively. These amounts are included in accounts receivable-related party in the accompanying consolidated balance sheets.

Operating Services

The Company is the operator of substantially all of its properties. As operator of these properties, the Company is responsible for the daily operations, monthly operation billings and monthly revenue disbursements for the properties. As of June 30, 2013 and December 31, 2012, amounts due from an affiliate related to joint interest billings and included in accounts receivable-related party in the accompanying consolidated balance sheets were \$183,000 and \$742,000, respectively.

Drilling Services

Bison has performed drilling and field services for the Company under master drilling and field service agreements. Under the Company's most recent master drilling agreement with Bison, effective as of January 1, 2013, Bison committed to accept orders from the Company for the use of at least two of its rigs. At June 30, 2013, Bison was providing drilling services to the Company using one of its rigs. This master drilling agreement is terminable by either party on 30 days prior written notice, although neither party will be relieved of its respective obligations arising from a drilling contract being performed prior to the termination of the master drilling agreement. The Company owed Bison \$708,000 as of June 30, 2013 and \$120,000 as of December 31, 2012.

MidMar

The Company is party to a gas purchase agreement, dated May 1, 2009, as amended, with MidMar Gas LLC ("MidMar"), an entity affiliated with Wexford that owns a gas gathering system and processing plant in the Permian Basin. Under this agreement, MidMar is obligated to purchase from the Company, and the Company is obligated to sell to MidMar, all of the gas conforming to certain quality specifications produced from certain of the Company's Permian Basin acreage. Following the expiration of the initial ten year term, the agreement will continue on a year-to-year basis until terminated by either party on 30 days' written notice. Under the gas purchase agreement, MidMar is obligated to pay the Company 87% of the net revenue received by MidMar for all components of the Company's dedicated gas, including the liquid hydrocarbons, and the sale of residue gas, in each case extracted, recovered or otherwise processed at MidMar's gas processing plant, and 94.56% of the net revenue received by MidMar from the sale of such gas components and residue gas, extracted, recovered or otherwise processed at Chevron's Headlee plant. The Company recognized revenues from Midmar of \$1,723,000 and \$2,818,000 for the three months and six months ended June 30, 2013, respectively, and \$618,000 and \$1,397,000 for the three months and six months ended June 30, 2012, respectively. As of June 30, 2013 and December 31, 2012, MidMar owed the Company \$465,000 and \$6,000, respectively, for the Company's portion of the net proceeds from the sale of gas, gas products and residue gas.

Sand Supply

Muskie, an entity affiliated with Wexford, holds certain rights in a lease covering land in Wisconsin for mining oil and natural gas fracture grade sand. The Company began purchasing sand from Muskie in March 2013. The Company incurred costs of zero and \$234,000 for the three months and six months ended June 30, 2013. As of June 30, 2013, the Company did not owe Muskie any amounts.

Midland Lease

Effective May 15, 2011, the Company occupied corporate office space in Midland, Texas under a lease with a five-year term. The office space is owned by an entity controlled by an affiliate of Wexford. The Company paid \$43,000 and \$82,000 for the three months and six months ended June 30, 2013, respectively, and \$40,000 and

\$72,000, for the three months and six months ended June 30, 2012, respectively, under this lease. In the second quarter of 2013, we amended this agreement to increase the size of the leased premises. The current monthly rent under the lease will

Table of Contents

Diamondback Energy, Inc. and Subsidiaries

Notes to Combined Consolidated Financial Statements-(Continued)

(Unaudited)

increase from \$13,000 to \$15,000 beginning on September 1, 2013 and \$21,000 beginning on October 1, 2013. The monthly rent will increase approximately 4% annually on June 1 of each year during the remainder of the lease term.

Oklahoma City Lease

Effective January 1, 2012, the Company occupied corporate office space in Oklahoma City, Oklahoma under a lease with a 67 month term. The office space is owned by an entity controlled by an affiliate of Wexford. The Company paid \$58,000 and \$111,000 for the three months and six months ended June 30, 2013, respectively, and \$82,000 and \$206,000 for the three months and six months ended June 30, 2012, respectively, under this lease. Effective April 1, 2013, we amended this lease to increase the size of the leased premises, at which time our monthly base rent increased to \$19,000 for the remainder of the lease term. The Company is also responsible for paying a portion of specified costs, fees and expenses associated with the operation of the premises.

Advisory Services Agreement & Professional Services from Wexford

The Company entered into an advisory services agreement (the “Advisory Services Agreement”) with Wexford, dated as of October 11, 2012, under which Wexford provides the Company with general financial and strategic advisory services related to the business in return for an annual fee of \$500,000, plus reasonable out-of-pocket expenses. The Advisory Services Agreement has a term of two years commencing on October 18, 2012, and will continue for additional one-year periods unless terminated in writing by either party at least ten days prior to the expiration of the then current term. It may be terminated at any time by either party upon 30 days prior written notice. In the event the Company terminates such agreement, it is obligated to pay all amounts due through the remaining term. In addition, the Company agreed to pay Wexford to-be-negotiated market-based fees approved by the Company’s independent directors for such services as may be provided by Wexford at the Company’s request in connection with future acquisitions and divestitures, financings or other transactions in which the Company may be involved. The services provided by Wexford under the Advisory Services Agreement do not extend to the Company’s day-to-day business or operations. The Company has agreed to indemnify Wexford and its affiliates from any and all losses arising out of or in connection with the Advisory Services Agreement except for losses resulting from Wexford’s or its affiliates’ gross negligence or willful misconduct. The Company incurred total costs of \$125,000 and \$250,000 for the three months and six months ended June 30, 2013, respectively, under the Advisory Services Agreement. Wexford provides certain professional services to the Company, for which the Company incurred total costs of \$57,000 and \$94,000 for the three months and six months ended June 30, 2012, respectively. As of June 30, 2013 and December 31, 2012, the Company owed Wexford no amounts and \$113,000, respectively. These amounts are included in accounts payable-related party in the accompanying consolidated balance sheets.

Secondary Offering Costs

On June 24, 2013, Gulfport and certain entities controlled by Wexford completed an underwritten secondary public offering of 6,000,000 shares of the Company’s common stock and, on July 5, 2013, the underwriters purchased an additional 869,222 shares of the Company’s common stock from these selling stockholders pursuant to an option to purchase such additional shares granted to the underwriters. The shares were sold to the public at \$34.75 per share and the selling stockholders received all proceeds from this offering. The Company incurred costs of approximately \$179,000 related to the secondary public offering.

11. DERIVATIVES

All derivative financial instruments are recorded at fair value. The Company has not designated its derivative instruments as hedges for accounting purposes and, as a result, marks its derivative instruments to fair value and recognizes the realized and unrealized changes in fair value in the combined consolidated statements of operations under the caption “Gain on derivative instruments.”

The Company has used price swap contracts to reduce price volatility associated with certain of its oil sales. With respect to the Company’s fixed price swap contracts, the counterparty is required to make a payment to the Company if

the settlement price for any settlement period is less than the swap price, and the Company is required to make a payment to the counterparty if the settlement price for any settlement period is greater than the swap price. The Company's derivative contracts are based upon reported settlement prices on commodity exchanges, with crude oil derivative settlements based on New York Mercantile Exchange West Texas Intermediate pricing, Argus Louisiana light sweet pricing or Inter-Continental Exchange ("ICE") pricing for Brent crude oil. The counterparties

Table of Contents

Diamondback Energy, Inc. and Subsidiaries

Notes to Combined Consolidated Financial Statements-(Continued)

(Unaudited)

to the Company's derivative contracts are BNP Paribas and Wells Fargo Bank, N.A., who the Company believes are acceptable credit risks.

As of June 30, 2013, the Company had open crude oil derivative positions with respect to future production as set forth in the tables below.

Crude Oil—NYMEX West Texas Intermediate Fixed Price Swap

Production Period	Volume (Bbls)	Fixed Swap Price
July–December 2013	184,000	\$80.55

Crude Oil—Argus Louisiana Light Sweet Fixed Price Swap

Production Period	Volume (Bbls)	Fixed Swap Price
July - December 2013	184,000	\$100.20
January - June 2014	181,000	100.20

Crude Oil—ICE Brent Fixed Price Swap

Production Period	Volume (Bbls)	Fixed Swap Price
July–December 2013	184,000	\$109.70
January–April 2014	120,000	109.70

The fair value of swaps is generally determined using established index prices and other sources which are based upon, among other things, futures prices and time to maturity. These fair values are recorded by netting asset and liability positions that are with the same counterparty and are subject to contractual terms which provide for net settlement. The net amounts are classified as current or noncurrent based on their anticipated settlement dates. The net fair value of the Company's derivative assets and liabilities and their locations on the consolidated balance sheet are as follows:

	June 30, 2013	December 31, 2012
Current Assets: Derivative instruments	\$3,191,000	\$—
Noncurrent Assets: Derivative instruments	—	—
Total Assets	\$3,191,000	\$—
Current Liabilities: Derivative instruments	\$2,679,000	\$4,817,000
Noncurrent Liabilities: Derivative instruments	—	388,000
Total Liabilities	\$2,679,000	\$5,205,000

The following table presents the netting offsets of the Company's derivative assets and liabilities as of June 30, 2013 and December 31, 2012.

Table of Contents

Diamondback Energy, Inc. and Subsidiaries

Notes to Combined Consolidated Financial Statements-(Continued)

(Unaudited)

	June 30, 2013		
	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Assets Presented in the Consolidated Balance Sheet
Derivative assets:			
Crude Oil—ICE Brent Fixed Price Swap	\$2,891,000	\$—	\$2,891,000
Crude Oil—Argus Louisiana Light Sweet Fixed Price Swap	300,000	—	300,000
	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet
Derivative liabilities:			
Crude Oil—NYMEX West Texas Intermediate Fixed Price Swap	\$2,679,000	\$—	\$2,679,000

	December 31, 2012		
	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet
Derivative liabilities:			
Crude Oil—NYMEX West Texas Intermediate Fixed Price Swap	\$5,205,000	\$—	\$5,205,000

None of the Company's derivatives have been designated as hedges. As such, all changes in fair value are immediately recognized in earnings. The following table summarizes the gains and losses on derivative instruments included in the combined consolidated statements of operations:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Unrealized gain on open non-hedge derivative instruments	\$3,893,000	\$12,065,000	\$5,428,000	\$8,638,000
Loss on settlement of non-hedge derivative instruments	(856,000)	(2,108,000)	(2,399,000)	(3,473,000)
Gain on derivative instruments	\$3,037,000	\$9,957,000	\$3,029,000	\$5,165,000

12. FAIR VALUE MEASUREMENTS

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Valuation techniques used to measure fair value must maximize the use of observable inputs and minimize the use of unobservable inputs.

The fair value hierarchy is based on three levels of inputs, of which the first two are considered observable and the last unobservable, that may be used to measure fair value. The Company's assessment of the significance of a particular input to the fair value measurements requires judgment and may affect the valuation of the assets and liabilities being measured and their placement within the fair value hierarchy. The Company uses appropriate valuation techniques

based on available inputs to measure the fair values of its assets and liabilities.

Level 1 - Observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the reporting date.

Table of Contents

Diamondback Energy, Inc. and Subsidiaries

Notes to Combined Consolidated Financial Statements-(Continued)

(Unaudited)

Level 2 - Observable market-based inputs or unobservable inputs that are corroborated by market data. These are inputs other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date.

Level 3 - Unobservable inputs that are not corroborated by market data and may be used with internally developed methodologies that result in management's best estimate of fair value.

Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

Certain assets and liabilities are reported at fair value on a recurring basis, including the Company's derivative instruments. The fair values of the Company's fixed price crude oil swaps are measured internally using established commodity futures price strips for the underlying commodity provided by a reputable third party, the contracted notional volumes, and time to maturity. These valuations are Level 2 inputs.

The following table provides fair value measurement information for financial assets and liabilities measured at fair value on a recurring basis as of June 30, 2013 and December 31, 2012.

Fair value measurements at June 30, 2013 using:

	Quoted Prices in Active Markets Level 1	Significant Other Observable Inputs Level 2	Significant Unobservable Inputs Level 3	Total
Assets:				
Fixed price swaps	\$—	\$3,191,000	\$—	\$3,191,000
Liabilities:				
Fixed price swaps	—	2,679,000	—	2,679,000

Fair value measurements at December 31, 2012 using:

	Quoted Prices in Active Markets Level 1	Significant Other Observable Inputs Level 2	Significant Unobservable Inputs Level 3	Total
Liabilities:				
Fixed price swaps	\$—	\$5,205,000	\$—	\$5,205,000

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

The following table provides the fair value of financial instruments that are not recorded at fair value in the combined consolidated financial statements.

	June 30, 2013		December 31, 2012	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Debt:				
Note payable	\$266,000	\$249,000	\$338,000	\$305,000

The fair value of the note payable is determined using internal discounted cash flow calculations based on the interest rate and payment terms of the note payable. The fair value of the note payable is classified as Level 3 in the fair value hierarchy.

Table of Contents

Diamondback Energy, Inc. and Subsidiaries

Notes to Combined Consolidated Financial Statements-(Continued)

(Unaudited)

13. CONTINGENCIES

In September 2010, Windsor Permian (now known as Diamondback O&G LLC) purchased certain property in Goodhue County, Minnesota, that was prospective for hydraulic fracturing grade sand. Prior to the purchase, the prior owners of the property had entered into a Mineral Development Agreement with the plaintiff and the Company purchased the property subject to that agreement. Windsor Permian subsequently contributed the property to Muskie. In an amended complaint filed in November 2012 by the plaintiff against the prior owners of the property, Windsor Permian and certain affiliates of Windsor Permian in the first judicial district court in Goodhue County, Minnesota, the plaintiff seeks damages from the Company and the other defendants alleging, among other things, interference with contractual relationship, interference with prospective advantage and unjust enrichment. In an order filed on May 24, 2013, the judge denied certain motions made by the defendants and set a trial date to determine liability, with a damage phase of the matter to commence on a later date if there is a determination of liability. Following a trial on the liability phase on June 21, 2013, the jury determined that the defendants intentionally interfered with plaintiff's contract but that the interference did not cause the plaintiff to be unable to acquire mining permits prior to the enactment of the moratorium by Goodhue County. In an order filed on July 10, 2013, the judge ordered the damage phase to be set for trial following a pretrial and scheduling conference set for August 12, 2013. The Company believes these claims are without merit and will continue to vigorously defend this action. While management has determined that the possibility of loss is remote, litigation is inherently uncertain and management cannot determine the amount of loss, if any, that may result.

The Company could be subject to various possible loss contingencies which arise primarily from interpretation of federal and state laws and regulations affecting the natural gas and crude oil industry. Such contingencies include differing interpretations as to the prices at which natural gas and crude oil sales may be made, the prices at which royalty owners may be paid for production from their leases, environmental issues and other matters. Management believes it has complied with the various laws and regulations, administrative rulings and interpretations.

14. SUBSEQUENT EVENTS

The Company has entered into two definitive agreements with unrelated third party sellers to purchase an aggregate of approximately 13,900 gross (11,150 net) operated acres in the Midland Basin for an aggregate of approximately \$165,000,000, subject to certain adjustments. The Company entered into one agreement on August 1, 2013 and one agreement on August 2, 2013. The proposed transactions are expected to close by the end of September 2013.

Table of Contents

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with our unaudited combined consolidated financial statements and notes thereto presented in this Quarterly Report on Form 10-Q as well as our audited combined consolidated financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2012. The following discussion contains "forward-looking statements" that reflect our future plans, estimates, beliefs, and expected performance. Actual results and the timing of events may differ materially from those contained in these forward-looking statements due to a number of factors. See "Part II, Item 1A. Risk Factors" and "Cautionary Statement Regarding Forward-Looking Statements".

Overview

We are an independent oil and natural gas company focused on the acquisition, development, exploration and exploitation of unconventional, long-life, onshore oil and natural gas reserves in the Permian Basin in West Texas. Our activities are primarily directed at the Clearfork, Spraberry, Wolfcamp, Cline, Strawn and Atoka formations which we refer to as the Wolfberry play. We intend to grow our reserves and production through development drilling, exploitation and exploration activities on our multi-year inventory of identified potential drilling locations and through acquisitions that meet our strategic and financial objectives, targeting oil-weighted reserves. Substantially all of our revenues are generated through the sale of oil, natural gas liquids and natural gas production. Our production was approximately 75% oil, 14% natural gas liquids and 11% natural gas for the three months ended June 30, 2013, and was approximately 73% oil, 16% natural gas liquids and 11% natural gas for the three months ended June 30, 2012. Our production was approximately 73% oil, 15% natural gas liquids and 12% natural gas for the six months ended June 30, 2013, and was approximately 74% oil, 15% natural gas liquids and 11% natural gas for the six months ended June 30, 2012. On June 30, 2013, our net acreage position in the Permian Basin was approximately 54,035 net acres.

Diamondback was incorporated in Delaware on December 30, 2011, and did not conduct any material business operations until October 11, 2012 when Diamondback merged with its parent entity, Diamondback Energy LLC, with Diamondback continuing as the surviving entity. Diamondback Energy LLC was a holding company and did not conduct any material business operations other than its ownership of our common stock and the membership interests in Windsor Permian LLC, or Windsor Permian. As a result of the merger, Windsor Permian became a wholly-owned subsidiary of Diamondback and subsequently changed its name to Diamondback O&G LLC. Also on October 11, 2012, Wexford Capital LP, or Wexford, our equity sponsor, caused all of the outstanding equity interests in Windsor UT LLC, or Windsor UT, to be contributed to Windsor Permian prior to the merger in a transaction we refer to as the "Windsor UT Contribution." The Windsor UT Contribution was treated as a combination of entities under common control with assets and liabilities transferred at their carrying amounts in a manner similar to a pooling of interests. We refer to the historical results of Windsor Permian and Windsor UT prior to October 11, 2012 as our "Predecessors."

Also on October 11, 2012, we acquired all of the oil and natural gas properties of Gulfport located in the Permian Basin in exchange for (i) 7,914,036 shares of our common stock, (ii) approximately \$63.6 million in the form of a non-interest bearing promissory note that was repaid in full upon the closing of our initial public offering, or IPO, and (iii) a post-closing cash adjustment of approximately \$18.6 million. We are the operator of the acreage acquired by us from Gulfport.

On October 17, 2012, we completed our IPO of 14,375,000 shares of common stock, which included 1,875,000 shares of common stock issued pursuant to the over-allotment option exercised by the underwriters. The stock was priced at \$17.50 per share and we received net proceeds of approximately \$234.1 million from the sale of these shares of

common stock, net of offering expenses and underwriting discounts and commissions.

In the first quarter of 2013, Windsor UT merged with and into Windsor Permian and Windsor Permian, the surviving entity in the merger, was renamed Diamondback O&G LLC, or Diamondback O&G.

On May 22, 2013, we completed an underwritten primary public offering of 5,175,000 shares of common stock, which included 675,000 shares of common stock issued pursuant to an option to purchase additional shares granted to the underwriters. The stock was sold to the public at \$29.25 per share and we received net proceeds of approximately \$144.4 million from the sale of these shares of common stock, net of offering expenses and underwriting discounts and commissions.

Table of Contents

On June 24, 2013, Gulfport Energy Corporation, which we refer to as “Gulfport,” and certain entities controlled by Wexford Capital LP, which we refer to as “Wexford,” completed an underwritten secondary public offering of 6,000,000 shares of our common stock and, on July 5, 2013, the underwriters purchased an additional 869,222 shares of our common stock from these selling stockholders pursuant to an option to purchase such additional shares granted to the underwriters. The shares were sold to the public at \$34.75 per share and the selling stockholders received all proceeds from this offering.

Recent Developments

We have entered into two definitive agreements with unrelated third party sellers to purchase an aggregate of approximately 13,900 gross (11,150 net) operated acres in the Midland Basin for an aggregate of approximately \$165.0 million, subject to certain adjustments. We entered into one agreement on August 1, 2013 and one agreement on August 2, 2013. The proposed transactions are expected to close by the end of September 2013.

Basis of Presentation

Transfers of a business between entities under common control are accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information. As discussed above, the Windsor UT Contribution was accounted for as a transaction between entities under common control. Accordingly, the financial information and production data contained in this report have been retrospectively adjusted to include the historical results of Windsor UT at historical carrying values and its operations prior to October 11, 2012, the effective date of the Windsor UT Contribution.

Since we began operations in 2007, we have increased our drilling activity, evaluated potential acquisitions and added to our acreage portfolio. Because of our growth through acquisitions and development of our properties, our historical results of operations and period-to-period comparisons of these results and certain financial data may not be meaningful or indicative of future results.

Operating Results Overview

During the three months ended June 30, 2013, our average daily production was approximately 6,590 BOE/d, consisting of 4,914 Bbls/d of oil, 4,489 Mcf/d of natural gas and 927 Bbls/d of natural gas liquids, an increase of 4,080 BOE/d, or 163%, from average daily production of 2,510 BOE/d for the three months ended June 30, 2012, consisting of 1,828 Bbls/d of oil, 1,734 Mcf/d of natural gas and 392 Bbls/d of natural gas liquids. The ST 4301H well in Midland County, with a 29 stage 7,141 foot lateral, achieved a peak 30 day rate of 916 BOE/d on submersible pump, with a previously reported peak 24 hour initial production, or IP, rate of 1,136 BOE/d. Our 14 producing horizontal Wolfcamp B wells have achieved peak 24 hour IP rates that averaged 920 BOE/d (88% oil) from lateral lengths that averaged 5,576 feet.

During the six months ended June 30, 2013, our average daily production was approximately 5,694 BOE/d, consisting of 4,134 Bbls/d of oil, 4,197 Mcf/d of natural gas and 860 Bbls/d of natural gas liquids, an increase of 3,323 BOE/d, or 140%, from average daily production of 2,371 BOE/d for the six months ended June 30, 2012, consisting of 1,747 Bbls/d of oil, 1,594 Mcf/d of natural gas and 358 Bbls/d of natural gas liquids.

During the three months ended June 30, 2013, we drilled 19 gross (16 net) wells, and participated in one additional gross non-operated well, in the Permian Basin. During the six months ended June 30, 2013, we drilled 38 gross (33 net) wells, and participated in one additional gross non-operated well, in the Permian Basin.

Sources of our revenue

Our revenues are derived from the sale of oil and natural gas production, as well as the sale of natural gas liquids that are extracted from our natural gas during processing. Our oil and natural gas revenues do not include the effects of derivatives. For the three months ended June 30, 2013 and 2012, our revenues were derived 90% and 90%, respectively, from oil sales, 6% and 8%, respectively, from natural gas liquids sales and 4% and 2%, respectively,

from natural gas sales. For the six months ended June 30, 2013 and 2012, our revenues were derived 89% and 90%, respectively, from oil sales, 7% and 8%, respectively, from natural gas liquids sales and 4% and 2%, respectively, from natural gas sales. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices.

Table of Contents

Results of Operations

The following table sets forth selected historical operating data for the periods indicated.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(unaudited)		(unaudited)	
Operating Results:				
Revenues				
Oil and natural gas revenues	\$45,394,000	\$16,030,000	\$74,303,000	\$32,381,000
Operating Expenses				
Lease operating expense	6,087,000	3,529,000	11,522,000	6,318,000
Production taxes	2,196,000	782,000	3,623,000	1,579,000
Gathering and transportation expense	247,000	79,000	380,000	146,000
Depreciation, depletion and amortization	14,815,000	5,659,000	25,553,000	10,416,000
General and administrative	2,621,000	1,653,000	5,092,000	2,837,000
Asset retirement obligation accretion expense	45,000	21,000	88,000	41,000
Total expenses	26,011,000	11,723,000	46,258,000	21,337,000
Income from operations	19,383,000	4,307,000	28,045,000	11,044,000
Net interest expense	(535,000)	(1,172,000)	(1,020,000)	(2,052,000)
Other income - related party	388,000	586,000	777,000	1,011,000
Gain on derivative instruments, net	3,037,000	9,957,000	3,029,000	5,165,000
Loss from equity investment	—	(54,000)	—	(67,000)
Total other income	2,890,000	9,317,000	2,786,000	4,057,000
Income before income taxes	22,273,000	13,624,000	30,831,000	15,101,000
Provision for deferred income taxes	7,802,000	—	10,964,000	—
Net income	\$14,471,000	\$13,624,000	\$19,867,000	\$15,101,000
Production Data:				
Oil (Bbls)	447,203	166,385	748,244	317,906
Natural gas (Mcf)	408,530	157,835	759,568	290,171
Natural gas liquids (Bbls)	84,360	35,678	155,689	65,188
Combined volumes (Boe)	599,651	228,369	1,030,528	431,456
Daily combined volumes (Boe/d)	6,590	2,510	5,694	2,371
Average Prices⁽¹⁾:				
Oil (per Bbl)	\$91.76	\$86.34	\$88.59	\$91.26
Natural gas (per Mcf)	4.08	1.97	3.71	2.27
Natural gas liquids (per Bbl)	31.91	37.92	33.38	41.59
Combined (per BOE)	75.70	70.19	72.10	75.05
Average Costs (per BOE)				
Lease operating expense	\$10.15	\$15.45	\$11.18	\$14.64
Gathering and transportation expense	0.41	0.35	0.37	0.34
Production taxes	3.66	3.42	3.52	3.66
Production taxes as a % of sales	4.8	% 4.9	% 4.9	% 4.9
Depreciation, depletion, and amortization	24.71	24.78	24.80	24.14
General and administrative	4.37	7.24	4.94	6.58

(1) After giving effect to our derivative instruments, the average prices per Bbl of oil and per BOE were \$89.84 and \$74.27, respectively, during the three months ended June 30, 2013, and \$73.67 and \$60.96, respectively, during the three months ended June 30, 2012. After giving effect to our derivative instruments, the average prices per Bbl of oil and per BOE were \$85.38 and \$69.77, respectively, during the six months ended June 30, 2013, and \$80.34 and \$67.00, respectively, during the six months ended June 30, 2012.

24

Table of Contents

Comparison of the Three Months Ended June 30, 2013 and 2012

Oil, Natural Gas Liquids and Natural Gas Revenues. Our oil, natural gas liquids and natural gas revenues increased by approximately \$29,364,000, or 183%, to \$45,394,000 for the three months ended June 30, 2013 from \$16,030,000 for the three months ended June 30, 2012. Our revenues are a function of oil, natural gas liquids and natural gas production volumes sold and average sales prices received for those volumes. Average daily production sold increased by 4,080 BOE/d to 6,590 BOE/d during the three months ended June 30, 2013 from 2,510 BOE/d during the three months ended June 30, 2012. The total increase in revenue of approximately \$29,364,000 is largely attributable to higher oil, natural gas liquids and natural gas production volumes for the three months ended June 30, 2013 as compared to the three months ended June 30, 2012. The increases in production volumes were due to a combination of increased drilling activity and the effect of the contribution of Gulfport's Permian Basin assets on October 11, 2012. Our production increased by 280,818 Bbls of oil, 48,682 Bbls of natural gas liquids and 250,695 Mcf of natural gas for the three months ended June 30, 2013 as compared to the three months ended June 30, 2012. The net dollar effect of the increases in prices of approximately \$2,778,000 (calculated as the change in period-to-period average prices multiplied by current period production volumes of oil, natural gas liquids and natural gas) and the net dollar effect of the increase in production of approximately \$26,586,000 (calculated as the increase in period-to-period volumes for oil, natural gas liquids and natural gas multiplied by the period average prices) are shown below.

	Change in prices	Production volumes ⁽¹⁾	Total net dollar effect of change
Effect of changes in price:			
Oil	\$5.42	447,203	\$2,423,000
Natural gas liquids	\$(6.01)	84,360	\$(507,000)
Natural gas	\$2.11	408,530	\$862,000
Total revenues due to change in price			\$2,778,000
	Change in production volumes ⁽¹⁾	Prior period Average Prices	Total net dollar effect of change
Effect of changes in production volumes:			
Oil	280,818	\$86.34	\$24,246,000
Natural gas liquids	48,682	\$37.92	\$1,846,000
Natural gas	250,695	\$1.97	\$494,000
Total revenues due to change in production volumes			\$26,586,000
Total change in revenues			\$29,364,000

(1) Production volumes are presented in Bbls for oil and natural gas liquids and Mcf for natural gas Lease Operating Expense. Lease operating expense was \$6,087,000 (\$10.15 per BOE) for the three months ended June 30, 2013, an increase of \$2,558,000, or 72%, from \$3,529,000 (\$15.45 per BOE) for the three months ended June 30, 2012. The increase is due to increased drilling activity, which resulted in additional producing wells for the three months ended June 30, 2013 as compared to the three months ended June 30, 2012. Our lease operating expense during the three months ended June 30, 2012 was adversely impacted by the cost of processing and treating non-hydrocarbon gases from certain of our wells that came on-line in 2011. During the fourth quarter of 2012, we completed construction of a gas gathering system that transports this gas stream to a sour gas pipeline, thereby eliminating the monthly processing and treating expense, which savings are reflected in our lease operating expense for the three months ended June 30, 2013. In addition, in the first quarter 2013, we moved a portion of our produced water by a pipeline connected to a commercial salt water disposal well rather than by truck. During the remainder of 2013, we intend to continue the migration of water disposal and oil transportation from truck carriers to pipelines. We believe that the connection to salt water disposal wells and other actions will help reduce our lease operating expense in future periods.

Table of Contents

Production Tax Expense. Production taxes as a percentage of oil and natural gas sales were 4.8% for the three months ended June 30, 2013, a decrease of 0.1% from 4.9% for the three months ended June 30, 2012. Production taxes are primarily based on the market value of our production at the wellhead and may vary across the different counties in which we operate. Total production taxes increased \$1,414,000 from \$782,000 during the three months ended June 30, 2012 to \$2,196,000 during the three months ended June 30, 2013, as a result of higher production and an increase in the market value of our production.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased \$9,156,000, or 162%, from \$5,659,000 for the three months ended June 30, 2012 to \$14,815,000 for the three months ended June 30, 2013. This increase was due to an increase in our full cost pool as a result of the acquisition of the Gulfport properties and increased capital expenditures in conjunction with our drilling program during the three months ended June 30, 2013. The average depletion rate was \$24.71 for the three months ended June 30, 2013 and \$24.78 for the three months ended June 30, 2012. The average depletion rate includes oil and gas depletion and other property and equipment depreciation.

General and Administrative Expense. General and administrative expense increased \$968,000 from \$1,653,000 for the three months ended June 30, 2012 to \$2,621,000 for the three months ended June 30, 2013. The increase was due to increases in salary, stock-based compensation, legal, secondary offering expenses, professional service and advisory service expenses. These increases were partially offset by increases in general and administrative costs related to exploration and development activity capitalized to the full cost pool and increases in COPAS overhead reimbursements due to increased drilling activity.

Net Interest Expense. Net interest expense for the three months ended June 30, 2013 was \$535,000, as compared to \$1,172,000 for the three months ended June 30, 2012, a decrease of \$637,000, or 54%. This decrease was due primarily to a decrease in our weighted average outstanding borrowings under our credit agreement to \$23,071,000 for the three months ended June 30, 2013 from \$99,724,000 for the same period in 2012.

Derivatives. We are required to recognize all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. We have not designated our derivative instruments as hedges for accounting purposes. As a result, we mark our derivative instruments to fair value and recognize the realized and unrealized changes in fair value on derivative instruments in our combined consolidated statements of operations under the line item captioned "Gain on derivative instruments." For the three months ended June 30, 2013 and 2012, we had a realized loss on settlement of derivative instruments of \$856,000 and \$2,108,000, respectively. For the three months ended June 30, 2013 and 2012, we had an unrealized gain on open derivative instruments of \$3,893,000 and \$12,065,000, respectively.

Income tax expense. Prior to our IPO in October 2012, the operations of Windsor Permian and Windsor UT, as limited liability companies, were not subject to federal income taxes. Deferred income tax expense of \$7,802,000 was incurred as a result of operations for the three months ended June 30, 2013.

Comparison of the Six Months Ended June 30, 2013 and 2012

Oil, Natural Gas Liquids and Natural Gas Revenues. Our oil, natural gas liquids and natural gas revenues increased by approximately \$41,922,000, or 129%, to \$74,303,000 for the six months ended June 30, 2013 from \$32,381,000 for the six months ended June 30, 2012. Our revenues are a function of oil, natural gas liquids and natural gas production volumes sold and average sales prices received for those volumes. Average daily production sold increased by 3,323 BOE/d to 5,694 BOE/d during the six months ended June 30, 2013 from 2,371 BOE/d during the six months ended June 30, 2012. The total increase in revenue of approximately \$41,922,000 is largely attributable to higher oil, natural gas liquids and natural gas production volumes for the six months ended June 30, 2013 as compared to the six months ended June 30, 2012, partially offset by a decrease in the average sales price received for these volumes. The increases in production volumes were due to a combination of increased drilling activity and the effect of the contribution of Gulfport's Permian Basin assets on October 11, 2012. Our production increased by 430,338 Bbls of oil, 90,501 Bbls of natural gas liquids and 469,397 Mcf of natural gas for the six months ended June 30, 2013 as compared to the six months ended June 30, 2012. The net dollar effect of the decreases in prices of approximately \$2,180,000 (calculated as the change in period-to-period average prices multiplied by current period production volumes of oil, natural gas liquids and natural gas) and the net dollar effect of the increase in production of approximately \$44,102,000 (calculated as the increase in period-to-period volumes for oil, natural gas liquids and natural gas multiplied by the

period average prices) are shown below.

26

Table of Contents

	Change in prices	Production volumes ⁽¹⁾	Total net dollar effect of change
Effect of changes in price:			
Oil	\$(2.67) 748,244	\$(1,998,000)
Natural gas liquids	\$(8.21) 155,689	\$(1,278,000)
Natural gas	\$1.44	759,568	\$1,096,000
Total revenues due to change in price			\$(2,180,000)
	Change in production volumes ⁽¹⁾	Prior period Average Prices	Total net dollar effect of change
Effect of changes in production volumes:			
Oil	430,338	\$91.26	\$39,273,000
Natural gas liquids	90,501	\$41.59	\$3,764,000
Natural gas	469,397	\$2.27	\$1,065,000
Total revenues due to change in production volumes			\$44,102,000
Total change in revenues			\$41,922,000

(1) Production volumes are presented in Bbls for oil and natural gas liquids and Mcf for natural gas Lease Operating Expense. Lease operating expense was \$11,522,000 (\$11.18 per BOE) for the six months ended June 30, 2013, an increase of \$5,204,000, or 82%, from \$6,318,000 (\$14.64 per BOE) for the six months ended June 30, 2012. The increase is due to increased drilling activity, which resulted in additional producing wells for the six months ended June 30, 2013 as compared to the six months ended June 30, 2012. Our lease operating expense during the six months ended June 30, 2012 was adversely impacted by the cost of processing and treating non-hydrocarbon gases from certain of our wells that came on-line in 2011. During the fourth quarter of 2012, we completed construction of a gas gathering system that transports this gas stream to a sour gas pipeline, thereby eliminating the monthly processing and treating expense, which savings are reflected in our lease operating expense for the six months ended June 30, 2013. In addition, in the first quarter 2013, we moved a portion of our produced water by a pipeline connected to a commercial salt water disposal well rather than by truck. During the remainder of 2013, we intend to continue the migration of water disposal and oil transportation from truck carriers to pipelines. We believe that the connection to salt water disposal wells and other actions will help reduce our lease operating expense in future periods.

Production Tax Expense. Production taxes as a percentage of oil and natural gas sales were 4.9% for both the six months ended June 30, 2013 and 2012. Production taxes are primarily based on the market value of our production at the wellhead and may vary across the different counties in which we operate. Total production taxes increased \$2,044,000 from \$1,579,000 during the six months ended June 30, 2012 to \$3,623,000 during the six months ended June 30, 2013, as a result of higher production and an increase in the market value of our production.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased \$15,137,000, or 145%, from \$10,416,000 for the six months ended June 30, 2012 to \$25,553,000 for the six months ended June 30, 2013. This increase was due to an increase in our full cost pool as a result of the acquisition of the Gulfport properties and increased capital expenditures in conjunction with our drilling program during the six months ended June 30, 2013. The average depletion rate was \$24.80 for the six months ended June 30, 2013 and \$24.14 for the six months ended June 30, 2012. The average depletion rate includes oil and gas depletion and other property and equipment depreciation. The increase in depletion rate was due to the result of the increases in the full cost pool as described above.

General and Administrative Expense. General and administrative expense increased \$2,255,000 from \$2,837,000 for the six months ended June 30, 2012 to \$5,092,000 for the six months ended June 30, 2013. The increase was due to increases in salary, stock-based compensation, legal, secondary offering expenses, professional

Table of Contents

service and advisory service expenses. These increases were partially offset by an increase in COPAS overhead reimbursements due to increased drilling activity.

Net Interest Expense. Net interest expense for the six months ended June 30, 2013 was \$1,020,000, as compared to \$2,052,000 for the six months ended June 30, 2012, a decrease of \$1,032,000, or 50%. This decrease was due primarily to a decrease in our weighted average outstanding borrowings under our credit agreement to \$21,677,000 for the six months ended June 30, 2013 from \$96,062,000 for the same period in 2012.

Derivatives. We are required to recognize all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. We have not designated our derivative instruments as hedges for accounting purposes. As a result, we mark our derivative instruments to fair value and recognize the realized and unrealized changes in fair value on derivative instruments in our combined consolidated statements of operations under the line item captioned "Gain on derivative instruments." For the six months ended June 30, 2013 and 2012, we had a realized loss on settlement of derivative instruments of \$2,399,000 and \$3,473,000, respectively. For the six months ended June 30, 2013 and 2012, we had an unrealized gain on open derivative instruments of \$5,428,000 and \$8,638,000, respectively.

Income tax expense. Prior to our IPO in October 2012, the operations of Windsor Permian and Windsor UT, as limited liability companies, were not subject to federal income taxes. Deferred income tax expense of \$10,964,000 was incurred as a result of operations for the six months ended June 30, 2013.

Table of Contents

Liquidity and Capital Resources

Our primary sources of liquidity have been proceeds from our public offerings, borrowings under our credit facility, cash flows from operations and, prior to the completion of our IPO, capital contributions and loans from our equity sponsor. Our primary use of capital has been for the acquisition, development and exploration of oil and natural gas properties. As we pursue reserves and production growth, we regularly consider which capital resources, including equity and debt financings, are available to meet our future financial obligations, planned capital expenditure activities and liquidity requirements. Our future ability to grow proved reserves and production will be highly dependent on the capital resources available to us.

Liquidity and cash flow

Our cash flows for the six months ended June 30, 2013 and 2012 are presented below:

	Six Months Ended June 30,	
	2013	2012
Net cash provided by operating activities	\$49,798,000	\$22,661,000
Net cash used in investing activities	(138,675,000) (59,616,000
Net cash provided by financing activities	\$144,417,000	\$32,337,000
Net change in cash	\$55,540,000	\$(4,618,000)

Operating Activities

Net cash provided by operating activities was \$49,798,000 for the six months ended June 30, 2013 as compared to \$22,661,000 for the six months ended June 30, 2012. The increase in operating cash flows is a result of increases in our oil and natural gas revenues due to production growth and by lower expenses in 2013.

Our operating cash flow is sensitive to many variables, the most significant of which is the volatility of prices for the oil and natural gas we produce. Prices for these commodities are determined primarily by prevailing market conditions. Regional and worldwide economic activity, weather and other substantially variable factors influence market conditions for these products. These factors are beyond our control and are difficult to predict.

Investing Activities

The purchase and development of oil and natural gas properties accounted for the majority of our cash outlays for investing activities. We used cash for investing activities of \$138,675,000 and \$59,616,000 during the six months ended June 30, 2013 and 2012, respectively.

During the six months ended June 30, 2013, we spent \$112,083,000 on capital expenditures in conjunction with our infrastructure projects and drilling program, in which we participated in the drilling of 40 gross (34 net) wells. We spent an additional \$6,192,000 on leasehold costs, \$1,615,000 for the purchase of other property and equipment, \$289,000, net, on the settlement of non-hedge derivative instruments and \$18,550,000 for the post-closing cash adjustment associated with the Gulfport transaction. These amounts were partially offset by proceeds of \$54,000 from the sale of property and equipment.

During the six months ended June 30, 2012, we spent \$49,294,000 on capital expenditures in conjunction with our drilling program in which we participated in the drilling of 24 gross (16 net) wells. We spent an additional \$5,911,000 on leasehold costs, \$637,000 for the purchase of other property and equipment and \$3,784,000, net, on the settlement of non-hedge derivative instruments and margin deposits. These amounts were partially offset by proceeds of \$10,000 from the sale of property and equipment.

Our investing activities for the six months ended June 30, 2013 and 2012 are summarized in the following table:

Table of Contents

	Six Months Ended June 30,		
	2013	2012	
Drilling and completion of wells	\$ (112,083,000) \$ (49,294,000)
Purchase of leasehold acquisitions	(6,192,000) (5,911,000)
Acquisition of Gulfport properties	(18,550,000) —	
Purchase of other property and equipment	(1,615,000) (637,000)
Proceeds from sale of property and equipment	54,000	10,000	
Settlement of non-hedge derivative instruments	(289,000) (5,263,000)
Receipt on derivative margins	—	1,479,000	
Net cash used in investing activities	\$ (138,675,000) \$ (59,616,000)
Financing Activities			

Net cash provided by financing activities for the six months ended June 30, 2013 was \$144,417,000 as compared to \$32,337,000 during the same period in 2012. On May 22, 2013, we completed an underwritten primary public offering of 5,175,000 shares of common stock, which included 675,000 shares of common stock purchased by the underwriters pursuant to an option to purchase additional shares, and we received net proceeds of approximately \$144.4 million, after deducting the underwriting discount and offering expenses. During the six months ended June 30, 2013 and 2012, we borrowed \$49,000,000 and \$15,000,000, respectively, under our revolving credit facility. The \$49,000,000 outstanding under our revolving credit facility was repaid with a portion of the net proceeds from our underwritten public offering in May 2013. During the six months ended June 30, 2012, we borrowed \$14,100,000 under our subordinated note with Wexford and received capital contributions from our members of \$4,008,000. In both periods, these proceeds were used primarily to fund our drilling costs and purchase property and equipment. During the six months ended June 30, 2013 and 2012, we paid \$447,000 and \$729,000, respectively, for costs associated with our public offerings. During the six months ended June 30, 2013, we incurred costs of approximately \$179,000 related to the secondary offering.

Credit Facility

On October 15, 2010, we entered into a secured loan agreement with BNP Paribas, or BNP, as the administrative agent, sole book runner and lead arranger. On May 10, 2012, the revolving credit agreement was amended to provide for the resignation of BNP, and the appointment of Wells Fargo Bank, National Association, as administrative agent for the lenders. The loan agreement, as amended, provides for a \$250 million revolving credit facility, subject to scheduled semi-annual and other elective collateral borrowing base redeterminations based on our oil and natural gas reserves (the “borrowing base”). The outstanding borrowings bear interest at a rate elected by us that is based on the prime, LIBOR or federal funds rate plus margins ranging from 1.25% to 3.50% depending on the base rate used and the amount of the loan outstanding in relation to the borrowing base.

Principal may be optionally repaid from time to time and is required to be paid (a) if the loan amount exceeds the borrowing base, whether due to a borrowing base redetermination or otherwise and (b) at the maturity date of October 15, 2014. We are obligated to pay a quarterly commitment fee equal to 0.5% per year of the unused portion of the borrowing base. The loan is secured by substantially all of our assets. The borrowing base is re-determined semi-annually with effective dates of April 1st and October 1st. In addition, we may request up to three additional redeterminations of the borrowing base during any 12-month period. The borrowing base was \$100.0 million at December 31, 2011. The borrowing base increased throughout 2012 and 2013 through various redeterminations and at December 31, 2012 and June 30, 2013, the borrowing base was \$135.0 million and \$180.0 million, respectively. In connection with the IPO, we repaid all outstanding borrowings under our revolving credit facility and, as of December 31, 2012, had no outstanding borrowings. In connection with our public offering of common stock in May 2013, we repaid all outstanding borrowings under our revolving credit facility and, as of June 30, 2013, had no outstanding borrowing under this facility.

Our revolving credit agreement contains various affirmative and restrictive covenants. These covenants, among other things, prohibit additional indebtedness, additional liens, sales of assets, mergers and consolidations, dividends and distributions, transactions with affiliates and entering into certain swap agreements and require the maintenance of various financial ratios described below.

As of July 24, 2012, our revolving credit agreement was amended and restated to include Diamondback Energy LLC and its subsidiaries as additional guarantors to the facility. The covenant prohibiting additional indebtedness was also amended to allow the issuance of unsecured debt of up to \$250.0 million and, in connection

Table of Contents

with any such issuance, the reduction of the borrowing base by 25% of the principal amount of such issuance. A borrowing base reduction in connection with such issuance may require a portion of the outstanding principal of the loan to be repaid. The amendment also provided that redemptions of any unsecured debt will be restricted unless certain liquidity requirements are met. Further, the amendment modified certain financial ratios, the current requirements of which are described below.

Financial Covenant	Required Ratio
Ratio of EBITDAX to interest expense, as defined in the credit agreement	Not less than 2.5 to 1.0
Ratio of total debt to EBITDAX	Not greater than 4.0 to 1.0
Ratio of debt under revolving credit agreement to EBITDAX	Not greater than 3.0 to 1.0
Ratio of current assets to liabilities, as defined in the credit agreement	Not less than 1.0 to 1.0

Our revolving credit agreement defines EBITDAX, for any period, as the sum of our consolidated net income for such period plus the following expenses or charges to the extent deducted from our consolidated net income for such period: interest; income taxes; depreciation, depletion, amortization and exploration expenses; extraordinary items and other similar non-cash charges, including expenses related to stock-based compensation and hedging, minus all non-cash income added to our consolidated net income.

As of September 28, 2012, the second amendment to our amended and restated credit agreement was executed, which among other things provided for an increase in permitted subordinated debt in a maximum principal amount not to exceed \$45.0 million, waived compliance with our current ratio covenant for the quarter ending September 30, 2012 and increased the aggregate limitation on lease payments during any period of twelve consecutive months from \$250,000 to \$550,000.

As of June 30, 2013, we were in compliance with all financial covenants under our revolving credit facility. The lenders may accelerate all of the indebtedness under our revolving credit facility upon the occurrence of any event of default unless we cure any such default within any applicable grace period. For payments of principal and interest under our revolving credit facility, we generally have a three business day grace period, and a 30-day cure period for most covenant defaults, but not for defaults of certain specific covenants, including the financial covenants and negative covenants.

Capital Requirements and Sources of Liquidity

We currently anticipate our 2013 capital budget for drilling and infrastructure will be approximately \$290.0 million to \$320.0 million. We do not have a specific acquisition budget since the timing and size of acquisitions cannot be accurately forecasted. We intend to allocate these expenditures as follows:

- \$267.6 million for the drilling and completion of operated wells of which approximately 65% is allocated to horizontal wells;

- \$9.0 million for our participation in the drilling and completion of non-operated wells; and

- \$25.0 million for the construction of infrastructure to support production, including investments in water disposal infrastructure and gathering line projects.

The amount and timing of these capital expenditures is largely discretionary and within our control. We could choose to defer a portion of these planned 2013 capital expenditures depending on a variety of factors, including but not limited to the success of our drilling activities, prevailing and anticipated prices for oil and natural gas, the availability of necessary equipment, infrastructure and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions, drilling and acquisition costs and the level of participation by other interest owners.

During the six months ended June 30, 2013, our aggregate capital expenditures for drilling and infrastructure were \$112.1 million and we spent \$6.2 million for leasehold acquisitions.

Based upon current oil and natural gas price expectations for 2013, we believe that our cash flow from operations, proceeds from our May 2013 public offering and borrowings under our revolving credit facility will be sufficient to fund our operations through year-end 2013. However, future cash flows are subject to a number of variables, including the level of oil and natural gas production and prices, and significant additional capital expenditures will be required

to more fully develop our properties. Further, our 2013 capital expenditure budget

31

Table of Contents

does not allocate any funds for leasehold interest and property acquisitions. We are currently evaluating our alternatives with respect to our pending acquisitions discussed under “Recent Developments” above, but expect to fund the aggregate purchase price for those acquisitions with some combination of cash on hand, borrowings under our revolving credit facility and proceeds from an offering of securities.

We monitor and adjust our projected capital expenditures in response to success or lack of success in drilling activities, changes in prices, availability of financing, drilling and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, contractual obligations, internally generated cash flow and other factors both within and outside our control. If we require additional capital, we may seek such capital through traditional reserve base borrowings, joint venture partnerships, production payment financing, asset sales, offerings of debt and or equity securities or other means. We cannot assure you that the needed capital will be available on acceptable terms or at all. If we are unable to obtain funds when needed or on acceptable terms, we may be required to curtail our drilling programs, which could result in a loss of acreage through lease expirations. In addition, we may not be able to complete acquisitions that may be favorable to us or finance the capital expenditures necessary to replace our reserves.

Critical Accounting Policies

There have been no changes in our critical accounting policies from those disclosed in our Annual Report on Form 10-K for the year ended December 31, 2012.

Off-balance Sheet Arrangements

We had no off-balance sheet arrangements as of June 30, 2013.

Contractual Obligations

There were no material changes in our contractual obligations and other commitments, as disclosed in our Annual Report on Form 10-K for the year ended December 31, 2012.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity Price Risk

Our major market risk exposure is in the pricing applicable to our oil and natural gas production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to our natural gas production. Pricing for oil and natural gas production has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside of our control.

We use price swap derivatives to reduce price volatility associated with certain of our oil sales. With respect to these fixed price swap contracts, the counterparty is required to make a payment to us if the settlement price for any settlement period is less than the swap price, and we are required to make a payment to the counterparty if the settlement price for any settlement period is greater than the swap price. Our derivative contracts are based upon reported settlement prices on commodity exchanges, with crude oil derivative settlements based on New York Mercantile Exchange West Texas Intermediate pricing, Argus Louisiana light sweet pricing or Inter-Continental Exchange, or ICE, pricing for Brent crude oil.

At June 30, 2013, we had a net asset derivative position with Wells Fargo Bank, N.A. of \$3,191,000, consisting of \$2,891,000 related to our ICE Brent fixed price swap and \$300,000 related to our Argus Louisiana Light Sweet fixed price swap, and a net liability derivative position with BNP Paribas of \$2,679,000 related to our NYMEX West Texas Intermediate fixed price swap, as compared to a net liability derivative position of \$5,205,000 as of December 31, 2012 related to our price swap derivatives. Utilizing actual derivative contractual volumes under our fixed price swaps with Wells Fargo Bank, N.A. as of June 30, 2013, a 10% increase in forward curves associated with the underlying commodity would have decreased the net asset derivative position of these instruments to a net liability derivative position of \$3,478,000, a decrease of \$6,669,000, while a 10% decrease in forward curves associated with the underlying commodity would have increased the net asset derivative position of these instruments by \$6,669,000.

Utilizing actual derivative contractual volumes under our NYMEX West Texas Intermediate fixed price swap as of June 30, 2013, a 10% increase in forward curves associated with the underlying commodity would have increased the net liability derivative position of these instruments by approximately \$1,750,000, while a 10% decrease in forward

curves associated with the underlying commodity would have decreased the net liability derivative position of these instruments by \$1,750,000. However, any realized derivative

32

Table of Contents

gain or loss would be substantially offset by a decrease or increase, respectively, in the actual sales value of production covered by the derivative instrument.

Counterparty and Customer Credit Risk

Our principal exposures to credit risk are through receivables resulting from joint interest receivables (approximately \$7,147,000 at June 30, 2013) and receivables from the sale of our oil and natural gas production (approximately \$16,374,000 at June 30, 2013).

We are subject to credit risk due to the concentration of our oil and natural gas receivables with several significant customers. We do not require our customers to post collateral, and the inability of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. For the six months ended June 30, 2013, three purchasers accounted for more than 10% of our revenue: Plains Marketing, L.P. (53%); Shell Trading (US) Company (15%); and Occidental Energy Marketing, Inc. (14%). For the year ended December 31, 2012, three purchasers accounted for more than 10% of our revenue: Plains Marketing, L.P. (53%); Occidental Energy Marketing, Inc. (16%); and Andrews Oil Buyers Inc. (10%). No other customer accounted for more than 10% of our revenue during these periods.

Joint operations receivables arise from billings to entities that own partial interests in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we intend to drill. We have little ability to control whether these entities will participate in our wells. At June 30, 2013, we had one customer that represented approximately 90% of our total joint operations receivables. At December 31, 2012, we had one customer that represented approximately 97% of our total joint operations receivables.

Interest Rate Risk

We are subject to market risk exposure related to changes in interest rates on our indebtedness under our revolving credit facility. The terms of our revolving credit facility provide for interest on borrowings at a floating rate equal to prime, LIBOR or federal funds rate plus margins ranging from 1.25% to 3.50% depending on the base rate used and the amount of the loan outstanding in relation to the borrowing base. As of June 30, 2013, we did not have any borrowings outstanding under our revolving credit facility. On May 21, 2013 the last date on which borrowings were outstanding under our revolving credit facility, such borrowings bore interest at a weighted average rate of 2.70%. An increase or decrease of 1% in the interest rate would have a corresponding decrease or increase in our net income of approximately \$490,000 based on the \$49,000,000 outstanding in the aggregate under our revolving credit facility on May 21, 2013.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Control and Procedures

Under the direction of our Chief Executive Officer and Chief Financial Officer, we have established disclosure controls and procedures, as defined in Rule 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended, or the Exchange Act, that are designed to ensure that 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 the SEC's rules and forms. The disclosure controls and procedures are also intended to ensure that such information is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosures. In designing and evaluating the disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives. In addition, the design of disclosure controls and procedures must reflect the fact that there are resource constraints and that management is required to apply judgment in evaluating the benefits of possible controls and procedures relative to their costs.

As of June 30, 2013, an evaluation was performed under the supervision and with the participation of 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(b) under the Exchange Act. Based upon our evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that as of June 30, 2013, our disclosure controls and procedures are effective.

Table of Contents

Changes in Internal Control over Financial Reporting

There have not been any changes in our internal control over financial reporting that occurred during the quarter ended June 30, 2013 that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting.

34

Table of Contents

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

In September 2010, Windsor Permian (now known as Diamondback O&G LLC) purchased certain property in Goodhue County, Minnesota from Scott and Susan Wesch that was prospective for hydraulic fracturing grade sand. Prior to this purchase, Scott and Susan Wesch had entered into a Mineral Development Agreement with Robert Stein, and Windsor Permian purchased the property subject to that agreement. Windsor Permian subsequently contributed the property to Muskie. In an amended complaint filed in November 2012 by Robert Stein against Scott and Susan Wesch, Windsor Permian and certain affiliates of Windsor Permian in the first judicial district court in Goodhue County, Minnesota, Stein seeks damages from Windsor Permian and the other defendants alleging, among other things, interference with contractual relationship, interference with prospective advantage and unjust enrichment. In an order filed on May 24, 2013, the judge denied certain motions made by the defendants and set a trial date to determine liability, with a damage phase of the matter to commence on a later date if there is a determination of liability. Following a trial on the liability phase on June 21, 2013, the jury determined that the defendants intentionally interfered with plaintiff's contract but that the interference did not cause the plaintiff to be unable to acquire mining permits prior to the enactment of the moratorium by Goodhue County. In an order filed on July 10, 2013, the judge ordered the damage phase to be set for trial following a pretrial and scheduling conference set for August 12, 2013. We believe these claims are without merit and will continue to vigorously defend this action. While management has determined that the possibility of loss is remote, litigation is inherently uncertain and management cannot determine the amount of loss, if any, that may result.

Due to the nature of our business, we are, from time to time, involved in routine litigation or subject to disputes or claims related to our business activities, including workers' compensation claims and employment related disputes. In the opinion of our management, none of the pending litigation, disputes or claims against us, if decided adversely, will have a material adverse effect on our financial condition, cash flows or results of operations.

ITEM 1A. RISK FACTORS.

Our business faces many risks. Any of the risks discussed in this Form 10-Q and our other SEC filings could have a material impact on our business, financial position or results of operations. Additional risks and uncertainties not presently known to us or that we currently believe to be immaterial may also impair our business operations.

In addition to the information set forth in this Form 10-Q, you should carefully consider the risk factors discussed in Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2012. There have been no material changes in our risk factors from those described in our Annual Report on Form 10-K for the year ended December 31, 2012.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

(a) Not applicable.

(b) Not applicable.

(c) We do not have a share repurchase program, and during the three months ended June 30, 2013, we did not purchase any shares of our common stock.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

Not applicable.

ITEM 4. MINE SAFETY DISCLOSURES.

Not applicable.

ITEM 5. OTHER INFORMATION

35

Table of Contents

None.

ITEM 6. EXHIBITS
EXHIBIT INDEX

Exhibit Number	Description
3.1	Amended and Restated Certificate of Incorporation of the Company (incorporated by reference to Exhibit 3.1 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on November 16, 2012).
3.2	Amended and Restated Bylaws of the Company (incorporated by reference to Exhibit 3.2 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on November 16, 2012).
4.1	Specimen certificate for shares of common stock, par value \$0.01 per share, of the Company (incorporated by reference to Exhibit 4.1 to Amendment No. 4 to the Registration Statement on Form S-1, File No. 333-179502, filed by the Company with the SEC on August 20, 2012).
4.2	Registration Rights Agreement, dated as of October 11, 2012, by and between the Company and DB Energy Holdings LLC (incorporated by reference to Exhibit 4.2 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on November 16, 2012).
4.3	Investor Rights Agreement, dated as of October 11, 2012, by and between the Company and Gulfport Energy Corporation (incorporated by reference to Exhibit 4.3 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on November 16, 2012).
10.1+	Form of Amendment to Restricted Stock Unit Certificate (incorporated by reference to Exhibit 10.38 to the Form 10-K/A, File No. 001-35700, filed by the Company with the SEC on April 11, 2013).
10.2	Lease Amendment No. 6 effective May 1, 2013 to Lease Agreement dated as of April 19, 2011, as amended, by and between Fasken Midland, LLC and Windsor Permian LLC (incorporated by reference to Exhibit 10.39 to the Form 10-K/A, File No. 001-35700, filed by the Company with the SEC on April 11, 2013).
10.3	First Amendment to Office Lease Agreement effective as of April 1, 2013 by and between Caliber Investment Group LLC and Diamondback E&P LLC (incorporated by reference to Exhibit 10.40 to the Registration Statement on Form S-1, File No. 333-189176, filed by the Company with the SEC on June 7, 2013).
10.4*	Lease Amendment No. 7 effective September 1, 2013 to Lease Agreement dated as of April 19, 2011, as amended, by and between Fasken Midland, LLC and Diamondback E&P LLC.
10.5*	Lease Amendment No. 8 effective October 1, 2013 to Lease Agreement dated as of April 19, 2011, as amended, by and between Fasken Midland, LLC and Diamondback E&P LLC.
31.1*	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
31.2*	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
32.1++	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
32.2++	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.

101.INS**	XBRL Instance Document.
101.SCH**	XBRL Taxonomy Extension Schema Document.
101.CAL**	XBRL Taxonomy Extension Calculation Linkbase.
101.DEF**	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB**	XBRL Taxonomy Extension Labels Linkbase Document.
101.PRE**	XBRL Taxonomy Extension Presentation Linkbase Document.

36

Table of Contents

- * Filed herewith.
Furnished herewith. Pursuant to Rule 406T of Regulation S-T, these interactive data files are being furnished
- ** herewith and are not deemed filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, as amended, are not deemed filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and otherwise are not subject to liability under these sections.
- + Management contract, compensatory plan or arrangement.
The certifications attached as Exhibit 32.1 and Exhibit 32.2 accompany this Quarterly Report on Form 10-Q pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, and
- ++ shall not be deemed “filed” by the Registrant for purposes of Section 18 of the Securities Exchange Act of 1934, as amended.

Table of Contents

SIGNATURES

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

DIAMONDBACK ENERGY, INC.

Date: August 7, 2013

/s/ Travis D. Stice
Travis D. Stice
Chief Executive Officer

/s/ Teresa L. Dick
Teresa L. Dick
Chief Financial Officer