Diamondback Energy, Inc.
Form 10-Q
November 05, 2013
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

ý QUARTERLY REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE QUARTERLY PERIOD ENDED September 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<br>(State or Other Jurisdiction of<br>Incorporation or Organization) | 45-4502447<br>(IRS Employer<br>Identification Number) |
| 500 West Texas, Suite 1225<br>Midland, Texas | 79701 |
| (Address of Principal Executive Offices) | (Zip Code) |

(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 ý 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 ý 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 | ¨ |

| | | | |
|---|---|---|---|
| Non-Accelerated Filer | x | 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 ý

As of October 28, 2013, 47,067,116 shares of the registrant’s common stock were outstanding.

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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.

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Diamondback Energy, Inc. and Subsidiaries
Consolidated Balance Sheets
(Unaudited)

| | September 30, 2013 | December 31, 2012 |
|---|---|---|
| Assets | | |
| Current assets: | | |
| Cash and cash equivalents | $53,100,000 | $26,358,000 |
| Accounts receivable: | | |
| Joint interest and other | 9,020,000 | 5,959,000 |
| Oil and natural gas sales | 21,141,000 | 8,081,000 |
| Related party | 1,121,000 | 772,000 |
| Inventories | 6,228,000 | 6,195,000 |
| Deferred income taxes | 423,000 | 1,857,000 |
| Derivative instruments | 223,000 | — |
| Prepaid expenses and other | 659,000 | 1,053,000 |
| Total current assets | 91,915,000 | 50,275,000 |
| | | |
| Property and equipment | | |
| Oil and natural gas properties, based on the full cost method of accounting ($424,556,000 and $121,245,000 excluded from amortization at September 30, 2013 and December 31, 2012, respectively) | 1,540,598,000 | 697,742,000 |
| Other property and equipment | 9,168,000 | 2,337,000 |
| Accumulated depletion, depreciation, amortization and impairment | (188,645,000) | (145,837,000) |
| | 1,361,121,000 | 554,242,000 |
| | | |
| Derivative instruments-long term | 527,000 | — |
| Other assets | 12,333,000 | 2,184,000 |
| Total assets | $1,465,896,000 | $606,701,000 |
| Liabilities and Stockholders' Equity | | |
| Current liabilities: | | |
| Accounts payable trade | $24,012,000 | $12,141,000 |
| Accounts payable-related party | 271,000 | 18,813,000 |
| Accrued capital expenditures | 55,190,000 | 29,397,000 |
| Other accrued liabilities | 21,040,000 | 10,649,000 |
| Revenues and royalties payable | 6,860,000 | 3,270,000 |
| Derivative instruments | 1,933,000 | 4,817,000 |
| Note payable-short term | 145,000 | 145,000 |
| Total current liabilities | 109,451,000 | 79,232,000 |
| | | |
| Long-term debt | 450,085,000 | 193,000 |
| Derivative instruments-long term | — | 388,000 |
| Asset retirement obligations-long term | 2,878,000 | 2,125,000 |
| Deferred income taxes-noncurrent | 80,544,000 | 62,695,000 |
| Total liabilities | 642,958,000 | 144,633,000 |
| Contingencies (Note 13) | | |
| Stockholders' equity: | | |

| | | |
|---|---|---|
| Common stock, $0.01 par value, 100,000,000 shares authorized, 47,021,035 issued and outstanding at September 30, 2013; 36,986,532 issued and outstanding at December 31, 2012 | 470,000 | 370,000 |
| Additional paid-in capital | 840,079,000 | 513,772,000 |
| Accumulated deficit | (17,611,000 ) | (52,074,000 ) |
| Total stockholders’ equity | 822,938,000 | 462,068,000 |
| Total liabilities and stockholders’ equity | $1,465,896,000 | $606,701,000 |

See accompanying notes to combined consolidated financial statements.

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

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2013 | 2012 | 2013 | 2012 |
| Revenues: | | | | |
| Oil sales | $53,086,000 | $14,530,000 | $119,373,000 | $43,542,000 |
| Natural gas sales | 859,000 | 208,000 | 2,586,000 | 605,000 |
| Natural gas sales - related party | 704,000 | 370,000 | 1,796,000 | 631,000 |
| Natural gas liquid sales | 1,970,000 | 671,000 | 5,441,000 | 2,246,000 |
| Natural gas liquid sales - related party | 1,172,000 | 1,035,000 | 2,898,000 | 2,171,000 |
| Total revenues | 57,791,000 | 16,814,000 | 132,094,000 | 49,195,000 |
| Costs and expenses: | | | | |
| Lease operating expenses | 4,718,000 | 3,242,000 | 14,527,000 | 8,667,000 |
| Lease operating expenses - related party | 246,000 | 267,000 | 840,000 | 841,000 |
| Production and ad valorem taxes | 3,420,000 | 1,194,000 | 7,970,000 | 2,992,000 |
| Production and ad valorem taxes - related party | 133,000 | 99,000 | 325,000 | 199,000 |
| Gathering and transportation | 69,000 | 9,000 | 175,000 | 61,000 |
| Gathering and transportation - related party | 192,000 | 109,000 | 466,000 | 203,000 |
| Depreciation, depletion and amortization | 17,423,000 | 6,136,000 | 42,976,000 | 16,552,000 |
| General and administrative expenses | 1,810,000 | 1,323,000 | 6,350,000 | 2,803,000 |
| General and administrative expenses - related party | 311,000 | 327,000 | 863,000 | 1,684,000 |
| Asset retirement obligation accretion expense | 46,000 | 22,000 | 134,000 | 63,000 |
| Total costs and expenses | 28,368,000 | 12,728,000 | 74,626,000 | 34,065,000 |
| Income from operations | 29,423,000 | 4,086,000 | 57,468,000 | 15,130,000 |
| Other income (expense) | | | | |
| Interest income | 1,000 | 1,000 | 1,000 | 3,000 |
| Interest expense | (1,089,000) | (1,130,000) | (2,109,000) | (3,184,000) |
| Other income - related party | 270,000 | 643,000 | 1,047,000 | 1,654,000 |
| Gain (loss) on derivative instruments, net | (4,910,000) | (3,148,000) | (1,881,000) | 2,017,000 |
| Loss from equity investment | — | — | — | (67,000) |
| Total other income (expense), net | (5,728,000) | (3,634,000) | (2,942,000) | 423,000 |
| Income before income taxes | 23,695,000 | 452,000 | 54,526,000 | 15,553,000 |
| Provision for income taxes | | | | |
| Deferred income tax provision | 9,099,000 | — | 20,063,000 | — |
| Net income | $14,596,000 | $452,000 | $34,463,000 | $15,553,000 |
| | | | | |
| Earnings per common share | | | | |
| Basic | $0.33 | | $0.85 | |
| Diluted | $0.33 | | $0.85 | |
| Weighted average common shares outstanding | | | | |
| Basic | 44,385,107 | | 40,308,989 | |
| Diluted | 44,697,609 | | 40,523,764 | |

See accompanying notes to combined consolidated financial statements.

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

| | Three Months Ended September 30, 2012 | Nine Months Ended September 30, 2012 |
|---|---|---|
| Pro forma information | | |
| Income before income taxes, as reported | $452,000 | $15,553,000 |
| Pro forma provision for income taxes | 161,000 | 5,545,000 |
| Pro forma net income | $291,000 | $10,008,000 |
| | | |
| Pro forma earnings per common share - basic and diluted | $0.02 | $0.68 |
| Pro forma weighted average common shares outstanding - basic and diluted | 14,697,496 | 14,697,496 |

See accompanying notes to combined consolidated financial statements.

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Diamondback Energy, Inc. and Subsidiaries
Consolidated Statement of Stockholders’ Equity
(Unaudited)

| | Common Stock | | Additional | Accumulated | |
|---|---|---|---|---|---|
| | Shares | Amount | Paid-in Capital | Deficit | Total |
| Balance December 31, 2012 | 36,986,532 | $370,000 | $513,772,000 | $(52,074,000) | $462,068,000 |
| Stock based compensation | — | — | 1,845,000 | — | 1,845,000 |
| Common shares issued in public offering, net of offering costs | 9,775,000 | 98,000 | 321,848,000 | — | 321,946,000 |
| Exercise of stock options and vesting of restricted stock units | 259,503 | 2,000 | 2,614,000 | — | 2,616,000 |
| Net income | — | — | — | 34,463,000 | 34,463,000 |
| Balance September 30, 2013 | 47,021,035 | $470,000 | $840,079,000 | $(17,611,000) | $822,938,000 |

See accompanying notes to combined consolidated financial statements.

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

| | Nine Months Ended September 30, | |
|---|---|---|
| | 2013 | 2012 |
| Cash flows from operating activities: | | |
| Net income | $34,463,000 | $15,553,000 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | |
| Provision for deferred income taxes | 20,063,000 | — |
| Asset retirement obligation accretion expense | 134,000 | 63,000 |
| Depreciation, depletion, and amortization | 42,976,000 | 16,552,000 |
| Amortization of debt issuance costs | 526,000 | 347,000 |
| Change in fair value of derivative instruments | (3,733,000) | (2,017,000) |
| Loss from equity investment | — | 67,000 |
| Equity based compensation expense | 1,426,000 | 873,000 |
| Gain on sale of assets | (31,000) | (26,000) |
| Changes in operating assets and liabilities: | | |
| Accounts receivable | (13,262,000) | (4,256,000) |
| Accounts receivable-related party | (350,000) | 5,061,000 |
| Inventories | 309,000 | (44,000) |
| Prepaid expenses and other | (1,376,000) | 1,000 |
| Accounts payable and accrued liabilities | 7,324,000 | 2,145,000 |
| Accounts payable and accrued liabilities-related party | (82,000) | 2,289,000 |
| Revenues and royalties payable | 3,260,000 | (740,000) |
| Revenues and royalties payable-related party | — | (2,404,000) |
| Net cash provided by operating activities | 91,647,000 | 33,464,000 |
| Cash flows from investing activities: | | |
| Additions to oil and natural gas properties | (188,201,000) | (73,237,000) |
| Additions to oil and natural gas properties-related party | (11,594,000) | (8,264,000) |
| Acquisition of Gulfport properties | (18,550,000) | — |
| Acquisition of mineral interests | (440,000,000) | — |
| Acquisition of leasehold interests | (166,635,000) | — |
| Purchase of other property and equipment | (4,965,000) | (778,000) |
| Proceeds from sale of property and equipment | 62,000 | 26,000 |
| Settlement of non-hedge derivative instruments | (289,000) | (7,025,000) |
| Receipt on derivative margins | — | 2,325,000 |
| Net cash used in investing activities | (830,172,000) | (86,953,000) |
| 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 senior notes | 450,000,000 | — |
| Proceeds from note payable - related party | — | 30,045,000 |
| Debt issuance costs | (9,524,000) | (72,000) |
| Public offering costs | (505,000) | (1,009,000) |
| Proceeds from public offering | 322,680,000 | — |
| Exercise of stock options | 2,616,000 | — |
| Contributions by members | — | 4,008,000 |
| Net cash provided by financing activities | 765,267,000 | 47,972,000 |

| | | |
|---|---|---|
| Net increase (decrease) in cash and cash equivalents | 26,742,000 | (5,517,000) |
| Cash and cash equivalents at beginning of period | 26,358,000 | 6,959,000 |
| Cash and cash equivalents at end of period | $53,100,000 | $1,442,000 |

See accompanying notes to combined consolidated financial statements.

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

| | Nine Months Ended September 30, | |
|---|---|---|
| | 2013 | 2012 |
| Supplemental disclosure of cash flow information: | | |
| Interest paid, net of capitalized interest | $383,000 | $2,778,000 |
| Supplemental disclosure of non-cash transactions: | | |
| Asset retirement obligation incurred | $162,000 | $145,000 |
| Asset retirement obligation acquired | $471,000 | $— |
| Distribution of equity method investments | $— | $10,504,000 |
| Note payable exchanged for equipment | $— | $411,000 |

See accompanying notes to combined consolidated financial statements.

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 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 (“Diamondback O&G”).
On May 21, 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.
In August 2013, the Company completed an underwritten public offering of 4,600,000 shares of common stock, which included 600,000 shares of common stock issued pursuant to an option to purchase additional shares granted to the underwriters. The stock was sold the public at $40.25 per share and the Company received net proceeds of approximately $177.5 million from the sale of these shares of common stock, net of offering expenses and underwriting discounts and commissions.

In September 2013, we completed an offering of $450.0 million principal amount of our 7.625% Senior Notes due 2021. See Note 7 below.

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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 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.

Reclassifications

The Company has reclassified certain prior year amounts to conform with the current year's presentation. The Company has reclassified ad valorem taxes from lease operating expenses to production and ad valorem 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

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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.

Debt Issuance Costs

Costs incurred of $10.3 million upon the issuance of the 7.625% Senior Notes due 2021 were capitalized and are being amortized over the term of the Senior Notes using the effective interest method. The Company includes unamortized costs in other assets in its consolidated balance sheets.

3. ACQUISITIONS

2013 Activity

In September 2013, the Company completed two separate acquisitions of additional leasehold interests in the Permian Basin from unrelated third party sellers for an aggregate purchase price of $165.0 million, subject to certain adjustments. The first of these acquisitions closed on September 4, 2013 when the Company acquired certain assets located in northwestern Martin County, Texas, consisting of a 100% working interest (80% net revenue interest) in 4,506 gross and net acres, with 18 gross and net producing vertical wells and one well waiting on completion, an estimated 1,199 MBOE of proved developed reserves (including 88 MBOE attributable to one PDNP well) as of September 1, 2013 and 457 gross (365 net) BOE per day of production during July 2013. The second of these acquisitions closed on September 26, 2013, when the Company acquired certain assets located primarily in southwestern Dawson County, Texas, consisting of a 70% working interest (54% net revenue interest) in 9,390 gross (6,638 net) acres, with 32 gross (23 net) producing vertical wells, an estimated 907 MBOE of proved developed reserves (including 45 MBOE attributable to one PDNP well) as of September 1, 2013 and 777 gross (417 net) BOE per day of production during June 2013. These acquisitions were funded with a portion of the net proceeds from the August 2013 equity offering discussed in Note 1 above.

On September 19, 2013, the Company completed the acquisition of the mineral interests underlying approximately 15,000 gross (12,500 net) acres in Midland County, Texas in the Permian Basin. The mineral interests entitle the Company to receive an average 19.5% royalty interest on all production from this acreage with no additional future capital or operating expense required. The $440.0 million purchase price was funded with the net proceeds of the Company’s offering of Senior Notes discussed in Note 7 below.

2012 Activity

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 nine months ended September 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 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 September 30, 2012 (Pro Forma) | | Nine Months Ended September 30, 2012 (Pro Forma) | |
|---|---|---|---|---|
| Pro forma total revenues | $23,839,000 | | $70,411,000 | |
| Pro forma income from operations | 5,564,000 | | 21,255,000 | |
| Pro forma net income | 1,930,000 | (1) | 21,678,000 | (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.

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## 4. PROPERTY AND EQUIPMENT

Property and equipment includes the following:

| | September 30, 2013 | December 31, 2012 |
|---|---|---|
| Oil and natural gas properties: | | |
| Subject to depletion | $1,116,042,000 | $576,497,000 |
| Not subject to depletion-acquisition costs | | |
| Incurred in 2013 | 315,331,000 | — |
| Incurred in 2012 | 106,269,000 | 117,395,000 |
| Incurred in 2011 | 1,598,000 | 1,670,000 |
| Incurred in 2010 | 1,358,000 | 1,647,000 |
| Incurred in 2009 | — | 533,000 |
| Total not subject to depletion | 424,556,000 | 121,245,000 |
| Gross oil and natural gas properties | 1,540,598,000 | 697,742,000 |
| Less accumulated depreciation, depletion, amortization and impairment | (187,427,000) | (145,102,000) |
| Oil and natural gas properties, net | 1,353,171,000 | 552,640,000 |
| Other property and equipment | 9,168,000 | 2,337,000 |
| Less accumulated depreciation | (1,218,000) | (735,000) |
| Other property and equipment, net | 7,950,000 | 1,602,000 |
| Property and equipment, net of accumulated depreciation, depletion, amortization and impairment | $1,361,121,000 | $554,242,000 |

The average depletion rate per barrel equivalent unit of production was $25.24 and $24.76 for the three months and nine months ended September 30, 2013, respectively, and $24.43 and $23.96 for the three months and nine months ended September 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 $1,038,000 and $2,678,000 for the three months and nine months ended September 30, 2013, respectively, and $1,068,000 and $2,843,000 for the three months and nine months ended September 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:

| | Nine Months Ended September 30, | |
|---|---|---|
| | 2013 | 2012 |
| Asset retirement obligation, beginning of period | $2,145,000 | $1,104,000 |
| Additional liability incurred | 162,000 | 145,000 |
| Liabilities acquired | 471,000 | — |
| Liabilities settled | (14,000) | — |

| | | |
|---|---|---|
| Accretion expense | 134,000 | 63,000 |
| Asset retirement obligation, end of period | 2,898,000 | 1,312,000 |
| Less current portion | 20,000 | 19,000 |
| Asset retirement obligations - long-term | $2,878,000 | $1,293,000 |

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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 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. As of June 15, 2012, the Company distributed its remaining 22% 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.

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

Senior Notes

On September 18, 2013, the Company completed an offering of $450.0 million in aggregate principal amount of 7.625% senior unsecured notes due 2021 (the "Senior Notes"). The Senior Notes bear interest at the rate of 7.625% per annum, payable semi-annually, in arrears on April 1 and October 1 of each year, commencing on April 1, 2014 and will mature on October 1, 2021. The Senior Notes are fully and unconditionally guaranteed by the Company's subsidiaries. The net proceeds from the Senior Notes were used to fund the acquisition of mineral interests underlying approximately 15,000 gross (12,500 net) acres in Midland County, Texas in the Permian Basin.

The Senior Notes were issued under, and are governed by, an indenture among the Company, the subsidiary guarantors party thereto and Wells Fargo Bank, N.A., as the trustee (the "Indenture"). The Indenture contains certain covenants that, subject to certain exceptions and qualifications, among other things, limit the Company's ability and the ability of the restricted subsidiaries to incur or guarantee additional indebtedness, make certain investments, declare or pay dividends or make other distributions on, or redeem or repurchase, capital stock, prepay subordinated indebtedness, sell assets including capital stock of subsidiaries, agree to payment restrictions affecting the Company's restricted subsidiaries, consolidate, merge, sell or otherwise dispose of all or substantially all of its assets, enter into transactions with affiliates, incur liens, engage in business other than the oil and gas business and designate certain of the Company's subsidiaries as unrestricted subsidiaries. If the Company experiences certain kinds of changes of control or if it sells certain of its assets, holders of the Senior Notes may have the right to require the Company to repurchase their Senior Notes.

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The Company will have the option to redeem the Senior Notes, in whole or in part, at any time on or after October 1, 2016 at the redemption prices (expressed as percentages of principal amount) of 105.719% for the 12-month period beginning on October 1, 2016, 103.813% for the 12-month period beginning on October 1, 2017, 101.906% for the 12-month period beginning on October 1, 2018 and 100.000% beginning on October 1, 2019 and at any time thereafter with any accrued and unpaid interest to, but not including, the date of redemption. In addition, prior to October 1, 2016, the Company may redeem all or a part of the Senior Notes at a price equal to 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date, plus a "make-whole" premium at the redemption date. Furthermore, before October 1, 2016, the Company may, at any time or from time to time, redeem up to 35% of the aggregate principal amount of the Senior Notes with the net cash proceeds of certain equity offerings at a redemption price of 107.625% of the principal amount of the Senior Notes being redeemed plus any accrued and unpaid interest to the date of redemption, if at least 65% of the aggregate principal amount of the Senior Notes originally issued under the Indenture remains outstanding immediately after such redemption and the redemption occurs within 120 days of the closing date of such equity offering.
In connection with the issuance of the Senior Notes, the Company and the subsidiary guarantors entered into a Registration Rights Agreement (the "Registration Rights Agreement") with the initial purchasers on September 18, 2013, pursuant to which the Company and the subsidiary guarantors have agreed to file a registration statement with respect to an offer to exchange the Senior Notes for a new issue of substantially identical debt securities registered under the Securities Act. Under the Registration Rights Agreement, the Company also agreed to use its commercially reasonable efforts to cause the exchange offer registration statement to become effective within 360 days after the issue date of the Senior Notes and to consummate the exchange offer 30 days after effectiveness. The Company may be required to file a shelf registration statement to cover resales of the Senior Notes under certain circumstances. If the Company fails to satisfy certain of its obligations under the Registration Rights Agreement, the Company agreed to pay additional interest to the holders of the Senior Notes as specified in the Registration Rights Agreement.

Credit Facility-Wells Fargo Bank
On October 15, 2010, the Company entered into a secured revolving credit 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 credit agreement was amended and restated as of July 24, 2012 and again as of November 1, 2013. The credit agreement, as so amended and restated, provides for a revolving credit facility in the maximum amount of $600 million, subject to scheduled semi-annual and other elective collateral borrowing base redeterminations based on the Company's oil and natural gas reserves and other factors (the "borrowing base"). The borrowing base is scheduled to be re-determined semi-annually with effective dates of April 1st and October 1st. In addition, the Company may request up to three additional redeterminations of the borrowing base during any 12-month period. As of November 1, 2013, the borrowing base was set at $225.0 million.

The outstanding borrowings under the credit agreement bear interest at a rate elected by the Company that is based on the prime rate or LIBOR plus margins ranging from 0.50% for prime-based loans and 1.50% for LIBOR loans to 1.50% for prime-based loans and 2.50% for LIBOR loans, in each case depending on the amount of the loan outstanding in relation to the borrowing base. The Company is obligated to pay a quarterly commitment fee ranging from 0.375% to 0.500% per year on the unused portion of the borrowing base, which fee is also dependent on the amount of the loan outstanding in relation to the borrowing base. Loan principal may be optionally repaid from time to time without premium or penalty (other than customary LIBOR breakage), and is required to be paid (a) if the loan amount exceeds the borrowing base, whether due to a borrowing base redetermination or otherwise (in some cases subject to a cure period) and (b) at the maturity date of November 1, 2018. The loan is secured by substantially all of the assets of the Company and its subsidiaries.

The credit agreement contains various affirmative, negative and financial maintenance covenants. These covenants, among other things, limit 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 the financial ratios described below.

| Financial Covenant | Required Ratio |
|---|---|
| Ratio of total debt to EBITDAX | Not greater than 4.0 to 1.0 |
| Ratio of current assets to liabilities, as defined in the credit agreement | Not less than 1.0 to 1.0 |

EBITDAX will be annualized beginning with the quarter ended September 30, 2013 and ending with the quarter ending March 31, 2014.

The covenant prohibiting additional indebtedness allows for the issuance of unsecured debt of up to $750 million in the form of senior or senior subordinated notes and, in connection with any such issuance, the reduction of the borrowing base by 25% of the stated principal amount of each 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. As of November 1, 2013, the Company had $450 million of senior unsecured notes outstanding.

As of September 30, 2013, the Company was in compliance with all financial covenants under its revolving credit facility, as then in effect. The lenders may accelerate all of the indebtedness under the Company's revolving credit facility upon the occurrence and during the continuance of any event of default. The credit agreement contains customary events of default, including non-payment, breach of covenants, materially incorrect representations, cross-default, bankruptcy and change of control. There are no cure periods for events of default due to non-payment of principal and breaches of negative and financial covenants, but non-payment of interest and breaches of certain affirmative covenants are subject to customary cure periods.

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 September 30, 2013 and December 31, 2012, the Company had amounts outstanding under this note of $230,000 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. Prior to the completion of the IPO, there was $30.1 million in aggregate principal and interest 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:

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| | Three Months Ended September 30, 2013 | | |
|---|---|---|---|
| | Income | Shares | Per Share |
| Basic: | | | |
| Net income attributable to common stock | $14,596,000 | 44,385,107 | $0.33 |
| Effect of Dilutive Securities: | | | |
| Dilutive effect of potential common shares issuable | $— | 312,502 | |
| Diluted: | | | |
| Net income attributable to common stock | $14,596,000 | 44,697,609 | $0.33 |

| | Nine Months Ended September 30, 2013 | | |
|---|---|---|---|
| | Income | Shares | Per Share |
| Basic: | | | |
| Net income attributable to common stock | $34,463,000 | 40,308,989 | $0.85 |
| Effect of Dilutive Securities: | | | |
| Dilutive effect of potential common shares issuable | $— | 214,775 | |
| Diluted: | | | |
| Net income attributable to common stock | $34,463,000 | 40,523,764 | $0.85 |

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 September 30, 2012 | | |
|---|---|---|---|
| | Income | Shares | Per Share |
| Basic: | | | |
| Pro forma net income attributable to common stock | $291,000 | 14,697,496 | $0.02 |
| Effect of Dilutive Securities: | | | |
| Dilutive effect of potential common shares issuable | $— | — | |
| Diluted: | | | |
| Pro forma net income attributable to common stock | $291,000 | 14,697,496 | $0.02 |

| | Nine Months Ended September 30, 2012 | | |
|---|---|---|---|
| | Income | Shares | Per Share |
| Basic: | | | |
| Pro forma net income attributable to common stock | $10,008,000 | 14,697,496 | $0.68 |
| Effect of Dilutive Securities: | | | |
| | $— | — | |

| | | | |
|---|---|---|---|
| Dilutive effect of potential common shares issuable | | | |
| Diluted: | | | |
| Pro forma net income attributable to common stock | $10,008,000 | 14,697,496 | $0.68 |

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9. STOCK AND EQUITY BASED COMPENSATION
For the three months and nine months ended September 30, 2013, the Company incurred $749,000 and $2,105,000, respectively, of stock based compensation, of which the Company capitalized $259,000 and $679,000, respectively, pursuant to the full cost method of accounting for oil and natural gas properties. For the three months and nine months ended September 30, 2012, the Company incurred $291,000 and $873,000, respectively, of equity based compensation, of which the Company capitalized $115,000 and $338,000, 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 nine months ended September 30, 2013.

| | 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 | (149,500) | $17.50 | | |
| Expired/Forfeited | — | $— | | |
| Outstanding at September 30, 2013 | 763,500 | $17.93 | 3.03 | $18,865,000 |
| Vested and Expected to vest at September 30, 2013 | 763,500 | $17.93 | 3.03 | $18,865,000 |
| Exercisable at September 30, 2013 | 263,000 | $17.50 | 2.71 | $6,612,000 |

As of September 30, 2013, the unrecognized compensation cost related to unvested stock options was $2,079,000. Such cost is expected to be recognized over a weighted-average period of 2.0 years.
The following table presents the Company's restricted stock awards and units activity under the 2012 Plan for the nine months ended September 30, 2013.

| | Restricted Stock Awards & Units | Weighted Average Grant-Date Fair Value |
|---|---|---|
| Unvested at December 31, 2012 | 206,507 | $17.50 |
| Granted | 11,099 | $41.66 |
| Vested | (58,923) | $18.23 |
| Forfeited | (4,444) | $17.50 |
| Unvested at September 30, 2013 | 154,239 | $18.96 |

As of September 30, 2013, the Company's unrecognized compensation cost related to unvested restricted stock awards and units was $2,578,000. Such cost is expected to be recognized over a weighted-average period of 1.7 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

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basis. For the three months and nine months ended September 30, 2013, the Company incurred total costs of $70,000 and $179,000, respectively. For the three months and nine months ended September 30, 2012, the Company incurred total costs of $235,000 and $4,357,000, 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 $620,000 and $1,772,000 for the three months and nine months ended September 30, 2012, respectively. As of September 30, 2013 and December 31, 2012, the Company owed the administrative services affiliate $1,000 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 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 nine months ended September 30, 2013, the affiliate reimbursed the Company $270,000 and $1,047,000, respectively, and for the three months and nine months ended September 30, 2012, the affiliate reimbursed the Company $643,000 and $1,654,000, respectively for services under the shared services agreement. As of September 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 September 30, 2013 and December 31, 2012, amounts due from an affiliate (a greater than 10% stockholder) related to joint interest billings and included in accounts receivable-related party in the accompanying consolidated balance sheets were $134,000 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 September 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 $270,000 as of September 30, 2013 and $120,000 as of December 31, 2012.

Effective September 9, 2013, the Company entered into a master service agreement with Panther Drilling Systems LLC (“Panther Drilling”), an entity controlled by Wexford, Panther Drilling provides directional drilling and other services. This master service agreement is terminable by either party on 30 days prior written notice, although neither party will be relieved of its respective obligations arising from work performed prior to the termination of the master service agreement. In the third quarter 2013, the Company began using Panther Drilling’s directional drilling services. The amount incurred in the third quarter for services performed by Panther Drilling was not material.

Coronado Midstream

The Company is party to a gas purchase agreement, dated May 1, 2009, as amended, with Coronado Midstream LLC (“Coronado Midstream”), formerly known as MidMar Gas LLC, an entity affiliated with Wexford that owns a gas gathering system and processing plant in the Permian Basin. Under this agreement, Coronado Midstream is obligated to purchase from the Company, and the Company is obligated to sell to Coronado Midstream, 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, Coronado Midstream is obligated to pay the Company 87% of the net revenue received by Coronado Midstream 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 Coronado Midstream's gas processing plant, and 94.56% of the net revenue received by Coronado Midstream 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 Coronado Midstream of $1,877,000 and $4,694,000 for the three months and nine months ended September 30, 2013, respectively, and $1,404,000 and $2,801,000 for the three months and nine months ended September 30, 2012, respectively. As of September 30, 2013 and December 31, 2012, Coronado Midstream owed the Company $987,000 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 nine months ended September 30, 2013. As of September 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 $49,000 and $131,000 for the three months and nine months ended September 30, 2013, respectively, and $46,000 and $117,000, for the three months and nine months ended September 30, 2012, respectively, under this lease. In the second and third quarters of 2013, the Company amended this agreement to increase the size of the leased premises. The monthly rent under the lease increased from $13,000 to $15,000 beginning on August 1, 2013 and will increase to $25,000 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 $67,000 and $178,000 for the three months and nine months ended September 30, 2013, respectively, and $60,000 and $267,000 for the three months and nine months ended September 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 $375,000 for the three months and nine months ended September 30, 2013, respectively, under the Advisory Services Agreement. Wexford provides certain professional services to the Company, for which the Company incurred total costs of $25,000 and $119,000 for the three months and nine months ended September 30, 2012, respectively. As of September 30, 2013 and December 31, 2012, the Company owed Wexford no amounts and

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$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 $185,000 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 (loss) on derivative instruments, net."

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 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 September 30, 2013, the Company had open crude oil derivative positions with respect to future production as set forth in the tables below. When aggregating multiple contracts, the weighted average contract price is disclosed.

Crude Oil—NYMEX West Texas Intermediate Fixed Price Swap

| Production Period | Volume (Bbls) | Fixed Swap Price |
|---|---|---|
| October–December 2013 | 92,000 | $80.55 |

Crude Oil—Argus Louisiana Light Sweet Fixed Price Swap

| Production Period | Volume (Bbls) | Fixed Swap Price |
|---|---|---|
| October - December 2013 | 92,000 | $100.20 |
| January - December 2014 | 515,000 | 100.76 |
| January 2015 | 31,000 | 101.00 |

Crude Oil—ICE Brent Fixed Price Swap

| Production Period | Volume (Bbls) | Fixed Swap Price |
|---|---|---|
| October–December 2013 | 92,000 | $109.70 |
| January–April 2014 | 120,000 | 109.70 |

Balance sheet offsetting of derivative assets and liabilities

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 following tables present the gross amounts of recognized derivative assets and liabilities, the amounts offset under master netting arrangements with counterparties and the resulting net amounts presented in the Company's consolidated balance sheets as of September 30, 2013 and December 31, 2012.

| | September 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 | $1,513,000 | $(763,000) | $750,000 |
| | 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 | $1,933,000 | $— | $1,933,000 |

| | 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 | $5,205,000 | $— | $5,205,000 |

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:

| | September 30, 2013 | December 31, 2012 |
|---|---|---|
| Current Assets: Derivative instruments | $223,000 | $— |
| Noncurrent Assets: Derivative instruments | 527,000 | — |
| Total Assets | $750,000 | $— |
| | | |
| Current Liabilities: Derivative instruments | $1,933,000 | $4,817,000 |
| Noncurrent Liabilities: Derivative instruments | — | 388,000 |
| Total Liabilities | $1,933,000 | $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:

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| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2013 | 2012 | 2013 | 2012 |
| Non-cash gain (loss) on open non-hedge derivative instruments | $(1,695,000) | $(2,252,000) | $3,733,000 | $6,386,000 |
| Loss on settlement of non-hedge derivative instruments | (3,215,000) | (896,000) | (5,614,000) | (4,369,000) |
| Gain (loss) on derivative instruments | $(4,910,000) | $(3,148,000) | $(1,881,000) | $2,017,000 |

## 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.

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 September 30, 2013 and December 31, 2012.

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Diamondback Energy, Inc. and Subsidiaries
Notes to Combined Consolidated Financial Statements-(Continued)
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| | Fair value measurements at September 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 | $— | $750,000 | $— | $750,000 |
| Liabilities: | | | | |
| Fixed price swaps | — | 1,933,000 | — | 1,933,000 |

| | 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.

| | September 30, 2013 | | December 31, 2012 | |
|---|---|---|---|---|
| | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| Debt: | | | | |
| 7.625% Senior Notes due 2021 | $450,000,000 | $460,406,000 | $— | $— |
| Note payable | 230,000 | 219,000 | 338,000 | 305,000 |

The fair value of the Senior Notes was determined using the September 30, 2013 quoted market price, a Level 1 classification in the fair value hierarchy. 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.

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. The damage phase is expected to be set for trial in 2014 following additional discovery and the filing of motions. The Company believes these claims are without merit and will continue to vigorously defend this action. While management has determined that

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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

On November 1, 2013, the Company entered into an amended and restated credit agreement with Wells Fargo Bank, National Association, as administrative agent for the lenders, and certain lenders party hereto. For a description of this amended and restated credit facility, see Note 7 — “Debt – Credit Facility – Wells Fargo Bank.”

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## 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 September 30, 2013, and was approximately 68% oil, 18% natural gas liquids and 14% natural gas for the three months ended September 30, 2012. Our production was approximately 74% oil, 14% natural gas liquids and 12% natural gas for the nine months ended September 30, 2013, and was approximately 72% oil, 16% natural gas liquids and 12% natural gas for the nine months ended September 30, 2012. On September 30, 2013, our net acreage position in the Permian Basin was approximately 66,150 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 Energy Corporation, which we refer to as "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 21, 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.

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On June 24, 2013, 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.

In August 2013, we completed an underwritten public offering of 4,600,000 shares of common stock, which included 600,000 shares of common stock issued pursuant to an option to purchase additional shares granted to the underwriters. The stock was sold the public at $40.25 per share and we received net proceeds of approximately $177.5 million from the sale of these shares of common stock, net of offering expenses and underwriting discounts and commissions.

In September 2013, we completed an offering of $450.0 million aggregate principal amount of our 7.625% Senior Notes due 2021, which we refer to as the senior notes. See “—Liquidity and Capital Resources—Financing Activity—Senior Notes.”

Recent Developments

Midland County Mineral Interest Acquisition

On September 19, 2013, we purchased mineral interests underlying approximately 15,000 gross (12,500 net) acres in Midland County, Texas in the Permian Basin for $440.0 million, subject to certain adjustments. We are the operator of approximately 50% of the acreage associated with these mineral interests. The mineral interests entitle us to receive an average 19.5% royalty interest on all production from this acreage with no additional future capital or operating expense required. As of September 1, 2013, there were 183 vertical wells and eight horizontal wells on this acreage and net production attributable to the acquired mineral interests was approximately 1,600 net BOE per day during June 2013. The acquisition price was funded with the net proceeds from our offering of senior notes. The free cash flow attributable to these mineral interests was approximately $3.7 million in June 2013.

Martin and Dawson County Leasehold Acquisitions

In September 2013, we completed two separate acquisitions of additional leasehold interests in the Permian Basin from unrelated third party sellers for an aggregate purchase price of $165.0 million, subject to certain adjustments. The first of these acquisitions closed on September 4, 2013 when we acquired certain assets located in northwestern Martin County, Texas, consisting of a 100% working interest (80% net revenue interest) in 4,506 gross and net acres, with 18 gross and net producing vertical wells and one well waiting on completion, an estimated 1,199 MBOE of proved developed reserves (including 88 MBOE attributable to one PDNP well) as of September 1, 2013 and 457 gross (365 net) BOE per day of production during July 2013. The second of these acquisitions closed on September 26, 2013, when we acquired certain assets located primarily in southwestern Dawson County, Texas, consisting of a 70% working interest (54% net revenue interest) in 9,390 gross (6,638 net) acres, with 32 gross (23 net) producing vertical wells, an estimated 907 MBOE of proved developed reserves (including 45 MBOE attributable to one PDNP well) as of September 1, 2013 and 777 gross (417 net) BOE per day of production during June 2013. These acquisitions were funded with a portion of the net proceeds from the August 2013 equity offering discussed above.

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.

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Operating Results Overview

During the three months ended September 30, 2013, our average daily production was approximately 7,419 BOE/d, consisting of 5,596 Bbls/d of oil, 4,850 Mcf/d of natural gas and 1,014 Bbls/d of natural gas liquids, an increase of 4,755 BOE/d, or 178%, from average daily production of 2,664 BOE/d for the three months ended September 30, 2012, consisting of 1,807 Bbls/d of oil, 2,220 Mcf/d of natural gas and 488 Bbls/d of natural gas liquids.

During the nine months ended September 30, 2013, our average daily production was approximately 6,275 BOE/d, consisting of 4,627 Bbls/d of oil, 4,417 Mcf/d of natural gas and 912 Bbls/d of natural gas liquids, an increase of 3,806 BOE/d, or 154%, from average daily production of 2,469 BOE/d for the nine months ended September 30, 2012, consisting of 1,767 Bbls/d of oil, 1,804 Mcf/d of natural gas and 402 Bbls/d of natural gas liquids.

During the three months ended September 30, 2013, we drilled 21 gross (18 net) wells, and participated in an additional 3 gross (1 net) non-operated wells, in the Permian Basin. During the nine months ended September 30, 2013, we drilled 58 gross (50 net) wells, and participated in an additional 4 gross (2 net) non-operated wells, 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 September 30, 2013 and 2012, our revenues were derived 92% and 86%, respectively, from oil sales, 5% and 11%, respectively, from natural gas liquids sales and 3% and 3%, respectively, from natural gas sales. For the nine months ended September 30, 2013 and 2012, our revenues were derived 90% and 89%, respectively, from oil sales, 7% and 9%, respectively, from natural gas liquids sales and 3% 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.

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Results of Operations

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

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2013 | 2012 | 2013 | 2012 |
| | (unaudited) | | (unaudited) | |
| Operating Results: | | | | |
| Revenues | | | | |
| Oil and natural gas revenues | $57,791,000 | $16,814,000 | $132,094,000 | $49,195,000 |
| Operating Expenses | | | | |
| Lease operating expense | 4,964,000 | 3,509,000 | 15,367,000 | 9,508,000 |
| Production and ad valorem taxes | 3,553,000 | 1,293,000 | 8,295,000 | 3,191,000 |
| Gathering and transportation expense | 261,000 | 118,000 | 641,000 | 264,000 |
| Depreciation, depletion and amortization | 17,423,000 | 6,136,000 | 42,976,000 | 16,552,000 |
| General and administrative | 2,121,000 | 1,650,000 | 7,213,000 | 4,487,000 |
| Asset retirement obligation accretion expense | 46,000 | 22,000 | 134,000 | 63,000 |
| Total expenses | 28,368,000 | 12,728,000 | 74,626,000 | 34,065,000 |
| Income from operations | 29,423,000 | 4,086,000 | 57,468,000 | 15,130,000 |
| Net interest expense | (1,088,000) | (1,129,000) | (2,108,000) | (3,181,000) |
| Other income - related party | 270,000 | 643,000 | 1,047,000 | 1,654,000 |
| Gain (loss) on derivative instruments, net | (4,910,000) | (3,148,000) | (1,881,000) | 2,017,000 |
| Loss from equity investment | — | — | — | (67,000) |
| Total other income (expense), net | (5,728,000) | (3,634,000) | (2,942,000) | 423,000 |
| Income before income taxes | 23,695,000 | 452,000 | 54,526,000 | 15,553,000 |
| Provision for deferred income taxes | 9,099,000 | — | 20,063,000 | — |
| Net income | $14,596,000 | $452,000 | $34,463,000 | $15,553,000 |
| Production Data: | | | | |
| Oil (Bbls) | 514,853 | 166,216 | 1,263,097 | 484,122 |
| Natural gas (Mcf) | 446,195 | 204,225 | 1,205,763 | 494,396 |
| Natural gas liquids (Bbls) | 93,329 | 44,851 | 249,018 | 110,039 |
| Combined volumes (Boe) | 682,548 | 245,104 | 1,713,076 | 676,560 |
| Daily combined volumes (Boe/d) | 7,419 | 2,664 | 6,275 | 2,469 |
| Average Prices[1]: | | | | |
| Oil (per Bbl) | $103.11 | $87.42 | $94.51 | $89.94 |
| Natural gas (per Mcf) | 3.50 | 2.83 | 3.63 | 2.50 |
| Natural gas liquids (per Bbl) | 33.67 | 38.04 | 33.49 | 40.14 |
| Combined (per BOE) | 84.67 | 68.60 | 77.11 | 72.71 |
| Average Costs (per BOE) | | | | |
| Lease operating expense | $7.27 | $14.32 | $8.97 | $14.05 |
| Gathering and transportation expense | 0.38 | 0.48 | 0.37 | 0.39 |
| Production and ad valorem taxes | 5.21 | 5.28 | 4.84 | 4.71 |
| Production and ad valorem taxes as a % of sales | 6.1% | 7.7% | 6.3% | 6.5% |
| Depreciation, depletion, and amortization | 25.53 | 25.03 | 25.09 | 24.46 |
| General and administrative | 3.11 | 6.73 | 4.21 | 6.63 |

(1) After giving effect to our derivative instruments, the average prices per Bbl of oil and per BOE were $96.86 and $79.96, respectively, during the three months ended September 30, 2013, and $82.03 and $64.94, respectively, during the three months ended September 30, 2012. After giving effect to our derivative instruments, the average prices per Bbl of oil and per BOE were $90.06 and $73.83, respectively, during the nine months ended September 30, 2013, and $80.92 and $66.26, respectively, during the nine months ended September 30, 2012.

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Comparison of the Three Months Ended September 30, 2013 and 2012
Oil, Natural Gas Liquids and Natural Gas Revenues. Our oil, natural gas liquids and natural gas revenues increased by approximately $40,977,000, or 244%, to $57,791,000 for the three months ended September 30, 2013 from $16,814,000 for the three months ended September 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 4,755 BOE/d to 7,419 BOE/d during the three months ended September 30, 2013 from 2,664 BOE/d during the three months ended September 30, 2012. The total increase in revenue of approximately $40,977,000 is largely attributable to higher oil, natural gas liquids and natural gas production volumes for the three months ended September 30, 2013 as compared to the three months ended September 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 348,637 Bbls of oil, 48,478 Bbls of natural gas liquids and 241,970 Mcf of natural gas for the three months ended September 30, 2013 as compared to the three months ended September 30, 2012. The net dollar effect of the increases in prices of approximately $7,969,000 (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 $33,008,000 (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 | $15.69 | 514,853 | $8,078,000 |
| Natural gas liquids | $(4.37) | 93,329 | $(408,000) |
| Natural gas | $0.67 | 446,195 | $299,000 |
| Total revenues due to change in price | | | $7,969,000 |

| | Change in production volumes(1) | Prior period Average Prices | Total net dollar effect of change |
|---|---|---|---|
| Effect of changes in production volumes: | | | |
| Oil | 348,637 | $87.42 | $30,479,000 |
| Natural gas liquids | 48,478 | $38.04 | $1,844,000 |
| Natural gas | 241,970 | $2.83 | $685,000 |
| Total revenues due to change in production volumes | | | $33,008,000 |
| Total change in revenues | | | $40,977,000 |

(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 $4,964,000 ($7.27 per BOE) for the three months ended September 30, 2013, an increase of $1,455,000, or 41%, from $3,509,000 ($14.32 per BOE) for the three months ended September 30, 2012. The increase is due to increased drilling activity, which resulted in additional producing wells for the three months ended September 30, 2013 as compared to the three months ended September 30, 2012. Our lease operating expense during the three months ended September 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 our gas stream to a sour gas pipeline, thereby eliminating the processing and treating expense, which savings are reflected in our lease operating expense for the three months ended September 30, 2013. In addition, in the first quarter 2013, we began moving a portion of our produced water by a pipeline connected to a commercial salt water disposal well rather than by truck, and as of July 2013 we were moving a majority of our produced water by pipeline. 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 completion of gathering systems, the connection to salt water disposal wells and other actions will help us to further reduce our lease operating expense in future periods.

Production and Ad Valorem Tax Expense. Production and ad valorem taxes as a percentage of oil and natural gas sales were 6.1% for the three months ended September 30, 2013, a decrease of 0.9% from 7.0% for the three months ended September 30, 2012. The decrease as a percentage of oil and natural gas sales is due to a decrease in the assessed taxable values of our property. 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 and ad valorem taxes increased $2,260,000 from $1,293,000 during the three months ended September 30, 2012 to $3,553,000 during the three months ended September 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 $11,287,000, or 184%, from $6,136,000 for the three months ended September 30, 2012 to $17,423,000 for the three months ended September 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 September 30, 2013. The average depletion rate was $25.53 for the three months ended September 30, 2013 and $25.03 for the three months ended September 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 $471,000 from $1,650,000 for the three months ended September 30, 2012 to $2,121,000 for the three months ended September 30, 2013. The increase was due to increases in salary, stock based compensation, legal, common stock and senior note 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 September 30, 2013 was $1,088,000, as compared to $1,129,000 for the three months ended September 30, 2012, a decrease of $41,000, or 4%. This decrease was due primarily to a decrease in our weighted average outstanding borrowings under our credit agreement as no amounts were outstanding for the three months ended September 30, 2013 compared to $100,000,000 for the same period in 2012. This decrease was partially offset by $690,000 of accrued interest attributable to the senior notes we issued in September 2013.

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 cash and non-cash changes in fair value on derivative instruments in our combined consolidated statements of operations under the line item captioned “Gain (loss) on derivative instruments, net.” For the three months ended September 30, 2013 and 2012, we had a cash loss on settlement of derivative instruments of $3,215,000 and $896,000, respectively. For the three months ended September 30, 2013 and 2012, we had a non-cash loss on open derivative instruments of $1,695,000 and $2,252,000, respectively.

Income tax expense. Prior to our initial public offering 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 $9,099,000 was incurred as a result of operations for the three months ended September 30, 2013.

Comparison of the Nine Months Ended September 30, 2013 and 2012

Oil, Natural Gas Liquids and Natural Gas Revenues. Our oil, natural gas liquids and natural gas revenues increased by approximately $82,899,000, or 169%, to $132,094,000 for the nine months ended September 30, 2013 from $49,195,000 for the nine months ended September 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 3,806 BOE/d to 6,275 BOE/d during the nine months ended September 30, 2013 from 2,469 BOE/d during the nine months ended September 30, 2012. The total increase in revenue of approximately $82,899,000 is largely attributable to higher oil, natural gas liquids and natural gas production volumes for the nine months ended September 30, 2013 as compared to the nine months ended September 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 778,975 Bbls of oil, 138,979 Bbls of natural gas liquids and 711,367 Mcf of natural gas for the nine months ended September 30, 2013 as compared to the nine months ended September 30, 2012. The net dollar effect of the decreases in prices of approximately $5,480,000 (calculated as the change in period-to-period average prices multiplied by current period production volumes of oil, natural gas liquids and

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natural gas) and the net dollar effect of the increase in production of approximately $77,419,000 (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 | $4.57 | 1,263,097 | $5,773,000 |
| Natural gas liquids | $(6.65) | 249,018 | $(1,656,000) |
| Natural gas | $1.13 | 1,205,763 | $1,363,000 |
| Total revenues due to change in price | | | $5,480,000 |

| | Change in production volumes(1) | Prior period Average Prices | Total net dollar effect of change |
|---|---|---|---|
| Effect of changes in production volumes: | | | |
| Oil | 778,975 | $89.94 | $70,061,000 |
| Natural gas liquids | 138,979 | $40.14 | $5,579,000 |
| Natural gas | 711,367 | $2.50 | $1,779,000 |
| Total revenues due to change in production volumes | | | $77,419,000 |
| Total change in revenues | | | $82,899,000 |

(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 $15,367,000 ($8.97 per BOE) for the nine months ended September 30, 2013, an increase of $5,859,000, or 62%, from $9,508,000 ($14.05 per BOE) for the nine months ended September 30, 2012. The increase is due to increased drilling activity, which resulted in additional producing wells for the nine months ended September 30, 2013 as compared to the nine months ended September 30, 2012. Our lease operating expense during the nine months ended September 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 our 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 nine months ended September 30, 2013. In addition, in the first quarter 2013, we began moving a portion of our produced water by a pipeline connected to a commercial salt water disposal well rather than by truck, and as of July 2013 we were moving a majority of our produced water by pipeline. 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 completion of gathering systems, the connection to salt water disposal wells and other actions will help us to further reduce our lease operating expense in future periods.

Production and Ad Valorem Tax Expense. Production taxes as a percentage of oil and natural gas sales were 6.3% for the nine months ended September 30, 2013, a decrease of 0.7% from 7.0% for the nine months ended September 30, 2012. The decrease as a percentage of oil and natural gas sales is due to a decrease in the assessed taxable values of our property. 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 $5,104,000 from $3,191,000 during the nine months ended September 30, 2012 to $8,295,000 during the nine months ended September 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 $26,424,000, or 160%, from $16,552,000 for the nine months ended September 30, 2012 to $42,976,000 for the nine months ended September 30, 2013. This increase was due to an increase in our full cost pool as a result of the acquisitions of the mineral interests in Midland County, leasehold acquisitions in Martin and Dawson County and

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the acquisition of the Gulfport properties as well as increased capital expenditures in conjunction with our drilling program during the nine months ended September 30, 2013. The average depletion rate was $25.09 for the nine months ended September 30, 2013 and $24.46 for the nine months ended September 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 $2,726,000 from $4,487,000 for the nine months ended September 30, 2012 to $7,213,000 for the nine months ended September 30, 2013. The increase was due to increases in salary, stock based compensation, legal, common stock and senior note offering expenses, professional 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 nine months ended September 30, 2013 was $2,108,000, as compared to $3,181,000 for the nine months ended September 30, 2012, a decrease of $1,073,000, or 34%. This decrease was due primarily to a decrease in our weighted average outstanding borrowings under our credit agreement to $14,372,000 for the nine months ended September 30, 2013 from $97,384,000 for the same period in 2012. This decrease was partially offset by $690,000 of accrued interest attributable to the senior notes we issued in September 2013.

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 cash and non-cash changes in fair value on derivative instruments in our combined consolidated statements of operations under the line item captioned “Gain (loss) on derivative instruments, net.” For the nine months ended September 30, 2013 and 2012, we had a cash loss on settlement of derivative instruments of $5,614,000 and $4,369,000, respectively. For the nine months ended September 30, 2013 and 2012, we had a non-cash gain on open derivative instruments of $3,733,000 and $6,386,000, respectively.

Income tax expense. Prior to our initial public offering 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 $20,063,000 was incurred as a result of operations for the nine months ended September 30, 2013.

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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 nine months ended September 30, 2013 and 2012 are presented below:

| | Nine Months Ended September 30, | |
|---|---|---|
| | 2013 | 2012 |
| Net cash provided by operating activities | $91,647,000 | $33,464,000 |
| Net cash used in investing activities | (830,172,000) | (86,953,000) |
| Net cash provided by financing activities | $765,267,000 | $47,972,000 |
| Net change in cash | $26,742,000 | $(5,517,000) |

Operating Activities

Net cash provided by operating activities was $91,647,000 for the nine months ended September 30, 2013 as compared to $33,464,000 for the nine months ended September 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 $830,172,000 and $86,953,000 during the nine months ended September 30, 2013 and 2012, respectively.

During the nine months ended September 30, 2013, we spent $190,084,000 on capital expenditures in conjunction with our infrastructure projects and drilling program, in which we drilled 58 gross (50 net) wells and participated in the drilling of an additional 4 gross (2 net) non-operated wells. We spent an additional $9,711,000 on leasehold costs, $4,965,000 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. On September 19, 2013, we completed the acquisition of mineral interests underlying approximately 15,000 gross (12,500 net) acres in Midland County, Texas in the Permian Basin for $440.0 million. The mineral interests entitle us to receive an average 20% royalty interest on all production from this acreage with no additional future capital or operating expense required. In September 2013, we completed two leasehold acquisitions in Martin County, Texas and Dawson County, Texas for an aggregate purchase price of $165.0 million, subject to adjustment. These amounts were partially offset by proceeds of $62,000 from the sale of property and equipment.

During the nine months ended September 30, 2012, we spent $73,553,000 on capital expenditures in conjunction with our drilling program in which we participated in the drilling of 34 gross (25 net) wells. We spent an additional $7,948,000 on leasehold costs, $778,000 for the purchase of other property and equipment and $4,700,000, net, on the settlement of non-hedge derivative instruments and margin deposits. These amounts were partially offset by proceeds of $26,000 from the sale of property and equipment.

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

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| | Nine Months Ended September 30, | |
|---|---|---|
| | 2013 | 2012 |
| Drilling and completion of wells | $(190,084,000) | $(73,553,000) |
| Purchase of leasehold acquisitions | (9,711,000) | (7,948,000) |
| Acquisition of Gulfport properties | (18,550,000) | — |
| Acquisition of mineral interests | (440,000,000) | — |
| Acquisition of leasehold interests | (166,635,000) | — |
| Purchase of other property and equipment | (4,965,000) | (778,000) |
| Proceeds from sale of property and equipment | 62,000 | 26,000 |
| Settlement of non-hedge derivative instruments | (289,000) | (7,025,000) |
| Receipt on derivative margins | — | 2,325,000 |
| Net cash used in investing activities | $(830,172,000) | $(86,953,000) |

Financing Activities

Net cash provided by financing activities for the nine months ended September 30, 2013 was $765,267,000 as compared to $47,972,000 during the same period in 2012. The 2013 amount provided by financing activities was primarily attributable to (a) the net proceeds of $144,491,000 from our May 2013 equity offering, $177,455,000 from our August 2013 equity offering and $450,000,000 from our September 2013 senior note offering and (b) borrowings of $49,000,000 under our credit facility. During the nine months ended September 30, 2012, we borrowed $15,000,000 under our revolving credit facility and $30,045,000 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.

Senior Notes

On September 18, 2013, we completed an offering of $450.0 million in aggregate principal amount of 7.625% senior unsecured notes due 2021, which we refer to as the senior notes. The senior notes bear interest at the rate of 7.625% per annum, payable semi-annually, in arrears on April 1 and October 1 of each year, commencing on April 1, 2014, and will mature on October 21, 2021. The senior notes are fully and unconditionally guaranteed by our subsidiaries. The net proceeds from the senior notes were used to fund the acquisition of mineral interests underlying approximately 15,000 gross (12,500 net) acres in Midland County, Texas in the Permian Basin.

The senior notes were issued under, and are governed by, an indenture among us, the subsidiary guarantors party thereto and Wells Fargo Bank, N.A., as the trustee, or the Indenture. The Indenture contains certain covenants that, subject to certain exceptions and qualifications, among other things, limit our ability and the ability of our restricted subsidiaries to incur or guarantee additional indebtedness, make certain investments, declare or pay dividends or make other distributions on, or redeem or repurchase, capital stock, prepay subordinated indebtedness, sell assets including capital stock of subsidiaries, agree to payment restrictions affecting our restricted subsidiaries, consolidate, merge, sell or otherwise dispose of all or substantially all of its assets, enter into transactions with affiliates, incur liens, engage in business other than the oil and gas business and designate certain of our subsidiaries as unrestricted subsidiaries. If we experience certain kinds of changes of control or if we sell certain of our assets, holders of the senior notes may have the right to require us to repurchase their senior notes.

We will have the option to redeem the senior notes, in whole or in part, at any time on or after October 1, 2016 at the redemption prices (expressed as percentages of principal amount) of 105.719% for the 12-month period beginning on October 1, 2016, 103.813% for the 12-month period beginning on October 1, 2017, 101.906% for the 12-month period beginning on October 1, 2018 and 100.000% beginning on October 1, 2019 and at any time thereafter with any accrued and unpaid interest to, but not including, the date of redemption. In addition, prior to October 1, 2016, we may redeem all or a part of the senior notes at a price equal to 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date, plus a "make-whole" premium at the redemption date. Furthermore, before October 1, 2016, we may, at any time or from time to time, redeem up to 35% of the aggregate principal amount of the senior notes with the net cash proceeds of certain equity offerings at a redemption price of 107.625% of the principal amount of the senior notes being redeemed plus any accrued and unpaid interest to the date of redemption, if at least 65% of the aggregate principal amount of the senior notes originally issued under the Indenture remains outstanding immediately after such redemption and the redemption occurs within 120 days of the closing date of such equity offering.

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In connection with the issuance of the senior notes, we and the subsidiary guarantors entered into a registration rights agreement with the initial purchasers on September 18, 2013, pursuant to which we and the subsidiary guarantors have agreed to file a registration statement with respect to an offer to exchange the senior notes for a new issue of substantially identical debt securities registered under the Securities Act. Under the registration rights agreement, we also agreed to use our commercially reasonable efforts to cause the exchange offer registration statement to become effective within 360 days after the issue date of the senior notes and to consummate the exchange offer 30 days after effectiveness. We may be required to file a shelf registration statement to cover resales of the senior notes under certain circumstances. If we fail to satisfy certain of our obligations under the registration rights agreement, we agreed to pay additional interest to the holders of the senior notes as specified in the registration rights agreement.

Second Amended and Restated Credit Facility

On October 15, 2010, we entered into a secured revolving credit 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 credit agreement was amended and restated as of July 24, 2012 and again as of November 1, 2013. The credit agreement, as so amended and restated, provides for a revolving credit facility in the maximum amount of $600 million, subject to scheduled semi-annual and other elective collateral borrowing base redeterminations based on our oil and natural gas reserves and other factors (the “borrowing base”). The borrowing base is scheduled to be 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. As of November 1, 2013, the borrowing base was set at $225.0 million.

The outstanding borrowings under the credit agreement bear interest at a rate elected by us that is based on the prime rate or LIBOR plus margins ranging from 0.50% for prime-based loans and 1.50% for LIBOR loans to 1.50% for prime-based loans and 2.50% for LIBOR loans, in each case depending on the amount of the loan outstanding in relation to the borrowing base. We are obligated to pay a quarterly commitment fee ranging from 0.375% to 0.50% per year on the unused portion of the borrowing base, which fee is also dependent on the amount of the loan outstanding in relation to the borrowing base. Loan principal may be optionally repaid from time to time without premium or penalty (other than customary LIBOR breakage), and is required to be paid (a) if the loan amount exceeds the borrowing base, whether due to a borrowing base redetermination or otherwise (in some cases subject to a cure period) and (b) at the maturity date of November 1, 2018. The loan is secured by substantially all of our assets.

The credit agreement contains various affirmative, negative and financial maintenance covenants. These covenants, among other things, limit 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 the financial ratios described below.

| Financial Covenant | Required Ratio |
|---|---|
| Ratio of total debt to EBITDAX | Not greater than 4.0 to 1.0 |
| Ratio of current assets to liabilities, as defined in the credit agreement | Not less than 1.0 to 1.0 |

EBITDAX will be annualized beginning with the quarter ended September 30, 2013 and ending with the quarter ending March 31, 2014.

The covenant prohibiting additional indebtedness allows for the issuance of unsecured debt of up to $750 million in the form of senior or senior subordinated notes and, in connection with any such issuance, the reduction of the borrowing base by 25% of the stated principal amount of each 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. As of November 1, 2013, we had $450 million of senior unsecured notes outstanding.

As of September 30, 2013, we were in compliance with all financial covenants under our revolving credit facility, as then in effect. The lenders may accelerate all of the indebtedness under our revolving credit facility upon the occurrence and during the continuance of any event of default. The credit agreement contains customary events of default, including non-payment, breach of covenants, materially incorrect representations, cross-default, bankruptcy and change of control. There are no cure periods for events of default due to non-payment of principal and breaches of negative and financial covenants, but non-payment of interest and breaches of certain affirmative covenants are subject to customary cure periods.

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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 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.

During the nine months ended September 30, 2013, our aggregate capital expenditures for drilling and infrastructure were $190.1 million. We do not have a specific acquisition budget since the timing and size of acquisitions cannot be accurately forecasted. During the nine months ended September 30, 2013, we spent $625.2 million on acquisitions.

In October 2013, our Board of Directors approved a 2014 capital expenditures budget for drilling and infrastructure in an estimated range of $425 million to $475 million, representing an increase of 48% over 2013. We estimate that, of these expenditures, approximately 85% will be spent on 65 to 75 gross operated horizontal wells focused in Midland, Andrews, Martin and Dawson Counties, 8% will be spent on 20 to 24 gross operated vertical wells (with an assumed average working interest of 90%) focused in Midland County, 5% will be spent on infrastructure and 2% will be spent on non-operated drilling. 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 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.

Based upon current oil and natural gas price expectations for 2014, we believe that our cash flow from operations, proceeds from our September 2013 offering of senior notes and borrowings under our revolving credit facility will be sufficient to fund our operations through year-end 2014. 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 2014 capital expenditure budget does not allocate any funds for leasehold interest and property acquisitions.

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 September 30, 2013.

Contractual Obligations

Except for our September 2013 issuance of senior notes described above, there were no other 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.

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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 September 30, 2013, we had a net asset derivative position with Wells Fargo Bank, N.A. of $750,000, related to our ICE Brent and Argus Louisiana Light Sweet fixed price swaps, and a net liability derivative position with BNP Paribas of $1,933,000 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 September 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 $7,914,000, a decrease of $8,664,000, while a 10% decrease in forward curves associated with the underlying commodity would have increased the net asset derivative position of these instruments by $8,664,000. Utilizing actual derivative contractual volumes under our NYMEX West Texas Intermediate fixed price swap as of September 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 $934,000, while a 10% decrease in forward curves associated with the underlying commodity would have decreased the net liability derivative position of these instruments by $934,000. However, any cash derivative 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 $7,885,000 at September 30, 2013) and receivables from the sale of our oil and natural gas production (approximately $21,141,000 at September 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 nine month