Diamondback Energy, Inc.
Form 10-Q
May 09, 2014
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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 March 31, 2014
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 (State or Other Jurisdiction of Incorporation or Organization)	45-4502447 (IRS Employer Identification Number)
500 West Texas, Suite 1200 Midland, Texas (Address of Principal Executive Offices) (432) 221-7400 (Registrant Telephone Number, Including Area Code)	79701 (Zip 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 ý Accelerated Filer ¨

Non-Accelerated Filer o 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 April 25, 2014, 50,789,385 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.

MMBtu. Million British Thermal Units.

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, 2013 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)

	March 31, 2014	December 31, 2013
	(In thousands, except par values and share data)	
Assets		
Current assets:		
Cash and cash equivalents	$25,314	$15,555
Accounts receivable:		
Joint interest and other	15,920	14,437
Oil and natural gas sales	38,360	23,533
Related party	2,298	1,303
Inventories	5,889	5,631
Deferred income taxes	1,377	112
Derivative instruments	—	213
Prepaid expenses and other	1,495	1,184
Total current assets	90,653	61,968
Property and equipment		
Oil and natural gas properties, based on the full cost method of accounting ($485,184 and $369,561 excluded from amortization at March 31, 2014 and December 31, 2013, respectively)	2,065,571	1,648,360
Pipeline and gas gathering assets	6,503	6,142
Other property and equipment	4,635	4,071
Accumulated depletion, depreciation, amortization and impairment	(243,131)	(212,236)
	1,833,578	1,446,337
Derivative instruments	—	218
Other assets	12,666	13,091
Total assets	$1,936,897	$1,521,614
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable-trade	$24,487	$2,679
Accounts payable-related party	313	17
Accrued capital expenditures	68,207	74,649
Other accrued liabilities	46,649	34,750
Revenues and royalties payable	12,645	9,225
Derivative instruments	2,910	—
Total current liabilities	155,211	121,320
Long-term debt	587,000	460,000
Asset retirement obligations	5,147	2,989
Deferred income taxes	106,630	91,764
Total liabilities	853,988	676,073
Contingencies (Note 12)		
Stockholders' equity:		
	508	471

Common stock, $0.01 par value, 100,000,000 shares authorized, 50,700,099 issued and outstanding at March 31, 2014; 47,106,216 issued and outstanding at December 31, 2013		
Additional paid-in capital	1,056,299	842,557
Retained earnings	26,102	2,513
Total stockholders' equity	1,082,909	845,541
Total liabilities and stockholders' equity	$1,936,897	$1,521,614

See accompanying notes to consolidated financial statements.

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

	Three Months Ended March 31,	
	2014	2013
	(In thousands, except per share amounts)	
Revenues:		
Oil sales	$89,758	$25,253
Natural gas sales	1,755	739
Natural gas sales - related party	1,580	412
Natural gas liquid sales	2,584	1,822
Natural gas liquid sales - related party	2,327	683
Total revenues	98,004	28,909
Costs and expenses:		
Lease operating expenses	7,807	4,706
Lease operating expenses - related party	108	202
Production and ad valorem taxes	5,578	1,878
Production and ad valorem taxes - related party	264	76
Gathering and transportation	214	75
Gathering and transportation - related party	368	58
Depreciation, depletion and amortization	30,973	10,738
General and administrative expenses (including non-cash stock based compensation, net of capitalized amounts, of $2,190 and $458 for the three months ended March 31, 2014 and 2013, respectively)	4,265	2,185
General and administrative expenses - related party	292	286
Asset retirement obligation accretion expense	72	43
Total costs and expenses	49,941	20,247
Income from operations	48,063	8,662
Other income (expense)		
Interest expense	(6,505)	(485)
Other income - related party	30	389
Loss on derivative instruments, net	(4,398)	(8)
Total other income (expense), net	(10,873)	(104)
Income before income taxes	37,190	8,558
Provision for income taxes		
Deferred	13,601	3,162
Net income	$23,589	$5,396
Earnings per common share		
Basic	$0.49	$0.15
Diluted	$0.48	$0.15
Weighted average common shares outstanding		
Basic	48,447	37,059
Diluted	48,867	37,206

See accompanying notes to consolidated financial statements.

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

	Common Stock		Additional	Retained	
	Shares	Amount	Paid-in Capital	Earnings	Total
	(In thousands)				
Balance December 31, 2013	47,106	$471	$842,557	$2,513	$845,541
Stock based compensation	—	—	3,256	—	3,256
Common shares issued in public offering, net of offering costs	3,450	35	208,410	—	208,445
Exercise of stock options and vesting of restricted stock units	145	2	2,076	—	2,078
Net income	—	—	—	23,589	23,589
Balance March 31, 2014	50,701	$508	$1,056,299	$26,102	$1,082,909

See accompanying notes to consolidated financial statements.

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

	Three Months Ended March 31,	
	2014	2013
	(In thousands)	
Cash flows from operating activities:		
Net income	$23,589	$5,396
Adjustments to reconcile net income to net cash provided by operating activities:		
Provision for deferred income taxes	13,601	3,162
Asset retirement obligation accretion expense	72	43
Depreciation, depletion, and amortization	30,973	10,738
Amortization of debt issuance costs	458	153
Change in fair value of derivative instruments	3,342	(1,537)
Stock based compensation expense	2,190	655
Gain on sale of assets	(11)	(9)
Changes in operating assets and liabilities:		
Accounts receivable	(12,490)	(8,393)
Accounts receivable-related party	(995)	3,908
Inventories	(258)	(89)
Prepaid expenses and other	(311)	(415)
Accounts payable and accrued liabilities	7,590	3,243
Accounts payable and accrued liabilities-related party	296	(108)
Revenues and royalties payable	3,420	108
Net cash provided by operating activities	71,466	16,855
Cash flows from investing activities:		
Additions to oil and natural gas properties	(84,211)	(50,094)
Additions to oil and natural gas properties-related party	(1,650)	(4,868)
Acquisition of Gulfport properties	—	(18,550)
Acquisition of leasehold interests	(312,207)	—
Pipeline and gas gathering assets	(532)	—
Purchase of other property and equipment	(595)	(302)
Proceeds from sale of property and equipment	11	9
Settlement of non-hedge derivative instruments	—	(289)
Net cash used in investing activities	(399,184)	(74,094)
Cash flows from financing activities:		
Proceeds from borrowings on credit facility	127,000	36,500
Debt issuance costs	(82)	—
Public offering costs	(75)	(103)
Proceeds from public offering	208,644	—
Exercise of stock options	1,990	—
Net cash provided by financing activities	337,477	36,397
Net increase (decrease) in cash and cash equivalents	9,759	(20,842)
Cash and cash equivalents at beginning of period	15,555	26,358
Cash and cash equivalents at end of period	$25,314	$5,516

See accompanying notes to consolidated financial statements.

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

	Three Months Ended March 31,	
	2014	2013
	(In thousands)	
Supplemental disclosure of cash flow information:		
Interest paid, net of capitalized interest	$149	$141
Supplemental disclosure of non-cash transactions:		
Asset retirement obligation incurred	$214	$62
Asset retirement obligation revisions in estimated liability	$588	$—
Asset retirement obligation acquired	$1,294	$—

See accompanying notes to consolidated financial statements.

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Diamondback Energy, Inc. and Subsidiaries
Notes to 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.

The subsidiaries of Diamondback, as of March 31, 2014, include Diamondback E&P LLC, a Delaware limited liability company, Diamondback O&G LLC, a Delaware limited liability company, Viper Energy Partners LLC, a Delaware limited liability company, Viper Energy Partners LP, a Delaware limited partnership, and Viper Energy Partners GP LLC, a Delaware limited liability company. The subsidiaries are all wholly owned.

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.

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 Capital, LP ("Wexford"), our equity sponsor, 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 to 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, the Company completed an offering of $450.0 million principal amount of its 7.625% Senior Notes due 2021. See Note 6 below.

In February 2014, the Company completed an underwritten public offering of 3,450,000 shares of common stock, which included 450,000 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 $62.67 per share and the Company received net proceeds of approximately $208.4 million from the sale of these shares of common stock, net of offering expenses and underwriting discounts and commissions.

Basis of Presentation

The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries after all significant intercompany balances and transactions have been eliminated upon consolidation.

These financial statements have been prepared by the Company without audit, pursuant to the rules and regulations of the Securities and Exchange Commission (the "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 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, 2013, which contains a summary of the Company's significant accounting policies and other disclosures.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

Certain amounts included in or affecting the Company's 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 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 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.

3. ACQUISITIONS

2014 Activity

On February 27 and 28, 2014, the Company completed acquisitions of oil and natural gas interests in the Permian Basin from unrelated third party sellers. The Company acquired approximately 6,450 gross (4,785 net) acres with a 74% working interest (56% net revenue interest). The acquisitions were accounted for according to the acquisition method, which requires the recording of net assets acquired and consideration transferred at fair value. These acquisitions were funded in part by the net proceeds of the February 2014 equity offering discussed in Note 1 above. The following represents the estimated fair values of the assets and liabilities assumed on the acquisition dates. The aggregate consideration transferred was $292,159,000 in cash, subject to post-closing adjustments, resulting in no goodwill or bargain purchase gain.

	(in thousands)
Proved oil and natural gas properties	$170,174
Unevaluated oil and natural gas properties	123,243
Asset retirement obligations	(1,258)
Total fair value of net assets	$292,159

The Company has included in its consolidated statements of operations revenues of $4,898,000 and direct operating expenses of $1,074,000 for the period from February 28, 2014 to March 31, 2014 due to the acquisitions. The disclosure of net earnings is impracticable to calculate due to the full cost method of depletion. The following unaudited summary pro forma combined consolidated statement of operations data of Diamondback for the three months ended March 31, 2014 and 2013 has been prepared to give effect to the acquisitions as if they had occurred on January 1, 2013. The pro forma data are not necessarily indicative of financial results that would have been attained had the acquisitions occurred on January 1, 2013. The pro forma data also necessarily exclude various operation expenses related to the properties and the financial statements should not be viewed as indicative of operations in future periods.

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

	Three Months Ended March 31,	
	2014	2013
	(Pro Forma)	(Pro Forma)
	(in thousands, except per share amounts)	
Revenues	$107,979	$44,391
Income from operations	52,193	14,656
Net income	26,209	9,175
Basic earnings per common share	$0.54	$0.25
Diluted earnings per common share	$0.54	$0.25

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. 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 71% working interest (55% net revenue interest) in 9,390 gross (6,638 net) acres. 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 14,804 gross (12,687 net) acres in Midland County, Texas in the Permian Basin. The mineral interests entitle the Company to receive an average 21.4% 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 6 below.

4. PROPERTY AND EQUIPMENT
Property and equipment includes the following:

	March 31, 2014	December 31, 2013
	(in thousands)	
Oil and natural gas properties:		
Subject to depletion	$1,580,387	$1,278,799
Not subject to depletion-acquisition costs		
Incurred in 2014	142,064	—
Incurred in 2013	256,998	279,353
Incurred in 2012	85,358	87,252
Incurred in 2011	764	1,598
Incurred in 2010	—	1,358
Total not subject to depletion	485,184	369,561
Gross oil and natural gas properties	2,065,571	1,648,360
Less accumulated depreciation, depletion, amortization and impairment	(241,514)	(210,837)
Oil and natural gas properties, net	1,824,057	1,437,523

Pipeline and gas gathering assets	6,503	6,142
Other property and equipment	4,635	4,071
Less accumulated depreciation	(1,617)	(1,399)
Other property and equipment, net	3,018	2,672
Property and equipment, net of accumulated depreciation, depletion, amortization and impairment	$1,833,578	$1,446,337

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

The average depletion rate per barrel equivalent unit of production was $25.19 and $24.50 for the three months ended March 31, 2014 and 2013, 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 $2,296,000 and $692,000 for the three months ended March 31, 2014 and 2013, 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:

	Three Months Ended March 31,	
	2014	2013
	(in thousands)	
Asset retirement obligation, beginning of period	$3,029	$2,145
Additional liability incurred	214	62
Liabilities acquired	1,294	—
Liabilities settled	(10)	—
Accretion expense	72	43
Revisions in estimated liabilities	588	—
Asset retirement obligation, end of period	5,187	2,250
Less current portion	40	20
Asset retirement obligations - long-term	$5,147	$2,230

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. DEBT

Long-term debt consisted of the following as of the dates indicated:

	March 31, 2014	December 31, 2013
	(in thousands)	
Revolving credit facility	$137,000	$10,000
7.625 % Senior Notes due 2021	450,000	450,000
Total long-term debt	$587,000	$460,000

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 14,804 gross (12,687 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.

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, which registration statement was filed with the SEC on March 14, 2014. 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 March 31, 2014 and December 31, 2013, the borrowing base was set at $225.0 million. In connection with our April 2014 redetermination, the administrative agent has informed the Company that it has approved a borrowing base of $450.0 million based on the Company's current assets. As of March 31, 2014, the Company had outstanding borrowings of $137.0 million which bore interest at a weighted average rate of 2.16%. As of December 31, 2013, the Company had outstanding borrowings of $10.0 million which bore interest at a weighted average rate of 1.67%.

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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

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 March 31, 2014, the Company had $450 million of senior unsecured notes outstanding.

As of March 31, 2014 and December 31, 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.

7. EARNINGS PER SHARE

Earnings Per Share

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

	Three Months Ended March 31, 2014		
	Income (in thousands)	Shares	Per Share
Basic:			
Net income attributable to common stock	$23,589	48,446,609	$0.49
Effect of Dilutive Securities:			
Dilutive effect of potential common shares issuable	$—	420,110	

Diluted:			
Net income attributable to common stock	$23,589	48,866,719	$0.48

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	Three Months Ended March 31, 2013		
	Income (in thousands)	Shares	Per Share
Basic:			
Net income attributable to common stock	$5,396	37,059,071	$0.15
Effect of Dilutive Securities:			
Dilutive effect of potential common shares issuable	$—	146,619	
Diluted:			
Net income attributable to common stock	$5,396	37,205,690	$0.15

8. STOCK BASED COMPENSATION

For the three months ended March 31, 2014 and 2013, the Company incurred $3,256,000 and $655,000, respectively, of stock based compensation, of which the Company capitalized $1,066,000 and $197,000, respectively, pursuant to the full cost method of accounting for oil and natural gas properties.

Stock Options

The following table presents the Company's stock option activity under the 2012 Plan for the three months ended March 31, 2014.

	Options	Weighted Average Exercise Price	Remaining Term (in years)	Intrinsic Value (in thousands)
Outstanding at December 31, 2013	712,955	$17.96		
Granted	—	$—		
Exercised	(114,050)	$18.22		
Expired/Forfeited	—	$—		
Outstanding at March 31, 2014	598,905	$17.91	2.41	$29,585
Vested and Expected to vest at March 31, 2014	598,905	$17.91	2.41	$29,585
Exercisable at March 31, 2014	151,655	$17.50	1.69	$7,554

The aggregate intrinsic value of stock options that were exercised during the three months ended March 31, 2014 was $5,310,000. As of March 31, 2014, the unrecognized compensation cost related to unvested stock options was $1,465,000. Such cost is expected to be recognized over a weighted-average period of 1.5 years.

Restricted Stock Units

The following table presents the Company's restricted stock units activity under the 2012 Plan during the three months ended March 31, 2014.

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	Restricted Stock Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2013	132,239	$19.20
Granted	99,150	$61.59
Vested	(31,383)	$61.44
Forfeited	—	$—
Unvested at March 31, 2014	200,006	$33.56

The aggregate fair value of restricted stock units that vested during the three months ended March 31, 2014 was $2,003,000. As of March 31, 2014, the Company's unrecognized compensation cost related to unvested restricted stock awards and units was $5,619,000. Such cost is expected to be recognized over a weighted-average period of 1.7 years.

Performance Based Restricted Stock Units

To provide long-term incentives for the executive officers to deliver competitive returns to the Company's stockholders, the Company has granted performance based restricted stock units to eligible employees. The ultimate number of shares awarded from these conditional restricted stock units is based upon measurement of total stockholder return of the Company's common stock ("TSR") as compared to a designated peer group during a three-year performance period. In February 2014, eligible employees received initial performance restricted stock unit awards totaling 79,150 units from which a minimum of 0% and a maximum of 200% units could be awarded. The awards have a performance period of January 1, 2013 to December 31, 2015 and cliff vest at December 31, 2015. There were no performance restricted stock units issued or outstanding during the three months ended March 31, 2013.

The fair value of each performance restricted stock unit is estimated at the date of grant using a Monte Carlo simulation, which results in an expected percentage of units to be earned during the performance period. The following table presents a summary of the grant-date fair values of performance restricted stock units granted and the related assumptions.

	2014	
Grant-date fair value	$125.63	
Risk-free rate	0.30	%
Company volatility	39.60	%

The following table presents the Company's performance restricted stock units activity under the 2012 Plan for the three months ended March 31, 2014.

	Performance Restricted Stock Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2013	—	$—
Granted	79,150	$125.63
Vested	—	$—
Forfeited	—	$—
Unvested at March 31, 2014 (1)	79,150	$125.63

(1) A maximum of 158,300 units could be awarded based upon the Company's final TSR ranking.

As of March 31, 2014, the Company's unrecognized compensation cost related to unvested restricted stock awards and units was $9,470,000. Such cost is expected to be recognized over a weighted-average period of 1.8 years.

9. 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. 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 has continued on a month-to-month basis. For the three months ended March 31, 2014 and 2013, the Company incurred total costs of $1,000 and $58,000, 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. As of March 31, 2014 and December 31, 2013, the Company owed the administrative services affiliate no amounts and $17,000, 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 was two years. The agreement now continues 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 ended March 31, 2014 and 2013, the affiliate reimbursed the Company $30,000 and $389,000, respectively, for services under the shared services agreement. As of March 31, 2014 and December 31, 2013, the affiliate owed the Company $13,000 amounts and no amounts, respectively. These amounts are included in accounts receivable-related party in the accompanying consolidated balance sheets.

Drilling Services

Bison Drilling and Field Services LLC ("Bison"), an entity controlled by Wexford, 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 March 31, 2014, 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 incurred total costs for services performed by Bison of $1,510,000 and $4,968,000 for the three months ended March 31, 2014 and 2013, respectively. The Company owed Bison $313,000 as of March 31, 2014 and no amounts as of December 31, 2013.

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 Company incurred $248,000 for services performed by Panther Drilling. The Company owed Panther Drilling no amounts as of March 31, 2014 or December 31, 2013.

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 $3,907,000 and $1,095,000 for the three months ended March 31, 2014 and 2013, respectively. As of March 31, 2014 and December 31, 2013, Coronado Midstream owed the Company $2,285,000 and $1,303,000, respectively, for the Company's portion of the net proceeds from the sale of gas, gas products and residue gas.

Sand Supply

Muskie Proppant LLC ("Muskie"), an entity affiliated with Wexford, processes and sells fracing grade sand for oil and natural gas operations. The Company began purchasing sand from Muskie in March 2013. On May 16, 2013, the Company entered into a master services agreement with Muskie, pursuant to which Muskie agreed to sell custom natural sand proppant to the Company based on the Company's requirements. The Company is not obligated to place any orders with, or accept any offers from, Muskie for sand proppant. The agreement may be terminated at the option of either party on 30 days' notice. The Company incurred no costs and costs of $234,000 for sand purchased from Muskie for the three months ended March 31, 2014 and 2013, respectively. The Company owed Muskie no amounts as of March 31, 2014 or December 31, 2013.

Midland Leases

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 $93,000 and $38,000 for the three months ended March 31, 2014 and 2013, 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 increased further to $25,000 beginning on October 1, 2013. The monthly rent will continue to increase approximately 4% annually on June 1 of each year during the remainder of the lease term.

The Company leased field office space in Midland, Texas from an unrelated third party from March 1, 2011 to March 1, 2014. Effective March 1, 2014, the building was purchased by an entity controlled by an affiliate of Wexford. The remaining term of the lease as of March 1, 2014 is four years. The Company paid rent of $11,000 to the related party for the three months ended March 31, 2014. The monthly base rent is $11,000 which will increase 3% annually on March 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 $64,000 and $53,000 for the three months ended March 31, 2014 and 2013, respectively, under this lease. Effective April 1, 2013, the Company amended this lease to increase the size of the leased premises, at which time the 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 $125,000 for the three months ended March 31, 2014 and 2013, respectively, under the Advisory

Services Agreement. As of March 31, 2014 and December 31, 2013, the Company owed Wexford no amounts for either period.

10. 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 cash and non-cash changes in fair value in the consolidated statements of operations under the caption "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 Argus Louisiana light sweet pricing or Inter–Continental Exchange ("ICE") pricing for Brent crude oil. The counterparties to the Company's derivative contracts are Wells Fargo Bank, N.A., JP Morgan Chase Bank, National Association and The Bank of Nova Scotia who the Company believes are acceptable credit risks.

As of March 31, 2014, 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—Argus Louisiana Light Sweet Fixed Price Swap

Production Period	Volume (Bbls)	Fixed Swap Price
April - December 2014	1,620,000	$98.67
January - March 2015	211,000	99.54

Crude Oil—ICE Brent Fixed Price Swap

Production Period	Volume (Bbls)	Fixed Swap Price
April 2014	30,000	$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 March 31, 2014 and December 31, 2013.

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	March 31, 2014		
	(in thousands)		
	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	$(3,200)	$290	$(2,910)

	December 31, 2013		
	(in thousands)		
	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	$998	$(567)	$431

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:

	March 31, 2014	December 31, 2013
	(in thousands)	
Current Assets: Derivative instruments	$—	$213
Noncurrent Assets: Derivative instruments	—	218
Total Assets	$—	$431
Current Liabilities: Derivative instruments	$(2,910)	$—
Noncurrent Liabilities: Derivative instruments	—	—
Total Liabilities	$(2,910)	$—

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 consolidated statements of operations:

	Three Months Ended March 31,	
	2014	2013
	(in thousands)	
Non-cash gain (loss) on open non-hedge derivative instruments	$(3,342)	$1,535
Loss on settlement of non-hedge derivative instruments	(1,056)	(1,543)
Loss on derivative instruments	$(4,398)	$(8)

11. 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 March 31, 2014 and December 31, 2013.

	Fair value measurements at March 31, 2014 using:			
	(in thousands)			
	Quoted Prices in Active Markets Level 1	Significant Other Observable Inputs Level 2	Significant Unobservable Inputs Level 3	Total
Liabilities:				
Fixed price swaps	—	(2,910)	—	(2,910)

	Fair value measurements at December 31, 2013 using:			
	(in thousands)			
	Quoted Prices in Active Markets Level 1	Significant Other Observable Inputs Level 2	Significant Unobservable Inputs Level 3	Total
Assets:				
Fixed price swaps	$—	$431	$—	$431

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 consolidated financial statements.

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	March 31, 2014		December 31, 2013	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in thousands)			
Debt:				
Revolving credit facility	$137,000	$137,000	$10,000	$10,000
7.625% Senior Notes due 2021	450,000	484,875	450,000	460,406

The fair value of the revolving credit facility approximates its carrying value based on borrowing rates available to the Company for bank loans with similar terms and maturities and is classified as Level 2 in the fair value hierarchy. The fair value of the Senior Notes was determined using the March 31, 2014 quoted market price, a Level 1 classification in the fair value hierarchy.

12. CONTINGENCIES

In September 2010, Windsor Permian LLC (“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 sought damages from the Company and the other defendants alleging, among other things, interference with contractual relationship, interference with prospective advantage and unjust enrichment. In an order filed on May 24, 2013, the judge denied certain motions made by the defendants and set a trial date to determine liability, with a damage phase of the matter to commence on a later date if there is a determination of liability. Following a trial on the liability phase on June 21, 2013, the jury determined that the defendants intentionally interfered with plaintiff’s contract but that the interference did not cause the plaintiff to be unable to acquire mining permits prior to the enactment of the moratorium by Goodhue County. In an order filed on July 10, 2013, the judge ordered the damage phase to be set for trial following a pretrial and scheduling conference. Subsequently, the plaintiff disclosed a new damage theory, and the defendants filed motions with the court to dismiss plaintiff’s claims on the grounds that the damage claim was speculative and that plaintiff could not prove damages as a matter of law. Plaintiff also filed a motion for leave to amend its complaint to assert a punitive damage claim. The motions were argued in December 2013. In March 2014, the judge entered an order granting the defendants’ motions to exclude testimony and for summary judgment. All parties agreed not to pursue an appeal from the order and waived any entitlement to costs, which effectively concluded this matter.
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.

13. SUBSEQUENT EVENTS

On each of April 9, 2014 and April 11, 2014, the Company entered into new commodity contracts with The Bank of Nova Scotia. The contracts are both fixed price oil swaps that will settle against the weighted average price per barrel

of Argus Louisiana light sweet during the calculation period. The following table presents the terms of the contracts:

	Volumes (Bbls)	Fixed Swap Price	Production Period		
Crude Oil—Argus Louisiana Light Sweet Fixed Price Swap	365,000	$100.00	May 2014	-	April 2015

On May 7, 2014, the Company's wholly-owned subsidiary Viper Energy Partners LP ("Viper") filed a registration statement on Form S-1 with the SEC in connection with its proposed initial public offering of limited partner interests. At or prior to the closing of this offering, the Company will contribute to Viper all of the equity interests in the Company's wholly-owned subsidiary Viper Energy Partners, LLC ("Energy Partners"), in exchange for limited partner interests in Viper. Energy Partners' assets currently consist of mineral interests underlying approximately 14,804 gross (12,687 net) acres in Midland County, Texas in the Permian Basin, approximately 50% of which are operated by us. Viper intends to distribute the net proceeds from the offering to the Company. A registration statement relating to these securities has been filed with the SEC but has not yet become effective. These securities may not be sold nor may any offers to buy be accepted prior to the time the registration statement becomes effective, and this report does not constitute an offer to sell or a solicitation of any offers to buy these securities.

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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 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, 2013. 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, 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 79% oil, 11% natural gas liquids and 10% natural gas for the three months ended March 31, 2014, and was approximately 70% oil, 17% natural gas liquids and 13% natural gas for the three months ended March 31, 2013. On March 31, 2014, our net acreage position in the Permian Basin was approximately 72,000 net acres. See Note 1 to our unaudited consolidated financial statements included elsewhere in this Quarterly Report for additional information regarding the organization and description of our business.

Recent Developments

Martin County Acquisition

On February 27 and 28, 2014, we completed acquisitions of oil and natural gas interests from unrelated third party sellers of additional leasehold interests in Martin County, Texas, in the Permian Basin, for an aggregate purchase price of approximately $292.2 million, subject to certain adjustments. These transactions included 6,450 gross (4,785 net) acres with a 74% working interest (56% net revenue interest) and net production of approximately 2,200 BOE/d (approximately 75% oil) during the first two weeks of February 2014 based on information reported by the operator, from 147 gross (109 net) producing vertical wells. Net proved reserves, based on our internal estimates as of December 31, 2013, were approximately 7,086 MBOE. Our estimate of proved reserves is based on our analysis of production data provided by the sellers, as well as available geologic and other data, and we may revise our estimates in the future. We believe the acreage is prospective for horizontal drilling in the Wolfcamp B, Lower Spraberry, Middle Spraberry, Wolfcamp A, Cline and Clearfork horizons, and have identified 42 potential horizontal drilling locations in each of the Wolfcamp B and Lower Spraberry horizons based on 160 acre spacing per well (or six across a section) and an aggregate of 112 potential horizontal drilling locations in the Middle Spraberry, Wolfcamp A, Cline and Clearfork intervals, based on 240 acre spacing per well (or four across a section). We funded these acquisitions with the net proceeds from an underwritten public offering of our common stock completed on February 26, 2014 and borrowings under our revolving credit facility. Upon completion of these acquisitions, we became the operator of this acquired acreage.

Common stock transaction

In February 2014, we completed an underwritten public offering of 3,450,000 shares of common stock, which included 450,000 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 $62.67 per share and we received net proceeds of approximately $208.4 million from the sale of these shares of common stock, net of offering expenses and underwriting discounts and commissions.

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Operating Results Overview

During the three months ended March 31, 2014, our average daily production was approximately 13,552 BOE/d, consisting of 10,663 Bbls/d of oil, 7,871 Mcf/d of natural gas and 1,578 Bbls/d of natural gas liquids, an increase of 8,764 BOE/d, or 183%, from average daily production of 4,788 BOE/d for the three months ended March 31, 2013, consisting of 3,345 Bbls/d of oil, 3,900 Mcf/d of natural gas and 793 Bbls/d of natural gas liquids.

During the three months ended March 31, 2014, we drilled 29 gross (24 net) wells, and participated in an additional one gross non-operated well, in the Permian Basin.

Sources of our revenue

Our revenues are derived from the sale of oil and natural gas production, as well as the sale of natural gas liquids that are extracted from our natural gas during processing. Our oil and natural gas revenues do not include the effects of derivatives. For the three months ended March 31, 2014 and 2013, our revenues were derived 92% and 87%, respectively, from oil sales, 5% and 9%, respectively, from natural gas liquids sales and 3% and 4%, respectively, from natural gas sales. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold, production mix or 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 March 31,	
	2014	2013
	(unaudited)	
	(in thousands, except Bbl, Mcf and BOE amounts)	
Operating Results:		
Revenues		
Oil and natural gas revenues	$98,004	$28,909
Operating Expenses		
Lease operating expense	7,915	4,908
Production and ad valorem taxes	5,842	1,954
Gathering and transportation expense	582	133
Depreciation, depletion and amortization	30,973	10,738
General and administrative	4,557	2,471
Asset retirement obligation accretion expense	72	43
Total expenses	49,941	20,247
Income from operations	48,063	8,662
Net interest expense	(6,505)	(485)
Other income - related party	30	389
Gain (loss) on derivative instruments, net	(4,398)	(8)
Total other income (expense), net	(10,873)	(104)
Income before income taxes	37,190	8,558
Provision for deferred income taxes	13,601	3,162
Net income	$23,589	$5,396
Production Data:		
Oil (Bbls)	959,631	301,041
Natural gas (Mcf)	708,419	351,038
Natural gas liquids (Bbls)	142,023	71,329
Combined volumes (BOE)	1,219,724	430,876
Daily combined volumes (BOE/d)	13,552	4,788
Average Prices[1]:		
Oil (per Bbl)	$93.53	$83.89
Natural gas (per Mcf)	4.71	3.28
Natural gas liquids (per Bbl)	34.58	35.12
Combined (per BOE)	80.35	67.09
Average Costs (per BOE)		
Lease operating expense	$6.49	$11.39
Gathering and transportation expense	0.48	0.31
Production and ad valorem taxes	4.79	4.53
Production and ad valorem taxes as a % of sales	6.0 %	6.8 %
Depreciation, depletion, and amortization	25.39	24.92
General and administrative[2]	3.74	5.73
Interest expense	5.33	1.13

(1) After giving effect to our derivative instruments, the average prices per Bbl of oil and per BOE were $92.43 and $79.48, respectively, during the three months ended March 31, 2014, and $78.76 and $63.51, respectively, during the three months ended March 31, 2013.

(2)

General and administrative includes non-cash stock based compensation, net of capitalized amounts, of $2,190 and $458 for the three months ended March 31, 2014 and 2013, respectively. Excluding stock based compensation from the above metric results in general and administrative cost per BOE of $1.94 and $4.67 for the three months ended March 31, 2014 and 2013, respectively.

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Comparison of the Three Months Ended March 31, 2014 and 2013

Oil, Natural Gas Liquids and Natural Gas Revenues. Our oil, natural gas liquids and natural gas revenues increased by approximately $69,095,000, or 239%, to $98,004,000 for the three months ended March 31, 2014 from $28,909,000 for the three months ended March 31, 2013. 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 8,764 BOE/d to 13,552 BOE/d during the three months ended March 31, 2014 from 4,788 BOE/d during the three months ended March 31, 2013. The total increase in revenue of approximately $69,095,000 is largely attributable to higher oil, natural gas liquids and natural gas production volumes for the three months ended March 31, 2014 as compared to the three months ended March 31, 2013. The increases in production volumes were due to a combination of increased drilling activity and growth through acquisitions. Our production increased by 658,590 Bbls of oil, 70,694 Bbls of natural gas liquids and 357,381 Mcf of natural gas for the three months ended March 31, 2014 as compared to the three months ended March 31, 2013. The net dollar effect of the increases in prices of approximately $10,194,000 (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 $58,901,000 (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 (in thousands)
Effect of changes in price:			
Oil	$9.64	959,631	$9,259
Natural gas liquids	$(0.54)	142,023	$(77)
Natural gas	$1.43	708,419	$1,012
Total revenues due to change in price			$10,194

	Change in production volumes[1]	Prior period Average Prices	Total net dollar effect of change (in thousands)
Effect of changes in production volumes:			
Oil	658,590	$83.89	$55,246
Natural gas liquids	70,694	$35.12	$2,483
Natural gas	357,381	$3.28	$1,172
Total revenues due to change in production volumes			$58,901
Total change in revenues			$69,095

(1) Production volumes are presented in Bbls for oil and natural gas liquids and Mcf for natural gas

Lease Operating Expense. Lease operating expense, or LOE, was $7,915,000 ($6.49 per BOE) for the three months ended March 31, 2014, an increase of $3,007,000, or 61%, from $4,908,000 ($11.39 per BOE) for the three months ended March 31, 2013. The increase is due to increased drilling activity and acquisitions, which resulted in additional producing wells for the three months ended March 31, 2014 as compared to the three months ended March 31, 2013. On a per BOE basis, LOE declined as new volumes came on line and expenses were held in line or were reduced. By the end of 2013, we were moving approximately 70% of our produced water by pipeline directly into commercial salt water disposal wells, rather than by truck, thereby further reducing one of our largest components of LOE.

Production and Ad Valorem Tax Expense. Production and ad valorem taxes increased to $5,842,000 for the three months ended March 31, 2014 from $1,954,000 for the three months ended March 31, 2013. In general, production taxes and ad valorem taxes are directly related to commodity price changes; however, Texas ad valorem taxes are based upon prior year commodity prices, whereas production taxes are based upon current year commodity

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prices. During the three months ended March 31, 2014, our production taxes per BOE increased by $0.55 as compared to the three months ended March 31, 2013, primarily reflecting the impact of higher oil and natural gas prices on production taxes. Our ad valorem taxes have increased primarily as a result of increased valuations on our properties.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization, or DD&A, expense increased $20,235,000, or 188%, from $10,738,000 for the three months ended March 31, 2013 to $30,973,000 for the three months ended March 31, 2014.

The following table provides components of our DD&A expense for the periods presented:

	Three Months Ended March 31,	
	2014	2013
	(in thousands, except BOE amounts)	
Depletion of proved oil and natural gas properties	$30,724	$10,556
Depreciation of other property and equipment	249	182
DD&A	$30,973	$10,738
Oil and natural gas properties DD&A per BOE	$25.19	$24.50
Total DD&A per BOE	$25.39	$24.92

The increases in depletion of proved oil and natural gas properties of $20,168,000 and $0.69 per BOE for the three months ended March 31, 2014 as compared to the three months ended March 31, 2013 resulted primarily from higher total production levels, increased net book value on new reserves added and an increase in capitalized interest to the full cost pool.

General and Administrative Expense. General and administrative expense increased $2,086,000 from $2,471,000 for the three months ended March 31, 2013 to $4,557,000 for the three months ended March 31, 2014. The increase was due to increases in stock based compensation, salary, legal, common stock 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 March 31, 2014 was $6,505,000, as compared to $485,000 for the three months ended March 31, 2013, an increase of $6,020,000, or 1,241%. This increase was due primarily to the issuance of $450.0 million in aggregate principal amount of our 7.625% senior notes 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 consolidated statements of operations under the line item captioned “Loss on derivative instruments, net.” For the three months ended March 31, 2014 and 2013, we had a cash loss on settlement of derivative instruments of $1,056,000 and $1,543,000, respectively. For the three months ended March 31, 2014 and 2013, we had a non-cash loss on open derivative instruments of $3,342,000 and a non-cash gain of $1,535,000, respectively.

Income tax expense. We recorded deferred income tax expense of $13,601,000 for the three months ended March 31, 2014 as compared to $3,162,000 for the three months ended March 31, 2013. Our effective tax rate was 36.6% for the three months ended March 31, 2014 as compared to 37.0% for the three months ended March 31, 2013.

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Liquidity and Capital Resources

Our primary sources of liquidity have been proceeds from our public equity offerings, borrowings under our revolving credit facility, proceeds from the issuance of the senior notes and cash flows from operations. 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 three months ended March 31, 2014 and 2013 are presented below:

	Three Months Ended March 31,	
	2014	2013
	(in thousands)	
Net cash provided by operating activities	$71,466	$16,855
Net cash used in investing activities	(399,184)	(74,094)
Net cash provided by financing activities	$337,477	$36,397
Net change in cash	$9,759	$(20,842)

Operating Activities

Net cash provided by operating activities was $71,466,000 for the three months ended March 31, 2014 as compared to $16,855,000 for the three months ended March 31, 2013. The increase in operating cash flows is a result of increases in our oil and natural gas revenues due to production growth and lower expenses in 2014.

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 $399,184,000 and $74,094,000 during the three months ended March 31, 2014 and 2013, respectively.

During the three months ended March 31, 2014, we spent $86,393,000 on capital expenditures in conjunction with our infrastructure projects and drilling program, in which we drilled 29 gross (24 net) wells and participated in the drilling of an additional one gross non-operated well. We spent an additional $312,207,000 on leasehold costs, $595,000 for the purchase of other property and equipment. On February 27 and 28, 2014, we completed acquisitions of additional oil and natural gas leasehold interests in Martin County, Texas, in the Permian Basin, from unrelated third party sellers for an aggregate purchase price of approximately $292.2 million, subject to certain adjustments. These amounts were partially offset by proceeds of $11,000 from the sale of property and equipment.

During the three months ended March 31, 2013, we spent $53,997,000 on capital expenditures in conjunction with our drilling program in which we participated in the drilling of 19 gross (17 net) wells. We spent an additional $965,000 on leasehold costs, $302,000 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 adjustment associated with our acquisition of Gulfport Energy Corporation’s oil and natural gas assets in the Permian Basin in connection with our initial public offering in October 2012. These amounts were partially offset by proceeds of $9,000 from the sale of property and equipment.

Our investing activities for the three months ended March 31, 2014 and 2013 are summarized in the following table:

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	Three Months Ended March 31,	
	2014	2013
	(in thousands)	
Drilling, completion and infrastructure	$(86,393)	$(53,997)
Acquisition of leasehold interests	(312,207)	(965)
Acquisition of Gulfport properties	—	(18,550)
Purchase of other property and equipment	(595)	(302)
Proceeds from sale of property and equipment	11	9
Settlement of non-hedge derivative instruments	—	(289)
Net cash used in investing activities	$(399,184)	$(74,094)

Financing Activities

Net cash provided by financing activities for the three months ended March 31, 2014 was $337,477,000 as compared to $36,397,000 during the same period in 2013. The 2014 amount provided by financing activities was primarily attributable to the net proceeds of $208.4 million from our February 2014 equity offering and borrowings of $127.0 million under our credit facility. During the three months ended March 31, 2013, we borrowed $36.5 million under our revolving credit facility. In both periods, these proceeds were used primarily to acquire property and fund our drilling costs.

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 1, 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 14,804 gross (12,687 net) acres in Midland County, Texas in the Permian Basin. The senior notes were issued to qualified institutional buyers pursuant to Rule 144A under the Securities Act and to certain non-U.S. persons in accordance with Regulation S under the Securities Act.

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. We may issue additional senior notes under the Indenture, and all senior notes issued under the Indenture will constitute part of a single class of securities for all purposes of the Indenture. On November 5, 2013, we supplemented the Indenture by the first supplemental indenture thereto to add a subsidiary guarantor of the senior notes. 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 our 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 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, which registration statement was filed with the SEC on March 14, 2014. 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 March 31, 2014 and December 31, 2013, the borrowing base was set at $225.0 million. In connection with our April 2014 redetermination, the administrative agent has informed us that it has approved a borrowing base of $450.0 million based on our current assets. As of March 31, 2014, we had outstanding borrowings of $137.0 million which bore interest at a weighted average rate of 2.16%. As of December 31, 2013, we had outstanding borrowings of $10.0 million which bore interest at a weighted average rate of 1.67%.

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 repaid (a) to the extent the loan amount exceeds the borrowing base, whether due to a borrowing base redetermination or otherwise (in some cases subject to a cure period), (b) in an amount equal to the net cash proceeds from the sale of property when a borrowing base deficiency or event of default exists under the credit agreement and (c) 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

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 March 31, 2014, we had $450 million of senior notes outstanding.

As of March 31, 2014, we were in compliance with all financial covenants under our revolving credit facility. The lenders may accelerate all of the indebtedness under our revolving credit facility upon the occurrence 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

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change of control. With certain specified exceptions, the terms and provisions of our revolving credit facility generally may be amended with the consent of the lenders holding a majority of the outstanding loans or commitments to lend.

Capital Requirements and Sources of Liquidity

We currently anticipate our 2014 capital budget for drilling and infrastructure will be approximately $425.0 million to $475.0 million, representing an increase of 48% over 2013. We estimate that, of these expenditures, approximately:

- 85% will be spent on 65 to 75 gross (52 to 60 net) operated horizontal wells focused in Midland, Andrews, Upton, Martin and Dawson Counties;
- 8% will be spent on 20 to 25 gross (16 to 20 net) operated vertical wells focused in Midland County;
- 5% will be spent on infrastructure; and
- 2% will be spent on non-operated drilling.

During the three months ended March 31, 2014, our aggregate capital expenditures for drilling and infrastructure were $86.4 million. We do not have a specific acquisition budget since the timing and size of acquisitions cannot be accurately forecasted. During the three months ended March 31, 2014, we spent $312.2 million on acquisitions.

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 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.

On May 7, 2014, our wholly-owned subsidiary Viper Energy Partners LP, or Viper, filed a registration statement on Form S-1 with the SEC in connection with its proposed initial public offering of limited partner interests. At or prior to the closing of this offering, we will contribute to Viper all of the equity interests in our wholly-owned subsidiary Viper Energy Partners, LLC, or Energy Partners in exchange for limited partner interests in Viper. Energy Partners' assets currently consist of mineral interests underlying approximately 14,804 gross (12,687 net) acres in Midland County, Texas in the Permian Basin, approximately 50% of which are operated by us. Viper intends to distribute the net proceeds from the offering to us. A registration statement relating to these securities has been filed with the SEC but has not yet become effective. These securities may not be sold nor may any offers to buy be accepted prior to the time the registration statement becomes effective, and this report does not constitute an offer to sell or a solicitation of any offers to buy these securities.

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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, 2013.

Off-balance Sheet Arrangements

We had no off-balance sheet arrangements as of March 31, 2014.

Contractual Obligations

There were no material changes in our contractual obligations and other commitments, as disclosed in our Annual Report on Form 10-K for the year ended December 31, 2013.

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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 Argus Louisiana light sweet pricing or Inter–Continental Exchange, or ICE, pricing for Brent crude oil.

At March 31, 2014, we had a net liability derivative position of $2,910,000, related to our ICE Brent and Argus Louisiana Light Sweet fixed price swaps, as compared to a net asset derivative position of $431,000 as of December 31, 2013 related to our price swap derivatives. Utilizing actual derivative contractual volumes under our fixed price swaps as of March 31, 2014, a 10% increase in forward curves associated with the underlying commodity would have increased the net liability derivative position by $18,694,000 to $21,604,000, while a 10% decrease in forward curves associated with the underlying commodity would have decreased the net liability derivative position into a net derivative asset position of $15,784,000 a decrease of $18,694,000. 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. In April 2014, we entered into additional fixed price swaps, with The Bank of Nova Scotia. See Note13 – “Subsequent Events” to the accompanying consolidated financial statements for a description of these additional derivative contracts.

Counterparty and Customer Credit Risk

Our principal exposures to credit risk are through receivables resulting from joint interest receivables (approximately $14,785,000 at March 31, 2014) and receivables from the sale of our oil and natural gas production (approximately $38,360,000 at March 31, 2014).

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 three months ended March 31, 2014, two purchasers accounted for more than 10% of our revenue: Shell Trading (US) Company (66%); and Plains Marketing, L.P. (16%). For the year ended December 31, 2013, two purchasers accounted for more than 10% of our revenue: Plains Marketing, L.P. (37%); and Shell Trading (US) Company (37%). No other customer accounted for more than 10% of our revenue during these periods.

Joint operations receivables arise from billings to entities that own partial interests in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we intend to drill. We have little ability to control whether these entities will participate in our wells. At March 31, 2014, we had one customer that represented approximately 69% of our total joint operations receivables. At December 31, 2013, we had one customer that represented approximately 86% of our total joint operations receivables.

Interest Rate Risk

We are subject to market risk exposure related to changes in interest rates on our indebtedness under our revolving credit facility. The terms of our revolving credit facility provide for interest on borrowings at a floating rate equal to prime, LIBOR or federal funds rate plus margins ranging from 0.5% to 2.50% depending on the base rate used and the amount of the loan outstanding in relation to the borrowing base. As of March 31, 2014, the weighted average interest rate on our borrowings was 2.16%. An increase or decrease of 1% in the interest rate would have a corresponding decrease or increase in our net income of approximately $1,370,000 based on the $137,000,000 outstanding in the aggregate under our revolving credit facility on March 31, 2014.

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ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Control and Procedures

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

As of March 31, 2014, an evaluation was performed under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Exchange Act. Based upon our evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that as of March 31, 2014, our disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting

There have not been any changes in our internal control over financial reporting that occurred during the quarter ended March 31, 2014 that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting.

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PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

In September 2010, Windsor Permian LLC ("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 sought damages from the Company and the other defendants alleging, among other things, interference with contractual relationship, interference with prospective advantage and unjust enrichment. In an order filed on May 24, 2013, the judge denied certain motions made by the defendants and set a trial date to determine liability, with a damage phase of the matter to commence on a later date if there is a determination of liability. Following a trial on the liability phase on June 21, 2013, the jury determined that the defendants intentionally interfered with plaintiff's contract but that the interference did not cause the plaintiff to be unable to acquire mining permits prior to the enactment of the moratorium by Goodhue County. In an order filed on July 10, 2013, the judge ordered the damage phase to be set for trial following a pretrial and scheduling conference. Subsequently, the plaintiff disclosed a new damage theory, and the defendants filed motions with the court to dismiss plaintiff's claims on the grounds that the damage claim was speculative and that plaintiff could not prove damages as a matter of law. Plaintiff also filed a motion for leave to amend its complaint to assert a punitive damage claim. The motions were argued in December 2013. In March 2014, the judge entered an order granting the defendants' motions to exclude testimony and for summary judgment. All parties agreed not to pursue an appeal from the order and waived any entitlement to costs, which effectively concluded this matter.

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

ITEM 1A.RISK FACTORS.

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

In addition to the information set forth in this Form 10–Q, you should carefully consider the risk factors discussed in Part I, Item 1A. Risk Factors in our Annual Report on Form 10–K for the year ended December 31, 2013. There have been no material changes in our risk factors from those described in our Annual Report on Form 10–K for the year ended December 31, 2013.

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

(a) Not applicable.

(b) Not applicable.

(c) We do not have a share repurchase program, and during the three months ended March 31, 2014, we did not purchase any shares of our common stock.

ITEM 3.DEFAULTS UPON SENIOR SECURITIES

Not applicable.

ITEM 4. MINE SAFETY DISCLOSURES.

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Not applicable.

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS

EXHIBIT INDEX

Exhibit Number	Description
2.1#	Purchase and Sale Agreement dated February 14, 2014, between Henry Resources LLC, Henry Production LLC, Henry Taw Production LP, Davlin LP, Good Providence LP, William R. Fair, UTH Investments LTD, Paloma Oil & Ranch LP, Chinati Oil & Ranch LP, J. Craig Corbett, Bambana Resources LP, and FC Permian Properties, Inc., as Sellers, and Diamondback E&P LLC, as Buyer (incorporated by reference to Exhibit 2.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on February 18, 2014).
2.2#	Purchase and Sale Agreement, dated February 14, 2014, between Henry Resources LLC, Henry Production LLC, Henry Taw Production LP, Davlin LP, Good Providence LP, William R. Fair, UTH Investments LTD, Paloma Oil & Ranch LP, Chinati Oil & Ranch LP, J. Craig Corbett, Bambana Resources LP, FC Permian Properties, Inc., Blake Braun, Richard D. Campbell, and Thomas J. Woodside, as Sellers, and Diamondback E&P LLC, as Buyer (incorporated by reference to Exhibit 2.2 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on February 18, 2014).
3.1	Amended and Restated Certificate of Incorporation of the Company (incorporated by reference to Exhibit 3.1 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on November 16, 2012).
3.2	Amended and Restated Bylaws of the Company (incorporated by reference to Exhibit 3.2 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on November 16, 2012).
4.1	Specimen certificate for shares of common stock, par value $0.01 per share, of the Company (incorporated by reference to Exhibit 4.1 to Amendment No. 4 to the Registration Statement on Form S-1, File No. 333-179502, filed by the Company with the SEC on August 20, 2012).
4.2	Registration Rights Agreement, dated as of October 11, 2012, by and between the Company and DB Energy Holdings LLC (incorporated by reference to Exhibit 4.2 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on November 16, 2012).
4.3	Investor Rights Agreement, dated as of October 11, 2012, by and between the Company and Gulfport Energy Corporation (incorporated by reference to Exhibit 4.3 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on November 16, 2012).
4.4	Indenture, dated as of September 18, 2013, among Diamondback Energy, Inc., the subsidiary guarantors party thereto and Wells Fargo, N.A., as trustee (including the form of Diamondback Energy, Inc.'s 7.625% Senior Note due October 2021 (incorporated by reference to Exhibit 4.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on September 18, 2013).
4.5	First Supplemental Indenture, dated as of November 5, 2013, by and between Diamondback Energy, the subsidiary guarantors party thereto and Wells Fargo, N.A, as trustee (incorporated by reference to Exhibit 4.5 to the Form 10-K, File No. 001-35700, filed by the Company with the SEC on February 19, 2014).
4.6	Registration Rights Agreement, dated as of September 18, 2013, among Diamondback Energy, Inc., the subsidiary guarantors party thereto and Credit Suisse Securities (USA) LLC, as representative of the several initial purchasers (incorporated by reference to Exhibit 4.2 to the

	Form 8-K, File No. 001-35700, filed by the Company with the SEC on September 18, 2013).
10.1+	2014 Executive Annual Incentive Compensation Plan (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on April 2, 2014).

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Exhibit Number	Description
10.2+*	Amended and Restated Employment Agreement, dated April 24, 2014, effective as of April 18, 2014, by and between Travis D. Stice and Diamondback E&P LLC.
10.3+	Amended and Restated Employment Agreement, dated as of February 27, 2014, effective as of January 1, 2014, by and between Teresa Dick and Diamondback E&P LLC (incorporated by reference to Exhibit 10.3 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on March 5, 2014).
10.4+	Amended and Restated Employment Agreement, dated as of February 27, 2014, effective as of January 1, 2014, by and between Michael Hollis and Diamondback E&P LLC (incorporated by reference to Exhibit 10.4 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on March 5, 2014).
10.5+	Amended and Restated Employment Agreement, dated as of February 27, 2014, effective as of January 1, 2014, by and between Jeff White and Diamondback E&P LLC (incorporated by reference to Exhibit 10.5 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on March 5, 2014).
10.6+*	Amended and Restated Employment Agreement, dated as of February 27, 2014, effective as of January 1, 2014, by and between Russell Pantermuehl and Diamondback E&P LLC.
31.1*	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
31.2*	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
32.1++	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
32.2++	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
101.INS**	XBRL Instance Document.
101.SCH**	XBRL Taxonomy Extension Schema Document.
101.CAL**	XBRL Taxonomy Extension Calculation Linkbase.
101.DEF**	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB**	XBRL Taxonomy Extension Labels Linkbase Document.
101.PRE**	XBRL Taxonomy Extension Presentation Linkbase Document.

#	The schedules (or similar attachments) referenced in this agreement have been omitted in accordance with Item 601(b)(2) of Regulation S-K. A copy of any omitted schedule (or similar attachment) will be furnished supplementally to the Securities and Exchange Commission upon request.
*	Filed herewith.
**	Furnished herewith. Pursuant to Rule 406T of Regulation S-T, these interactive data files are being furnished herewith and are not deemed filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, as amended, are not deemed filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and otherwise are not subject to liability under these sections.
+	Management contract, compensatory plan or arrangement.
++	The certifications attached as Exhibit 32.1 and Exhibit 32.2 accompany this Annual Report on Form 10-K pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, and shall not be deemed “filed” by the Registrant for purposes of Section 18 of the Securities Exchange Act of 1934, as amended.

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SIGNATURES

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

DIAMONDBACK ENERGY, INC.

Date: May 9, 2014

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

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