Diamondback Energy, Inc.
Form 10-Q
November 06, 2015

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

FORM 10-Q

ý QUARTERLY REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE QUARTERLY PERIOD ENDED September 30, 2015
OR
o 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	79701
(Address of Principal Executive Offices)	(Zip Code)

(432) 221-7400
(Registrant Telephone Number, Including Area Code)

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the past 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act. (Check One):

Large Accelerated Filer	ý	Accelerated Filer	o

Non-Accelerated Filer	o	Smaller Reporting Company	o

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 November 3, 2015, 66,703,004 shares of the registrant's common stock were outstanding.

DIAMONDBACK ENERGY, INC
FORM 10-Q
FOR THE QUARTER ENDED SEPTEMBER 30, 2015
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GLOSSARY OF OIL AND NATURAL GAS TERMS

The following is a glossary of certain oil and gas terms that are used in this Quarterly Report on Form 10-Q (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.
Basin	A large depression on the earth's surface in which sediments accumulate.
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.
Crude oil	Liquid hydrocarbons retrieved from geological structures underground to be refined into fuel sources.
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.
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.
Horizontal wells	Wells drilled directionally horizontal to allow for development of structures not reachable through traditional vertical drilling mechanisms.
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.
Mineral interests	The interests in ownership of the resource and mineral rights, giving an owner the right to profit from the extracted resources.
MMBtu	Million British Thermal Units.
Net acres or net wells	The sum of the fractional working interest owned in gross acres.
Net revenue interest	An owner's interest in the revenues of a well after deducting proceeds allocated to royalty and overriding interests.
Oil and natural gas properties	Tracts of land consisting of properties to be developed for oil and natural gas resource extraction.
Operator	The individual or company responsible for the exploration and/or production of an oil or natural gas well or lease.
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.
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 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.

Reserves	Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and natural gas or related substances to the market and all permits and financing required to implement the project. Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).
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.
Royalty interest	An interest that gives an owner the right to receive a portion of the resources or revenues without having to carry any costs of development.
Spacing	The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres (e.g., 40-acre spacing) and is often established by regulatory agencies.
Working interest	An 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.

GLOSSARY OF CERTAIN OTHER TERMS

The following is a glossary of certain other terms that are used in this report.

2012 Plan	The Company's 2012 Equity Incentive Plan.
Company	Diamondback Energy, Inc., a Delaware corporation.
Exchange Act	The Securities Exchange Act of 1934, as amended.
GAAP	Accounting principles generally accepted in the United States.
General Partner	Viper Energy Partners GP LLC, a Delaware limited liability company and the General Partner of the Partnership.
Indenture	The indenture relating to the Senior Notes, dated as of September 18, 2013, among the Company, the subsidiary guarantors party thereto and Wells Fargo, as the trustee, as supplemented.
NYMEX	New York Mercantile Exchange.
Partnership	Viper Energy Partners LP, a Delaware limited partnership.
Partnership agreement	The first amended and restated agreement of limited partnership, dated June 23, 2014, entered into by the General Partner and Diamondback in connection with the closing of the Viper Offering.
SEC	Securities and Exchange Commission.
Securities Act	The Securities Act of 1933, as amended.
Senior Notes	The Company's 7.625% senior unsecured notes due 2021 in the aggregate principal amount of $450 million.
Viper LTIP	Viper Energy Partners LP Long Term Incentive Plan.
Viper Offering	The Partnerships' initial public offering.
Wells Fargo	Wells Fargo Bank, National Association.

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, and Section 21E of 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 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 report 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, 2014 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;
- acquisitions;
- 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 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 report are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved or occur, and actual results could differ materially and adversely from those anticipated or implied in the forward-looking statements.

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

	September 30, 2015	December 31, 2014
	(In thousands, except par values and share data)	
Assets		
Current assets:		
Cash and cash equivalents	$43,827	$30,183
Restricted cash	500	500
Accounts receivable:		
Joint interest and other	41,021	50,943
Oil and natural gas sales	42,221	43,050
Related party	—	4,001
Inventories	2,602	2,827
Derivative instruments	40,009	115,607
Prepaid expenses and other	3,259	4,600
Total current assets	173,439	251,711
Property and equipment:		
Oil and natural gas properties, based on the full cost method of accounting ($1,099,604 and $773,520 excluded from amortization at September 30, 2015 and December 31, 2014, respectively)	3,850,064	3,118,597
Pipeline and gas gathering assets	7,176	7,174
Other property and equipment	48,913	48,180
Accumulated depletion, depreciation, amortization and impairment	(1,147,936)	(382,144)
Net property and equipment	2,758,217	2,791,807
Derivative instruments	—	1,934
Deferred income taxes	5,641	—
Other assets	54,257	50,029
Total assets	$2,991,554	$3,095,481
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable-trade	$32,010	$26,230
Accrued capital expenditures	58,818	129,397
Other accrued liabilities	76,527	41,149
Revenues and royalties payable	20,421	30,000
Deferred income taxes	12,396	39,953
Total current liabilities	200,172	266,729
Long-term debt	489,000	673,500
Asset retirement obligations	12,662	8,447
Deferred income taxes	—	161,592
Total liabilities	701,834	1,110,268
Commitments and contingencies (Note 14)		
Stockholders' equity:		
	667	569

Common stock, $0.01 par value, 100,000,000 shares authorized, 66,656,433 issued and outstanding at September 30, 2015; 56,887,583 issued and outstanding at December 31, 2014		
Additional paid-in capital	2,222,695	1,554,174
Retained earnings	(166,951)	196,268
Total Diamondback Energy, Inc. stockholders’ equity	2,056,411	1,751,011
Noncontrolling interest	233,309	234,202
Total equity	2,289,720	1,985,213
Total liabilities and equity	$2,991,554	$3,095,481

See accompanying notes to combined consolidated financial statements.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(In thousands, except per share amounts)			
Revenues:				
Oil sales	$101,307	$126,406	$301,850	$331,446
Natural gas sales	5,673	2,338	11,791	6,006
Natural gas sales - related party	—	2,374	2,640	6,370
Natural gas liquid sales	4,966	3,619	13,585	9,507
Natural gas liquid sales - related party	—	4,390	2,544	10,806
Total revenues	111,946	139,127	332,410	364,135
Costs and expenses:				
Lease operating expenses	22,189	13,766	65,117	31,998
Lease operating expenses - related party	—	39	—	218
Production and ad valorem taxes	8,966	8,634	24,883	22,318
Production and ad valorem taxes - related party	—	320	153	1,032
Gathering and transportation	1,688	110	3,374	426
Gathering and transportation - related party	—	750	969	1,719
Depreciation, depletion and amortization	52,375	45,370	169,148	116,364
Impairment of oil and gas properties	273,737	—	597,188	—
General and administrative expenses (including non-cash equity based compensation, net of capitalized amounts, of $4,402 and $2,069 for the three months ended September 30, 2015 and 2014, respectively, and $13,659 and $5,387 for the nine months ended September 30, 2015 and 2014, respectively)	6,861	6,016	21,774	13,891
General and administrative expenses - related party	665	479	1,672	1,095
Asset retirement obligation accretion expense	238	127	588	303
Total costs and expenses	366,719	75,611	884,866	189,364
Income (loss) from operations	(254,773)	63,516	(552,456)	174,771
Other income (expense)				
Interest expense	(10,633)	(9,846)	(31,404)	(24,090)
Other income	260	17	1,130	17
Other income - related party	40	31	118	91
Other expense	—	(8)	—	(1,416)
Gain (loss) on derivative instruments, net	27,603	14,909	26,834	(577)
Total other income (expense), net	17,270	5,103	(3,322)	(25,975)
Income (loss) before income taxes	(237,503)	68,619	(555,778)	148,796
Provision for (benefit from) income taxes	(81,461)	23,978	(194,823)	52,742
Net income (loss)	(156,042)	44,641	(360,955)	96,054
Less: Net income attributable to noncontrolling interest	739	902	2,264	973
Net income (loss) attributable to Diamondback Energy, Inc.	$(156,781)	$43,739	$(363,219)	$95,081

Earnings (loss) per common share				
Basic	$(2.40)	$0.79	$(5.88)	$1.85
Diluted	$(2.40)	$0.79	$(5.88)	$1.83
Weighted average common shares outstanding				
Basic	65,251	55,152	61,727	51,489
Diluted	65,251	55,442	61,727	51,888

See accompanying notes to combined consolidated financial statements.

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

	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Retained Earnings	Non-controlling Interest	Total
	(In thousands)					
Balance December 31, 2013	47,106	$471	$842,557	$2,513	$ —	$845,541
Net proceeds from issuance of common units - Viper Energy Partners LP	—	—	—	—	232,334	232,334
Unit-based compensation	—	—	—	—	1,011	1,011
Stock-based compensation	—	—	9,134	—	—	9,134
Tax benefits related to stock-based compensation	—	—	3,173	—	—	3,173
Common shares issued in public offering, net of offering costs	9,200	92	693,289	—	—	693,381
Exercise of stock options and vesting of restricted stock units	380	4	5,214	—	—	5,218
Net income	—	—	—	95,081	973	96,054
Balance September 30, 2014	56,686	$567	$1,553,367	$97,594	$ 234,318	$1,885,846
Balance December 31, 2014	56,888	$569	$1,554,174	$196,268	$ 234,202	$1,985,213
Unit-based compensation	—	—	—	—	2,956	2,956
Stock-based compensation	—	—	15,827	—	—	15,827
Distribution to noncontrolling interest	—	—	—	—	(6,113)	(6,113)
Common shares issued in public offering, net of offering costs	9,487	94	649,979	—	—	650,073
Exercise of stock options and vesting of restricted stock units	282	4	2,715	—	—	2,719
Net income (loss)	—	—	—	(363,219)	2,264	(360,955)
Balance September 30, 2015	66,657	$667	$2,222,695	$(166,951)	$ 233,309	$2,289,720

See accompanying notes to combined consolidated financial statements.

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

	Nine Months Ended September 30, 2015	2014
	(In thousands)	
Cash flows from operating activities:		
Net income (loss)	$(360,955)	$96,054
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
(Benefit from) provision for deferred income taxes	(194,790)	48,760
Excess tax benefit from stock-based compensation	—	749
Impairment of oil and gas properties	597,188	—
Asset retirement obligation accretion expense	588	303
Depreciation, depletion, and amortization	169,148	116,364
Amortization of debt issuance costs	1,918	1,505
Change in fair value of derivative instruments	77,532	(5,630)
Stock-based compensation expense	13,659	5,387
Gain on sale of assets, net	(91)	1,405
Changes in operating assets and liabilities:		
Accounts receivable	13,112	(33,985)
Accounts receivable-related party	—	(2,612)
Inventories	225	915
Prepaid expenses and other	569	(5,681)
Accounts payable and accrued liabilities	22,756	7,812
Accounts payable and accrued liabilities-related party	—	(17)
Accrued interest	8,324	11,940
Revenues and royalties payable	(9,579)	8,726
Net cash provided by operating activities	339,604	251,995
Cash flows from investing activities:		
Additions to oil and natural gas properties	(326,441)	(309,009)
Additions to oil and natural gas properties-related party	(26)	(3,410)
Acquisition of mineral interests	(32,291)	(57,688)
Acquisition of leasehold interests	(425,507)	(840,482)
Pipeline and gas gathering assets	(2)	(1,437)
Purchase of other property and equipment	(992)	(43,215)
Proceeds from sale of property and equipment	97	11
Equity investments	(2,702)	(33,851)
Net cash used in investing activities	(787,864)	(1,289,081)
Cash flows from financing activities:		
Proceeds from borrowings on credit facility	392,501	425,900
Repayment on credit facility	(577,001)	(295,900)
Debt issuance costs	(303)	(2,358)
Public offering costs	(586)	(2,203)
Proceeds from public offerings	650,688	928,432
Exercise of stock options	2,718	5,131
Excess tax benefits of stock-based compensation	—	3,173
Distribution to non-controlling interest	(6,113)	—

Net cash provided by financing activities	461,904	1,062,175
Net increase in cash and cash equivalents	13,644	25,089
Cash and cash equivalents at beginning of period	30,183	15,555
Cash and cash equivalents at end of period	$43,827	$40,644

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

	Nine Months Ended September 30,	
	2015	2014
	(In thousands)	
Supplemental disclosure of cash flow information:		
Interest paid, net of capitalized interest	$21,117	$12,729
Supplemental disclosure of non-cash transactions:		
Asset retirement obligation incurred	$448	$567
Asset retirement obligation revisions in estimated liability	$60	$588
Asset retirement obligation acquired	$3,123	$3,678
Change in accrued capital expenditures	$(70,579)	$43,865
Capitalized stock-based compensation	$5,125	$4,758

See accompanying notes to combined 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.

On June 17, 2014, Diamondback entered into a contribution agreement with Viper Energy Partners LP (the “Partnership”), Viper Energy Partners GP LLC (the “General Partner”) and Viper Energy Partners LLC to transfer Diamondback’s ownership interest in Viper Energy Partners LLC to the Partnership in exchange for 70,450,000 common units. Diamondback also owns and controls the General Partner, which holds a non-economic general partner interest in the Partnership. On June 23, 2014, the Partnership completed its initial public offering (the “Viper Offering”) of 5,750,000 common units, and the Company’s common units represented an approximate 92% limited partner interest in the Partnership. On September 19, 2014, the Partnership completed an underwritten public offering of 3,500,000 common units. At the completion of this offering, the Company owned approximately 88% of the common units of the Partnership. See Note 4—Viper Energy Partners LP for additional information regarding the Partnership.

The wholly-owned subsidiaries of Diamondback, as of September 30, 2015, include Diamondback E&P LLC, a Delaware limited liability company, Diamondback O&G LLC, a Delaware limited liability company, Viper Energy Partners GP LLC, a Delaware limited liability company, and White Fang Energy LLC, a Delaware limited liability company. The consolidated subsidiaries include the wholly-owned subsidiaries as well as Viper Energy Partners LP, a Delaware limited partnership, and Viper Energy Partners LLC, a Delaware limited liability company.

Basis of Presentation

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

The Partnership is consolidated in the financial statements of the Company. As of September 30, 2015, the Company owned approximately 88% of the common units of the Partnership and the Company’s wholly-owned subsidiary, Viper Energy Partners GP LLC, is the General Partner of the Partnership.

These financial statements have been prepared by the Company without audit, pursuant to the rules and regulations of 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 GAAP have been omitted pursuant to such rules and regulations, although the Company believes the disclosures are adequate to make the information presented not misleading. This Quarterly Report on Form 10–Q should be read in conjunction with the Company’s most recent Annual Report on Form 10–K for the fiscal year ended December 31, 2014, 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.

New Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board issued Accounting Standards Update 2014-09, "Revenue from Contracts with Customers". This update supersedes most of the existing revenue recognition requirements in GAAP and requires (i) an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled to in exchange for those goods or services and (ii) requires expanded disclosures regarding the nature, amount, timing, and certainty of revenue and cash flows from contracts with customers. The standard will be effective for annual and interim reporting periods beginning after December 15, 2017, with early application not permitted. The standard allows for either full retrospective adoption, meaning the standard is applied to all periods presented in the financial statements, or modified retrospective adoption, meaning the standard is applied only to the most current period presented. The Company is currently evaluating the impact, if any, that the adoption of this update will have on the Company's financial position, results of operations, and liquidity.

In April 2015, the Financial Accounting Standards Board issued Accounting Standards Update 2015-03, "Interest—Imputation of Interest". This update requires that debt issuance costs related to a recognized debt liability (except costs associated with revolving debt arrangements) be presented in the balance sheet as a direct deduction from that debt liability, consistent with the presentation of a debt discount to simplify the presentation of debt issuance costs. The standard will be effective for financial statements issued for fiscal years beginning after December 15, 2015, and interim periods within fiscal years beginning after December 15, 2016. Early application will be permitted for financial statements that have not previously been issued. Adoption of the new guidance will only affect the presentation of the Company's consolidated balance sheets and will not have a material impact on its consolidated financial statements.

3. ACQUISITIONS

2015 Activity

Since January 1, 2015, the Company has completed acquisitions from unrelated third party sellers of an aggregate of approximately 16,034 gross (12,396 net) acres in the Midland Basin, primarily in northwest Howard County, for an aggregate purchase price of approximately $425.5 million, subject to certain adjustments. 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 with the net proceeds of the May 2015 equity offering discussed in Note 9 and borrowings under the Company's revolving credit facility discussed in Note 8.

On July 9, 2015, the Company completed the sale of an approximate average 1.5% overriding royalty interest in certain of its acreage primarily located in Howard County, Texas to the Partnership for $31.1 million. The Partnership primarily funded this acquisition with borrowings under its revolving credit facility discussed in Note 8.

2014 Activity

On September 9, 2014, the Company completed the acquisition of oil and natural gas interests in the Permian Basin from unrelated third party sellers. The Company acquired approximately 17,617 gross (12,967 net) acres with an approximate 74% working interest (approximately 75% net revenue interest). The acquisition was accounted for according to the acquisition method, which requires the recording of net assets acquired and consideration transferred at fair value. This acquisition was funded with the net proceeds of the July 2014 equity offering discussed in Note 9 below and borrowings under the Company’s revolving credit facility discussed in Note 8.

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

There were no material changes from the purchase price allocation disclosed in the Company's Annual Report on Form 10-K for the year ended December 31, 2014.

The Company has included in its consolidated statements of operations revenues of $4.9 million and direct operating expenses of $2.8 million for the three months ended September 30, 2015 due to the acquisition and revenues of $15.9 million and direct operating expenses of $8.4 million for the nine months ended September 30, 2015 due to the acquisition. For each of the three and nine months ended September 30, 2014, the Company has included in its consolidated statements of operations revenues of $2.8 million and direct operating expenses of $1.4 million attributable to the period from September 9, 2014 to September 30, 2014 due to the acquisition. The disclosure of net earnings is impracticable to calculate due to the full cost method of depletion.

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 with the net proceeds of the February 2014 equity offering discussed in Note 9 and borrowings under the Company's revolving credit facility discussed in Note 8.

There were no material changes from the purchase price allocation disclosed in the Company's Annual Report on Form 10-K for the year ended December 31, 2014.

The Company has included in its consolidated statements of operations revenues of $9.8 million and direct operating expenses of $2.7 million for the three months ended September 30, 2015 and revenues of $11.8 million and direct operating expenses of $0.1 million for the three months ended September 30, 2014, due to the acquisitions. The Company has included in its consolidated statements of operations revenues of $24.1 million and direct operating expenses of $6.9 million for the nine months ended September 30, 2015 and revenues of $31.0 million and direct operating expenses of $4.7 million for the nine months ended September 30, 2014 attributable to the period from February 28, 2014 to September 30, 2014, due to the acquisitions. The disclosure of net earnings is impracticable to calculate due to the full cost method of depletion.

Pro Forma Financial Information

The following unaudited summary pro forma combined consolidated statement of operations data of Diamondback for the three and nine months ended September 30, 2014 have been prepared to give effect to the February 27 and 28, 2014 acquisitions and the September 9, 2014 acquisition as if they had occurred on January 1, 2014. The pro forma data are not necessarily indicative of financial results that would have been attained had the acquisitions occurred on January 1, 2014. 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.

	Pro Forma (Unaudited)	
	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2014
	(in thousands)	
Revenues	$139,127	$409,520

Income from operations	63,516	186,483
Net income	43,739	102,583

4. VIPER ENERGY PARTNERS LP

The Partnership is a publicly traded Delaware limited partnership, the common units of which are listed on the NASDAQ Global Market under the symbol “VNOM”. The Partnership was formed by Diamondback on February 27, 2014, to, among other things, own, acquire and exploit oil and natural gas properties in North America. The Partnership is currently focused on oil and natural gas properties in the Permian Basin. Viper Energy Partners GP LLC, a fully-consolidated subsidiary of Diamondback, serves as the general partner of, and holds a non-economic general partner interest in, the Partnership. As of September 30, 2015, the Company owned approximately 88% of the common units of the Partnership.

Prior to the completion on June 23, 2014 of the Viper Offering, Diamondback owned all of the general and limited partner interests in the Partnership. The Viper Offering consisted of 5,750,000 common units representing approximately 8% of the limited partner interests in the Partnership at a price to the public of $26.00 per common unit, which included 750,000 common units issued pursuant to an option to purchase additional common units granted to the underwriters on the same terms. The Partnership received net proceeds of approximately $137.2 million from the sale of these common units, net of offering expenses and underwriting discounts and commissions.

In connection with the Viper Offering, Diamondback contributed all of the membership interests in Viper Energy Partners LLC to the Partnership in exchange for 70,450,000 common units. In addition, in connection with the closing of the Viper Offering, the Partnership agreed to distribute to Diamondback all cash and cash equivalents and the royalty income receivable on hand in the aggregate amount of approximately $11.3 million and the net proceeds from the Viper Offering. As of September 30, 2014, the Partnership had distributed $148.8 million to Diamondback and the Partnership recorded a payable balance of approximately $11.3 million. The contribution of Viper Energy Partners LLC to the Partnership was accounted for as a combination of entities under common control with assets and liabilities transferred at their carrying amounts in a manner similar to a pooling of interests. During the three and nine months ended September 30, 2015, the Partnership distributed $15.5 million and $46.5 million, respectively, to Diamondback in respect of its common units.

Partnership Agreement

In connection with the closing of the Viper Offering, the General Partner and Diamondback entered into the first amended and restated agreement of limited partnership, dated June 23, 2014 (the “Partnership Agreement”). The Partnership Agreement requires the Partnership to reimburse the General Partner for all direct and indirect expenses incurred or paid on the Partnership’s behalf and all other expenses allocable to the Partnership or otherwise incurred by the General Partner in connection with operating the Partnership’s business. The Partnership Agreement does not set a limit on the amount of expenses for which the General Partner and its affiliates may be reimbursed. These expenses include salary, bonus, incentive compensation and other amounts paid to persons who perform services for the Partnership or on its behalf and expenses allocated to the General Partner by its affiliates. The General Partner is entitled to determine the expenses that are allocable to the Partnership.

Tax Sharing

In connection with the closing of the Viper Offering, the Partnership entered into a tax sharing agreement with Diamondback, dated June 23, 2014, pursuant to which the Partnership agreed to reimburse Diamondback for its share of state and local income and other taxes for which the Partnership’s results are included in a combined or consolidated tax return filed by Diamondback with respect to taxable periods including or beginning on June 23, 2014. The amount of any such reimbursement is limited to the tax the Partnership would have paid had it not been included in a combined group with Diamondback. Diamondback may use its tax attributes to cause its combined or consolidated group, of which the Partnership may be a member for this purpose, to owe less or no tax. In such a situation, the Partnership agreed to reimburse Diamondback for the tax the Partnership would have owed had the tax attributes not been available or used for the Partnership’s benefit, even though Diamondback had no cash tax expense for that period.

Other Agreements

See Note 11—Related Party Transactions for information regarding the advisory services agreement the Partnership and the General Partner entered into with Wexford Capital LP ("Wexford").

The Partnership has entered into a secured revolving credit facility with Wells Fargo, as administrative agent sole book runner and lead arranger. See Note 8—Debt for a description of this credit facility.

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

5. PROPERTY AND EQUIPMENT

Property and equipment includes the following:

	September 30, 2015	December 31, 2014
	(in thousands)	
Oil and natural gas properties:		
Subject to depletion	$2,750,460	$2,345,077
Not subject to depletion-acquisition costs		
Incurred in 2015	421,576	—
Incurred in 2014	543,499	576,802
Incurred in 2013	71,802	130,474
Incurred in 2012	62,727	65,480
Incurred in 2011	—	764
Total not subject to depletion	1,099,604	773,520
Gross oil and natural gas properties	3,850,064	3,118,597
Accumulated depletion	(870,569)	(379,481)
Impairment	(273,737)	—
Oil and natural gas properties, net	2,705,758	2,739,116
Pipeline and gas gathering assets	7,176	7,174
Other property and equipment	48,913	48,180
Accumulated depreciation	(3,630)	(2,663)
Property and equipment, net of accumulated depreciation, depletion, amortization and impairment	$2,758,217	$2,791,807

The Company uses the full cost method of accounting for its oil and natural gas properties. Under this method, all acquisition, exploration and development costs, including certain internal costs, are capitalized and amortized on a composite unit of production method based on proved oil, natural gas liquids and natural gas reserves. 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 $4.0 million and $2.4 million for the three months ended September 30, 2015 and 2014, respectively, and $12.1 million and $7.3 million for the nine months ended September 30, 2015 and 2014, 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. Sales of oil and natural gas properties, whether or not being amortized currently, are accounted for as adjustments of capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil, natural gas liquids and natural gas.

Under this method of accounting, the Company is required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the proved oil and gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes, or the cost center ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on the trailing

12-month unweighted average of the first-day-of-the-month price, adjusted for any contract provisions or financial derivatives, if any, that hedge the Company’s oil and natural gas revenue, and excluding the estimated abandonment costs for properties with asset retirement obligations recorded on the balance sheet, (b) the cost of properties not being amortized, if any, and (c) the lower of cost or market value of unproved properties included in the cost being amortized, including related deferred taxes for differences between the book and tax basis of the oil and natural gas properties. If the net book value, including related deferred taxes, exceeds the ceiling, an impairment or non-cash writedown is required.

Diamondback Energy, Inc. and Subsidiaries
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As a result of the significant decline in prices from over $91.00 per Bbl in September 2014 to a range of prices between $38.00 per Bbl and $62.00 per Bbl in 2015, the Company recorded non-cash ceiling test impairments for the nine months ended September 30, 2015 of $597.2 million, which is included in accumulated depletion. The Company did not have any impairment of its proved oil and gas properties during 2014. The impairment charge affected the Company’s reported net income but did not reduce our cash flow. In addition to commodity prices, the Company’s production rates, levels of proved reserves, future development costs, transfers of unevaluated properties and other factors will determine its actual ceiling test calculation and impairment analysis in future periods.

6. ASSET RETIREMENT OBLIGATIONS

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

	Nine Months Ended September 30,	
	2015	2014
	(in thousands)	
Asset retirement obligation, beginning of period	$8,486	$3,029
Additional liability incurred	448	567
Liabilities acquired	3,123	3,678
Liabilities settled	(4)	(10)
Accretion expense	588	303
Revisions in estimated liabilities	60	588
Asset retirement obligation, end of period	12,701	8,155
Less current portion	39	40
Asset retirement obligations - long-term	$12,662	$8,115

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.

7. EQUITY METHOD INVESTMENTS

In October 2014, the Company paid $0.6 million for a minority interest in an entity that was formed to develop, own and operate an integrated water management system to gather, store, process, treat, distribute and dispose of water to exploration and production companies operating in Midland, Martin and Andrews Counties, Texas. The board of this entity may also authorize the entity to offer these services to other counties in the Permian Basin and to pursue other business opportunities. The Company has committed to invest an aggregate amount of $5.0 million in this entity, and several other third parties have committed to invest an aggregate of $15.0 million. For the three and nine months ended September 30, 2015, the Company invested an additional $1.0 million and $2.7 million, respectively, in this entity. The Company will retain a minority interest after all commitments are received. The entity was formed as a limited liability company and maintains a specific ownership account for each investor, similar to a partnership capital account structure. Therefore, the Company accounts for this investment under the equity method of accounting.

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

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

	September 30, 2015	December 31, 2014
	(in thousands)	
Revolving credit facility	$10,000	$223,500
7.625 % Senior Notes due 2021	450,000	450,000
Partnership revolving credit facility	29,000	—
Total long-term debt	$489,000	$673,500

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. On June 23, 2014, in connection with the Viper Offering, the Company designated the Partnership, the General Partner and Viper Energy LLC as unrestricted subsidiaries and, upon such designation, Viper Energy LLC, which was a guarantor under the indenture governing of the Senior Notes, was released as a guarantor under the indenture. As of September 30, 2015, the Senior Notes are fully and unconditionally guaranteed by Diamondback O&G LLC, Diamondback E&P LLC and White Fang Energy LLC and will also be guaranteed by any future restricted subsidiaries of Diamondback. 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, National Association (“Wells Fargo”), as the trustee, as supplemented (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 with the initial purchasers on September 18, 2013, pursuant to which the Company and the subsidiary guarantors agreed to file a registration statement with respect to an offer to exchange the Senior Notes

Diamondback Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements-(Continued)
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for a new issue of substantially identical debt securities registered under the Securities Act, which registration statement was declared effective by the SEC on September 15, 2014 and the exchange offer completed on October 23, 2014.

The Company's Credit Facility

On June 9, 2014, Diamondback O&G LLC, as borrower, entered into a first amendment and on November 13, 2014, Diamondback O&G LLC entered into a second amendment to the second amended and restated credit agreement, dated November 1, 2013 (the "credit agreement"). The first amendment modified certain provisions of the credit agreement to, among other things, allow one or more of the Company's subsidiaries to be designated as "Unrestricted Subsidiaries" that are not subject to certain restrictions contained in the credit agreement. In connection with the Viper Offering, the Partnership, the General Partner and Viper Energy Partners LLC were designated as unrestricted subsidiaries under the credit agreement. As of September 30, 2015, the credit agreement was guaranteed by Diamondback, Diamondback E&P LLC and White Fang Energy LLC and will also be guaranteed by any future restricted subsidiaries of Diamondback. The credit agreement is also secured by substantially all of the assets of Diamondback O&G LLC, the Company and the other guarantors.

The second amendment increased the maximum amount of the credit facility to $2.0 billion, modified the dates and deadlines of the credit agreement relating to the scheduled borrowing base redeterminations based on the Company's oil and natural gas reserves and other factors and added new provisions that allow the Company to elect a commitment amount that is less than its borrowing base as determined by the lenders. The borrowing base is scheduled to be re-determined semi-annually with effective dates of May 1st and November 1st. In addition, the Company may request up to three additional redeterminations of the borrowing base during any 12-month period. As of September 30, 2015, the borrowing base was set at $725.0 million, of which the Company had elected a commitment amount of $500.0 million, and the Company had outstanding borrowings of $10.0 million.

The outstanding borrowings under the credit agreement bear interest at a rate elected by the Company that is equal to an alternative base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.5% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.5% to 1.50% in the case of the alternative base rate and from 1.50% to 2.50% in the case of LIBOR, 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 repaid (a) to the extent that 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 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 $750.0 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 September 30, 2015, the Company had $450.0 million of senior unsecured notes outstanding.

As of September 30, 2015 and December 31, 2014, 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.

The Partnership's Credit Agreement

On July 8, 2014, the Partnership entered into a secured revolving credit agreement with Wells Fargo, as the administrative agent, sole book runner and lead arranger. The credit agreement, which was amended August 15, 2014 to add additional lenders to the lending group, provides for a revolving credit facility in the maximum amount of $500.0 million, subject to scheduled semi-annual and other elective collateral borrowing base redeterminations based on the Partnership's oil and natural gas reserves and other factors. The borrowing base is scheduled to be re-determined semi-annually with effective dates of April 1st and October 1st. In addition, the Partnership may request up to three additional redeterminations of the borrowing base during any 12-month period. The credit agreement was further amended on May 22, 2015 to, among other things, increase the borrowing base from $110.0 million to $175.0 million and to provide for certain restrictions on purchasing margin stock. As of September 30, 2015, the borrowing base remained at $175.0 million. The Partnership had $29.0 million outstanding under its credit agreement as of September 30, 2015.

The outstanding borrowings under the credit agreement bear interest at a rate elected by the Partnership that is equal to an alternative base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.5% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.5% to 1.50% in the case of the alternative base rate and from 1.50% to 2.50% in the case of LIBOR, in each case depending on the amount of the loan outstanding in relation to the borrowing base. The Partnership 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 repaid (a) to the extent that 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 July 8, 2019. The loan is secured by substantially all of the assets of the Partnership and its subsidiaries.

The credit agreement contains various affirmative, negative and financial maintenance covenants. These covenants, among other things, limit additional indebtedness, purchases of margin stock, 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[1]	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

(1) EBITDAX is annualized for the four fiscal quarters ending on the last day of the fiscal quarter for which financial statements are available, beginning with the quarter ended September 30, 2014.

The covenant prohibiting additional indebtedness allows for the issuance of unsecured debt of up to $250.0 million in the form of senior unsecured 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.

The lenders may accelerate all of the indebtedness under the Partnership’s credit agreement upon the occurrence and during the continuance of any event of default. The Partnership’s 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.

9. CAPITAL STOCK AND EARNINGS PER SHARE

As of September 30, 2015, Diamondback had completed the following equity offerings since January 1, 2014:

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Notes to Consolidated Financial Statements-(Continued)
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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.

In July 2014, the Company completed an underwritten public offering of 5,750,000 shares of common stock, which included 750,000 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 $87.00 per share and the Company received net proceeds of approximately $485.0 million from the sale of these shares of common stock, net of offering expenses and underwriting discounts and commissions.

In January 2015, the Company completed an underwritten public offering of 2,012,500 shares of common stock, which included 262,500 shares of common stock issued pursuant to an option to purchase additional shares granted to the underwriters. The stock was sold to the underwriters at $59.34 per share and the Company received net proceeds of approximately $119.4 million from the sale of these shares of common stock, net of offering expenses and underwriting discounts and commissions.

In May 2015, 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 underwriters at $72.53 per share and the Company received net proceeds of approximately $333.6 million from the sale of these shares of common stock, net of offering expenses and underwriting discounts and commissions.

In August 2015, the Company completed an underwritten public offering of 2,875,000 shares of common stock, which included 375,000 shares of common stock issued pursuant to an option to purchase additional shares granted to the underwriters. The stock was sold to the underwriters at $68.74 per share and the Company received net proceeds of approximately $197.6 million from the sale of these shares of common stock, net of offering expenses and underwriting discounts and commissions.

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. Diluted earnings per share include the effect of potentially dilutive shares outstanding for the period. Additionally, for the diluted earnings per share computation, the per share earnings of the Partnership are included in the consolidated earnings per share computation based on the consolidated group’s holdings of the subsidiary. A reconciliation of the components of basic and diluted earnings per common share is presented in the table below:

	Three Months Ended September 30,					
	2015			2014		
	Income	Shares	Per Share	Income	Shares	Per Share
	(in thousands, except per share amounts)					

Basic:						
Net income attributable to common stock	$(156,781)	65,251	$(2.40)	$43,739	55,152	$0.79
Effect of Dilutive Securities:						
Dilutive effect of potential common shares issuable	$—	—		(53)	290	
Diluted:						
Net income attributable to common stock	$(156,781)	65,251	$(2.40)	$43,686	55,442	$0.79

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Diamondback Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements-(Continued)
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	Nine Months Ended September 30,					
	2015			2014		
	Income	Shares	Per Share	Income	Shares	Per Share
	(in thousands, except per share amounts)					
Basic:						
Net income attributable to common stock	$(363,219)	61,727	$(5.88)	$95,081	51,489	$1.85
Effect of Dilutive Securities:						
Dilutive effect of potential common shares issuable	$—	—		16	399	
Diluted:						
Net income attributable to common stock	$(363,219)	61,727	$(5.88)	$95,097	51,888	$1.83

For the three and nine months ended September 30, 2015, there were 124,400 shares and 191,118 shares, respectively, that were not included in the computation of diluted earnings per share because their inclusion would have been anti-dilutive for the periods presented but could potentially dilute basic earnings per share in future periods.

10. EQUITY-BASED COMPENSATION

The following table presents the effects of the equity compensation plans and related costs:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
General and administrative expenses	$4,402	$2,069	$13,659	$5,387
Equity-based compensation capitalized pursuant to full cost method of accounting for oil and natural gas properties	1,534	2,043	5,125	4,758

Stock Options

The following table presents the Company’s stock option activity under the Company’s 2012 Equity Incentive Plan (“2012 Plan”) for the nine months ended September 30, 2015.

	Options	Weighted Average Exercise Price	Remaining Term (in years)	Intrinsic Value (in thousands)
Outstanding at December 31, 2014	313,105	$18.29		
Exercised	(150,605)	$18.05		
Outstanding at September 30, 2015	162,500	$18.51	1.29	$7,489
Vested and Expected to Vest at September 30, 2015	162,500	$18.51	1.29	$7,489
Exercisable at September 30, 2015	118,500	$17.50	1.03	$5,581

The aggregate intrinsic value of stock options that were exercised during the nine months ended September 30, 2015 and 2014 was $8.4 million and $16.8 million, respectively. As of September 30, 2015, the unrecognized compensation cost related to unvested stock options was $0.1 million. Such cost is expected to be recognized over a weighted-average period of 1.27 years.

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

Restricted Stock Units

The following table presents the Company's restricted stock units activity under the 2012 Plan during the nine months ended September 30, 2015.

	Restricted Stock Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2014	167,291	$49.99
Granted	98,664	$68.46
Vested	(139,671)	$43.32
Forfeited	(1,954)	$74.57
Unvested at September 30, 2015	124,330	$61.74

The aggregate fair value of restricted stock units that vested during the nine months ended September 30, 2015 and 2014 was $9.8 million and $7.2 million, respectively. As of September 30, 2015, the Company's unrecognized compensation cost related to unvested restricted stock awards and units was $5.0 million. Such cost is expected to be recognized over a weighted-average period of 1.24 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 shareholder 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. In February 2015, eligible employees received additional performance restricted stock unit awards totaling 90,249 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, 2014 to December 31, 2016 and cliff vest at December 31, 2016.

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 for the February 2015 and February 2014 awards.

	2015	2014
Grant-date fair value	$137.14	$125.63
Risk-free rate	0.49%	0.30%
Company volatility	43.36%	39.60%

The following table presents the Company's performance restricted stock units activity under the 2012 Plan for the nine months ended September 30, 2015.

	Performance Restricted Stock	Weighted Average Grant-Date

	Units	Fair Value
Unvested at December 31, 2014	79,150	$125.63
Granted	90,249	$137.14
Unvested at September 30, 2015[(1)]	169,399	$131.76

(1) A maximum of 338,798 units could be awarded based upon the Company’s final TSR ranking.

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As of September 30, 2015, the Company’s unrecognized compensation cost related to unvested performance based restricted stock awards and units was $9.5 million. Such cost is expected to be recognized over a weighted-average period of 1.1 years.

Partnership Unit Options

In accordance with the Viper Energy Partners LP Long Term Incentive Plan (“Viper LTIP”), the exercise price of unit options granted may not be less than the market value of the common units at the date of grant. The units issued under the Viper LTIP will consist of new common units of the Partnership. On June 17, 2014, the Board of Directors of the General Partner granted 2,500,000 unit options to the executive officers of the General Partner. The unit options vest approximately 33% ratably on each of the first three anniversaries of the date of grant or earlier upon a change of control (as defined in the Viper LTIP). Vested unit options will be automatically exercised upon the earlier of a change of control or the third anniversary of the grant date unless extended in accordance with the terms of the Viper LTIP (the “Exercise Date”). In the event the fair market value per unit as of the Exercise Date is less than the exercise price per option unit, the vested options will automatically terminate and become null and void on the Exercise Date.

The fair value of the unit options on the date of grant is expensed over the applicable vesting period. The Partnership estimates the fair values of unit options granted using a Black-Scholes option valuation model, which requires the Partnership to make several assumptions. At the time of grant the Partnership did not have a history of market prices, thus the expected volatility was determined using the historical volatility for a peer group of companies. The expected term of options granted was determined based on the contractual term of the awards. The risk-free interest rate is based on the U.S. treasury yield curve rate for the expected term of the unit option at the date of grant. The expected dividend yield was based upon projected performance of the Partnership.

	2014	
Grant-date fair value	$4.24	
Expected volatility	36.0	%
Expected dividend yield	5.9	%
Expected term (in years)	3.0	
Risk-free rate	0.99	%

The following table presents the unit option activity under the Viper LTIP for the nine months ended September 30, 2015.

		Weighted Average		
	Unit Options	Exercise Price	Remaining Term (in years)	Intrinsic Value (in thousands)
Outstanding at December 31, 2014	2,500,000	$26.00		
Granted	—	$—		
Outstanding at September 30, 2015	2,500,000	$—	1.75	$—
Vested and Expected to Vest at September 30, 2015	2,500,000	$—	1.75	$—
Exercisable at September 30, 2015	—	$—	0	$—

As of September 30, 2015, the unrecognized compensation cost related to unvested unit options was $6.1 million. Such cost is expected to be recognized over a weighted-average period of 1.8 years.

Phantom Units

Under the Viper LTIP, the Board of Directors of the General Partner is authorized to issue phantom units to eligible employees. The Partnership estimates the fair value of phantom units as the closing price of the Partnership's common units on the grant date of the award, which is expensed over the applicable vesting period. Upon vesting, the phantom units entitle the recipient to one common unit of the Partnership for each phantom unit.

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The following table presents the phantom unit activity under the Viper LTIP for the nine months ended September 30, 2015.

	Phantom Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2014	17,776	$ 19.51
Granted	24,690	$ 15.48
Vested	(17,118)	$ 17.57
Unvested at September 30, 2015	25,348	$ 16.89

The aggregate fair value of phantom units that vested during the nine months ended September 30, 2015 was $0.3 million. As of September 30, 2015, the unrecognized compensation cost related to unvested phantom units was $0.4 million. Such cost is expected to be recognized over a weighted-average period of 1.4 years.

11. RELATED PARTY TRANSACTIONS

Immediately upon the completion of the Company's initial public offering on October 17, 2012, Wexford beneficially owned approximately 47% of the Company's outstanding common stock. As of September 30, 2015, Wexford beneficially owned less than 1% of the Company's outstanding common stock. A partner at Wexford serves as Chairman of the Board of Directors of each of the Company and the General Partner. Another partner at Wexford serves a member of the Board of Directors of the General Partner.

Administrative Services

An entity then under common management with the Company provided technical, administrative and payroll services to the Company under a shared services agreement that 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, continued on a month-to-month basis. Effective August 31, 2014, this agreement was mutually terminated.

Effective January 1, 2012, the Company entered into an additional shared services agreement with this entity. Under this agreement, the Company provided 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. Thereafter, the agreement continued on a month-to-month basis subject to the right of either party to terminate the agreement upon 30 days' prior written notice. Effective August 31, 2014, this agreement was mutually terminated. Costs that are attributable to and billed to other affiliates are reported as other income-related party.

Drilling Services

Bison Drilling and Field Services LLC ("Bison") has performed drilling and field services for the Company under master drilling and field service agreements. Under the Company's most recent master drilling agreement with Bison, effective as of January 1, 2013, Bison committed to accept orders from the Company for the use of at least two of its rigs. At September 30, 2015, the Company was not utilizing any Bison 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. For the three and nine months ended September 30, 2014, the Company incurred total costs for services performed by

Bison of $0.9 million and $3.4 million, respectively. Bison is an affiliate of Wexford.

Effective September 9, 2013, the Company entered into a master service agreement with Panther Drilling Systems LLC ("Panther Drilling"), under which 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. For the three and nine months ended September 30, 2015, Panther Drilling did not perform any services for the Company. For the nine months ended September 30, 2014, the Company incurred $0.3 million for services performed by Panther

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Drilling. Panther Drilling did not perform any services for the Company for the three months ended September 30, 2014. Panther Drilling is an affiliate of Wexford.

Coronado Midstream

The Company is party to a gas purchase agreement, dated May 1, 2009, as amended, with Coronado Midstream LLC, formerly known as MidMar Gas LLC, an entity that owns a gas gathering system and processing plant in the Permian Basin. Under this agreement, Coronado Midstream LLC is obligated to purchase from the Company, and the Company is obligated to sell to Coronado Midstream LLC, 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 LLC is obligated to pay the Company 87% of the net revenue received by Coronado Midstream LLC 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 LLC's gas processing plant, and 94.56% of the net revenue received by Coronado Midstream LLC from the sale of such gas components and residue gas, extracted, recovered or otherwise processed at Chevron's Headlee plant. An entity controlled by Wexford had owned an approximately 28% equity interest in Coronado Midstream LLC until Coronado Midstream LLC was sold in March 2015. Coronado Midstream LLC is no longer a related party and any revenues, production and ad valorem taxes and gathering and transportation expense after March 2015 are not classified as those attributable to a related party. The Company recognized related party revenues from Coronado Midstream LLC of $5.2 million for the three months ended March 31, 2015. The Company recognized revenues from Coronado Midstream LLC of $6.8 million and $17.2 million for the three and nine months ended September 30, 2014, respectively. The Company recognized production and ad valorem taxes and gathering and transportation expenses from Coronado Midstream LLC of $1.1 million for the three months ended March 31, 2015. The Company recognized production and ad valorem taxes and gathering and transportation expenses from Coronado Midstream LLC of $1.1 million and $2.8 million for the three and nine months ended September 30, 2014, respectively. As of December 31, 2014, Coronado Midstream LLC owed the Company $4.0 million for the Company's portion of the net proceeds from the sale of gas, gas products and residue gas.

Midland Corporate Lease

Effective May 15, 2011, the Company occupied corporate office space in Midland, Texas under a lease with a five-year term. The office space is owned by an entity controlled by an affiliate of Wexford. The Company paid $0.3 million and $0.7 million for the three and nine months ended September 30, 2015, respectively, under this lease. The Company paid $0.1 million and $0.3 million for the three and nine months ended September 30, 2014, respectively, under this lease.

The following table contains information regarding recent amendments to the Midland corporate lease:

Date of Amendment	Reason for Amendment	Current Monthly Base Rent	New Monthly Base Rent or Rent for Additional Space	Approx. Annual Increase of Monthly Base Rent
Second quarter 2014	Lease additional space	$25,000	$27,000	N/A
Fourth quarter 2014[(1)]	Lease additional space	$27,000	$53,000	4%
November 2014[(2)(3)]	Extend the term	N/A	N/A	N/A
April 2015	Lease additional space	N/A	$23,000	N/A

June 2015	Lease additional space	N/A	$22,000	2%

(1) The monthly rent will continue to increase approximately 4% annually on June 1 of each year during the remainder of the lease term.

(2) The lease was amended to extend the term of the lease for an additional 10-year period.

(3) Upon commencement of the extension in June 2016, the monthly base rent will increase to $94,000, with an increase of approximately 2% annually.

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Field Office Lease

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 term of the lease expires on February 28, 2018. The Company paid rent of less than $0.1 million and $0.1 million to the related party for the three and nine months ended September 30, 2015, respectively. The Company paid rent of less than $0.1 million to the related party for both the three and nine months ended September 30, 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. During the third quarter of 2014, the Company entered into a sublease with Bison, in which Bison agreed to lease the field office space for the same term as the initial lease and agreed to pay the monthly rent of $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 $0.1 million and $0.2 million for the three and nine months ended September 30, 2014, 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 was also responsible for paying a portion of specified costs, fees and expenses associated with the operation of the premises. Effective September 23, 2014, this lease agreement was mutually terminated.

Advisory Services Agreement - The Company

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 $0.5 million, plus reasonable out-of-pocket expenses. The Advisory Services Agreement had an initial term of two years commencing on October 18, 2012, and continues 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 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 $0.1 million and $0.4 million for the three and nine months ended September 30, 2015, respectively, under the Advisory Services Agreement. The Company incurred total costs of $0.1 million and $0.4 million for the three and nine months ended September 30, 2014, respectively, under the Advisory Services Agreement.

Advisory Services Agreement- The Partnership

In connection with the closing of the Viper Offering, the Partnership and the General Partner entered into an advisory services agreement (the “Viper Advisory Services Agreement”) with Wexford, dated as of June 23, 2014, under which Wexford provides the Partnership and the General Partner with general financial and strategic advisory services related to the business in return for an annual fee of $0.5 million, plus reasonable out-of-pocket expenses. The Viper Advisory Services Agreement has an initial term of two years commencing on June 23, 2014, 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 Partnership or the General Partner terminates such agreement, the Partnership is obligated to pay all amounts due through the remaining term. In addition, the Partnership and the General Partner have agreed to pay Wexford to-be-negotiated market-based fees approved by the conflict committee of the board of directors of the General Partner for such services as may be provided by Wexford at the Partnership’s or the General Partner’s request in connection with acquisitions and divestitures, financings or other transactions in which they may be involved. The services provided by Wexford under the Viper Advisory Services Agreement do not extend to the Partnership or General Partners day-to-day business or operations. The Partnership and General Partner have agreed to indemnify Wexford and its affiliates from any and all losses arising out of or in connection with the Viper Advisory Services Agreement except for losses resulting from Wexford's or its affiliates' gross negligence or willful misconduct. For the three and nine months ended September 30, 2015, the Partnership incurred costs of $0.2 million and $0.5 million, respectively, under the Viper Advisory Services Agreement. For both the three and nine months ended September 30, 2014, the Partnership incurred costs of $0.1 million under the Viper Advisory Services Agreement.

12. 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 combined consolidated statements of operations under the caption “Gain (loss) on derivative instruments, net.”

The Company has used price swap contracts to reduce price volatility associated with certain of its oil sales. With respect to the Company's fixed price swap contracts, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is less than the swap price, and the Company is required to make a payment to the counterparty if the settlement price for any settlement period is greater than the swap price. The Company's derivative contracts are based upon reported settlement prices on commodity exchanges, with crude oil derivative settlements based on Argus Louisiana light sweet pricing, New York Mercantile Exchange West Texas Intermediate pricing or Inter–Continental Exchange pricing for Brent crude oil.

By using derivative instruments to hedge exposure to changes in commodity prices, the Company exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes the Company, which creates credit risk. The Company's counterparties are participants in the secured second amended and restated credit agreement, which is secured by substantially all of the assets of the guarantor subsidiaries; therefore, the Company is not required to post any collateral. The Company does not require collateral from its counterparties. The Company has entered into derivative instruments only with counterparties that are also lenders in our credit facility and have been deemed an acceptable credit risk.

As of September 30, 2015, the Company had open crude oil derivative positions with respect to future production as set forth in the table 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
October - December 2015	276,000	90.99

Crude Oil—NYMEX West Texas Intermediate Fixed Price Swap

Production Period	Volume (Bbls)	Fixed Swap Price
October - December 2015	460,000	84.10

Crude Oil—Inter–Continental Exchange Brent Fixed Price Swap

Production Period	Volume (Bbls)	Fixed Swap Price
October - December 2015	184,000	88.78
January - February 2016	91,000	88.72

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

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and liability positions that are with the same counterparty and are subject to contractual terms which provide for net settlement.

The following tables present the gross amounts of recognized derivative assets and liabilities, the amounts offset under master netting arrangements with counterparties and the resulting net amounts presented in the Company's consolidated balance sheets as of September 30, 2015 and December 31, 2014.

	September 30, 2015	December 31, 2014
	(in thousands)	
Gross amounts of recognized assets	$40,009	$117,541
Gross amounts offset in the Consolidated Balance Sheet	—	—
Net amounts of assets presented in the Consolidated Balance Sheet	$40,009	$117,541

The net amounts are classified as current or noncurrent based on their anticipated settlement dates. The net fair value of the Company's derivative assets and liabilities and their locations on the consolidated balance sheet are as follows:

	September 30, 2015	December 31, 2014
	(in thousands)	
Current Assets: Derivative instruments	$40,009	$115,607
Noncurrent Assets: Derivative instruments	—	1,934
Total Assets	$40,009	$117,541

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in thousands)			
Change in fair value of open non-hedge derivative instruments	$(7,901)	$16,440	$(77,532)	$5,630
Gain (loss) on settlement of non-hedge derivative instruments	35,504	(1,531)	104,366	(6,207)
Gain (loss) on derivative instruments	$27,603	$14,909	$26,834	$(577)

13. 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.

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

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

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

Assets and Liabilities Measured at Fair Value on a Recurring Basis

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

The following table provides fair value measurement information for financial assets and liabilities measured at fair value on a recurring basis as of September 30, 2015 and December 31, 2014.

	September 30, 2015	December 31, 2014
	(in thousands)	
Fixed price swaps:		
Quoted prices in active markets level 1	$—	$—
Significant other observable inputs level 2	40,009	117,541
Significant unobservable inputs level 3	—	—
Total	$40,009	$117,541

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 balance sheets.

	September 30, 2015		December 31, 2014	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in thousands)			
Debt:				
Revolving credit facility	$10,000	$10,000	$223,500	$223,500
7.625% Senior Notes due 2021	450,000	474,750	450,000	440,438
Partnership revolving credit facility	29,000	29,000	—	—

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 September 30, 2015 quoted market price, a Level 1 classification in the fair value hierarchy. The fair value of the Partnership's revolving credit facility approximates its carrying value based on borrowing rates available to us for bank loans with similar terms and maturities and is classified as Level 2 in the fair value hierarchy.

14. COMMITMENTS AND CONTINGENCIES

Lease Commitments

The following is a schedule of minimum future lease payments with commitments that have initial or remaining noncancelable lease terms in excess of one year as of September 30, 2015:

Year Ending December 31,	Drilling Rig Commitments	Office and Equipment Leases
	(in thousands)	
2016	$27,317	$1,743
2017	19,892	2,012
2018	13,031	1,932
2019	—	1,797
2020	—	1,618
Thereafter	—	9,337
Total	$60,240	$18,439

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.

Litigation

The Company is one of the defendants in a lawsuit that arose after a contractor’s ditching machine cut a third party’s refined gasoline pipeline. This matter possibly could result in an adverse outcome. The estimated possible damages are in the range of $2.0 million to $4.0 million plus attorneys’ fees. The Company believes any loss would be covered by its insurance and would not have a material adverse effect on the Company’s financial condition. The Company’s financial statements do not include a loss contingency reserve for this matter.

15. GUARANTOR FINANCIAL STATEMENTS

Diamondback E&P LLC, Diamondback O&G LLC and White Fang Energy LLC (the “Guarantor Subsidiaries”) are guarantors under the Indenture relating to the Senior Notes. On June 23, 2014, in connection with the Viper Offering, the Company designated the Partnership, the General Partner and Viper Energy Partners LLC (the “Non-Guarantor Subsidiaries”) as unrestricted subsidiaries under the Indenture and, upon such designation, Viper Energy Partners LLC, which was a guarantor under the Indenture prior to such designation, was released as a guarantor under the Indenture. Viper Energy Partners LLC is a limited liability company formed on September 18, 2013 to own and acquire mineral and other oil and natural gas interests in properties in the Permian Basin in West Texas. The following presents condensed combined consolidated financial information for the Company (which for purposes of this Note 16 is referred to as the “Parent”), the Guarantor Subsidiaries and the Non–Guarantor Subsidiaries on a consolidated basis. Elimination entries presented are necessary to combine the entities. The information is presented in accordance with the requirements of Rule 3-10 under the SEC’s Regulation S-X. The financial information may not necessarily be indicative of results of operations, cash flows or financial position had the Guarantor Subsidiaries operated as independent entities. The Company has not presented separate financial and narrative information for each of the Guarantor Subsidiaries because it believes such financial and narrative information would not provide any additional information that would be material in evaluating the sufficiency of the Guarantor Subsidiaries.

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Condensed Consolidated Balance Sheet
September 30, 2015
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$227	$38,649	$4,951	$—	$43,827
Restricted cash	—	—	500	—	500
Accounts receivable	9	72,635	10,596	2	83,242
Intercompany receivable	2,248,015	2,980,548	—	(5,228,563)	—
Inventories	—	2,602	—	—	2,602
Other current assets	497	42,318	453	—	43,268
Total current assets	2,248,748	3,136,752	16,500	(5,228,561)	173,439
Property and equipment:					
Oil and natural gas properties, at cost, based on the full cost method of accounting	—	3,306,760	543,304	—	3,850,064
Pipeline and gas gathering assets	—	7,176	—	—	7,176
Other property and equipment	—	48,913	—	—	48,913
Accumulated depletion, depreciation, amortization and impairment	—	(1,089,767)	(59,386)	1,217	(1,147,936)
Net property and equipment	—	2,273,082	483,918	1,217	2,758,217
Investment in subsidiaries	274,184	—	—	(274,184)	—
Other assets	13,773	10,259	35,866	—	59,898
Total assets	$2,536,705	$5,420,093	$536,284	$(5,501,528)	$2,991,554
Liabilities and Stockholders' Equity					
Current liabilities:					
Accounts payable-trade	$—	$32,010	$—	$—	$32,010
Intercompany payable	2	5,228,559	—	(5,228,561)	—
Other current liabilities	30,292	135,766	2,104	—	168,162
Total current liabilities	30,294	5,396,335	2,104	(5,228,561)	200,172
Long-term debt	450,000	10,000	29,000	—	489,000
Asset retirement obligations	—	12,662	—	—	12,662
Total liabilities	480,294	5,418,997	31,104	(5,228,561)	701,834
Commitments and contingencies					
Stockholders' equity:	2,056,411	1,096	505,180	(506,276)	2,056,411
Noncontrolling interest	—	—	—	233,309	233,309
Total equity	2,056,411	1,096	505,180	(272,967)	2,289,720
Total liabilities and equity	$2,536,705	$5,420,093	$536,284	$(5,501,528)	$2,991,554

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Diamondback Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements-(Continued)
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Condensed Consolidated Balance Sheet
December 31, 2014
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$6	$15,067	$15,110	$—	$30,183
Restricted cash	—	—	500	—	500
Accounts receivable	—	85,752	8,239	2	93,993
Accounts receivable - related party	—	4,001	—	—	4,001
Intercompany receivable	1,658,215	2,167,434	—	(3,825,649)	—
Inventories	—	2,827	—	—	2,827
Other current assets	562	119,392	253	—	120,207
Total current assets	1,658,783	2,394,473	24,102	(3,825,647)	251,711
Property and equipment					
Oil and natural gas properties, at cost, based on the full cost method of accounting	—	2,607,513	511,084	—	3,118,597
Pipeline and gas gathering assets	—	7,174	—	—	7,174
Other property and equipment	—	48,180	—	—	48,180
Accumulated depletion, depreciation, amortization and impairment	—	(351,200)	(32,799)	1,855	(382,144)
	—	2,311,667	478,285	1,855	2,791,807
Investment in subsidiaries	839,217	—	—	(839,217)	—
Other assets	9,155	7,793	35,015	—	51,963
Total assets	$2,507,155	$4,713,933	$537,402	$(4,663,009)	$3,095,481
Liabilities and Stockholders' Equity					
Current liabilities:					
Accounts payable-trade	$—	$26,224	$6	$—	$26,230
Intercompany payable	95,362	3,730,287	—	(3,825,649)	—
Other current liabilities	49,190	189,264	2,045	—	240,499
Total current liabilities	144,552	3,945,775	2,051	(3,825,649)	266,729
Long-term debt	450,000	223,500	—	—	673,500
Asset retirement obligations	—	8,447	—	—	8,447
Deferred income taxes	161,592	—	—	—	161,592
Total liabilities	756,144	4,177,722	2,051	(3,825,649)	1,110,268
Commitments and contingencies					
Stockholders' equity:	1,751,011	536,211	535,351	(1,071,562)	1,751,011
Noncontrolling interest	—	—	—	234,202	234,202
Total equity	1,751,011	536,211	535,351	(837,360)	1,985,213
Total liabilities and equity	$2,507,155	$4,713,933	$537,402	$(4,663,009)	$3,095,481

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

Condensed Consolidated Statement of Operations
Three Months Ended September 30, 2015
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil sales	$—	$84,002	$—	$17,305	$101,307
Natural gas sales	—	4,905	—	768	5,673
Natural gas liquid sales	—	4,262	—	704	4,966
Royalty income	—	—	18,777	(18,777)	—
Total revenues	—	93,169	18,777	—	111,946
Costs and expenses:					
Lease operating expenses	—	22,189	—	—	22,189
Production and ad valorem taxes	—	7,280	1,686	—	8,966
Gathering and transportation	—	1,521	167	—	1,688
Depreciation, depletion and amortization	—	43,655	8,737	(17)	52,375
Impairment expense	—	273,737	—	—	273,737
General and administrative expenses	4,020	1,864	1,642	—	7,526
Asset retirement obligation accretion expense	—	238	—	—	238
Total costs and expenses	4,020	350,484	12,232	(17)	366,719
Income (loss) from operations	(4,020)	(257,315)	6,545	17	(254,773)
Other income (expense)					
Interest expense	(8,914)	(1,361)	(358)	—	(10,633)
Other income	—	92	168	—	260
Other income - related party	—	40	—	—	40
Gain on derivative instruments, net	—	27,603	—	—	27,603
Total other income (expense), net	(8,914)	26,374	(190)	—	17,270
Income (loss) before income taxes	(12,934)	(230,941)	6,355	17	(237,503)
Benefit from income taxes	(81,461)	—	—	—	(81,461)
Net income (loss)	68,527	(230,941)	6,355	17	(156,042)
Less: Net income attributable to noncontrolling interest	—	—	—	739	739
Net income (loss) attributable to Diamondback Energy, Inc.	$68,527	$(230,941)	$6,355	$(722)	$(156,781)

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

Condensed Consolidated Statement of Operations
Three Months Ended September 30, 2014
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil sales	$—	$105,202	$—	$21,204	$126,406
Natural gas sales	—	3,824	—	888	4,712
Natural gas liquid sales	—	6,880	—	1,129	8,009
Royalty income	—	—	22,767	(22,767)	—
Total revenues	—	115,906	22,767	454	139,127
Costs and expenses:					
Lease operating expenses	—	13,805	—	—	13,805
Production and ad valorem taxes	—	7,475	1,460	19	8,954
Gathering and transportation	—	866	—	(6)	860
Depreciation, depletion and amortization	—	38,028	9,025	(1,683)	45,370
General and administrative expenses	4,063	1,039	2,143	(750)	6,495
Asset retirement obligation accretion expense	—	127	—	—	127
Total costs and expenses	4,063	61,340	12,628	(2,420)	75,611
Income (loss) from operations	(4,063)	54,566	10,139	2,874	63,516
Other income (expense)					
Interest expense	(8,821)	(708)	(317)	—	(9,846)
Other income	6	—	11	—	17
Other income - intercompany	—	781	—	(750)	31
Other expense	—	(8)	—	—	(8)
Other expense - intercompany	—	—	(750)	750	—
Gain on derivative instruments, net	—	14,909	—	—	14,909
Total other income (expense), net	(8,815)	14,974	(1,056)	—	5,103
Income (loss) before income taxes	(12,878)	69,540	9,083	2,874	68,619
Provision for income taxes	23,978	—	—	—	23,978
Net income (loss)	(36,856)	69,540	9,083	2,874	44,641
Less: Net income attributable to noncontrolling interest	—	—	—	902	902
Net income (loss) attributable to Diamondback Energy, Inc.	$(36,856)	$69,540	$9,083	$1,972	$43,739

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

Condensed Consolidated Statement of Operations
Nine Months Ended September 30, 2015
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil sales	$—	$250,704	$—	$51,146	$301,850
Natural gas sales	—	12,580	—	1,851	14,431
Natural gas liquid sales	—	14,185	—	1,944	16,129
Royalty income	—	—	54,941	(54,941)	—
Total revenues	—	277,469	54,941	—	332,410
Costs and expenses:					
Lease operating expenses	—	65,117	—	—	65,117
Production and ad valorem taxes	—	20,605	4,431	—	25,036
Gathering and transportation	—	4,176	167	—	4,343
Depreciation, depletion and amortization	—	141,923	26,587	638	169,148
Impairment expense	—	597,188	—	—	597,188
General and administrative expenses	12,773	6,172	4,501	—	23,446
Asset retirement obligation accretion expense	—	588	—	—	588
Total costs and expenses	12,773	835,769	35,686	638	884,866
Income (loss) from operations	(12,773)	(558,300)	19,255	(638)	(552,456)
Other income (expense)					
Interest expense	(26,735)	(3,936)	(733)	—	(31,404)
Other income	1	169	960	—	1,130
Other income - related party	—	118	—	—	118
Gain on derivative instruments, net	—	26,834	—	—	26,834
Total other income (expense), net	(26,734)	23,185	227	—	(3,322)
Income (loss) before income taxes	(39,507)	(535,115)	19,482	(638)	(555,778)
Benefit from income taxes	(194,823)	—	—	—	(194,823)
Net income (loss)	155,316	(535,115)	19,482	(638)	(360,955)
Less: Net income attributable to noncontrolling interest	—	—	—	2,264	2,264
Net income (loss) attributable to Diamondback Energy, Inc.	$155,316	$(535,115)	$19,482	$(2,902)	$(363,219)

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

Condensed Consolidated Statement of Operations
Nine Months Ended September 30, 2014
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil sales	$—	$280,024	$—	$51,422	$331,446
Natural gas sales	—	10,394	—	1,982	12,376
Natural gas liquid sales	—	17,394	—	2,919	20,313
Royalty income	—	—	55,869	(55,869)	—
Total revenues	—	307,812	55,869	454	364,135
Costs and expenses:					
Lease operating expenses	—	32,216	—	—	32,216
Production and ad valorem taxes	—	19,540	3,791	19	23,350
Gathering and transportation	—	2,151	—	(6)	2,145
Depreciation, depletion and amortization	—	98,445	19,602	(1,683)	116,364
General and administrative expenses	11,476	1,832	2,584	(906)	14,986
Asset retirement obligation accretion expense	—	303	—	—	303
Total costs and expenses	11,476	154,487	25,977	(2,576)	189,364
Income (loss) from operations	(11,476)	153,325	29,892	3,030	174,771
Other income (expense)					
Interest income - intercompany	10,755	—	—	(10,755)	—
Interest expense	(21,365)	(2,408)	(317)	—	(24,090)
Interest expense - intercompany	—	—	(10,755)	10,755	—
Other income	6	—	11	—	17
Other income - related party	—	997	—	(906)	91
Other expense	—	(1,416)	—	—	(1,416)
Other expense - intercompany	—	—	(906)	906	—
Loss on derivative instruments, net	—	(577)	—	—	(577)
Total other income (expense), net	(10,604)	(3,404)	(11,967)	—	(25,975)
Income (loss) before income taxes	(22,080)	149,921	17,925	3,030	148,796
Provision for income taxes	52,742	—	—	—	52,742
Net income (loss)	(74,822)	149,921	17,925	3,030	96,054
Less: Net income attributable to noncontrolling interest	—	—	—	973	973
Net income (loss) attributable to Diamondback Energy, Inc.	$(74,822)	$149,921	$17,925	$2,057	$95,081

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

Condensed Consolidated Statement of Cash Flows
Nine Months Ended September 30, 2015
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided (used in) by operating activities	$(19,081)	$312,712	$45,973	$—	$339,604
Cash flows from investing activities:					
Additions to oil and natural gas properties	—	(326,538)	71	—	(326,467)
Acquisition of leasehold interests	—	(425,507)	—	—	(425,507)
Acquisition of mineral interests	—	—	(32,291)	—	(32,291)
Purchase of other property and equipment	—	(992)	—	—	(992)
Proceeds from sale of property and equipment	—	97	—	—	97
Equity investments	—	(2,702)	—	—	(2,702)
Intercompany transfers	(147,214)	147,214	—	—	—
Other investing activities	—	(2)	—	—	(2)
Net cash provided by (used in) investing activities	(147,214)	(608,430)	(32,220)	—	(787,864)
Cash flows from financing activities:					
Proceeds from borrowing on credit facility	—	363,501	29,000	—	392,501
Repayment on credit facility	—	(577,001)	—	—	(577,001)
Proceeds from public offerings	650,688	—	—	—	650,688
Distribution from subsidiary	46,496	—	—	(46,496)	—
Distribution to non-controlling interest	—	—	(52,609)	46,496	(6,113)
Intercompany transfers	(532,800)	532,800	—	—	—
Other financing activities	2,132	—	(303)	—	1,829
Net cash provided by (used in) financing activities	166,516	319,300	(23,912)	—	461,904
Net increase (decrease) in cash and cash equivalents	221	23,582	(10,159)	—	13,644
Cash and cash equivalents at beginning of period	6	15,067	15,110	—	30,183
Cash and cash equivalents at end of period	$227	$38,649	$4,951	$—	$43,827

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

Condensed Consolidated Statement of Cash Flows
Nine Months Ended September 30, 2014
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by operating activities	$1,915	$220,447	$29,633	$—	$251,995
Cash flows from investing activities:					
Additions to oil and natural gas properties	—	(307,144)	(5,275)	—	(312,419)
Acquisition of leasehold interests	—	(840,482)	—	—	(840,482)
Acquisition of mineral interests	—	—	(57,688)	—	(57,688)
Purchase of other property and equipment	—	(43,215)	—	—	(43,215)
Cost method investment	—	—	(33,851)	—	(33,851)
Intercompany transfers	(631,100)	631,100	—	—	—
Other investing activities	—	(1,426)	—	—	(1,426)
Net cash used in investing activities	(631,100)	(561,167)	(96,814)	—	(1,289,081)
Cash flows from financing activities:					
Proceeds from borrowing on credit facility	—	347,900	78,000	—	425,900
Repayment on credit facility	—	(217,900)	(78,000)	—	(295,900)
Proceeds from public offerings	693,886	—	234,546	—	928,432
Distribution to parent	—	—	(148,760)	—	(148,760)
Distribution to subsidiary	148,760	—	—	—	148,760
Intercompany transfers	(217,900)	217,900	—	—	—
Other financing activities	10,431	(825)	(5,863)	—	3,743
Net cash provided by (used in) financing activities	635,177	347,075	79,923	—	1,062,175
Net increase (decrease) in cash and cash equivalents	5,992	6,355	12,742	—	25,089
Cash and cash equivalents at beginning of period	526	14,267	762	—	15,555
Cash and cash equivalents at end of period	$6,518	$20,622	$13,504	$—	$40,644

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 report 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, 2014. 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 73% oil, 16% natural gas liquids and 11% natural gas for the three months ended September 30, 2015, and was approximately 75% oil, 14% natural gas liquids and 11% natural gas for the three months ended September 30, 2014. Our production was approximately 74% oil, 15% natural gas liquids and 11% natural gas for the nine months ended September 30, 2015, and was approximately 76% oil, 14% natural gas liquids and 10% natural gas for the nine months ended September 30, 2014. On September 30, 2015, our net acreage position in the Permian Basin was approximately 85,229 net acres.

2015 Highlights

Common stock transactions

In January 2015, we completed an underwritten public offering of 2,012,500 shares of common stock, which included 262,500 shares of common stock issued pursuant to an option to purchase additional shares granted to the underwriters. The stock was sold to the underwriters at $59.34 per share and we received net proceeds of approximately $119.4 million from the sale of these shares of common stock, net of offering expenses and underwriting discounts and commissions.

In May 2015, we completed an underwritten public offering of 4,600,000 shares of common stock, which included 600,000 shares of common stock issued pursuant to an option to purchase additional shares granted to the underwriters. The stock was sold to the underwriters at $72.53 per share and we received net proceeds of approximately $333.6 million from the sale of these shares of common stock, net of offering expenses and underwriting discounts and commissions.

In August 2015, we completed an underwritten public offering of 2,875,000 shares of common stock, which included 375,000 shares of common stock issued pursuant to an option to purchase additional shares granted to the underwriters. The stock was sold to the underwriters at $68.74 per share and we received net proceeds of approximately $197.6 million from the sale of these shares of common stock, net of offering expenses and underwriting discounts and commissions.

Acquisitions

Since January 1, 2015, we have acquired from unrelated third party sellers an aggregate of approximately 16,034 gross (12,396 net) acres in the Midland Basin, primarily in northwest Howard County, in the Permian Basin, for an aggregate purchase price of approximately $425.5 million, subject to certain adjustments. Approximately 83% of this acreage is held by production. We believe the acreage is prospective for horizontal drilling in the Lower Spraberry, Wolfcamp A and Wolfcamp B horizons, and have identified an aggregate of approximately 232 net potential horizontal drilling locations in these horizons based on 660 foot spacing between wells. We currently estimate that approximately 42% of the potential horizontal locations will have approximately 10,000 foot laterals, which can provide higher rates of return and capital efficiency than shorter laterals. The average lateral length for these potential horizontal locations is estimated to be approximately 8,357 feet. We also believe that additional development potential may exist in the Middle Spraberry horizon. Salt water disposal infrastructure is already in place on the acreage in Northwest Howard County, and the acquisitions include 3-D seismic data that can be used to geosteer the drilling of horizontal wells. On July 9, 2015, we completed the sale of an approximate average 1.5% overriding royalty interest in certain of our acreage primarily located in Howard County, Texas to the Partnership for $31.1 million.

Operating Results Overview

During the three months ended September 30, 2015, our average daily production was approximately 34,082 BOE/d, consisting of 24,956 Bbls/d of oil, 23,068 Mcf/d of natural gas and 5,281 Bbls/d of natural gas liquids, an increase of 13,446 BOE/d, or 65%, from average daily production of 20,636 BOE/d for the three months ended September 30, 2014, consisting of 15,503 Bbls/d of oil, 13,058 Mcf/d of natural gas and 2,957 Bbls/d of natural gas liquids.

During the nine months ended September 30, 2015, our average daily production was approximately 31,576 BOE/d, consisting of 23,589 Bbls/d of oil, 20,235 Mcf/d of natural gas and 4,615 Bbls/d of natural gas liquids, an increase of 14,208 BOE/d, or 81.8%, from average daily production of 17,368 BOE/d for the nine months ended September 30, 2014, consisting of 13,176 Bbls/d of oil, 10,619 Mcf/d of natural gas and 2,422 Bbls/d of natural gas liquids.

During the three months ended September 30, 2015, we drilled 21 gross (18 net) horizontal wells and participated in the drilling of six gross (2.6 net) non-operated wells in the Permian Basin. During the nine months ended September 30, 2015, we drilled 47 gross (40 net) horizontal wells and three gross (two net) vertical wells and participated in the drilling of 12 gross (five net) non-operated wells in the Permian Basin.

During the third quarter of 2015, we completed our first operated Wolfcamp A well as part of a triple stacked lateral that included a Lower Spraberry and Wolfcamp B. The Trailand A Unit 3906A has a 7,297 foot lateral and was completed with 33 frac stages. It achieved an average peak 30-day 2-stream initial production rate of 1,034 BOE/d (90% oil) on electric submersible pump when normalized to a 7,500 foot lateral. Initial performance indicates that this well is tracking a 750 to 850 MBOE type curve. The Lower Spraberry and Wolfcamp B completions appear consistent with our Ryder Scott type curves for Spanish Trail. We also completed our first operated Middle Spraberry well during the third quarter of 2015. The ST W 705MS has a lateral length of 7,503 feet and was completed with 32 stages. Its peak 30-hour 2-stream initial production rate is 851 BOE/d (91% oil) on electric submersible pump. During the third quarter of 2015, we began drilling our first three-well pad in Glasscock County, which targeted the Lower Spraberry, Wolfcamp A and Wolfcamp B formations. We intend to complete these wells later this year and are currently drilling another pad in the county that targets the Wolfcamp A and Wolfcamp B. We intend to begin drilling a three-well pad in Howard County at the end of the year. This pad will target the Lower Spraberry, Wolfcamp A and Wolfcamp B. We are drilling our first operated four-well stacked pad in southwest Martin County that targets the Middle Spraberry, Lower Spraberry, Wolfcamp A and Wolfcamp B.

As a result of the significant decline in prices from over $91.00 per Bbl in September 2014 to a range of prices between $38.00 per Bbl and $62.00 per Bbl in 2015, we recorded non-cash ceiling test impairments for the three and nine months ended September 30, 2015 of $273.7 million and $597.2 million, respectively.

Oil, natural gas liquids and gas prices have remained low in the fourth quarter of 2015. If prices remain at or below the current low levels, subject to numerous factors and inherent limitations, we will incur an additional non-cash full cost impairment in the fourth quarter of 2015, which will have an adverse effect on our results of operations.

We have received cost concessions from our service providers of 20% to 30% as compared to their peak pricing during 2014. During the third quarter of 2015, we added a fourth and fifth horizontal rig. In October 2015, we released one of our five rigs. We currently intend to run four horizontal rigs during the fourth quarter of 2015 and continue to expect to complete 60 to 70 gross horizontal wells during 2015 for an estimated $400.0 million to $450.0 million of capital expenditures in 2015. We believe that with service cost concessions and increased efficiencies, our high quality assets still provide us with economic wells in a lower cost environment.

Sources of our revenue

Our revenues are derived from the sale of oil and natural gas production, as well as the sale of natural gas liquids that are extracted from our natural gas during processing. Our oil and natural gas revenues do not include the effects of derivatives. For the three months ended September 30, 2015, our revenues were derived 91% from oil sales, 4% from natural gas liquids sales and 5% from natural gas sales and for the three months ended September 30, 2014, our revenues were derived 91% from oil sales, 6% from natural gas liquids sales and 3% from natural gas sales. For the nine months ended September 30, 2015, our revenues were derived 91% from oil sales, 5% from natural gas liquids sales and 4% from natural gas sales and for the nine months ended September 30, 2014, our revenues were derived 91% from oil sales, 6% from natural gas liquids sales and 3% 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.

Since our production consists primarily of oil, our revenues are more sensitive to fluctuations in oil prices than they are to fluctuations in natural gas liquids or natural gas prices. Oil, natural gas liquids and natural gas prices have historically been volatile. During 2014, West Texas Intermediate posted prices ranged from $53.45 to $107.95 per Bbl and the Henry Hub spot market price of natural gas ranged from $2.74 to $8.15 per MMBtu. On September 30, 2015, the West Texas Intermediate posted price for crude oil was $45.09 per Bbl and the Henry Hub spot market price of natural gas was $2.47 per MMBtu.

Results of Operations

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in thousands, except Bbl, Mcf and BOE amounts)			
Revenues:				
Oil, natural gas and natural gas liquids revenues	$111,946	$139,127	$332,410	$364,135
Operating Expenses:				
Lease operating expenses	22,189	13,805	65,117	32,216
Production and ad valorem taxes	8,966	8,954	25,036	23,350
Gathering and transportation expense	1,688	860	4,343	2,145
Depreciation, depletion and amortization	52,375	45,370	169,148	116,364
Impairment of oil and gas properties	273,737	—	597,188	—
General and administrative	7,526	6,495	23,446	14,986
Asset retirement obligation accretion expense	238	127	588	303
Total expenses	366,719	75,611	884,866	189,364
Income (loss) from operations	(254,773)	63,516	(552,456)	174,771
Net interest expense	(10,633)	(9,846)	(31,404)	(24,090)
Other income	300	48	1,248	108
Other expense	—	(8)	—	(1,416)
Gain (loss) on derivative instruments, net	27,603	14,909	26,834	(577)
Total other income (expense), net	17,270	5,103	(3,322)	(25,975)
Income (loss) before income taxes	(237,503)	68,619	(555,778)	148,796
Income tax provision (benefit)	(81,461)	23,978	(194,823)	52,742
Net income (loss)	(156,042)	44,641	(360,955)	96,054
Less: Net income attributable to noncontrolling interest	739	902	2,264	973
Net income (loss) attributable to Diamondback Energy, Inc.	$(156,781)	$43,739	(363,219)	95,081

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	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in thousands, except Bbl, Mcf and BOE amounts)			
Production Data:				
Oil (Bbls)	2,295,940	1,426,271	6,439,699	3,596,983
Natural gas (Mcf)	2,122,248	1,201,296	5,524,138	2,899,097
Natural gas liquids (Bbls)	485,871	272,013	1,259,777	661,160
Combined volumes (BOE)	3,135,519	1,898,500	8,620,166	4,741,326
Daily combined volumes (BOE/d)	34,082	20,636	31,576	17,367
Average Prices:				
Oil (per Bbl)	$44.12	$88.63	$46.87	$92.15
Natural gas (per Mcf)	2.67	3.92	2.61	4.27
Natural gas liquids (per Bbl)	10.22	29.44	12.80	30.72
Combined (per BOE)	35.70	73.28	38.56	76.80
Oil, hedged($/Bbl)(1)	59.59	87.55	63.08	90.42
Average price, hedged($/BOE)(1)	47.03	72.48	50.67	75.49
Average Costs (per BOE)				
Lease operating expense	$7.08	$7.27	$7.55	$6.79
Gathering and transportation expense	0.54	0.45	0.50	0.45
Production and ad valorem taxes	2.86	4.72	2.90	4.92
Production and ad valorem taxes as a % of sales	8.0 %	6.4 %	7.5 %	6.4 %
Depreciation, depletion, and amortization	$16.70	$23.90	$19.62	$24.54
General and administrative	2.40	3.42	2.72	3.16
Interest expense	3.39	5.19	3.64	5.08
Components of general and administrative expense:				
Non-cash stock based compensation, net of capitalized amounts	$4,402	$2,069	$13,659	$5,387
General and administrative cost per BOE excluding non-cash stock based compensation, net of capitalized amounts	$1.00	$2.33	$1.14	$2.03

(1) Hedged prices reflect the effect of our commodity derivative transactions on our average sales prices. Our calculation of such effects include realized gains and losses on cash settlements for commodity derivatives, which we do not designate for hedge accounting.

Comparison of the Three Months Ended September 30, 2015 and 2014

Oil, Natural Gas Liquids and Natural Gas Revenues. Our oil, natural gas liquids and natural gas revenues decreased by approximately $27.2 million, or 20%, to $111.9 million for the three months ended September 30, 2015 from $139.1 million for the three months ended September 30, 2014. 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 13,446 BOE/d to 34,082 BOE/d during the three months ended September 30, 2015 from 20,636 BOE/d during the three months ended September 30, 2014. The total decrease in revenue of approximately $27.2 million is largely attributable to lower average sales prices partially offset by higher oil, natural gas liquids and natural gas production volumes for the three months ended September 30, 2015 as compared to the three months ended September 30, 2014. The increases in production volumes were due to a combination of increased drilling activity and growth through acquisitions. Our production increased by 869,669 Bbls of oil, 213,858 Bbls of natural gas liquids and 920,952 Mcf of natural gas for the three months ended September 30, 2015 as compared to the three months ended September 30, 2014. The net dollar effect of the decreases in prices of approximately $114.2 million (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 $87.0 million (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	$(44.51)	2,295,940	$(102,192)
Natural gas liquids	(19.22)	485,871	(9,338)
Natural gas	(1.25)	2,122,248	(2,653)
Total revenues due to change in price			$(114,183)

	Change in production volumes(1)	Prior period average prices	Total net dollar effect of change (in thousands)
Effect of changes in production volumes:			
Oil	869,669	$88.63	$77,096
Natural gas liquids	213,858	29.44	6,296
Natural gas	920,952	3.92	3,610
Total revenues due to change in production volumes			87,002
Total change in revenues			$(27,181)

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

Lease Operating Expense. Lease operating expense was $22.2 million ($7.08 per BOE) for the three months ended September 30, 2015, an increase of $8.4 million, or 61%, from $13.8 million ($7.27 per BOE) for the three months ended September 30, 2014. The increase is due to increased drilling activity and acquisitions, which resulted in 236 additional gross producing wells as of September 30, 2015 as compared to September 30, 2014. Upon becoming the operator of wells acquired in our acquisitions, we seek to achieve the efficiencies in those wells that we have established with our existing portfolio of wells.

Production and Ad Valorem Tax Expense. Production and ad valorem taxes were $9.0 million for both the three months ended September 30, 2015 and 2014. 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, among other factors, whereas production taxes are based upon current year commodity prices. During the three months ended September 30, 2015, our production taxes per BOE decreased by $1.86 as compared to the three months ended September 30, 2014, primarily reflecting the impact of lower oil and natural gas prices on production taxes in 2015, offset by an increase in ad valorem taxes primarily as a result of increased production, as a result of our acquisitions and drilling activity.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased $7.0 million, or 15%, from $45.4 million for the three months ended September 30, 2014 to $52.4 million for the three months ended September 30, 2015.

The following table provides the components of our depreciation, depletion and amortization expense for the periods presented:

	Three Months Ended September 30,	
	2015	2014
	(in thousands, except BOE amounts)	
Depletion of proved oil and natural gas properties	$51,996	$45,010
Depreciation of other property and equipment	379	360
Depreciation, depletion and amortization	$52,375	$45,370
Oil and natural gas properties depreciation, depletion and amortization per BOE	$16.58	$23.71
Total depreciation, depletion and amortization per BOE	$16.70	$23.90

The increases in depletion of proved oil and natural gas properties of $7.0 million for the three months ended September 30, 2015 as compared to the three months ended September 30, 2014 resulted primarily from higher total production levels and an increase in net book value on new reserves. On a per BOE basis, depreciation, depletion and amortization decreased primarily due to the impairment of oil and gas properties recorded in the second and third quarter of 2015.

Impairment of Oil and Gas Properties. During the three months ended September 30, 2015, we recorded an impairment of oil and gas properties of $273.7 million as a result of the significant decline in prices from the second quarter of 2015.

General and Administrative Expense. General and administrative expense increased $1.0 million from $6.5 million for the three months ended September 30, 2014 to $7.5 million for the three months ended September 30, 2015. The increase was due to increases in salaries and benefits expense as a result of an increase in workforce and equity based compensation.

Net Interest Expense. Net interest expense for the three months ended September 30, 2015 was $10.6 million as compared to $9.8 million for the three months ended September 30, 2014, an increase of $0.8 million. This increase was due primarily to the higher average level of outstanding borrowings under our credit facility during the three months ended September 30, 2015 as compared to the three months ended September 30, 2014.

Derivatives. We are required to recognize all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. We have not designated our derivative instruments as hedges for accounting purposes. As a result, we mark our derivative instruments to fair value and recognize the cash and non-cash changes in fair value on derivative instruments in our combined consolidated statements of operations under the line item captioned “Gain (loss) on derivative instruments, net.” For the three months ended September 30, 2015 and 2014, we had a cash gain on settlement of derivative instruments of $35.5 million and a cash loss on settlement of derivative instruments of $1.5 million, respectively. For the three months ended September 30, 2015, we had a negative change in the fair value of open derivative instruments of $7.9 million as compared to a positive change in the fair value of open derivative instruments of $16.4 million during the three months ended September 30, 2014.

Income Tax Expense (Benefit). We recorded income tax benefit of $81.5 million for the three months ended September 30, 2015 as compared to $24.0 million for the three months ended September 30, 2014. Our effective tax rate was 34.3% for the three months ended September 30, 2015 as compared to 34.9% for the three months ended September 30, 2014.

Comparison of the Nine Months Ended September 30, 2015 and 2014

Oil, Natural Gas Liquids and Natural Gas Revenues. Our oil, natural gas liquids and natural gas revenues decreased by approximately $31.7 million, or 9%, to $332.4 million for the nine months ended September 30, 2015 from $364.1 million for the nine months ended September 30, 2014. 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 14,208 BOE/d to 31,576 BOE/d during the nine months ended September 30, 2015 from 17,368 BOE/d during the nine months ended September 30, 2014. The total decrease in revenue of approximately $31.7 million is largely attributable to lower average sales prices partially offset by higher oil, natural gas liquids and natural gas production volumes for the nine months ended September 30, 2015 as compared to the nine months ended September

30, 2014. The increases in production volumes were due to a combination of increased drilling activity and growth through acquisitions. Our production increased by 2,842,716 Bbls of oil, 598,617 Bbls of natural gas liquids and 2,625,041 Mcf of natural gas for the nine months ended September 30, 2015 as compared to the nine months ended September 30, 2014. The net dollar effect of the decreases in prices of approximately $323.3 million (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 $291.6 million (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	$(45.28)	6,439,699	$(291,590)
Natural gas liquids	$(17.92)	1,259,777	$(22,575)
Natural gas	$(1.66)	5,524,138	$(9,170)
Total revenues due to change in price			$(323,335)

	Change in production volumes(1)	Prior period average prices	Total net dollar effect of change (in thousands)
Effect of changes in production volumes:			
Oil	2,842,716	$92.15	$262,011
Natural gas liquids	598,617	$30.72	$18,390
Natural gas	2,625,041	$4.27	$11,209
Total revenues due to change in production volumes			$291,610
Total change in revenues			$(31,725)

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

Lease Operating Expense. Lease operating expense was $65.1 million ($7.55 per BOE) for the nine months ended September 30, 2015, an increase of $32.9 million, or 102%, from $32.2 million ($6.79 per BOE) for the nine months ended September 30, 2014. The increase is due to increased drilling activity and acquisitions, which resulted in 236 additional gross producing wells as of September 30, 2015 as compared to September 30, 2014. Upon becoming the operator of wells acquired in our acquisitions, we seek to achieve the efficiencies in those wells that we have established with our existing portfolio of wells.

Production and Ad Valorem Tax Expense. Production and ad valorem taxes increased to $25.0 million for the nine months ended September 30, 2015 from $23.4 million for the nine months ended September 30, 2014. 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, among other factors, whereas production taxes are based upon current year commodity prices. During the nine months ended September 30, 2015, our production taxes per BOE decreased by $2.02 as compared to the nine months ended September 30, 2014, primarily reflecting the impact of lower oil and natural gas prices on production taxes in 2015, offset by an increase in ad valorem taxes primarily as a result of increased production, as a result of our acquisitions and drilling activity.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased $52.8 million, or 45%, to $169.1 million for the nine months ended September 30, 2015 from $116.4 million for the nine months ended September 30, 2014.

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The following table provides the components of our depreciation, depletion and amortization expense for the periods presented:

	Nine Months Ended September 30,	
	2015	2014
	(in thousands, except BOE amounts)	
Depletion of proved oil and natural gas properties	$167,928	$115,437
Depreciation of other property and equipment	1,220	927
Depreciation, depletion and amortization	$169,148	$116,364
Oil and natural gas properties depreciation, depletion and amortization per BOE	$19.50	$24.39
Total depreciation, depletion and amortization per BOE	$19.62	$24.54

The increases in depletion of proved oil and natural gas properties of $52.8 million for the nine months ended September 30, 2015 as compared to the nine months ended September 30, 2014 resulted primarily from higher total production levels and an increase in net book value on new reserves. On a per BOE basis, depreciation, depletion and amortization decreased primarily due to the impairment of oil and gas properties recorded in the second and third quarter of 2015.

Impairment of Oil and Gas Properties. During the nine months ended September 30, 2015, we recorded an impairment of oil and gas properties of $597.2 million as a result of the significant decline in prices from the third quarter of 2014.

General and Administrative Expense. General and administrative expense increased $8.5 million from $15.0 million for the nine months ended September 30, 2014 to $23.4 million for the nine months ended September 30, 2015. The increase was due to increases in salaries and benefits expense as a result of an increase in workforce and equity-based compensation.

Net Interest Expense. Net interest expense for the nine months ended September 30, 2015 was $31.4 million as compared to $24.1 million for the nine months ended September 30, 2014, an increase of $7.3 million. This increase was due primarily to the higher average level of outstanding borrowings under our credit facility during the nine months ended September 30, 2015 as compared to the nine months ended September 30, 2014.

Derivatives. We are required to recognize all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. We have not designated our derivative instruments as hedges for accounting purposes. As a result, we mark our derivative instruments to fair value and recognize the cash and non-cash changes in fair value on derivative instruments in our combined consolidated statements of operations under the line item captioned “Gain (loss) on derivative instruments, net.” For the nine months ended September 30, 2015 and 2014, we had a cash gain on settlement of derivative instruments of $104.4 million and a cash loss on settlement of derivative instruments of $6.2 million, respectively. For the nine months ended September 30, 2015, we had a negative change in the fair value of open derivative instruments of $77.5 million as compared to a positive change in the fair value of open derivative instruments of $5.6 million during the three months ended September 30, 2014.

Income Tax Expense (Benefit). We recorded income tax benefit of $194.8 million for the nine months ended September 30, 2015 as compared to income tax expense of $52.7 million for the nine months ended September 30, 2014. Our effective tax rate was 35.1% for the nine months ended September 30, 2015 as compared to 35.4% for the nine months ended September 30, 2014.

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 nine months ended September 30, 2015 and 2014 are presented below:

	Nine Months Ended September 30,	
	2015	2014
	(in thousands)	
Net cash provided by operating activities	$339,604	$251,995
Net cash used in investing activities	(787,864)	(1,289,081)
Net cash provided by financing activities	461,904	1,062,175
Net change in cash	$13,644	$25,089

Operating Activities

Net cash provided by operating activities was $339.6 million for the nine months ended September 30, 2015 as compared to $252.0 million for the nine months ended September 30, 2014. The increase in operating cash flows is primarily the result of the increase in our oil and natural gas revenues due to an 81.8% increase in our net BOE production, partially offset by a 49.8% decrease in our net realized sales prices.

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. See “—Sources of our revenue” above.

Investing Activities

The purchase and development of oil and natural gas properties accounted for the majority of our cash outlays for investing activities. Net cash used in investing activities was $787.9 million and $1,289.1 million during the nine months ended September 30, 2015 and 2014, respectively.

During the nine months ended September 30, 2015, we spent $326.5 million on capital expenditures in conjunction with our infrastructure projects and drilling program, in which we drilled 47 gross (40 net) horizontal wells and three gross (two net) vertical wells and participated in the drilling of 12 gross (five net) non-operated wells in the Permian Basin. We spent an additional $425.5 million on leasehold costs, $1.0 million for the purchase of other property and equipment. In June 2015, we completed acquisitions of oil and natural gas leasehold and mineral interests in Howard County, Texas, in the Permian Basin from unrelated third party sellers for an aggregate purchase price of approximately $425.5 million. Also, during the first nine months of 2015, we completed several smaller acquisitions of oil and natural gas leasehold and mineral interests in the Permian Basin from unrelated third party sellers for an aggregate purchase price of $32.3 million.

During the nine months ended September 30, 2014, we spent $313.9 million on capital expenditures in conjunction with our drilling program in which we drilled 61 gross (49 net) horizontal wells, 31 gross (25 net) vertical wells and participated in the drilling of an additional three gross (one net) non-operated wells. We spent an additional $840.5 million on leasehold acquisitions and $43.2 million for the purchase of other property and equipment. In February 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 $289.0 million. On August 25, 2014, we completed an acquisition of surface rights in the Permian Basin from unrelated third party sellers for a purchase price of approximately $41.9 million. On September 9, 2014, we completed the acquisition of oil and natural gas interests from unrelated third party sellers of additional leasehold interests in Midland, Glasscock, Reagan and Upton Counties, Texas in the Permian Basin, for an aggregate purchase price of $524.5 million. We also spent approximately $57.7 million on acquisitions of mineral interests underlying approximately 10,565 gross (3,461) net acres in the Midland and Delaware basins and approximately $33.9 million for a minor equity interest in an entity that owns mineral, overriding royalty, net profits, leasehold and other similar interests.

Our investing activities for the nine months ended September 30, 2015 and 2014 are summarized in the following table:

	Nine Months Ended September 30,	
	2015	2014
	(in thousands)	
Drilling, completion and infrastructure	$(326,469)	$(313,856)
Acquisition of leasehold interests	(425,507)	(840,482)
Acquisition of mineral interests	(32,291)	(57,688)
Purchase of other property and equipment	(992)	(43,215)
Proceeds from sale of property and equipment	97	11
Equity investments	(2,702)	(33,851)
Net cash used in investing activities	$(787,864)	$(1,289,081)

Financing Activities

Net cash provided by financing activities for the nine months ended September 30, 2015 and 2014 was $461.9 million and $1,062.2 million, respectively. During the nine months ended September 30, 2015, the amount provided by financing activities was primarily attributable to the aggregate net proceeds from our January, May and August 2015 equity offerings of $650.7 million partially offset by repayments net of borrowings, of $184.5 million, under our credit facility. The 2014 amount provided by financing activities was primarily attributable to the net proceeds of $208.4 million from our February 2014 equity offering, net proceeds from the Viper Offering of $137.2 million, net proceeds of $485.0 million from our July 2014 equity offering, net proceeds of $95.1 million from the Viper September 2014 equity offering and borrowings, net of repayment of $130.0 million, under our credit facility.

The Company’s Second Amended and Restated Credit Facility

Our second amended and restated credit agreement, dated November 1, 2013, as amended on June 9, 2014 and November 13, 2014, with a syndicate of banks, including Wells Fargo, as administrative agent, sole book runner and lead arranger, provides for a revolving credit facility in the maximum amount of $2.0 billion, 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 is scheduled to be re-determined semi-annually with effective dates of May 1st and November 1st. In addition, we may request up to three additional redeterminations of the borrowing base during any 12-month period. As of September 30, 2015, the borrowing base was set at $725.0 million, although we elected a commitment amount of $500.0 million. As of September 30, 2015, we had outstanding borrowings of $10.0 million, which bore a weighted-average interest rate of 1.63%, and $490.0 million available for future borrowings under this facility. As of September 30, 2015, the credit agreement was guaranteed by Diamondback, Diamondback E&P LLC and White Fang Energy LLC and will also be guaranteed by any future restricted subsidiaries of Diamondback. The credit agreement is also secured by substantially all of the assets of Diamondback O&G LLC, the Company and the other guarantors.

The outstanding borrowings under the credit agreement bear interest at a rate elected by us that is equal to an alternative base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.5% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.5% to 1.50% in the case of the alternative base rate and from 1.50% to 2.50% in the case of LIBOR, 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 0.500% 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 repaid (a) to the extent that 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 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 $750.0 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 September 30, 2015, we had $450.0 million of senior unsecured notes outstanding.

As of September 30, 2015, 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 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.

Partnership Credit Facility-Wells Fargo Bank

On July 8, 2014, the Partnership entered into a secured revolving credit agreement with Wells Fargo, as the administrative agent, sole book runner and lead arranger. The credit agreement, which was amended August 15, 2014 to add additional lenders to the lending group, provides for a revolving credit facility in the maximum amount of $500.0 million, subject to scheduled semi-annual and other elective collateral borrowing base redeterminations based on the Partnership’s oil and natural gas reserves and other factors. The borrowing base is scheduled to be re-determined semi-annually with effective dates of April 1st and October 1st. The credit agreement was further amended on May 22, 2015 to, among other things, increase the borrowing base from $110.0 million to $175.0 million and to provide for certain restrictions on purchasing margin stock. In addition, the Partnership may request up to three additional redeterminations of the borrowing base during any 12-month period. As of September 30, 2015, the borrowing base remained at $175.0 million and the Partnership had $29.0 million outstanding borrowings.

The outstanding borrowings under the Partnership’s credit agreement bear interest at a rate elected by the Partnership that is equal to an alternative base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.5% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.5% to 1.50% in the case of the alternative base rate and from 1.50% to 2.50% in the case of LIBOR, in each case depending on the amount of the loan outstanding in relation to the borrowing base. The Partnership 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 repaid (a) to the extent that 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 July 8, 2019. The loan is secured by substantially all of the assets of the Partnership and its subsidiaries.

The credit agreement contains various affirmative, negative and financial maintenance covenants. These covenants, among other things, limit additional indebtedness, purchases of margin stock, 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[1]	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

(1) EBITDAX is annualized for the four fiscal quarters ending on the last day of the fiscal quarter for which financial statements are available, beginning with the quarter ended September 30, 2014.

The covenant prohibiting additional indebtedness allows for the issuance of unsecured debt of up to $250.0 million in the form of senior unsecured notes and, in connection with any such issuance, the reduction of the borrowing

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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.

The lenders may accelerate all of the indebtedness under the Partnership's credit agreement upon the occurrence and during the continuance of any event of default. The Partnership's 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.

Capital Requirements and Sources of Liquidity

Our board of directors approved a 2015 capital budget for drilling and infrastructure of $400.0 million to $450.0 million (although at the upper end of that range). We estimate that, of these expenditures, approximately:

- $285.0 million to $315.0 million will be spent on drilling and completing 60 to 70 gross (49 to 57 net) operated horizontal wells focused in Midland, Andrews, Upton, Martin and Dawson Counties;

- $20.0 million to $30.0 million will be spent on infrastructure;

- $20.0 million to $30.0 million will be spent on non-operated activity and other expenditures; and

- an estimated $75.0 million for expenditures related to 2014 activity (net of expenditures from 2015 expected to be carried into 2016).

During the nine months ended September 30, 2015, our aggregate capital expenditures for drilling and infrastructure were $326.5 million. We do not have a specific acquisition budget since the timing and size of acquisitions cannot be accurately forecasted. During the nine months ended September 30, 2015, we spent approximately $425.5 million on acquisitions of leasehold interests and $32.3 million on acquisitions of mineral interests. For information regarding our recently completed and pending acquisitions, see "—2015 Highlights—Acquisitions."

The amount and timing of these capital expenditures are 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 and production expectations for 2015, 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 2015. 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 2015 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.

Contractual Obligations

Except as discussed in Note 14 of the Notes to the Consolidated Financial Statements of this report, there were no material changes to our contractual obligations and other commitments, as disclosed in our Annual Report on Form 10-K for the year ended December 31, 2014.

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, 2014

Off-balance Sheet Arrangements

We had no off-balance sheet arrangements as of September 30, 2015. Please read Note 14 included in Notes to the Combined Consolidated Financial Statements set forth in Part I, Item 1 of this report, for a discussion of our commitments and contingencies, some of which are not recognized in the balance sheets under GAAP.

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.

At September 30, 2015, we had a net asset derivative position of $40.0 million, related to our price swap derivatives, as compared to a net asset derivative position of $117.5 million as of December 31, 2014 related to our price swap derivatives. Utilizing actual derivative contractual volumes under our fixed price swaps as of September 30, 2015, a 10% increase in forward curves associated with the underlying commodity would have decreased the net asset position to $35.2 million, a decrease of $4.8 million, while a 10% decrease in forward curves associated with the underlying commodity would have increased the net asset derivative position to $44.8 million, an increase of $4.8 million. However, any cash derivative gain or loss would be substantially offset by a decrease or increase, respectively, in the actual sales value of production covered by the derivative instrument.

Counterparty and Customer Credit Risk

Our principal exposures to credit risk are through receivables resulting from joint interest receivables (approximately $41.0 million at September 30, 2015) and receivables from the sale of our oil and natural gas production (approximately $42.2 million at September 30, 2015).

We are subject to credit risk due to the concentration of our oil and natural gas receivables with several significant customers. We do not require our customers to post collateral, and the inability of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. For the nine months ended September 30, 2015, two purchasers accounted for more than 10% of our revenue: Shell Trading (US) Company (60%) and Enterprise Crude Oil LLC (14%). For the year ended December 31, 2014, two purchasers accounted for more than 10% of our revenue: Shell Trading (US) Company (64%) and Enterprise Crude Oil LLC

(16%). 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 September 30, 2015, we had three customers that represented approximately 76% of our total joint operations receivables. At December 31, 2014, we had two customers that represented approximately 61% 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 an alternative base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.5% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.5% to 1.50% in the case of the alternative base rate and from 1.50% to 2.50% in the case of LIBOR, in each case depending on the amount of the loan outstanding in relation to the borrowing base. Our weighted-average interest rate on borrowings under our credit facility was 1.63% at September 30, 2015. An increase or decrease of 1% in the interest rate would have a corresponding decrease or increase in our interest expense of approximately $0.1 million based on the $10.0 million outstanding in the aggregate under our revolving credit facility on September 30, 2015.

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 September 30, 2015, 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 September 30, 2015, 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 September 30, 2015 that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting.

PART II
ITEM 1. LEGAL PROCEEDINGS

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.

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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 materially impair our business operations, financial condition or future results.

In addition to the information set forth in this report, 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, 2014. 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, 2014.

ITEM 6. EXHIBITS

EXHIBIT INDEX

Exhibit Number	Description
3.1	Amended and Restated Certificate of Incorporation of the Company (incorporated by reference to Exhibit 3.1 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on November 16, 2012).
3.2	Amended and Restated Bylaws of the Company (incorporated by reference to Exhibit 3.2 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on November 16, 2012).
4.1	Specimen certificate for shares of common stock, par value $0.01 per share, of the Company (incorporated by reference to Exhibit 4.1 to Amendment No. 4 to the Registration Statement on Form S-1, File No. 333-179502, filed by the Company with the SEC on August 20, 2012).
4.2	Registration Rights Agreement, dated as of October 11, 2012, by and between the Company and DB Energy Holdings LLC (incorporated by reference to Exhibit 4.2 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on November 16, 2012).
4.3	Investor Rights Agreement, dated as of October 11, 2012, by and between the Company and Gulfport Energy Corporation (incorporated by reference to Exhibit 4.3 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on November 16, 2012).
10.1*	Lease Amendment No. 11 effective July 31, 2014 to Lease Agreement dated as of April 19, 2011, as amended, by and between Fasken Midland, LLC and Diamondback E&P LLC.
10.2*	Lease Amendment No. 12 effective October 23, 2014 to Lease Agreement dated as of April 19, 2011, as amended, by and between Fasken Midland, LLC and Diamondback E&P LLC.
10.3*	Lease Amendment No. 13 effective October 30, 2014 to Lease Agreement dated as of April 19, 2011, as amended, by and between Fasken Midland, LLC and Diamondback E&P LLC.
10.4*	Lease Amendment No. 14 effective November 10, 2014 to Lease Agreement dated as of April 19, 2011, as amended, by and between Fasken Midland, LLC and Diamondback E&P LLC.
10.5*	Lease Amendment No. 15 effective November 10, 2014 to Lease Agreement dated as of April 19, 2011, as amended, by and between Fasken Midland, LLC and Diamondback E&P LLC.
10.6*	Lease Amendment No. 16 effective April 1, 2015 to Lease Agreement dated as of April 19, 2011, as amended, by and between Fasken Midland, LLC and Diamondback E&P LLC.
10.7*	Lease Amendment No. 17 effective June 1, 2015 to Lease Agreement dated as of April 19, 2011, as amended, by and between Fasken Midland, LLC and Diamondback E&P LLC.
31.1*	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
31.2*	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
32.1**	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
32.2**	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Labels Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.

*	Filed herewith.
**	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.

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: November 5, 2015	/s/ Travis D. Stice Travis D. Stice Chief Executive Officer (Principal Executive Officer)
Date: November 5, 2015	/s/ Teresa L. Dick Teresa L. Dick Chief Financial Officer (Principal Financial and Accounting Officer)