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

Form 10–K

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2018

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission File Number
001-33024

Harvest Oil & Gas Corp.

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**83–0656612** (I.R.S. Employer Identification No.)
1001 Fannin, Suite 750, Houston, Texas (Address of principal executive offices)	**77002** (Zip Code)

Registrant's telephone number, including area code: **(713) 651-1144**

Securities registered pursuant to Section 12(b) of the Act: **None**

Securities registered pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well–known seasoned issuer, as defined in Rule 405 of the Securities Act. YES ☐ NO ☑

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. YES ☐ NO ☑

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

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). YES ☑ NO ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S–K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10–K. ☑

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer", "accelerated filer", "smaller reporting company", and "emerging growth company" in Rule 12b–2 of the Exchange Act.

Large accelerated filer ☐	Accelerated filer ☐
Non-accelerated filer ☑	Smaller reporting company ☐
	Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b–2 of the Exchange Act). YES ☐ NO ☑

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Section 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. YES ☑ NO ☐

As of June 29, 2018, the last business day of the registrant's most recently completed second quarter, the registrant's equity was not listed on a domestic exchange or over-the-counter market. The registrant's common stock began trading on the OTCQX U.S. Premier Marketplace on September 20, 2018.

As of March 22, 2019, the registrant had 10,042,468 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:
Portions of the registrant's definitive proxy statement for its 2019 Annual Meeting of Stockholders, which will be filed with the United States Securities and Exchange Commission within 120 days of December 31, 2018, are incorporated by reference into Part III of this Annual Report on Form 10-K.

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GLOSSARY OF OIL AND NATURAL GAS TERMS

Bbl. One stock tank barrel or 42 US gallons liquid volume of oil or other liquid hydrocarbons.

Bcf. One billion cubic feet of natural gas.

Bcfe. One billion cubic feet equivalent of natural gas, determined using a ratio of one Bbl of oil, condensate or natural gas liquids to six Mcf of natural gas.

Btu. A British thermal unit is a measurement of the heat generating capacity of natural gas. One Btu is the heat required to raise the temperature of a one–pound mass of pure liquid water one degree Fahrenheit at the temperature at which water has its greatest density (39 degrees Fahrenheit).

Completion. Installation of permanent equipment for production of oil or gas, or, in the case of a dry well, reporting to the appropriate authority that the well has been abandoned.

Condensate. A mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

Developed oil and gas reserves. Reserves of any category that can be expected to be recovered:

- through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well, and

- through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Development costs. Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

- gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves;

- drill, fracture, stimulate and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly;

- acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

- provide improved recovery systems.

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

Dry hole or *well.* An exploratory, development or extension well that proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as a producing oil or gas well.

Exploration costs. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and natural gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells.

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir.

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

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

MBbls. One thousand barrels of oil or other liquid hydrocarbons.

Mcf. One thousand cubic feet of natural gas.

Mcfe. One thousand cubic feet equivalent of natural gas, determined using the ratio of one Bbl of oil, condensate or natural gas liquids to six Mcf of natural gas. The ratio of six Mcf of natural gas to one Bbl of oil or natural gas liquids is commonly used in the oil and natural gas business and represents the approximate energy equivalency of six Mcf of natural gas to one Bbl of oil or natural gas liquids, and does not represent the sales price equivalency of natural gas to oil or natural gas liquids.

MMBbls. One million barrels of oil or other liquid hydrocarbons.

MMBtu. One million British thermal units.

MMcf. One million cubic feet of natural gas.

MMcfe. One million cubic feet equivalent of natural gas, determined using the ratio of one Bbl of oil, condensate or natural gas liquids to six Mcf of natural gas.

Natural gas liquids. The hydrocarbon liquids contained within natural gas.

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

NYMEX. The New York Mercantile Exchange.

Oil. Crude oil and condensate.

Overriding royalty interest ("ORRI"). Fractional, undivided interests or rights of participation in the oil and natural gas, or in the proceeds from the sale of oil and natural gas, produced from a specified tract or tracts, which are limited in duration to the terms of an existing lease and which are not subject to any portion of the expense of development, operation or maintenance.

Production costs. Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

- costs of labor to operate the wells and related equipment and facilities;
- repairs and maintenance;
- materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities;

- property taxes and insurance applicable to proved properties and wells and related equipment and facilities; and
- severance taxes.

Productive well. An exploratory, development or extension well that is not a dry well.

Proved developed reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well. Additional reserves expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included in "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved reserves. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward from known reservoirs, and under existing economic conditions, operating methods and government regulations – prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

Proved undeveloped reserves ("PUDs"). Reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having PUDs only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Estimates for PUDs are not attributed to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

Recompletion. The completion for production of an existing wellbore in another formation from that which the well has been previously completed.

Reserves. Estimated remaining quantities of oil and 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 gas or related substances to market, and all permits and financing required to implement the project.

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

Standardized measure. The after-tax present value of estimated future net cash flows to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the Securities and Exchange Commission (the "SEC"), using prices and costs employed in the determination of proved reserves, without giving effect to non–property related expenses such as certain general and administrative expenses and debt service or to depreciation, depletion and amortization and discounted using an annual discount rate of 10%.

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

Undeveloped oil and gas reserves. Reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.

Workover. Operations on a producing well to restore or increase production.

PART I

ITEM 1. BUSINESS

Overview

Harvest Oil & Gas Corp. ("Harvest" or "Successor"), a Delaware corporation, is an independent oil and natural gas company that was formed in 2018 in connection with the reorganization of EV Energy Partners, L.P. ("EVEP," "Partnership" or "Predecessor"). As used herein, the terms the "Company," "we," "our" or "us" refer to (i) Harvest Oil & Gas Corp. after the Effective Date (as defined below) and (ii) EVEP prior to, and including, the Effective Date, in each case, together with their respective consolidated subsidiaries or on an individual basis, depending on the context in which the statements are made.

We operate one reportable segment engaged in the development and production of oil and natural gas properties. As of December 31, 2018, our oil and natural gas properties are located in the Barnett Shale, the San Juan Basin, the Appalachian Basin (which includes the Utica Shale), Michigan, the Mid–Continent areas in Oklahoma, Texas, Arkansas, Kansas and Louisiana, the Permian Basin and the Monroe Field in Northern Louisiana. As of December 31, 2018, we had estimated net proved reserves of 711.9 Bcfe and a standardized measure of $436.4 million. Of our total net proved reserves, 98% are proved developed, 67% are natural gas and 53% are operated.

As a result of the ongoing review of our asset base in order to maximize shareholder value, we have initiated processes to divest certain assets and in the future may look to divest additional assets or all of our remaining assets and use the proceeds to repay bank debt, return capital to shareholders, concentrate in existing positions or venture into new basins. In January and February 2019, we entered into definitive agreements to sell all of our oil and gas properties in the San Juan Basin and certain of our oil and gas properties in the Mid-Continent area. See "—Current Developments—Divestitures" below for additional information.

Emergence from Voluntary Reorganization under Chapter 11

On March 13, 2018, EVEP and 13 affiliated debtors (collectively, the "Debtors") entered into a Restructuring Support Agreement (the "Restructuring Support Agreement") with certain holders of the Predecessor's notes, certain lenders under the Predecessor's reserve-based lending facility, EnerVest, Ltd. ("EnerVest") and EnerVest Operating, L.L.C. The Restructuring Support Agreement set forth, subject to certain conditions, the commitment of the Debtors and the consenting creditors to support a comprehensive restructuring of the Debtors' long-term debt (the "Restructuring"). On April 2, 2018 (the "Petition Date"), the Debtors each filed Chapter 11 proceedings under Chapter 11 in the United States Bankruptcy Court for the District of Delaware (the "Bankruptcy Court"). The Debtors' Chapter 11 proceedings were jointly administered under the caption *In re EV Energy Partners, L.P., et al*., Case No. 18-10814. During the pendency of the Chapter 11 proceedings, EVEP continued to operate its business and manage its properties under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code and orders of the Bankruptcy Court as "Debtors-in-Possession." On May 17, 2018, the Bankruptcy Court entered an order confirming the Plan.

On June 4, 2018 (the "Effective Date"), the Debtors satisfied the conditions to effectiveness of the Debtors' First Modified Joint Prepackaged Plan of Reorganization (as amended, modified and supplemented from time to time, the "Plan"), and the Plan became effective in accordance with its terms. In accordance with the Plan, EVEP's equity was cancelled, EVEP transferred all of its assets and operations to Harvest, EVEP was dissolved and Harvest became the successor reporting company to EVEP pursuant to Rule 15d-5 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). See Note 2 and Note 3 of the Notes to Consolidated Financial Statements included under "Item 8. Financial Statements and Supplementary Data" contained herein for additional information.

Predecessor and Successor Reporting

Upon emergence from bankruptcy on the Effective Date, we elected to adopt fresh start accounting effective May 31, 2018 (the "convenience date") to coincide with the timing of the Company's normal accounting period close. As a result

of the adoption of fresh start accounting and the effects of the implementation of the Plan, the Company's consolidated financial statements and certain presentations are separated into two distinct periods, the period before the convenience date (labeled Predecessor) and the period after the convenience date (labeled Successor), to indicate the application of different basis of accounting between the periods presented. Despite the separate presentation, there was continuity of the Company's operations.

See Note 3 of the Notes to Consolidated Financial Statements included under "Item 8. Financial Statements and Supplementary Data" contained herein for additional information.

Current Developments

Our Operating Plan and Strategy

We focus our efforts on maintaining or minimizing the decline in our reserves and production while controlling costs at a level that is appropriate for long–term operations. Our future cash flows from operations are dependent upon our ability to manage our overall cost structure. As initial reservoir pressures are depleted, production from our wells decreases. We attempt to mitigate or reduce this natural decline through drilling or workover operations. We will maintain our focus on drilling costs as well as the costs necessary to produce our reserves. Our drilling program is dependent on our capital resources and the inventory and economics of drilling prospects and can be limited by many factors, including our ability to timely obtain drilling permits and regulatory approvals. Our overall operating plan also includes regular reviews of our asset base. As a result of this ongoing review, we have initiated processes to divest of certain assets, and in the future, we may look to divest additional assets or all of our remaining assets in order to maximize shareholder value.

In order to mitigate the impact of lower prices on our cash flows, we are a party to derivatives, and we intend to enter into derivatives in the future to reduce the impact of price volatility on our cash flows. Although we have entered into derivative contracts covering a portion of our future production through December 2020, a sustained lower price environment would result in lower prices for unprotected volumes and reduce the prices at which we can enter into derivative contracts for additional volumes in the future. We have mitigated, but not eliminated, the potential effects of changing prices on our cash flows from operations for those periods. An extended period of depressed commodity prices would alter our development plans, as well as adversely affect our ability to access additional capital in the capital markets. Please refer to Item 7A. "Quantitative And Qualitative Disclosures About Market Risk" contained herein for more information.

Divestitures

In August 2018, we closed the sale of certain oil and gas properties in Central Texas and Karnes County, Texas to Magnolia Oil & Gas Parent LLC and Magnolia Oil & Gas Corporation (collectively, "Magnolia") for total consideration of $134.4 million in cash, net of purchase price adjustments, and 4.2 million shares of common stock of Magnolia (NYSE: MGY). Based on the closing price for Magnolia's common stock on August 31, 2018, total consideration was $192.7 million, net of purchase price adjustments.

During January 2019, we sold all of our 4.2 million shares of common stock of Magnolia for net proceeds of $51.7 million.

In addition, in August 2018, we closed the sale of certain oil and gas properties in Central Texas to a third party for total consideration of $3.4 million, net of purchase price adjustments.

In December 2018, we closed the sale of certain oil and gas properties in Central Texas to a third party for total consideration of $2.6 million, net of preliminary purchase price adjustments.

In addition, in December 2018, we closed the sale of certain oil and gas properties in the Mid–Continent area to a third party for total consideration of $1.0 million, net of purchase price adjustments.

In January 2019, we closed the sale of certain oil and gas properties in the Mid-Continent area to a third party for total consideration of $1.7 million, net of preliminary purchase price adjustments.

In February 2019, we entered into a definitive agreement to sell all of our (i) oil and gas properties in the San Juan Basin and (ii) membership interests in EnerVest Mesa, LLC, a wholly-owned subsidiary of EV Properties, L.P., to a third party for total consideration of $42.8 million in cash, subject to purchase price adjustments. The transaction is expected to close in April 2019 and has an effective date of October 1, 2018.

Also, in February 2019, we entered into a definitive agreement to sell certain oil and gas properties in the Mid-Continent area to a third party for total consideration of $2.5 million in cash, subject to purchase price adjustments. The transaction is expected to close in April 2019 and has an effective date of October 1, 2018.

See Note 8 of the Notes to Consolidated Financial Statements included under "Item 8. Financial Statements and Supplementary Data" contained herein for additional information.

Our Relationship with EnerVest

As a result of the Restructuring, EnerVest is no longer a related party to the Company. However, we continue to have a relationship with EnerVest through a services agreement entered into in connection with the Restructuring (the "Services Agreement") pursuant to which EnerVest operates the majority of our properties and provides other administrative services. See Note 13 and 17 of the Notes to Consolidated Financial Statements included under "Item 8. Financial Statements and Supplementary Data" contained herein for additional information regarding the Services Agreement and the related party status of EnerVest, respectively.

Oil and Natural Gas Operations and Properties

At December 31, 2018, our oil and natural gas properties were located in the Barnett Shale, the San Juan Basin, the Appalachian Basin (which includes the Utica Shale), Michigan, the Mid–Continent areas in Oklahoma, Texas, Arkansas, Kansas and Louisiana, the Permian Basin and the Monroe Field in Northern Louisiana.

Barnett Shale

Our properties are primarily located in Denton, Montague, Parker, Tarrant and Wise counties in Northern Texas. Our estimated net proved reserves as of December 31, 2018 were 280.1 Bcfe, 62% of which is natural gas. During 2018, we drilled 15 gross wells (4.7 net wells) in the Barnett Shale, which were successfully completed. As of December 31, 2018, we owned an average 28% working interest in 1,356 gross productive wells in this area.

San Juan Basin

Our properties are primarily located in Rio Arriba County, New Mexico and La Plata County in Colorado. Our estimated net proved reserves as of December 31, 2018 were 157.6 Bcfe, 64% of which is natural gas. During 2018, we did not drill any wells in the San Juan Basin. As of December 31, 2018, we owned an average 81% working interest in 496 gross productive wells in this area. In February 2019, we entered into a definitive agreement to sell all of our oil and gas properties in the San Juan Basin. See "—Current Developments—Divestitures" above for additional information.

Appalachian Basin (including the Utica Shale)

Our activities are concentrated in the Ohio and West Virginia areas of the Appalachian Basin. Our Ohio area properties are producing primarily from the Knox and Clinton formations and other Devonian age sands in 40 counties in Eastern Ohio and 8 counties in Western Pennsylvania. Our West Virginia area properties are producing primarily from the Balltown, Benson and Big Injun formations in 22 counties in North Central West Virginia. Our estimated net proved reserves as of December 31, 2018 were 129.2 Bcfe, 68% of which is natural gas. During 2018, we drilled 1 gross well (0.9 net wells) in the Appalachian Basin. As of December 31, 2018, we owned an average 64% working interest in 10,424 gross productive wells in this area.

Michigan

Our properties are located in the Antrim Shale reservoir in Otsego and Montmorency counties in northern Michigan. Our estimated net proved reserves as of December 31, 2018 were 64.5 Bcfe, 98% of which is natural gas. During 2018, we did not drill any wells in Michigan. As of December 31, 2018, we owned an average 65% working interest in 1,502 gross productive wells in this area.

Mid–Continent Area

Our properties are primarily located in 43 counties in Oklahoma, 22 counties in Texas, four parishes in North Louisiana, two counties in Kansas and six counties in Arkansas. Our estimated net proved reserves as of December 31, 2018 were 31.2 Bcfe, 58% of which is natural gas. During 2018, we did not drill any wells in the Mid-Continent area. As of December 31, 2018, we owned an average 16% working interest in 1,666 gross productive wells in this area. In January and February 2019, we entered into definitive agreements to sell certain of our oil and gas properties in the Mid-Continent area. Our estimated net proved reserves as of December 31, 2018, for the properties to be sold are 9.5 Bcfe, 55% of which is natural gas. See "—Current Developments—Divestitures" above for additional information.

Permian Basin

Our properties are primarily located in the Yates, Seven Rivers, Queen, Morrow, Clear Fork and Wichita Albany formations in four counties in New Mexico and Texas. Our estimated net proved reserves as of December 31, 2018 were 28.1 Bcfe, 38% of which is natural gas. During 2018, we did not drill any wells in the Permian Basin. As of December 31, 2018, we owned an average 97% working interest in 136 gross productive wells in this area.

Monroe Field

Our properties are primarily located in two parishes in Northeast Louisiana. Our estimated net proved reserves as of December 31, 2018 were 21.2 Bcfe, 100% of which is natural gas. During 2018, we did not drill any wells in the Monroe Field. As of December 31, 2018, we owned an average 98% working interest in 3,831 gross productive wells in this area.

Our Oil, Natural Gas and Natural Gas Liquids Data

Our Reserves

Oil, natural gas and natural gas liquids reserve information presented herein is derived from our reserve reports prepared by Cawley, Gillespie & Associates, Inc. ("Cawley Gillespie") and Wright & Company, Inc. ("Wright"), our independent reserve engineers. All of our proved reserves are located in the United States. The following table presents our estimated net proved reserves at December 31, 2018:

	Oil (MMBbls)	Natural Gas (Bcf)	Natural Gas Liquids (MMBbls)	Bcfe
Proved reserves:				
Developed	9.9	468.5	28.5	698.5
Undeveloped	—	8.2	0.8	13.4
Total	9.9	476.7	29.3	711.9

In addition, the following table summarizes information about our proved reserves by geographic region as of December 31, 2018:

	Estimated Net Proved Reserves			
	Oil (MMBbls)	Natural Gas (Bcf)	Natural Gas Liquids (MMBbls)	Bcfe
Barnett Shale	0.2	175.0	17.3	280.1
San Juan Basin [1]	1.3	100.4	8.2	157.6
Appalachian Basin	6.4	87.9	0.5	129.2
Michigan	0.1	63.2	0.1	64.5
Mid–Continent area [2]	1.5	18.2	0.7	31.2
Permian Basin	0.4	10.8	2.5	28.1
Monroe Field	—	21.2	—	21.2
Total	9.9	476.7	29.3	711.9

(1) In February 2019, we entered into a definitive agreement to sell all of our oil and gas properties in the San Juan Basin. See "—Current Developments—Divestitures" below for additional information.

(2) In January and February 2019, we entered into definitive agreements to sell certain of our oil and gas properties in the Mid-Continent area. These properties included estimated net proved reserves of 9.5 Bcfe, 55% of which is natural gas, as of December 31, 2018. See "—Current Developments—Divestitures" above for additional information.

Proved developed reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. PUDs are proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. See "Glossary of Oil and Natural Gas Terms." Proved undeveloped locations conform to the SEC rules defining proved undeveloped locations. We do not have any reserves that would be classified as synthetic oil or synthetic natural gas.

Our estimates of proved reserves are based on the quantities of oil, natural gas and natural gas liquids which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations – prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimate. Reserves for proved developed producing wells were estimated using production performance and material balance methods. Certain new producing properties with little production history were forecast using a combination of production performance and analogy to offset production, both of which are believed to provide accurate forecasts. Non–producing reserve estimates for both developed and undeveloped properties were forecast using either or both volumetric or analogy methods. These methods are believed to provide accurate forecasts due to the mature nature of the properties targeted for development and an abundance of subsurface control data.

The data in the above tables represents estimates only. Oil, natural gas and natural gas liquids reserve engineering is inherently a subjective process of estimating underground accumulations of oil, natural gas and natural gas liquids that cannot be measured exactly. The accuracy of any reserve estimate is a function of the quality of available data and engineering and geological interpretation and judgment. Accordingly, reserve estimates may vary from the quantities of oil, natural gas and natural gas liquids that are ultimately recovered. Please read "Item 1A. Risk Factors."

Future prices received for production and costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. The standardized measure of discounted future net cash flows is the after-tax present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the SEC, without giving effect to non–property related expenses such as general and administrative expenses and debt service or to depreciation, depletion and amortization and discounted using an annual discount rate of 10%. Future income tax expenses are calculated by applying the year-end statutory tax rates to the pre-tax net cash flows. Standardized measure does not give effect to derivative transactions. The standardized measure shown should not be construed as the current market value of the reserves. The 10% discount factor, which is required by Financial

Accounting Standards Board pronouncements, is not necessarily the most appropriate discount rate. The present value, no matter what discount rate is used, is materially affected by assumptions as to timing of future production, which may prove to be inaccurate.

At December 31, 2018, our proved reserves had a standardized measure of discounted future net cash flows of $436.4 million and a present value of future net pre-tax cash flows attributable to estimated net proved reserves, discounted at 10% per annum ("PV-10") of $509.6 million. PV–10, is a computation of the standardized measure of discounted future net cash flows on a pre–tax basis and is computed on the same basis as standardized measure but does not include a provision for federal income taxes, Texas gross margin tax or other state taxes. PV–10 is considered a non–GAAP financial measure under the regulations of the SEC. We believe PV–10 to be an important measure for evaluating the relative significance of our oil and natural gas properties. We further believe investors and creditors may utilize our PV–10 as a basis for comparison of the relative size and value of our reserves to other companies. PV–10, however, is not a substitute for the standardized measure. Our PV–10 measure and standardized measure do not purport to present the fair value of our reserves.

The table below provides a reconciliation of PV–10 to the standardized measure at December 31, 2018 (dollars in millions):

Standardized measure	$	436.4
Future income taxes, discounted at 10%		73.2
PV-10	$	509.6

Our Proved Undeveloped Reserves

We annually review all PUDs to ensure an appropriate plan for development exists. As of December 31, 2017, the Predecessor had no reportable estimated PUDs with respect to any of its properties due to uncertainty regarding the Predecessor's ability to continue as a going concern and the availability of capital that would be required to develop the PUD reserves.

At December 31, 2018 (Successor), we had 13.4 Bcfe of PUDs compared with zero PUDs at December 31, 2017 (Predecessor). The following table describes the changes in PUDs during 2018:

	Bcfe
PUDs as of December 31, 2017 (Predecessor)	—
Revisions of previous estimates	66.7
Sales of minerals in place	(53.3)
PUDs as of December 31, 2018 (Successor)	13.4

The following describes the material changes to our PUDs during 2018:

Revisions of previous estimates. This change from prior estimates primarily results from our emergence from bankruptcy on June 4, 2018 and the availability of capital required to develop the PUDs within the SEC five-year development limitation on PUDs.

Sales of minerals in place. In August 2018, we sold oil and natural gas properties in Central Texas and Karnes County, Texas, which included 53.3 Bcfe of PUDs.

Internal Controls Applicable to our Reserve Estimates

Our policies and procedures regarding internal controls over the recording of our reserves is structured to objectively and accurately estimate our reserves quantities and present values in compliance with both accounting principles generally accepted in the United States and the SEC's regulations. Compliance with these rules and regulations is the responsibility of Terry Wagstaff, our Vice President of Acquisitions and Engineering, who is also our principal engineer. Mr. Wagstaff has over 35 years of experience in the oil and natural gas industry, with exposure to reserves and reserve related valuations

and issues during most of this time, and is a qualified reserves estimator ("QRE"), as defined by the standards of the Society of Petroleum Engineers. Further professional qualifications include a Bachelor of Science in Petroleum Engineering, extensive internal and external reserve training, asset evaluation and management, and he is a registered professional engineer in the state of Texas. In addition, our principal engineer is an active participant in industry reserve seminars, professional industry groups, and is a member of the Society of Petroleum Engineers.

Our controls over reserve estimates included retaining Cawley Gillespie and Wright as our independent petroleum engineers. We provided information about our oil and natural gas properties, including production profiles, prices and costs, to Cawley Gillespie and Wright, and they prepared their own estimates of 44% and 56%, respectively, of our reserves attributable to our properties. All of the information regarding reserves in this annual report on Form 10–K is derived from the reports of Cawley Gillespie and Wright, which are included as exhibits to this annual report on Form 10–K.

The principal engineer at Cawley Gillespie responsible for preparing our reserve estimates is W. Todd Brooker, a President and Principal with Cawley Gillespie. Mr. Brooker is a licensed professional engineer in the state of Texas (license #83462) with over 25 years of experience in petroleum engineering. The principal engineer at Wright responsible for preparing our reserve estimates is D. Randall Wright, the President of Wright. Mr. Wright is a licensed professional engineer in the state of Texas (license #43291) with over 45 years of experience in petroleum engineering.

We and EnerVest maintain an internal staff of petroleum engineers, geoscience professionals and petroleum landmen who work closely with Cawley Gillespie and Wright to ensure the integrity, accuracy and timeliness of data furnished to Cawley Gillespie and Wright in their reserves estimation process. Our Vice President of Acquisitions and Engineering reviews and approves the reserve information compiled by our internal staff. Our technical team meets regularly with representatives of Cawley Gillespie and Wright to review properties and discuss the methods and assumptions used by Cawley Gillespie and Wright in their preparation of the year end reserves estimates. Our technical team and Vice President of Acquisitions and Engineering also meet regularly to review the methods and assumptions used by Cawley Gillespie and Wright in their preparation of the year end reserves estimates.

The audit committee of our board of directors meets with management, including the Vice President of Acquisitions and Engineering, to discuss matters and policies related to our reserves.

Our Productive Wells

The following table sets forth information relating to the productive wells in which we owned a working interest as of December 31, 2018. Productive wells consist of producing wells and wells capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. Gross wells are the total number of productive wells in which we have a working interest, regardless of our percentage interest. A net well is not a physical well, but is a concept that reflects the actual total working interest we hold in a given well. We compute the number of net wells we own by totaling the percentage interests we hold in all our gross wells. Operated wells are the wells operated by EnerVest in which we own an interest.

Our wells may produce both oil and natural gas. We classify a well as an oil well if the net equivalent production of oil was greater than natural gas for the well.

	Gross Wells			Net Wells		
	Oil	Natural Gas	Total	Oil	Natural Gas	Total
Barnett Shale:						
Operated	—	—	—	—	—	—
Non–operated	19	1,337	1,356	4	374	378
San Juan Basin: [1]						
Operated	20	400	420	20	367	387
Non–operated	23	53	76	2	11	13
Appalachian Basin:						
Operated	1,733	4,757	6,490	1,686	4,503	6,189
Non–operated	428	3,506	3,934	33	445	478
Michigan:						
Operated	1	1,204	1,205	1	958	959
Non–operated	29	268	297	1	11	12
Mid–Continent area: [2]						
Operated	56	109	165	45	70	115
Non–operated	630	871	1,501	44	106	150
Permian Basin:						
Operated	1	132	133	1	129	130
Non–operated	3	—	3	1	—	1
Monroe Field:						
Operated	—	3,831	3,831	—	3,744	3,744
Non–operated	—	—	—	—	—	—
Total [3]	2,943	16,468	19,411	1,838	10,718	12,556

(1) In February 2019, we entered into a definitive agreement to sell all of our oil and gas properties in the San Juan Basin. See "—Current Developments—Divestitures" above for additional information.

(2) In January and February 2019, we entered into definitive agreements to sell certain of our oil and gas properties in the Mid-Continent area. These properties included 632 gross non-operated wells (57 net non-operated wells) as of December 31, 2018. See "—Current Developments—Divestitures" above for additional information.

(3) In addition, we own small royalty interests in over 1,000 wells.

Our Developed and Undeveloped Acreage

The following table sets forth information relating to our leasehold acreage as of December 31, 2018:

	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
Barnett Shale	151,329	38,075	12,947	2,583
San Juan Basin [1]	139,047	63,246	34,110	26,933
Appalachian Basin	614,183	467,798	320,269	258,273
Michigan	87,903	63,420	1,038	1,035
Mid–Continent area [2]	295,076	55,191	11,506	834
Permian Basin	11,695	10,868	520	385
Monroe Field [3]	5,904	5,904	170,346	145,666
Total	1,305,137	704,502	550,736	435,709

(1) In February 2019, we entered into a definitive agreement to sell all of our oil and gas properties in the San Juan Basin. See "—Current Developments—Divestitures" above for additional information.

(2) In January and February 2019, we entered into definitive agreements to sell certain of our oil and gas properties in the Mid-Continent area. These properties included 59,558 gross developed acres (17,500 net developed acres) and 680 gross undeveloped acres (198 net undeveloped acres) as of December 31, 2018. See "—Current Developments—Divestitures" above for additional information.

(3) There are no spacing requirements on substantially all of the wells on our Monroe Field properties; therefore, one developed acre is assigned to each productive well for which there is no spacing unit assigned.

Substantially all of our acreage is held by production, which means that as long as our wells on the acreage continue to produce, we will continue to hold the leases. The acreage in which we hold interests that are not held by production are not significant to our overall undeveloped acreage.

Title to Properties

As is customary in the oil and natural gas industry, we initially conduct only a cursory review of the title to our properties on which we do not have proved reserves. Prior to the commencement of drilling operations on those properties, we conduct a thorough title examination and perform curative work with respect to significant defects. To the extent title opinions or other investigations reflect title defects on those properties, we are typically responsible for curing any title defects at our expense. We generally will not commence drilling operations on a property until we have cured any material title defects on such property. Prior to completing an acquisition of producing leases, we perform title reviews on the most significant leases and, depending on the materiality of the properties, we may obtain a title opinion or review previously obtained title opinions. As a result, we have obtained title opinions on a significant portion of our properties and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the oil and natural gas industry. Our properties are subject to customary royalty and other interests, liens for current taxes and other burdens that we believe do not materially interfere with the use of or affect our carrying value of the properties.

Production, Average Sales Price and Average Production Cost by Field

The following table sets forth our production, production prices and production costs for the Successor seven months ended December 31, 2018, and for the Predecessor five months ended May 31, 2018 and years ended December 31, 2017 and 2016 from the Barnett Shale, the Appalachian Basin and the San Juan Basin, which are the only fields during those years for which our estimated net proved reserves at December 31, 2018 attributable to the field represented 15% or more of our total estimated net proved reserves at December 31, 2018:

	Successor	Predecessor		
	Seven Months Ended December 31, 2018	Five Months Ended May 31, 2018	Year Ended December 31, 2017	Year Ended December 31, 2016
Oil				
Production (MBbls):				
Barnett Shale	21	23	35	39
Appalachian Basin	290	209	541	611
San Juan Basin	44	29	74	75
Average sales price per Bbl:				
Barnett Shale	$ 64.22	$ 62.87	$ 48.74	$ 36.96
Appalachian Basin	$ 62.22	$ 61.63	$ 47.29	$ 39.59
San Juan Basin	$ 56.31	$ 53.03	$ 38.20	$ 31.01
Natural Gas				
Production (MMcf):				
Barnett Shale	8,117	5,556	12,948	19,936
Appalachian Basin	5,159	3,458	11,465	12,097
San Juan Basin	2,960	2,205	5,336	3,751
Average sales price per Mcf:				
Barnett Shale	$ 2.77	$ 2.28	$ 2.70	$ 1.93
Appalachian Basin	$ 2.78	$ 2.44	$ 2.45	$ 1.70
San Juan Basin	$ 2.50	$ 2.24	$ 2.82	$ 2.37
Natural Gas Liquids				
Production (MBbls):				
Barnett Shale	753	519	1,183	1,320
Appalachian Basin	26	29	43	59
San Juan Basin	303	204	390	405
Average sales price per Bbl:				
Barnett Shale	$ 25.17	$ 23.78	$ 19.91	$ 14.01
Appalachian Basin	$ 20.00	$ 28.79	$ 15.53	$ 14.12
San Juan Basin [1]	$ 34.71	$ 32.28	$ 27.34	$ 20.94
Average unit costs per Mcfe:				
Lease operating expenses per Mcfe [2]				
Barnett Shale	$ 1.33	$ 1.34	$ 1.25	$ 0.95
Appalachian Basin	$ 2.23	$ 2.31	$ 1.85	$ 1.65
San Juan Basin	$ 1.83	$ 1.81	$ 1.59	$ 1.80

(1) Excludes a royalty adjustment of $5.0 million during the seven months ended December 31, 2018. Including this royalty adjustment, revenues from natural gas liquids would have been $3.05 per Bbl, for the seven months ended December 31, 2018. See Note 13 of the Notes to Consolidated Financial Statements included under "Item 8. Financial Statements and Supplementary Data" contained herein for additional information.

(2) Excluding ad valorem taxes.

Our Drilling Activity

We intend to concentrate our drilling activity on low risk development drilling opportunities. The number and types of wells we drill will vary depending on the commodity price environment, the amount of funds we have available for drilling, the cost of each well, the size of the fractional working interests we acquire in each well, the estimated recoverable reserves attributable to each well and the accessibility to the well site.

The following table summarizes our approximate gross and net interest in development wells completed during the year ended December 31, 2018, 2017 and 2016, regardless of when drilling was initiated. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled, quantities of reserves found or economic value.

	Year Ended December 31,		
	2018	2017	2016
Gross wells:			
Productive	30.0	33.0	9.0
Dry	—	—	—
Total	30.0	33.0	9.0
Net wells:			
Productive	6.3	3.8	2.6
Dry	—	—	—
Total	6.3	3.8	2.6

As of December 31, 2018, we were not participating in the drilling of any development wells.

We did not drill any exploratory wells during the seven months ended December 31, 2018. The Predecessor did not drill any exploratory wells during the five months ended May 31, 2018 or the years ended December 31, 2017 or 2016.

Well Operations

We have entered into operating agreements with EnerVest. Under these operating agreements, EnerVest acts as contract operator of the oil and natural gas wells and related gathering systems and production facilities in which we own an interest, provided that our interest entitles us to control the appointment of the operator of the well, gathering system or production facilities. As contract operator, EnerVest designs and manages the drilling and completion of our wells and manages the day to day operating and maintenance activities for our wells.

Under these operating agreements, EnerVest has established a joint account for each well in which we have an interest. We are required to pay our working interest share of amounts charged to the joint account. The joint account is charged with all direct expenses incurred in the operation of our wells and related gathering systems and production facilities. The determination of which direct expenses can be charged to the joint account and the manner of charging direct expenses to the joint account for our wells is done in accordance with the Council of Petroleum Accountants Societies ("COPAS") model form of accounting procedure.

Under the COPAS model form, direct expenses include the costs of third party services performed on our properties and wells, as well as gathering and other equipment used on our properties. In addition, direct expenses include the allocable share of the cost of services performed on our properties and wells by EnerVest employees. The allocation of the cost of EnerVest employees who perform services on our properties is based on time sheets maintained by EnerVest's employees. Direct expenses charged to the joint account also include an amount determined by EnerVest to be the fair rental value of facilities owned by EnerVest and used in the operation of our properties.

Principal Customers, Marketing Arrangements and Delivery Commitments

The market for our oil, natural gas and natural gas liquids production depends on factors beyond our control, including the extent of domestic production and imports of oil, natural gas and natural gas liquids, the proximity and capacity of natural gas pipelines and other transportation facilities, the demand for oil, natural gas and natural gas liquids, the marketing of competitive fuels and the effect of state and federal regulation. The oil and natural gas industry also competes with other industries in supplying the energy and fuel requirements of industrial, commercial and individual consumers.

Our oil, natural gas and natural gas liquids production is sold to a variety of purchasers. The terms of sale under the majority of existing contracts are short–term, usually one year or less in duration. The prices received for oil, natural gas and natural gas liquids sales are generally tied to monthly or daily indices as quoted in industry publications.

During 2018, Energy Transfer Operating, L.P. accounted for 15.5% of consolidated oil, natural gas and natural gas liquids revenues. In 2017, Energy Transfer Partners, L.P. and EnLink Midstream Partners, L.P. accounted for 15.5% and 11.0%, respectively, of the Predecessor's consolidated oil, natural gas and natural gas liquids revenues. In 2016, Energy Transfer Partners, L.P., EnLink Midstream Partners, L.P. and Ergon Oil Purchasing, Inc. accounted for 18.5%, 13.4% and 10.4%, respectively, of the Predecessor's consolidated oil, natural gas and natural gas liquids revenues. We believe that the loss of a major customer would have a temporary effect on our revenues but that over time, we would be able to replace our major customers.

Information regarding our delivery commitments is contained in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Contractual Obligations" contained herein.

Competition

The oil and natural gas industry is highly competitive. We encounter strong competition from other independent operators and from major oil and natural gas companies in acquiring properties, contracting for drilling equipment and securing trained personnel. Many of these competitors have financial and technical resources and staffs substantially larger than ours. As a result, our competitors may be able to pay more for desirable leases, or to evaluate, bid for and purchase a greater number of properties or prospects than our financial or personnel resources will permit.

We are also affected by competition for drilling rigs and the availability of related equipment. In the past, the oil and natural gas industry has experienced shortages of drilling rigs, equipment, pipe and personnel, which have delayed development drilling and other exploitation activities and have caused significant price increases. We are unable to predict when, or if, such shortages may occur or how they would affect our development and exploitation program.

Competition is also strong for attractive oil and natural gas producing properties, undeveloped leases and drilling rights, and there can be no assurances that we will be able to compete satisfactorily when attempting to make further acquisitions.

Seasonal Nature of Business

Seasonal weather conditions and lease stipulations can limit our drilling and producing activities and other operations primarily in certain areas of the Appalachian Basin, the San Juan Basin and Michigan. As a result, we generally perform the majority of our drilling in these areas during the summer and autumn months. In addition, the Monroe Field properties in Louisiana are subject to flooding. These seasonal anomalies can pose challenges for meeting our drilling objectives and increase competition for equipment, supplies and personnel during the drilling season, which could lead to shortages and increased costs or delay our operations. Generally demand for natural gas is higher in summer and winter months. In addition, certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter natural gas requirements during off–peak months. This can also lessen seasonal demand fluctuations.

Environmental, Health and Safety Matters and Regulation

Our operations are subject to stringent and complex federal, state and local laws and regulations that govern the health and safety aspects of our operations and protection of the environment, as well as the discharge of materials into the environment. These laws and regulations may, among other things:

- require the acquisition of various permits before drilling commences;
- require the installation of pollution control equipment in connection with operations and place other conditions on our operations;
- place restrictions or regulations upon the use or disposal of the material utilized in our operations;
- restrict the types, quantities and concentrations of various substances that can be released into the environment or used in connection with drilling, production and transportation activities;
- limit or prohibit drilling activities on lands lying within wilderness, wetlands and other protected areas;
- govern gathering, transportation and marketing of oil and natural gas and pipeline and facilities construction;
- require remedial measures to mitigate pollution from former and ongoing operations, such as site restoration, pit closure and plugging of abandoned wells; and
- require the expenditure of significant amounts in connection with worker health and safety.

These laws, rules and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, Congress and federal, state and local agencies frequently revise environmental laws and regulations, and such changes could result in increased costs for environmental compliance, such as waste handling, permitting, or cleanup for the oil and natural gas industry and could have a significant impact on our operating costs. In general, the oil and natural gas industry has recently been the subject of increased legislation and regulatory attention with respect to environmental matters. In early 2017, the US Environmental Protection Agency (the "EPA") identified environmental compliance by the energy extraction sector as one of its enforcement initiatives for fiscal years 2018 and 2019; however, in 2019, the EPA proposed to transition its focus to significant public health and environmental problems without regard to sector. Even if regulatory burdens temporarily ease, the historic trend of more expansive and stricter environmental regulation may continue for the long term.

The following is a summary of some of the existing laws, rules and regulations to which our business operations are subject.

Solid and Hazardous Waste Handling

The federal Resource Conservation and Recovery Act ("RCRA") and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous solid waste. Although oil and natural gas waste generally is exempt from regulations as hazardous waste under RCRA, we generate waste as a routine part of our operations that may be subject to RCRA. Although a substantial amount of the waste generated in our operations are regulated as non–hazardous solid waste rather than hazardous waste, there is no guarantee that the EPA or individual states will not adopt more stringent requirements for the handling of non–hazardous or exempt waste or categorize some non–hazardous or exempt waste as hazardous in the future. For example, following the filing of a lawsuit in the US District Court for the District of Columbia in May 2016 by several non-governmental environmental groups against the EPA for the agency's failure to timely assess its RCRA Subtitle D criteria regulations for oil and gas wastes, the EPA and the environmental groups entered into an agreement that was finalized in a consent decree issued by the District Court on December 28, 2016. Under the consent decree, the EPA is required to propose no later than March 15, 2019, a rulemaking for revision of certain Subtitle D criteria regulations pertaining to oil and gas wastes or sign a determination that revision

of the regulations is not necessary. If the EPA proposes a rulemaking for revised oil and gas waste regulations, the consent decree requires that the EPA take final action following notice and comment rulemaking no later than July 15, 2021. Non-exempt waste is subject to more rigorous and costly disposal requirements. Any such change could result in an increase in our costs to manage and dispose of waste, which could have a material adverse effect on our results of operations and financial position.

Comprehensive Environmental Response, Compensation and Liability Act

The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA") imposes joint and several liability for costs of investigation and remediation and for natural resource damages without regard to fault or legality of the original conduct, on certain classes of persons with respect to the release into the environment of substances designated under CERCLA as "hazardous substances." These classes of persons, or so–called potentially responsible parties ("PRPs") include the current and past owners or operators of a site where the release occurred and anyone who disposed or arranged for the disposal of a hazardous substance found at the site. CERCLA also authorizes the EPA and, in some instances, third parties to take actions in response to threats to public health or the environment and to seek to recover from PRPs the costs of such action. Many states have adopted comparable or more stringent state statutes.

Although CERCLA generally exempts "petroleum" from the definition of hazardous substance, in the course of our operations, we have generated and will generate wastes that may fall within CERCLA's definition of hazardous substance and may have disposed of these wastes at disposal sites owned and operated by others. Comparable state statutes may not provide a comparable exemption for petroleum. We may also be the owner or operator of sites on which hazardous substances have been released. In the event contamination is discovered at a site on which we are or have been an owner or operator or to which we sent hazardous substances, we could be liable for the costs of investigation and remediation and natural resources damages.

We currently own, lease, or operate numerous properties that have been used for oil and natural gas exploration and production for many years. Although we believe we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes or hydrocarbons may have been released on or under the properties owned or leased by us, or on or under other locations, including offsite locations, where such substances have been taken for disposal. In addition, some of these properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or hydrocarbons were not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remediate property, including groundwater, containing or impacted by previously disposed wastes (including wastes disposed or released by prior owners or operators, or property contamination, including groundwater contamination by prior owners or operators) or to perform remedial plugging operations to prevent future or mitigate existing contamination.

Clean Water Act

The Federal Water Pollution Control Act (the "Clean Water Act") and analogous state laws impose restrictions and strict controls with respect to the discharge of pollutants, including discharges, spills and leaks of produced water and other oil and natural gas wastes, into state waters and waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. The Clean Water Act also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by a permit issued by the US Army Corps of Engineers (the "Corps"). In June 2015, the EPA issued a final rule revising its definition of "waters of the United States." Litigation surrounding this rule is ongoing and the rule was stayed nationwide by the US Sixth Circuit Court of Appeals in October 2015. In January 2018, the US Supreme Court ruled that the rule revising the definition of the term "waters of the United States" must first be reviewed in federal district courts, which resulted in a withdrawal of the Sixth Circuit stay. The EPA proposed to repeal the rule and, in January 2018, issued a final rule to delay its implementation until 2020 to allow time for the EPA to reconsider the definition. Subsequent litigation in the federal district courts has resulted in patchwork application of the rule in some states (e.g. Pennsylvania), but not others (e.g. Texas, Louisiana). In December 2018, the EPA and the Corps issued a proposed rule revising the definition of "waters of the United States" that would provide discrete categories of jurisdictional waters and tests for determining whether a particular waterbody meets any of those classifications. Several groups have already announced

their intention to challenge the proposed rule. Federal and state regulatory agencies can impose administrative, civil and criminal penalties, as well as require remedial or mitigation measures, for non–compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations. In the event of an unauthorized discharge of wastes, we may be liable for penalties and cleanup and response costs.

Safe Drinking Water Act and Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. Hydraulic fracturing activities are typically regulated by state oil and gas commissions or similar state agencies. Although the federal Safe Drinking Water Act (the "SDWA") expressly excludes regulation of these fracturing activities (except for fracturing activities involving the use of diesel), several federal agencies have recently conducted investigations or asserted regulatory authority over certain aspects of the process due to public concerns raised regarding potential impacts of hydraulic fracturing on groundwater quality. These recent developments at the federal level, as well as at state, regional and local levels, could result in regulation of hydraulic fracturing becoming more stringent and costly. In December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources, concluding that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources "under some circumstances," including water withdrawals for fracturing in times or areas of low water availability; surface spills during the management of fracturing fluids, chemicals or produced water; injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater to surface waters; and disposal or storage of fracturing wastewater in unlined pits. This report could result in additional regulatory scrutiny that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and business.

Legislation was introduced in prior sessions of Congress to provide for federal regulation of hydraulic fracturing by eliminating the current exemption in the SDWA, and, further, to require disclosure of the chemicals used in the fracturing process, but did not pass. Also, some states and local or regional regulatory bodies have adopted, or are considering adopting, regulations that could restrict or ban hydraulic fracturing in certain circumstances or that require disclosure of chemicals in the fracturing fluids. For example, New York has imposed a ban on hydraulic fracturing. Further, Pennsylvania has adopted a variety of regulations limiting how and where fracturing can be performed, and Wyoming and Texas have adopted legislation requiring drilling operators conducting hydraulic fracturing activities in that state to publicly disclose the chemicals used in the fracturing process. States have also considered or adopted other restrictions on drilling and completion operations, including requirements regarding casing and cementing of wells; testing of nearby water wells; restrictions on access to, and usage of, water; and restrictions on the type of chemical additives that may be used in hydraulic fracturing operations. Further, the EPA has published guidance on hydraulic fracturing using diesel. The EPA has also published an effluent limit guideline final rule prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plants. The Bureau of Land Management (the "BLM") published a final rule that established new or more stringent standards relating to hydraulic fracturing on federal and American Indian lands but, in late 2017, the BLM repealed this rule following years of litigation. The rescission of this rule is being challenged by several environmental groups and states in ongoing litigation.

State and federal regulatory agencies have also recently focused on a possible connection between the operation of injection wells used for oil and gas wastewater and an observed increase in minor seismic activity and tremors. When caused by human activity, such events are called induced seismicity. In a few instances, operators of injection wells in the vicinity of minor seismic events have reduced injection volumes or suspended operations, often voluntarily. Some state regulatory agencies have modified their regulations to account for induced seismicity. For example, the Texas Railroad Commission rules allow it to modify, suspend, or terminate a permit based on a determination that the permitted activity is likely to be contributing to seismic activity. Regulatory agencies are continuing to study possible linkage between injection activity and induced seismicity.

If new laws or regulations imposing significant restrictions or conditions on hydraulic fracturing activities are adopted in areas where we conduct business, we could incur substantial compliance costs and such requirements could adversely delay or restrict our ability to conduct fracturing activities on our assets.

Oil Pollution Act

The primary federal law for oil spill liability is the Oil Pollution Act ("OPA") which amends and augments oil spill provisions of the Clean Water Act and imposes certain duties and liabilities on certain "responsible parties" related to the prevention of oil spills and damages resulting from such spills in or threatening United States waters or adjoining shorelines. A liable "responsible party" includes the owner or operator of a facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge, or in the case of offshore facilities, the lessee or permittee of the area in which a discharging facility is located. OPA assigns joint and several liability, without regard to fault, to each liable party for oil removal costs and a variety of public and private damages. Although defenses exist to the liability imposed by OPA, they are limited. In the event of an oil discharge or substantial threat of discharge, we may be liable for costs and damages.

Air Emissions

Our operations are subject to the federal Clean Air Act ("CAA") and analogous state laws and local ordinances governing the control of emissions from sources of air pollution. The CAA and analogous state laws require new and modified sources of air pollutants to obtain permits prior to commencing construction. Major sources of air pollutants are subject to more stringent, federally imposed requirements including additional permits. Federal and state laws designed to control hazardous (or toxic) air pollutants, might require installation of additional controls. Administrative enforcement actions for failure to comply strictly with air pollution regulations or permits are generally resolved by payment of monetary fines and correction of any identified deficiencies. Alternatively, regulatory agencies could bring lawsuits for civil penalties or seek injunctive relief, requiring us to forego construction, modification or operation of certain air emission sources.

On April 17, 2012, the EPA issued final rules to subject oil and natural gas production, storage, processing and transmission operations to regulation under the New Source Performance Standards ("NSPS") and the National Emission Standards for Hazardous Air Pollutants ("NESHAP") programs under the CAA, and to impose new and amended requirements under both programs. The EPA rules include NSPS standards for completion of hydraulically fractured natural gas wells. Since January 1, 2015, operators have been required to capture the natural gas and make it available for use or sale, which can be done through the use of green completions. The standards are applicable to new hydraulically fractured wells and also existing wells that are refractured. Further, the finalized regulations also establish specific new requirements, effective in 2012, for emissions from compressors, controllers, dehydrators, storage tanks, natural gas processing plants and certain other equipment. These rules may require changes to our operations, including the installation of new equipment to control emissions. We continuously evaluate the effect of new rules on our business.

The EPA has adopted rules to regulate methane emissions, including, as of June 2016, from new and modified oil and gas production sources and natural gas processing and transmission sources, and has announced its intention to regulate methane emissions from existing oil and gas sources. However, in September 2018, the EPA, under the new administration, did propose amendments to the NSPS Subpart OOOOa standards that would relax the requirements implemented in June 2016. In addition, in April 2018, a coalition of states filed a lawsuit aiming to force EPA to establish guidelines for limiting methane emissions from existing sources in the oil and natural gas sector; that lawsuit is currently pending. The status of future regulation remains unclear but if adopted could require changes to our operations, including the installation of new emission control equipment. Simultaneously with the methane rules, the EPA adopted new rules governing the aggregating of multiple surface sites into a single-source of air quality permitting purposes, a change which could impact the applicability of permitting requirement to our operations and subject certain operations to additional regulatory requirements. We continuously evaluate the effect of these rules on our operations. In late 2016, the BLM adopted a rule governing flaring and venting on public and tribal lands, which could require additional equipment and emissions controls as well as inspection requirements. Similar to the EPA rule, in September 2018, the BLM issued a rule that relaxes or rescinds certain requirements of its November 2016 rule. This rule has been challenged in court by both California and New Mexico and litigation is ongoing. Additionally, the US House of Representatives passed a resolution under the Congressional Review Act disapproving the rules; however, the Senate action failed. If allowed to stand, these additional regulations on our air emissions are likely to result in increased compliance costs and additional operating restrictions on our business.

National Environmental Policy Act

Oil and natural gas exploration and production activities on federal lands may be subject to the National Environmental Policy Act ("NEPA") which requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. Depending on the mitigation strategies recommended in the Environmental Assessment or Environmental Impact Statement, we could incur added costs, which may be significant. Reviews and decisions under NEPA are also subject to protest or appeal, any or all of which may delay or halt projects. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay or impose additional conditions upon the development of oil and natural gas projects.

Climate Change Legislation

More stringent laws and regulations relating to climate change and greenhouse gases ("GHGs") may be adopted in the future and could cause us to incur material expenses in complying with them. In the absence of comprehensive federal legislation on GHG emission control, the EPA attempted to require the permitting of GHG emissions; although the Supreme Court struck down the permitting requirements, it upheld the EPA's authority to control GHG emissions when a permit is required due to emissions of other pollutants. Some states, regions and localities have adopted or have considered programs to address GHG emissions. In addition, both houses of Congress previously considered legislation to reduce emissions of greenhouse gases and many states have adopted or considered measures to establish GHG emissions reduction levels, often involving the planned development of GHG emission inventories and/or GHG cap and trade programs; this legislation was not passed. Depending on the regulatory reach of new CAA legislation implementing regulations or new EPA and/or state, regional or local rules restricting the emission of GHGs, we could incur significant costs to control our emissions and comply with regulatory requirements. In addition, the EPA has adopted a mandatory GHG emissions reporting program which imposes reporting and monitoring requirements on various industries, including onshore and offshore oil and natural gas production facilities and onshore oil and natural gas processing, transmission, storage and distribution facilities. Compliance with these requirements has and is anticipated to require us to make investments in monitoring and recordkeeping equipment. We do not believe, however, that our compliance with applicable monitoring, recordkeeping and reporting requirements under the GHG reporting program will have a material adverse effect on our results of operations or financial position. We began reporting emissions in 2012 for emissions occurring in 2011 and continue to report as required on an annual basis.

The EPA began regulating methane emissions, including from new and modified oil and gas production sources and natural gas processing and transmission sources. In June 2016, the EPA published the NSPS Subpart OOOOa standards that require new, modified or reconstructed facilities in the oil and natural gas sector to reduce methane gas and volatile compound emissions. In September 2018, under the new administration, the EPA proposed amendments that would relax the requirements of the Subpart OOOOa standards. In addition, in April 2018, a coalition of states filed a lawsuit aiming to force the EPA to establish guidelines for limiting methane emissions from existing sources in the oil and natural gas sector; that lawsuit is currently pending. Simultaneously with the methane rules for new and modified sources, the EPA adopted new rules governing the aggregating of multiple surface sites into a single-source of air quality permitting purposes, a change which could impact the applicability of permitting requirement to our operations and subject certain operations to additional regulatory requirements. We continuously evaluate the effect of these rules on our operations.

On November 18, 2016, the BLM published a final rule that was intended to reduce waste of natural gas from venting, flaring, and leaks during oil and natural gas production activities on onshore Federal and American Indian leases. Unlike the somewhat overlapping EPA regulations, which apply to new, modified and reconstructed sources, the BLM's 2016 rule was drafted to address existing facilities, including a substantial number of existing wells that are likely to be marginal or low-producing, including leak detection and repair and other requirements regarding methane emissions. Similar to the EPA rule, in September 2018, the BLM issued a rule that relaxes or rescinds certain requirements of its November 2016 rule. California and New Mexico have challenged the rule in ongoing litigation.

In December 2015, the United States participated in the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France. The resulting Paris Agreement calls for the parties to undertake "ambitious efforts" to limit the average global temperature and to conserve and enhance sinks and reservoirs of GHGs. The Paris Agreement went into effect on November 4, 2016. The Paris Agreement establishes a framework for the parties to cooperate and report actions to reduce GHG emissions. However, on June 1, 2017, President Trump announced that the United States would withdraw from the Paris Agreement. The Paris Agreement provides for a four-year exit process beginning when it took effect in November 2016, which would result in an effective exit date of November 2020. It is not clear what steps the Trump Administration plans to take to withdraw from the Paris Agreement, whether a new agreement can be negotiated, or what terms would be included in such an agreement. Restrictions on GHG emissions that may be imposed could adversely affect the oil and gas industry. The adoption of legislation or regulatory programs to reduce GHG emissions could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory requirements. Any GHG emissions legislation or regulatory programs applicable to power plants or refineries could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce GHG emissions could have an adverse effect on our business, financial condition and results of operations.

Because of the lack of any comprehensive legislative program addressing GHGs, there is a great deal of uncertainty as to how and when federal regulation of GHGs might take place. Moreover, the federal, regional, state and local regulatory initiatives also could adversely affect the marketability of the oil, natural gas and natural gas liquids we produce. The impact of such future programs cannot be predicted, but we do not expect our operations to be affected any differently than other similarly situated domestic competitors.

Endangered Species Act

The Endangered Species Act was established to protect endangered and threatened species. Pursuant to that act, if a species is listed as threatened or endangered, restrictions may be imposed on activities that would harm the species or that would adversely affect that species' habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. We conduct operations on oil and natural gas leases that have species that are listed and species that could be listed as threatened or endangered under these laws. The US Fish and Wildlife Service designates the species' protected habitat as part of the effort to protect the species. A protected habitat designation or the mere presence of threatened or endangered species could result in material restrictions to our use of the land and may materially delay or prohibit land access for oil and natural gas development. It also may adversely impact the value of the affected leases.

OSHA and Other Laws and Regulation

To the extent not preempted by other applicable laws, we are subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") and comparable state statutes, where applicable. These laws and the implementing regulations strictly govern the protection of the health and safety of employees. The OSHA hazard communication standard, the EPA community right–to–know regulations under the Title III of CERCLA and similar state statutes, where applicable, require that we organize and/or disclose information about hazardous materials used or produced in our operations. We believe that we are in substantial compliance with these applicable requirements and with other OSHA and comparable state statute requirements.

We believe that we are in substantial compliance with all existing environmental laws and regulations applicable to our current operations and that our continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations. We did not incur any material capital expenditures for remediation or pollution control activities for the years ended December 31, 2018, 2017 and 2016. Additionally, we are not aware of any environmental issues or claims that will require material capital expenditures during 2019 or that will otherwise have a material impact on our financial position or results of operations in the future. However, we cannot assure you that the passage of more stringent laws and regulations in the future will not have a negative impact on our business activities, financial condition and results of operations.

Other Regulation of the Oil and Natural Gas Industry

The oil and natural gas industry is extensively regulated by numerous federal, state, local and tribal authorities. Rules and regulations affecting the oil and natural gas industry are under constant review for amendment or expansion, which could increase the regulatory burden and the potential for financial sanctions for noncompliance. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations binding on the oil and natural gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

Drilling and Production

Statutes, rules and regulations affecting exploration and production undergo constant review and often are amended, expanded and reinterpreted, making difficult the prediction of future costs or the impact of regulatory compliance attributable to new laws and statutes. The regulatory burden on the oil and natural gas industry increases the cost of doing business and, consequently, affects its profitability. Our drilling and production operations are subject to various types of regulation at the federal, state and local levels. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. Most states and some counties and municipalities in which we operate also regulate one or more of the following:

- the location of wells;
- the method of drilling, completing and operating wells;
- the surface use and restoration of properties upon which wells are drilled;
- the venting or flaring of natural gas;
- the plugging and abandoning of wells;
- notice to surface owners and other third parties; and
- produced water and disposal of waste water, drilling fluids and other liquids and solids utilized or produced in the drilling and extraction process.

State and federal regulations are generally intended to prevent waste of oil and natural gas, protect correlative rights to produce oil and natural gas between owners in a common reservoir or formation, control the amount of oil and natural gas produced by assigning allowable rates of production and control contamination of the environment. Pipelines and natural gas plants operated by other companies that provide midstream services to us are also subject to the jurisdiction of various federal, state and local authorities, which can affect our operations. State laws also regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties and impose bonding requirements in order to drill and operate wells. Some states have taken up consideration of forced pooling. Other states rely on voluntary pooling of lands and leases.

States generally impose a production, ad valorem or severance tax with respect to the production and sale of oil and natural gas within their respective jurisdictions. States do not generally regulate wellhead prices or engage in other, similar direct economic regulation, but there can be no assurance they will not do so in the future.

We do not control the availability of transportation and processing facilities used in the marketing of our production. For example, we may have to shut–in a productive natural gas well because of a lack of available natural gas gathering or transportation facilities.

If we conduct operations on federal, state or Indian oil and natural gas leases, these operations must comply with numerous regulatory restrictions, including various non–discrimination statutes, royalty and related valuation requirements, and certain of these operations must be conducted pursuant to certain on-site security regulations and other appropriate permits issued by the BLM, Bureau of Ocean Energy Management, Bureau of Safety and Environmental Enforcement, Bureau of Indian Affairs, tribal or other appropriate federal, state and/or Indian tribal agencies.

The Mineral Leasing Act of 1920 (the "Mineral Act") prohibits direct or indirect ownership of any interest in federal onshore oil and gas leases by a foreign citizen of a country that denies "similar or like privileges" to citizens of the United States. Such restrictions on citizens of a "non-reciprocal" country include ownership or holding or controlling stock in a corporation that holds a federal onshore oil and gas lease. If this restriction is violated, the corporation's lease can be cancelled in a proceeding instituted by the United States Attorney General. Although the regulations of the BLM (which administers the Mineral Act) provide for agency designations of non–reciprocal countries, there are presently no such designations in effect. It is possible that our stockholders may be citizens of foreign countries which at some time in the future might be determined to be non–reciprocal under the Mineral Act.

Federal Regulation of Oil, Natural Gas and Natural Gas Liquids, including Regulation of Transportation

The availability, terms and cost of transportation significantly affect sales of natural gas. The interstate transportation and sale for resale of natural gas are subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by the Federal Energy Regulatory Commission ("FERC"). Federal and state regulations govern the price and terms for access to natural gas pipeline transportation. FERC's regulations for interstate natural gas transmission in some circumstances may also affect the intrastate transportation of natural gas. FERC regulates the rates, terms and conditions applicable to the interstate transportation of natural gas by pipelines under the Natural Gas Act as well as under Section 311 of the Natural Gas Policy Act.

Under FERC's current regulatory regime, interstate transportation services must be provided on an open-access, non-discriminatory basis at cost-based rates or at market-based rates if the transportation market at issue is sufficiently competitive. The FERC-regulated tariffs, under which interstate pipelines provide such open-access transportation service, contain strict limits on the means by which a shipper releases its pipeline capacity to another potential shipper, which provisions include FERC's "shipper-must-have-title" rule. Violations by a shipper (i.e., a pipeline customer) of FERC's capacity release rules or shipper-must-have-title rule could subject a shipper to substantial penalties from FERC.

With respect to its regulation of natural gas pipelines under the NGA, FERC has not generally required the applicant for construction of a new interstate natural gas pipeline to produce evidence of the greenhouse gas emissions of the proposed pipeline's customers. In August 2017, the US Circuit Court of Appeals for the DC Circuit issued a decision remanding a natural gas pipeline certificate application to FERC, which required FERC to revise its environmental impact statement for the proposed pipeline to take into account GHG carbon emissions from downstream power plants using natural gas transported by the new pipeline. It is too early to determine the impacts of this Court decision, but it could be significant.

Sales of our oil and natural gas liquids are also affected by the availability, terms and costs of transportation. The rates, terms, and conditions applicable to the interstate transportation of oil and natural gas liquids by pipelines are regulated by the FERC under the Interstate Commerce Act (the "ICA"). FERC has implemented a simplified and generally applicable ratemaking methodology for interstate oil and natural gas liquids pipelines to fulfill the requirements of Title XVIII of the Energy Policy Act of 1992 comprised of an indexing system to establish ceilings on interstate oil and natural gas liquids pipeline rates. In addition, FERC issued a declaratory order in November 2017, involving a marketing affiliate of an oil pipeline, which held that certain arrangements between an oil pipeline and its marketing affiliate would violate the ICA's anti-discrimination provisions. FERC held that providing transportation service to affiliates at what is essentially the variable cost of the movement, while requiring non-affiliated shippers to pay the (higher) filed tariff rate, would violate the ICA. Rehearing has been sought of this FERC order by various pipelines. It is too recent an event to determine the impact this FERC order may have on oil pipelines, their marketing affiliates, and the price of oil and other liquids transported by such pipelines.

Gathering service, which occurs on pipeline facilities located upstream of FERC-jurisdictional interstate transportation services, is regulated by the states onshore and in state waters. Depending on changes in the function performed by particular pipeline facilities, FERC has in the past reclassified certain FERC-jurisdictional transportation facilities as non-jurisdictional gathering facilities and FERC has reclassified certain non-jurisdictional gathering facilities as FERC-jurisdictional transportation facilities. Any such changes could result in an increase to our costs of transporting gas to point-of-sale locations.

The pipelines used to gather and transport natural gas being produced by us are also subject to regulation by the US Department of Transportation (the "DOT") under the Natural Gas Pipeline Safety Act of 1968, as amended ("NGPSA"), the Pipeline Safety Act of 1992, as reauthorized and amended ("Pipeline Safety Act"), and the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011. The DOT Pipeline and Hazardous Materials Safety Administration ("PHMSA") has established a risk–based approach to determine which gathering pipelines are subject to regulation and what safety standards regulated gathering pipelines must meet. In addition, the PHMSA had initially considered regulations regarding, among other things, the designation of additional high consequence areas along pipelines, minimum requirements for leak detection systems, installation of emergency flow restricting devices, and revision of valve spacing requirements. In October 2015, the PHMSA issued proposed new safety regulations for hazardous liquid pipelines, including a requirement that all hazardous liquid pipelines have a system for detecting leaks and that operators establish a timeline for inspections of affected pipelines following extreme weather events or natural disasters. If such revisions to gathering line regulations and liquids pipelines regulations are enacted by the PHMSA, we could incur significant expenses.

Transportation of our oil, natural gas liquids and purity components (ethane, propane, butane, iso–butane, and natural gasoline) by rail is also subject to regulation by the DOT's PHMSA and the DOT's Federal Railroad Administration ("FRA") under the Hazardous Materials Regulations at 49 CFR Parts 171-180 ("HMR"), including Emergency Orders by the FRA and new regulations being proposed by the PHMSA, arising due to the consequences of train accidents and the increase in the rail transportation of flammable liquids.

Although natural gas sales prices are currently unregulated, Congress historically has been active in the area of natural gas regulation. We cannot predict whether new legislation to regulate natural gas might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures, and what effect, if any, the proposals might have on the operations of the underlying properties. Sales of oil and natural gas liquids are not currently regulated and are made at market prices.

Exports of US Crude Oil Production and Natural Gas Production

The federal government has recently ended its decades-old prohibition of exports of oil produced in the lower 48 states of the US. The general perception in the industry is that ending the prohibition of exports of oil produced in the US will be positive for producers of US oil. In addition, the US Department of Energy (the "DOE") authorizes exports of natural gas, including exports of natural gas by pipelines connecting US natural gas production to pipelines in Mexico, which are expected to increase significantly with the changes taking place in the Mexican government's regulations of the energy sector in Mexico. In addition, the DOE authorizes the export of liquefied natural gas ("LNG") through LNG export facilities, the construction of which are regulated by FERC. In the third quarter of 2016, the first quantities of natural gas produced in the lower 48 states of the US were exported as LNG from the first of several LNG export facilities being developed and constructed in the US Gulf Coast region. While it is too recent an event to determine the impact this change may have on our operations or our sales of natural gas, the perception in the industry is that this will be a positive development for producers of US natural gas.

Hydraulic Fracturing

Most of our oil and natural gas properties are subject to hydraulic fracturing to economically develop the properties. The hydraulic fracturing process is integral to our drilling and completion costs in these areas and typically represent up to 60% of the total drilling/completion costs per well.

We diligently review best practices and industry standards, and comply with all regulatory requirements in the protection of these potable water sources. Protective practices include, but are not limited to, setting multiple strings of

protection pipe across the potable water sources and cementing these pipes from setting depth to surface, continuously monitoring the hydraulic fracturing process in real time, and disposing of all non–commercially produced fluids in certified disposal wells at depths below the potable water sources.

In compliance with laws enacted in various states, we will disclose hydraulic fracturing data to the appropriate chemical registry. These laws generally require disclosure for each chemical ingredient that is subject to the requirements of OSHA regulations, as well as the total volume of water used in the hydraulic fracturing treatment.

There have not been any material incidents, citations or suits related to our hydraulic fracturing activities involving violations of environmental laws and regulations.

Other Regulation

In addition to the regulation of oil and natural gas pipeline transportation rates, the oil and natural gas industry generally is subject to compliance with various other federal, state and local regulations and laws. Some of those laws relate to occupational safety, resource conservation and equal employment opportunity. We do not believe that compliance with these laws will have a material adverse effect upon our stockholders.

Insurance

In accordance with industry practice, we maintain insurance against some, but not all, of the operating risks to which our business is exposed. We currently have insurance policies that include coverage for control of well, general liability (includes sudden and accidental pollution), physical damage to our oil and gas natural properties, auto liability, worker's compensation and employer's liability, among other things.

Currently, we have general liability insurance coverage up to $1.0 million per occurrence, which includes sudden and accidental environmental liability coverage for the effects of pollution on third parties arising from our operations. Our insurance policies contain maximum policy limits and in most cases, deductibles that must be met prior to recovery. These insurance policies are subject to certain customary exclusions and limitations. In addition, we maintain $100.0 million in excess liability coverage, which is in addition to and triggered if the general liability per occurrence limit is reached.

We do not currently have any insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations. However, we believe our general liability and excess liability insurance policies would cover third party claims related to hydraulic fracturing operations and associated legal expenses, in accordance with, and subject to, the terms of such policies.

We re–evaluate the purchase of insurance, coverage limits and deductibles annually. Future insurance coverage for the oil and natural gas industry could increase in cost and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that are economically acceptable. No assurance can be given that we will be able to maintain insurance in the future at rates that we consider reasonable, and we may elect to self–insure or maintain only catastrophic coverage for certain risks in the future.

Employees

As of December 31, 2018, we have five full–time employees, none of which are field personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We consider our relations with our employees to be satisfactory.

Our operations are primarily carried out by EnerVest pursuant to the Services Agreement.

Offices

We do not have any material owned or leased property (other than our interests in oil and gas properties). Under our Services Agreement, EnerVest provides us office space for our executive officers and other employees at EnerVest's offices in Houston, Texas.

Available Information

Our annual reports on Form 10–K, quarterly reports on Form 10–Q, current reports on Form 8–K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act, are made available free of charge on our website at www.hvstog.com as soon as reasonably practicable after these reports have been electronically filed with, or furnished to, the SEC. Our website also includes our Code of Business Conduct and the charters of our audit committee and compensation committee. No information from our website is incorporated herein by reference.

ITEM 1A. RISK FACTORS

Our business and operations are subject to many risks. The risks described below, in addition to the risks described in "Item 1. Business" and "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" of this annual report, may not be the only risks we face, as our business and operations may also be subject to risks that we do not yet know of, or that we currently believe are immaterial. You should carefully consider the following risk factors together with all of the other information included in this annual report, including the financial statements and related notes, when deciding to invest in us. You should be aware that the occurrence of any of the events described in this Risk Factors section and elsewhere in this annual report could have a material adverse effect on our business, financial position, results of operations and cash flows and the trading price of our securities could decline and you could lose all or part of your investment.

Risks Related to our Emergence from Bankruptcy

We recently emerged from bankruptcy, which may adversely affect our business and relationships.

It is possible that our having filed for bankruptcy and our recent emergence from bankruptcy may adversely affect our business and relationships with customers, vendors, royalty or working interest owners, contractors, employees or suppliers. Due to uncertainties, many risks exist, including the following:

- key suppliers, vendors or other contract counterparties may terminate their relationships with us or require additional financial assurances or enhanced performance from us;
- our ability to renew existing contracts and compete for new business may be adversely affected;
- our ability to attract, motivate and/or retain key executives may be adversely affected; and
- competitors may take business away from us, and our ability to attract and retain customers may be negatively impacted.

The occurrence of one or more of these events could have a material and adverse effect on our operations, financial condition and reputation. We cannot assure you that having been subject to bankruptcy protection will not adversely affect our operations in the future.

Our actual financial results after emergence from bankruptcy may not be comparable to our historical financial information as a result of the implementation of the Plan and the transactions contemplated thereby and our adoption of fresh start accounting.

In connection with the disclosure statement we filed with the Bankruptcy Court, and the hearing to consider confirmation of the Plan, we prepared projected financial information to demonstrate to the Bankruptcy Court the

feasibility of the Plan and our ability to continue operations upon our emergence from bankruptcy. Those projections were prepared solely for the purpose of bankruptcy proceedings and have not been, and will not be, updated on an ongoing basis and should not be relied upon by investors. At the time they were prepared, the projections reflected numerous assumptions concerning our anticipated future performance with respect to prevailing and anticipated market and economic conditions that were and remain beyond our control and that may not materialize. Projections are inherently subject to substantial and numerous uncertainties and to a wide variety of significant business, economic and competitive risks and the assumptions underlying the projections and/or valuation estimates may prove to be wrong in material respects. Actual results may vary significantly from those contemplated by the projections. As a result, investors should not rely on these projections.

In addition, upon our emergence from bankruptcy, we adopted fresh start accounting. Accordingly, our future financial conditions and results of operations may not be comparable to the financial condition or results of operations reflected in the Predecessor's historical financial statements. The lack of comparable historical financial information may discourage investors from purchasing our common stock.

Upon our emergence from bankruptcy, the composition of our board of directors changed significantly.

Pursuant to the Plan, the composition of our board of directors changed significantly. Upon emergence, our board of directors consists of five directors, only one of whom, our President and Chief Executive Officer, previously served on the board of directors of the Predecessor. The new directors have different backgrounds, experiences and perspectives from those individuals who previously served on our board of directors and, thus, may have different views on the issues that will determine our future. As a result, the future strategy and our plans may differ materially from those of the past.

Risks Related to our Business

Oil, natural gas and natural gas liquids prices are highly volatile and have declined significantly in recent years. Depressed prices can significantly and adversely affect our business, financial condition, results of operations and cash flows from operations.

Our revenue, profitability, cash flow and future rate of growth depend upon the prices for oil, natural gas and natural gas liquids. Prices for these commodities have been depressed when compared with historical prices prior to the second half of 2014, and the prices we receive for our production are volatile. For example, oil and natural gas commodity prices declined significantly in the fourth quarter of 2018, with the posted price for West Texas Intermediate oil falling to a low of $44.48 per barrel in December 2018 as compared to the quarter-high of $76.40 in October 2018. Prices for oil, natural gas and natural gas liquids may fluctuate widely in response to relatively minor changes in supply and demand, market uncertainty and a variety of additional factors that are beyond our control, such as:

- the domestic and foreign supply of and demand for oil, natural gas and natural gas liquids;
- the amount of added production from development of unconventional natural gas reserves;
- the price and quantity of foreign imports of oil, natural gas and natural gas liquids;
- the level of consumer product demand;
- weather conditions;
- the value of the US dollar relative to the currencies of other countries;
- market uncertainty and overall domestic and global economic conditions;
- political and economic conditions and events in foreign oil and natural gas producing countries, including embargoes, continued hostilities in the Middle East and other sustained military campaigns, conditions in South America, China and Russia, and acts of terrorism or sabotage;

- the increasing exports of oil produced in the US and natural gas produced in the US from LNG liquefaction facilities;
- the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- technological advances affecting energy production and consumption;
- domestic and foreign governmental regulations and taxation;
- the impact of energy conservation efforts and the increasing use of renewable sources of energy such as wind energy and solar photovoltaic energy;
- the capacity of the US and international refiners to utilize US supplies of oil, natural gas and natural gas liquids;
- the proximity and capacity of natural gas pipelines and other transportation facilities to our production; and
- the price and availability of alternative fuels.

A drop in commodity prices can significantly affect our financial results and cash flows and impede our growth. The ways in which such price decreases could have a material negative effect on our business include:

- a significant decrease in the number of wells we drill on our acreage, thereby reducing our production and cash flows;
- a reduction in cash flow, which would decrease funds available to repay current or future indebtedness or for capital expenditures employed to replace reserves and maintain or increase production;
- access to sources of capital, such as equity or long-term debt markets, could be severely limited or unavailable; and
- a reduction in the borrowing base of our credit facility.

In addition, changes in prices have a significant impact on the value of our reserves, and lower prices may reduce the amount of oil, natural gas or natural gas liquids that we can economically produce. This may result in our having to make substantial downward adjustments to our estimated proved reserves. If this occurs, or if our estimates of development costs increase, production data factors change or drilling results deteriorate, accounting rules may require us to write down, as a non–cash charge to earnings, the carrying value of our oil and natural gas properties for impairments. An impairment charge could have a material adverse effect on our results of operations in the period in which it is recorded. We are required to perform impairment tests on our assets whenever events or changes in circumstances lead to a reduction of the estimated useful life or estimated future cash flows that would indicate that the carrying amount may not be recoverable or whenever management's plans change with respect to those assets. For example, we expect to record an impairment charge related to our pending sale of our properties in the San Juan Basin.

The terms of our indebtedness include restrictions and financial covenants that may restrict our business and financing activities.

The operating and financial restrictions and covenants in our financing agreements may restrict our ability to finance operations or capital needs or to engage, expand or pursue our business activities. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources." Our future ability to comply with these restrictions and covenants is uncertain and will be affected by the levels of cash flow from our operations and other events or circumstances beyond our control. If market or other economic conditions deteriorate, our ability to comply with these covenants may be impaired. If we violate any provisions of such financing agreements that are not

cured or waived within the appropriate time periods provided therein, a significant portion of our indebtedness may become immediately due and payable and our lenders' commitment to make further loans to us may terminate. We might not have, or be able to obtain, sufficient funds to make these accelerated payments. In addition, our obligations under our credit facility are secured by substantially all of our assets, and if we are unable to repay our indebtedness under our credit facility, the lenders could seek to foreclose on our assets.

The terms and conditions governing our indebtedness:

- depending on the amount of outstanding indebtedness, could require us to dedicate a substantial portion of our cash flow from operations to service our existing debt, thereby reducing the cash available to finance our operations and other business activities and could limit our flexibility in planning for or reacting to changes in our business and the industry in which we operate;

- increase our vulnerability to economic downturns and adverse developments in our business;

- limit our ability to access the capital markets to raise capital on favorable terms or to obtain additional financing for working capital, capital expenditures or acquisitions or to refinance existing indebtedness;

- place restrictions on our ability to obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations;

- place us at a competitive disadvantage relative to competitors with lower levels of indebtedness in relation to their overall size or less restrictive terms governing their indebtedness;

- make it more difficult for us to satisfy our obligations under our debt and increase the risk that we may default on our debt obligations; and

- limit management's discretion in operating our business.

Our lenders periodically redetermine the amount we may borrow under our credit facility, which may materially impact our operations.

Our credit facility allows us to borrow in an amount up to the borrowing base, which is primarily based on the estimated value of our oil and natural gas properties and our commodity derivative contracts as determined semi-annually by our lenders in their sole discretion. The borrowing base is subject to redetermination on at least a semi-annual basis primarily based on an engineering report with respect to our estimated natural gas, oil and natural gas liquids reserves, which takes into account the prevailing natural gas, oil and natural gas liquids prices at such time, as adjusted for the impact of our commodity derivative contracts. Accordingly, declining commodity prices may have an impact on the amount we can borrow, which could affect our cash flows and ability to execute on our business plans. Any reduction in the borrowing base would materially and adversely affect our business and financing activities, limit our flexibility and management's discretion in operating our business, and increase the risk that we may default on our debt obligations. In addition, as hedges expire, the borrowing base is subject to further reduction. Our credit facility requires us to repay any deficiency over a certain period or pledge additional oil and gas properties to eliminate such deficiency, which we are required to do within 30 days of electing to do so. If our outstanding borrowings exceed the borrowing base and we are unable to repay the deficiency or pledge additional oil and gas properties to eliminate such deficiency, our failure to repay any of the installments due related to the borrowing base deficiency would constitute an event of default under the credit facility and as such, the lenders could declare all outstanding principal and interest to be due and payable, could freeze our accounts, or foreclose against the assets securing the obligations owed under the credit facility.

We may not be able to generate enough cash flow to meet our debt obligations and may be forced to take other actions to satisfy our debt obligations that may not be successful.

We have historically funded our operations, including our operating and capital expenditures, our debt service obligations and our acquisitions primarily through cash generated from operations, amounts available under our credit

facility and equity and debt offerings. Our future cash flows are subject to a number of variables, including oil and natural gas prices, and due to the steep decline in commodity prices, our ability to obtain funding in the equity or capital markets has been, and will continue to be, constrained, and there can be no assurances that our liquidity requirements will continue to be satisfied given current commodity prices. If our sources of liquidity are not sufficient to fund our current or future liquidity needs, including as a result of a decrease in the borrowing base under our credit facility, we may be required to take other actions, including those actions discussed below.

We expect our earnings and cash flow to vary significantly from year to year due to the cyclical nature of our industry. As a result, the amount of debt that we can service in some periods may not be appropriate for us in other periods. Moreover, and subject to certain limitations, we may be able to incur substantial additional indebtedness in the future. Additionally, our future cash flow may be insufficient to meet our debt obligations and commitments. Any insufficiency could negatively impact our business. A range of economic, competitive, business and industry factors will affect our future financial performance, and, as a result, our ability to generate cash flow from operations and to pay our debt. Many of these factors, such as oil and natural gas prices, economic and financial conditions in our industry and the global economy or competitive initiatives of our competitors, are beyond our control.

If we do not generate enough cash flow from operations to satisfy our debt obligations, we may have to undertake alternative strategic actions or financing plans, such as:

- refinancing or restructuring debt;
- selling assets;
- reducing or delaying capital investments;
- seeking to raise additional capital;
- liquidating all or a portion of our hedge portfolio;
- seeking additional partners to develop our assets;
- reducing our planned capital program;
- continuing to take, and potentially increasing, our cost saving measures to reduce costs, including renegotiation contracts with contractors, suppliers and service providers, reducing the number of staff and contractors and deferring and eliminating discretionary costs; or
- revising or delaying our other strategic plans.

We continually monitor the capital markets and our capital structure and may make changes to our capital structure from time to time, with the goal of maintaining financial flexibility, preserving or improving liquidity, strengthening our balance sheet, meeting our debt service obligations and/or achieving cost efficiency. Our ability to restructure or refinance our indebtedness will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of our indebtedness could cause us to incur high transaction costs, may be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict our business operations. The terms of existing or future debt instruments, including our credit facility, may restrict us from adopting some of these alternatives. In addition, any failure to make payments of interest and principal on our outstanding indebtedness on a timely basis would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness. In the absence of sufficient cash flows and capital resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations to meet our debt service and other obligations. Our debt instruments restrict our ability to dispose of assets and our use of the proceeds from such disposition. We may not be able to consummate those dispositions, and the proceeds of any such disposition may not be adequate to meet any debt service obligations then due.

We can provide no assurances that any alternative strategic action or financing plan undertaken will be successful in allowing us to meet our debt obligations or will result in additional liquidity. Our inability to generate sufficient cash flow to satisfy our debt obligations or to obtain alternative financing could materially and adversely affect our ability to make payments on our indebtedness and our business, financial condition, results of operations and cash flows.

Our variable rate indebtedness subjects us to interest rate risk, which could cause our debt service obligations to increase significantly.

Borrowings under our credit facility bear interest at variable rates and expose us to interest rate risk. If interest rates increase and we are unable to effectively hedge our interest rate risk, our debt service obligations on the variable rate indebtedness would increase even if the amount borrowed remained the same, and our net income would decrease. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk — Interest Price Risk" included in Part II of this annual report for further information regarding interest rate sensitivity.

Despite our current level of indebtedness, we may still be able to incur substantially more debt. This could further exacerbate the risks associated with our indebtedness.

We and our subsidiaries may be able to incur substantial additional indebtedness in the future, subject to certain limitations, including under our credit facility. If new debt is added to our current debt levels, the related risks that we now face could increase. Our level of indebtedness could, for instance, prevent us from engaging in transactions that might otherwise be beneficial to us or from making desirable capital expenditures. This could put us at a competitive disadvantage relative to other less leveraged competitors that have more cash flow to devote to their operations. In addition, the incurrence of additional indebtedness could make it more difficult to satisfy our existing financial obligations.

Our inability to finance the development of our properties, future oil and natural gas price declines and other factors may result in additional write-downs of our asset carrying values.

Accounting rules require us to write down, as a non–cash charge to earnings, the carrying value of our oil and natural gas properties in the event we have impairments. We are required to perform impairment tests on our assets periodically and whenever events or changes in circumstances warrant a review of our assets. To the extent such tests indicate a reduction of the estimated useful life or estimated future cash flows of our assets, the carrying value may not be recoverable and therefore requires a write–down. An impairment charge could have a material adverse effect on our results of operations in the period in which it is recorded. During the seven months ended December 31, 2018, we recorded impairment charges of approximately $3.1 million, which were related to properties located in Central Texas and Karnes County, Texas that were sold during August 2018. We expect to record an impairment charge in connection with the sale of our properties in the San Juan Basin during the first quarter of 2019. We may incur additional impairment charges in the future, particularly if commodity prices significantly decrease.

Proved undeveloped drilling locations are susceptible to uncertainties that could materially alter the occurrence or timing of their drilling and result in changes to the amount of our proved undeveloped reserves.

Our ability to drill and develop these locations depends on a number of uncertainties, including the availability of capital, construction of infrastructure, inclement weather, regulatory changes and approvals, oil and natural gas prices, costs, drilling results and the availability of water. We cannot be certain in advance of drilling and testing whether any particular drilling location will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. As a result, we do not know with certainty if these locations we have identified will ever be drilled or if we will be able to produce oil or natural gas from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

The recovery of PUDs requires significant capital expenditures and successful drilling operations. We can provide no assurances that we will have the ability to finance these future expenditures, whether development will occur as scheduled or that the results of such development will be as estimated. In addition, delays in the development could force us to reclassify certain of our proved reserves as unproved reserves. Further, the decision of the operators to develop the PUDs

attributable to our properties that EnerVest does not operate will be subject to the business plans and constraints of the operators of these properties, and be beyond our control.

We depend on EnerVest to provide us services necessary to operate our business and substantially all of our properties. If EnerVest were unable or unwilling to provide these services, it would result in disruption in our business which could have an adverse effect on our ability to service our debt obligations.

Under the Services Agreement, EnerVest provides services to us such as accounting, human resources, office space, digital infrastructure and other administrative services. If EnerVest were to become unable or unwilling to provide these services, we would need to develop these services internally or arrange for the services from another service provider. Developing the capabilities internally or by retaining another service provider could have an adverse effect on our business, and the services, when developed or retained, may not be of the same quality as provided to us by EnerVest.

EnerVest also operates a substantial amount of our properties pursuant to the Services Agreement. As of December 31, 2018, EnerVest operated oil and natural gas properties representing 92% of our proved oil and gas reserves and also had an economic interest in some of our properties. However, on February 1, 2019, operatorship of certain properties was transferred to a third party as a result of an EnerVest transaction. As a result, EnerVest now operates oil and gas properties representing approximately 53% of our proved oil and gas reserves. Our limited control over the operations related to our properties operated by EnerVest is set forth in our Services Agreement. The success and timing of drilling and development activities on the properties operated by EnerVest depends on a number of factors that will be largely outside of our control.

Prior to the Restructuring, EnerVest and its affiliates had a significant economic interest in the Predecessor through its 71.25% ownership of the Predecessor's general partner which, in turn, owned a 2% general partnership interest in the Predecessor and all of its incentive distribution rights. In connection with the Restructuring, the Predecessor's general partner was dissolved and EnerVest no longer has an economic interest in us. As a result, our interests may not be aligned or could be in conflict with EnerVest's interests.

We currently own interests in oil and natural gas properties in which partnerships managed by EnerVest also own an interest. If the EnerVest partnerships elect to sell their interest in these properties, we would own a minority interest in the properties, and EnerVest may lose the ability to operate the properties.

We own interests in oil and natural gas properties in which partnerships managed by EnerVest also own interests. These properties are primarily in the Barnett Shale and Appalachian Basin, and these properties represented approximately 57% of our estimated net proved reserves as of December 31, 2018. If the EnerVest partnerships were to sell their interest in those properties in which we own less than a majority working interest to an entity not affiliated with EnerVest, our working interest would not be large enough that we could control the selection of the operator and EnerVest may lose the ability to operate the properties on our behalf. Loss of operations would mean that EnerVest would no longer control decisions regarding the development and production of those properties, and any replacement operator could make decisions regarding development or production activities that make it difficult to implement our strategy.

Our hedging transactions may limit our gains, result in financial losses or could reduce our net income, which may adversely affect our ability to service our debt obligations and expose us to counterparty credit risk.

We enter into derivative contracts from time to time to manage our exposure to fluctuations in oil, natural gas and natural gas liquids prices, to achieve more predictable cash flows and to reduce our exposure to fluctuations in the prices of oil, natural gas and natural gas liquids. The prices at which we hedge our production in the future will be dependent upon commodity prices at the time we enter into these transactions, which may be substantially higher or lower than current oil and natural gas prices. Accordingly, these derivative contracts limit our potential gains if prices rise above the fixed prices established by the derivative contracts. These derivative contracts may also expose us to other risks of financial losses; for example, if our production is less than we anticipated at the time we entered into the derivatives contract, we might be forced to satisfy all or a portion of our hedging obligations without the benefit of the cash flows from our sale of the underlying physical commodity, resulting in a substantial diminution of our liquidity.

During periods of falling commodity prices, our derivative contracts expose us to risk of financial loss if the counterparty to the derivative contract fails to perform its obligations under the derivative contract (e.g., our counterparty fails to perform its obligation to make payments to us under the derivative contract when the market (floating) price under such derivative contract falls below the specified fixed price). To mitigate counterparty credit risk, we conduct our hedging activities with financial institutions who are lenders under our credit facility. Disruptions in the financial markets could lead to sudden changes in a counterparty's liquidity, which could impair their ability to perform under the terms of the derivative contract. We are unable to predict sudden changes in a counterparty's creditworthiness or ability to perform. Even if we do accurately predict sudden changes, our ability to negate the risk may be limited depending upon market conditions. If the creditworthiness of our counterparties deteriorates and results in their nonperformance, we could incur a significant loss.

Our policy has been to hedge a significant portion of our near–term estimated production. However, we are not under an obligation to hedge a specific portion of our production except that our credit facility requires us to hedge no less than 70% of our projected production volumes (excluding projected production volumes from certain properties) for the 18-month period following the Effective Date. As of December 31, 2018, we have commodity contracts covering approximately 68% of our estimated production attributable to our net proved reserves from January 2019 through December 2020. Accordingly, our price hedging strategy may not protect us from significant declines in oil and natural gas prices received for our future production. Conversely, our hedging strategy may limit our ability to realize cash flows from commodity price increases.

Our limited ability to hedge our natural gas liquids production could adversely impact our net cash provided by operating activities and results of operations.

A liquid, readily available and commercially viable market for hedging natural gas liquids has not developed in the same way that exists for oil and natural gas. The current direct natural gas liquids hedging market is constrained in terms of price, volume, duration and number of counterparties, which may limit our ability to hedge our natural gas liquids production effectively. As a result, our net cash provided by operating activities and results of operations could be adversely impacted by fluctuations in the market prices for natural gas liquids.

The adoption of derivatives legislation and regulations related to derivative contracts could have an adverse impact on our ability to hedge risks associated with our business.

Title VII of the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") establishes federal oversight and regulation of over-the-counter ("OTC") derivatives and requires the Commodity Futures Trading Commission (the "CFTC") and the SEC to enact further regulations affecting derivative contracts, including the derivative contracts we use to hedge our exposure to price volatility through the OTC market. Although the CFTC and the SEC have issued final regulations in certain areas, final rules in other areas and the scope of relevant definitions and/or exemptions still remain to be finalized.

In one of its rulemaking proceedings still pending under the Dodd-Frank Act, the CFTC issued on December 5, 2016, a re-proposed rule imposing position limits for certain futures and option contracts in various commodities (including crude oil and natural gas) and for swaps that are their economic equivalents. Under the proposed rules on position limits, certain types of hedging transactions are exempt from these limits on the size of positions that may be held, provided that such hedging transactions satisfy the CFTC's requirements for certain enumerated "bona fide hedging" transactions or positions. A final rule has not yet been issued. Similarly, on December 2, 2016, the CFTC has re-issued a proposed rule regarding the capital a swap dealer or major swap participant is required to set aside with respect to its swap business, but the CFTC has not yet issued a final rule.

The CFTC issued a final rule on margin requirements for uncleared swap transactions on January 6, 2016, which includes an exemption from any requirement to post margin to secure uncleared swap transactions entered into by commercial end-users in order to hedge commercial risks affecting their business. In addition, the CFTC has issued a final rule authorizing an exemption from the otherwise applicable mandatory obligation to clear certain types of swap transactions through a derivatives clearing organization and to trade such swaps on a regulated exchange, which exemption applies to swap transactions entered into by commercial end-users in order to hedge commercial risks affecting their

business. The mandatory clearing requirement currently applies only to certain interest rate swaps and credit default swaps, but the CFTC could act to impose mandatory clearing requirements for other types of swap transactions. The Dodd-Frank Act also imposes recordkeeping and reporting obligations on counterparties to swap transactions and other regulatory compliance obligations.

All of the above regulations could increase the costs to us of entering into financial derivative transactions to hedge or mitigate our exposure to commodity price volatility and other commercial risks affecting our business. While it is not possible at this time to predict when the CFTC will issue final rules applicable to position limits or capital requirements, depending on our ability to satisfy the CFTC's requirements for a commercial end-user using swaps to hedge or mitigate our commercial risks, these rules and regulations may require us to comply with position limits and with certain clearing and trade-execution requirements in connection with our financial derivative activities. When a final rule on capital requirements for swap dealers is issued, the Dodd-Frank Act may require our current swap dealer counterparties to post additional capital as a result of entering into uncleared financial derivatives with us, which capital requirements rule could increase the costs to us of future financial derivatives transactions. The Volcker Rule provisions of the Dodd-Frank Act may also require our current bank counterparties that engage in financial derivative transactions to spin off some of their derivatives activities to separate entities, which separate entities may not be as creditworthy as the current bank counterparties. Under such rules, other bank counterparties may cease their current business as hedge providers. These changes could reduce the liquidity of the financial derivatives markets thereby reducing the ability of entities like us, as commercial end-users, to have access to financial derivatives to hedge or mitigate our exposure to commodity price volatility.

As a result, the Dodd-Frank Act and any new regulations issued thereunder could significantly increase the cost of derivative contracts (including through requirements to post cash collateral), which could adversely affect our capital available for other commercial operations purposes, materially alter the terms of future swaps relative to the terms of our existing bilaterally negotiated financial derivative contracts and reduce the availability of derivatives to protect against commercial risks we encounter.

If we reduce our use of derivative contracts as a result of the new requirements, our results of operations may become more volatile and cash flows less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the volatility of oil, natural gas and natural gas liquids prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil, natural gas and natural gas liquids. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our consolidated financial condition, results of operations or cash flows.

Should we fail to comply with all applicable statutes, rules, regulations and orders administered by the CFTC or FERC, we could be subject to substantial penalties and fines.

Under the Energy Policy Act of 2005, FERC has been given greater civil penalty authority under the Natural Gas Act ("NGA"), including the ability to impose penalties of up to $1 million per day for each violation and disgorgement of profits associated with any violation. While our operations have not been regulated by FERC as a natural gas company under the NGA, FERC has adopted regulations that may subject certain of our otherwise non-FERC jurisdictional operations to FERC annual reporting and posting requirements. We also must comply with the anti-market manipulation rules enforced by FERC under the NGA. Under the Commodity Exchange Act (as amended by the Dodd-Frank Act) and regulations promulgated thereunder by the CFTC, the CFTC has also adopted anti-market manipulation, fraud and market disruption rules relating to the prices of commodities, futures contracts, options on futures, and swaps. Additional rules and legislation pertaining to those and other matters may be considered or adopted by Congress, the FERC, or the CFTC from time to time. Failure to comply with those statutes, regulations, rules and orders could subject us to civil penalty liability.

The distressed financial conditions of customers could have an adverse impact on us in the event these customers are unable to pay us for the products or services we provide.

Some of our customers may experience, in the future, severe financial problems that have had or may have a significant impact on their creditworthiness. We cannot provide assurance that one or more of our financially distressed customers

will not default on their obligations to us or that such a default or defaults will not have a material adverse effect on our business, financial position, future results of operations or future cash flows. Furthermore, the bankruptcy of one or more of our customers, or some other similar proceeding or liquidity constraint, might make it unlikely that we would be able to collect all or a significant portion of amounts owed by the distressed entity or entities. In addition, such events might force such customers to reduce or curtail their future use of our products and services, which could have a material adverse effect on our results of operations and financial condition.

We may be subject to risks in connection with divestitures.

In 2018, we completed divestitures of several of our assets and we have additional divestitures pending, as discussed in "Item 1. Business—Overview—Recent Developments," in accordance with our ongoing review of our asset base in order to maximize shareholder value. Various factors could materially affect our ability to dispose of such assets, including the approvals of governmental agencies or third parties and the availability of purchasers willing to acquire the assets on terms we deem acceptable. Though we continue to evaluate various options for the divestiture of such assets, there can be no assurance that this evaluation will result in any specific action.

Sellers often retain certain liabilities or agree to indemnify buyers for certain matters related to the sold assets. The magnitude of any such retained liability or of the indemnification obligation is difficult to quantify at the time of the transaction and ultimately could be material. Also, as is typical in divestiture transactions, third parties may be unwilling to release us from guarantees or other credit support provided prior to the sale of the divested assets. As a result, after a divestiture, we may remain secondarily liable for the obligations guaranteed or supported to the extent that the buyer of the assets fails to perform these obligations.

Unless we replace the reserves we produce, our revenues and production will decline, which would adversely affect our cash flows from operations and our ability to service our debt obligations.

Producing reservoirs are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our decline rate may change when we drill additional wells, make acquisitions or under other circumstances. Our future cash flows and income are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs, which would adversely affect our business, financial condition and results of operations. Factors that may hinder our ability to acquire additional reserves include competition, access to capital, prevailing oil, natural gas and natural gas liquids prices and the number and attractiveness of properties for sale.

Our estimated reserve quantities and future production rates are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in these reserve estimates or the underlying assumptions will materially affect the quantities and present value of our reserves.

Numerous uncertainties are inherent in estimating quantities of our reserves. Our estimates of our net proved reserve quantities are based upon reports from Cawley Gillespie and Wright, independent petroleum engineering firms used by us. The process of estimating oil, natural gas and natural gas liquids reserves is complex, requiring significant decisions and assumptions in the evaluation of available geological, engineering and economic data for each reservoir, and these reports rely upon various assumptions, including assumptions regarding future oil, natural gas and natural gas liquids prices, production levels, and operating and development costs. As a result, estimated quantities of proved reserves and projections of future production rates and the timing of development expenditures may prove to be inaccurate. Over time, we may make material changes to reserve estimates taking into account the results of actual drilling and production. Any significant variance in our assumptions and actual results could greatly affect our estimates of reserves, the economically recoverable quantities of oil, natural gas and natural gas liquids attributable to any particular group of properties, the classifications of reserves based on risk of recovery, and estimates of the future net cash flows. In addition, our wells are characterized by low production rates per well. As a result, changes in future production costs assumptions could have a significant effect on our proved reserve quantities.

The standardized measure of discounted future net cash flows of our estimated net proved reserves is not necessarily the same as the current market value of our estimated net proved reserves. We base the discounted future net cash flows from our estimated net proved reserves on average prices for the 12 months preceding the date of the estimate. Actual prices received for production and actual costs of such production will be different than these assumptions, perhaps materially.

The timing of both our production and our incurrence of expenses in connection with the development and production of our properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general. Any material inaccuracy in our reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves which could adversely affect our business, results of operations and financial condition.

Our future development operations may require substantial capital expenditures. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our production and reserves.

The oil and natural gas industry is capital intensive. We may make substantial capital expenditures in our business in the future for the development, production and acquisition of reserves. As part of our exploration and development operations, we have expanded, and expect to further expand, the application of horizontal drilling and multi-stage hydraulic fracture stimulation techniques. The utilization of these techniques requires substantially greater capital expenditures as compared to the drilling of a vertical well, sometimes more than three times the cost. The incremental capital expenditures are the result of greater measured depths and additional hydraulic fracture stages in horizontal wellbores.

We intend to finance our future capital expenditures primarily with cash flows from operations and borrowings under our credit facility. In the future, we may also finance such expenditures through the issuance of debt and equity securities. The incurrence of debt will require that a portion of our cash flows from operations be used for the payment of interest and principal on our debt, thereby reducing our ability to use cash flows to fund working capital, capital expenditures and acquisitions. Our cash flows from operations and access to capital are subject to a number of variables, including:

- the estimated quantities of our reserves;
- the amount of oil, natural gas and natural gas liquids we produce from existing wells;
- the prices at which we sell our production; and
- our ability to acquire, locate and produce new reserves.

If our revenues or the borrowing base under our credit facility decrease as a result of lower commodity prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. Our credit facility may restrict our ability to obtain new financing. If additional capital is needed, we may not be able to obtain debt or equity financing on terms favorable to us, or at all. If cash generated by operations or available under our credit facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our prospects, which in turn could lead to a possible decline in our reserves and production, and could adversely affect our business, results of operation and financial conditions. In addition, we may lose opportunities to acquire oil and natural gas properties and businesses.

We rely on development drilling to assist in maintaining our levels of production. If our development drilling is unsuccessful, our cash available for servicing our debt obligations and financial condition will be adversely affected.

Part of our business strategy has focused on maintaining or minimizing the decline in production levels by drilling development wells. Although we were successful in development drilling in the past, we cannot assure you that we will continue to maintain production levels through development drilling, particularly in the current commodity price

environment. Our drilling involves numerous risks, including the risk that we will not encounter commercially productive oil or natural gas reservoirs. We must incur significant expenditures to drill and complete wells. Additionally, seismic technology does not allow us to know conclusively, prior to drilling a well, that oil or natural gas is present or economically producible. The costs of drilling and completing wells are often uncertain, and it is possible that we will make substantial expenditures on development drilling and not discover reserves in commercially viable quantities. These expenditures will reduce cash available for servicing our debt obligations.

Our drilling operations may be curtailed, delayed or cancelled as a result of a variety of factors, including:

- unexpected drilling conditions;
- facility or equipment failure or accidents;
- shortages or delays in the availability of drilling rigs and equipment;
- adverse weather conditions;
- compliance with environmental and governmental requirements;
- title problems;
- unusual or unexpected geological formations;
- pipeline ruptures;
- fires, blowouts, craterings and explosions; and
- uncontrollable flows of oil or natural gas or well fluids.

Our business strategy involves the use of the latest available horizontal drilling, completion and production technology, which involve risks and uncertainties in their application.

Our operations involve the use of the latest horizontal drilling, completion and production technologies, as developed by us and our service providers, in an effort to improve efficiencies in recovery of hydrocarbons. Use of these new technologies may not prove successful and could result in significant cost overruns or delays or reduction in production, and in extreme cases, the abandonment of a well. The difficulties we face drilling horizontal wells include:

- landing our wellbore in the desired drilling zone;
- staying in the desired drilling zone while drilling horizontally through the formation;
- running our production casing the entire length of the wellbore; and
- running tools and other equipment consistently through the horizontal wellbore.

Difficulties that we face while completing our wells include the following:

- designing and executing the optimum fracture stimulation program for a specific target zone;
- running tools the entire length of the wellbore during completion operations; and
- cleaning out the wellbore after completion of the fracture stimulation.

In addition, certain of the new techniques we are adopting may cause irregularities or interruptions in production due to offset wells being shut in and the time required to drill and complete multiple wells before any such wells begin producing. Furthermore, the application of technology developed in drilling, completing and producing in one productive formation may not be successful in other prospective formations with little or no horizontal drilling history. If our use of the latest technologies does not prove successful, our drilling and production results may be less than anticipated or we may experience cost overruns, delays in obtaining production or abandonment of a well. As a result, the return on our investment will be adversely affected, we could incur material write-downs of unevaluated properties or undeveloped reserves and the value of our undeveloped acreage and reserves could decline in the future.

We could experience periods of higher costs if oil and natural gas prices rise or as drilling activity otherwise increases in our area of operations. Higher costs could reduce our profitability, cash flow and ability to pursue our drilling program as planned.

Historically, our capital and operating costs typically rise during periods of sustained increasing oil, natural gas and natural gas liquids prices. These cost increases result from a variety of factors beyond our control as drilling activity increases, such as increases in the cost of electricity, tubular goods, water, sand and other disposable materials used in fracture stimulation and other raw materials that we and our vendors rely upon; and the cost of services and labor especially those required in horizontal drilling and completion. Since late 2014, oil and natural gas prices declined substantially resulting in decreased levels of drilling activity in the US oil and natural gas industry, including in our area of operations. This led to significantly lower costs of some drilling and completion equipment, services, materials and supplies. As commodity prices rise or stabilize or drilling activity otherwise increases in our area of operations, these lower cost levels may not be sustainable over long periods. As a result, such costs may rise, thereby negatively impacting our profitability, cash flow and causing us to possibly reconfigure or reduce our drilling program. This impact may be magnified to the extent that our ability to participate in the commodity price increases is limited by our derivative risk management activities.

We may be unable to compete effectively with larger companies, which may adversely affect our ability to generate sufficient revenue and our ability to service our debt obligations.

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources than us. These companies may have a greater ability to continue drilling activities during periods of low prices, to contract for drilling equipment, to secure trained personnel, and to absorb the burden of present and future federal, state, local and other laws and regulations. The oil and natural gas industry has periodically experienced shortages of drilling rigs, equipment, pipe and personnel, which has delayed development drilling and other exploitation activities and has caused significant price increases. Competition has been strong in hiring experienced personnel, particularly in the accounting and financial reporting, tax and land departments. Our inability to compete effectively with larger companies could have a material adverse impact on our business activities, financial condition and results of operations.

Our business is subject to operational risks that will not be fully insured, which, if they were to occur, could adversely affect our financial condition or results of operations and, as a result, our ability to service our debt obligations.

Our business activities are subject to operational risks, including:

- damages to equipment caused by adverse weather conditions, including hurricanes and flooding;
- facility or equipment malfunctions;
- pipeline ruptures or spills;
- fires, blowouts, craterings and explosions;
- uncontrollable flows of oil or natural gas or well fluids; and

- surface spillage and surface or ground water contamination from petroleum constituents or hydraulic fracturing chemical additives.

In addition, a portion of our natural gas production is processed to extract natural gas liquids at processing plants that are owned by others. If these plants were to cease operations for any reason, we would need to arrange for alternative transportation and processing facilities. These alternative facilities may not be available, which could cause us to shut–in our natural gas production, or the alternative facilities could be more expensive than the facilities we currently use.

Any of these events could adversely affect our ability to conduct operations or cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution or other environmental contamination, loss of wells, regulatory penalties, suspension of operations, and attorneys' fees and other expenses incurred in the prosecution or defense of litigation.

As is customary in the industry, we maintain insurance against some but not all of these risks. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. Losses could therefore occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could have a material adverse impact on our business activities, financial condition, results of operations and ability to service our debt obligations.

Our business depends on gathering and compression facilities owned by third parties and transportation facilities owned by third-party transporters and we rely on third parties to gather and deliver our oil, natural gas and natural gas liquids to certain designated interconnects with third-party transporters. Any limitation in the availability of those facilities or delay in providing interconnections to newly drilled wells would interfere with our ability to market the oil, natural gas and natural gas liquids we produce and could reduce our revenues.

The marketability of our oil, natural gas and natural gas liquids production depends in part on the availability, proximity and capacity of pipeline systems owned by third parties in the respective operating areas. The amount of oil and natural gas that can be produced and sold is subject to curtailment in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage to the gathering, compression or transportation system, or lack of contracted capacity on such systems. The curtailments arising from these and similar circumstances may last from a few days to several months. In many cases, we are provided only with limited, if any, notice as to when these circumstances will arise and their duration. In addition, some of our wells are drilled in locations that are not serviced by gathering and transportation pipelines, or the gathering and transportation pipelines in the area may not have sufficient capacity to transport the additional production. As a result, we may not be able to sell the oil and natural gas production from these wells until the necessary gathering and transportation systems are constructed. Any significant curtailment in gathering system or pipeline capacity, or significant delay in the construction of necessary gathering, compression and transportation facilities, could reduce our revenues.

The third parties on whom we rely for gathering, compression and transportation services are subject to complex federal, state and other laws and regulations that could adversely affect the cost, manner or feasibility of doing business.

The operations of the third parties on whom we rely for gathering, compression and transportation services are subject to complex and stringent laws and regulations that require obtaining and maintaining numerous permits, approvals and certifications from various federal, state and local government authorities. These third parties may incur substantial costs in order to comply with existing laws and regulations. If existing laws and regulations governing such third-party services are revised or reinterpreted, or if new laws and regulations become applicable to their operations, these changes may affect the costs that we pay for such services. Similarly, a failure to comply with such laws and regulations by the third parties on whom we rely could have a material adverse effect on our business, financial condition and results of operations.

Our financial condition and results of operations may be materially adversely affected if we incur costs and liabilities due to a failure to comply with environmental regulations or a release of hazardous substances into the environment.

We may incur significant costs and liabilities as a result of environmental requirements applicable to the operation of our wells, gathering systems and other facilities. These costs and liabilities could arise under a wide range of federal, state and local environmental laws and regulations, including, for example:

- the Clean Air Act and comparable state laws and regulations that impose obligations related to emissions of air pollutants;
- the Clean Water Act and comparable state laws and regulations that impose obligations related to discharges of pollutants into regulated bodies of water;
- the Resource Conservation and Recovery Act (the "RCRA"), and comparable state laws that impose requirements for the handling and disposal of waste from our facilities;
- the Comprehensive Environmental Response, Compensation and Liability Act (the "CERCLA") and comparable state laws that regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or at locations to which we have sent waste for disposal;
- the Safe Drinking Water Act (the "SDWA") and state or local laws and regulations related to hydraulic fracturing;
- the Oil Pollution Act (the "OPA") which subjects responsible parties to liability for removal costs and damages arising from an oil spill in federal jurisdictional waters;
- the US Environmental Protection Agency (the "EPA") community right to know regulations under the Title III of CERCLA and similar state statutes that require that we organize and/or disclose information about hazardous materials used or produced in our operations; and
- the Endangered Species Act, which may restrict or prohibit operations in protected areas.

Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of orders enjoining future operations. Certain environmental statutes, including RCRA, CERCLA, OPA and analogous state laws and regulations, impose strict joint and several liability for costs required to clean up and restore sites where hazardous substances or other waste products have been disposed of or otherwise released. More stringent laws and regulations, including any related to climate change and greenhouse gases, may be adopted in the future. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances or other waste products into the environment.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations.

Our operations are subject to complex and stringent laws and regulations, which are continuously being reviewed for amendment and/or expansion. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. Failure or delay in obtaining and maintaining regulatory approvals or drilling permits could have a material adverse effect on our ability to develop our properties, and receipt of drilling permits with onerous conditions could increase our compliance costs. In addition, regulations regarding resource conservation practices and the protection of correlative rights affect our operations by limiting the quantity of oil, natural gas and natural gas liquids we may produce and sell.

We are subject to, and may incur liabilities under, federal, state and local laws and regulations as interpreted and enforced by governmental authorities possessing jurisdiction over various aspects of the exploration and production of oil, natural gas and natural gas liquids.

For example, several states have enacted Surface Damage Acts ("SDAs") that are designed to compensate surface owners/users for damages caused by mineral owners. Most SDAs contain entry notification and negotiation requirements to facilitate contact between operators and surface owners/users. Most also contain binding requirements for payments by the operator to surface owners/users in connection with exploration and operating activities. Costs and delays associated with SDAs could impair operational effectiveness and increase development costs. In addition, many states, including Texas, impose a production, ad valorem or severance tax with respect to the production and sale of oil and gas within their jurisdiction.

Other activities subject to regulation are:

- the location and spacing of wells;
- the method of drilling and completing and operating wells;
- the rate and method of production;
- the surface use and restoration of properties upon which wells are drilled and other exploration activities;
- notice to surface owners and other third parties;
- the venting or flaring of natural gas;
- the plugging and abandoning of wells;
- the discharge of contaminants into water and the emission of contaminants into air;
- the disposal of fluids used or other wastes obtained in connection with operations;
- the marketing, transportation and reporting of production; and
- the valuation and payment of royalties.

While the cost of compliance with these laws has not been material to our operations in the past, the possibility exists that new laws, regulations or enforcement policies could be more stringent and significantly increase our compliance costs. If we are not able to recover the resulting costs through insurance or increased revenues, our ability to service our debt obligations could be adversely affected.

Climate change legislation or regulations restricting emissions of greenhouse gases ("GHGs") could result in increased operating costs and reduced demand for the oil, natural gas and natural gas liquids we produce.

The EPA requires the reporting of GHG emissions from specified large GHG emission sources, including onshore and offshore oil and natural gas production facilities and onshore oil and natural gas processing, transmission, storage and distribution facilities, which may include facilities we operate. We began reporting emissions in 2012 for emissions occurring in 2011 and continue to report as required on an annual basis.

More stringent laws and regulations relating to climate change and GHGs may be adopted and could cause us to incur material expenses to comply.

Both houses of Congress previously considered legislation to reduce emissions of GHGs and many states have adopted or considered measures to reduce GHG emission reduction levels, often involving the planned development of GHG

emission inventories and/or cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions or major producers of fuels to acquire and surrender emission allowances. The adoption and implementation of any legislation or regulatory programs imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil, natural gas and natural gas liquids that we produce.

In the absence of comprehensive federal legislation on GHG emission control, the EPA attempted to require the permitting of GHG emissions; although the Supreme Court struck down the permitting requirements, it upheld EPA's authority to control GHG emissions when a permit is required due to emissions of other pollutants. The EPA has adopted rules to regulate methane emissions, including, as of June 2016, from new and modified oil and gas production sources and natural gas processing and transmission sources, and has announced its intention to regulate methane emissions from existing oil and gas sources. However, in September 2018, the EPA, under the new administration, did propose amendments to the New Source Performance Standards ("NSPS") Subpart OOOOa standards that would relax the requirements implemented in June 2016. In addition, in April 2018, a coalition of states filed a lawsuit aiming to force the EPA to establish guidelines for limiting methane emissions from existing sources in the oil and natural gas sector; that lawsuit is currently pending. In late 2016, the Bureau of Land Management (the "BLM") adopted a rule governing flaring and venting of methane from existing wells and other facilities on public and tribal lands, which could require additional equipment and emissions controls as well as inspection requirements. This rule has been challenged in court by California and New Mexico and litigation is ongoing. Additionally, the US House of Representatives passed a resolution under the Congressional Review Act disapproving the rules; however, the Senate action failed.

Significant physical effects of climatic change have the potential to damage our facilities, disrupt our production activities and cause us to incur significant costs in preparing for or responding to those effects.

Climate change could have an effect on the severity of weather (including hurricanes and floods), sea levels, the arability of farmland, and water availability and quality. If such effects were to occur, our exploration and production operations have the potential to be adversely affected. Potential adverse effects could include damages to our facilities from powerful winds or rising waters in low lying areas, disruption of our production activities either because of climate-related damages to our facilities or our costs of operation potentially arising from such climatic effects, less efficient or non–routine operating practices necessitated by climate effects or increased costs for insurance coverages in the aftermath of such effects. Significant physical effects of climate change could also have an indirect effect on our financing and operations by disrupting the transportation or process related services provided by midstream companies, service companies or suppliers with whom we have a business relationship. We may not be able to recover through insurance some or any of the damages, losses or costs that may result from potential physical effects of climate change.

Federal legislation and state and local legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from dense rock formations. The hydraulic fracturing process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. We routinely use hydraulic fracturing techniques in most of our drilling and completion programs. Hydraulic fracturing is typically regulated by state oil and natural gas commissions or similar state agencies, but the EPA has asserted federal regulatory authority pursuant to the SDWA over certain hydraulic fracturing activities involving the use of diesel. In addition, in past sessions, legislation was introduced before Congress to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the fracturing process. At the state level, some states, including Pennsylvania, Louisiana and Texas, where we operate, have adopted, and other states are considering adopting, requirements that could impose more stringent permitting, public disclosure or well construction requirements on hydraulic fracturing activities including restrictions on drilling and completion operations, including requirements regarding casing and cementing of wells; testing of nearby water wells; restrictions on access to, and usage of, water; and restrictions on the type of chemical additives that may be used in hydraulic fracturing operations. Additionally, some states, localities and local regulatory districts have adopted or have considered adopting regulations to limit, and in some cases impose a moratorium on, hydraulic fracturing. In the event that new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added

costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

In addition, certain governmental reviews are either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The EPA previously issued a final rule revising its definition of the term "waters of the United States." The US Sixth Circuit Court of Appeals issued a nationwide stay that was later withdrawn by the US Supreme Court ruling in January 2018. In December 2018, the EPA and the US Army Corps of Engineers issued a proposed rule revising the definition. The ultimate interpretation by the EPA of the term "waters of the United States" may constitute an expansion of federal jurisdiction over certain bodies of water. Litigation surrounding the initial rule is ongoing and several groups have already announced their intentions to challenge the recent proposed rule. Further, the EPA has published guidance on hydraulic fracturing using diesel and also published an effluent limit guideline final rule prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plants. The ongoing scrutiny of hydraulic fracturing, depending on the degree of pursuit and any meaningful results obtained, could result in further regulation of hydraulic fracturing under the federal SDWA or other regulatory programs.

We are now subject to regulation under NSPS and National Emission Standards for Hazardous Air Pollutants ("NESHAP") programs, which could result in increased operating costs.

On April 17, 2012, the EPA issued final rules that subject oil and natural gas production, processing, transmission and storage operations to regulation under the NSPS and the NESHAP programs. The EPA rules include NSPS standards for completions of hydraulically fractured natural gas wells. Beginning January 1, 2015, operators must capture the natural gas and make it available for use or sale, which can be done through the use of green completions. The standards are applicable to newly fractured wells and also existing wells that are refractured. Further, the finalized regulations also establish specific new requirements, effective in 2012, for emissions from compressors, controllers, dehydrators, storage tanks, natural gas processing plants and certain other equipment. These rules may require changes to our operations, including the installation of new equipment to control emissions. We continuously evaluate the effect of new rules on our business.

We may encounter obstacles to marketing our oil, natural gas and natural gas liquids, which could adversely impact our revenues.

The marketability of our production will depend in part upon the availability and capacity of natural gas gathering systems, pipelines and other transportation facilities owned by third parties. Transportation space on the gathering systems and pipelines we utilize is occasionally limited or unavailable due to repairs or improvements to facilities or due to space being utilized by other companies that have priority transportation agreements. Our access to transportation options can also be affected by US federal and state regulation of oil and natural gas production and transportation, general economic conditions and changes in supply and demand. The availability of markets is beyond our control. If market factors dramatically change, the impact on our revenues could be substantial and could adversely affect our ability to produce and market oil, natural gas and natural gas liquids, the value of our securities and our ability to service our debt obligations.

We may experience a temporary decline in revenues and production if we lose one of our significant customers.

To the extent any significant customer reduces the volume of its oil or natural gas purchases from us, we could experience a temporary interruption in sales of, or a lower price for, our production and our revenues which could adversely affect our ability to service our debt obligations.

We may incur substantial debt in the future to enable us to maintain or increase our production levels and to otherwise pursue our business plan.

Our business requires a significant amount of capital expenditures to maintain and grow production levels. Commodity prices have historically been volatile, and we cannot predict the prices we will receive in the future. If prices were to decline for an extended period of time, if the costs of our operations were to increase substantially, or if other events were

to occur which reduced our revenues or increased our costs, we may be required to borrow significant amounts in the future to enable us to finance the expenditures necessary to replace the reserves we produce.

Oil and gas exploration and production activities are complex and involves risks that could lead to legal proceedings resulting in the incurrence of substantial liabilities.

Like many oil and gas companies, we are from time to time involved in various legal and other proceedings in the ordinary course our business, such as title, royalty or contractual disputes, regulatory compliance matters and personal injury or property damage matters, in the ordinary course of our business. Such legal proceedings are inherently uncertain and their results cannot be predicted. Regardless of the outcome, such proceedings could have an adverse impact on us because of legal costs, diversion of management and other personnel and other factors. In addition, it is possible that a resolution of one or more such proceedings could result in liability, penalties or sanctions, as well as judgments, consent decrees or orders requiring a change in our business practices, which could materially and adversely affect our business, operating results and financial condition. Accruals for such liabilities, penalties or sanctions may be insufficient, and judgments and estimates to determine accruals or range of losses related to legal and other proceedings could change from one period to the next, and such changes could be material.

Loss of our information and computer systems could adversely affect our business.

We are heavily dependent on our information systems and computer based programs, including our well operations information, seismic data, electronic data processing and accounting data. If any of such programs or systems were to fail or create erroneous information in our hardware or software network infrastructure, possible consequences include our loss of communication links, inability to find, produce, process and sell oil and natural gas and inability to automatically process commercial transactions or engage in similar automated or computerized business activities. Any such consequence could have a material adverse effect on our business.

A cyber incident could result in information theft, data corruption, operational disruption and/or financial loss.

The oil and gas industry has become increasingly dependent on digital technologies to conduct day-to-day operations including certain exploration, development and production activities. For example, software programs are used to interpret seismic data, manage drilling rigs, production equipment and gathering and transportation systems, conduct reservoir modeling and reserves estimation, and for compliance reporting. The use of mobile communication devices has increased rapidly. Industrial control systems such as SCADA (supervisory control and data acquisition) now control large scale processes that can include multiple sites and long distances, such as power generation and transmission, communications and oil and gas pipelines.

We depend on digital technology, including information systems and related infrastructure as well as cloud applications and services, all of which is managed by EnerVest pursuant to the Services Agreement, to process and record financial and operating data, communicate with our employees, vendors and service providers, analyze seismic and drilling information, estimate quantities of oil and gas reserves as well as other activities related to our business. Our vendors, service providers, purchasers of our production, and financial institutions, are also dependent on digital technology. The technologies needed to conduct oil and gas exploration and development activities and global competition for oil and gas resources make certain information the target of theft or misappropriation.

As dependence on digital technologies has increased, cyber incidents, including deliberate attacks or unintentional events, also have increased. A cyber attack could include gaining unauthorized access to digital systems for purposes of misappropriating assets or sensitive information, corrupting data, or causing operational disruption, or result in denial-of-service on websites. SCADA-based systems are potentially vulnerable to targeted cyber attacks due to their critical role in operations.

Our technologies, systems, networks, and those of our vendors and service providers may become the target of cyber attacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or other disruption of our business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period.

A cyber incident involving our information systems and related infrastructure, or that of our vendors and service providers, could disrupt our business plans and negatively impact our operations in the following ways, among others:

- unauthorized access to seismic data, reserves information or other sensitive or proprietary information could have a negative impact on our ability to compete for oil and gas resources;
- data corruption, communication interruption, or other operational disruption during drilling activities could result in failure to reach the intended target or a drilling incident;
- data corruption or operational disruption of production infrastructure could result in loss of production, or accidental discharge;
- a cyber attack on a vendor or service provider could result in supply chain disruptions which could delay or halt a development project, effectively delaying the start of cash flows from the project;
- a cyber attack on a third party gathering or pipeline service provider could prevent us from marketing our production, resulting in a loss of revenues;
- a cyber attack involving commodities exchanges or financial institutions could slow or halt commodities trading, thus preventing us from marketing our production or engaging in hedging activities, resulting in a loss of revenues;
- a cyber attack on a communications network or power grid could cause operational disruption resulting in loss of revenues;
- a deliberate corruption of our financial or operational data could result in events of non-compliance which could lead to regulatory fines or penalties; and
- business interruptions could result in expensive remediation efforts, distraction of management, damage to our reputation, or a negative impact on the price of our common stock.

Our implementation of various controls and processes to monitor and mitigate security threats and to increase security for our information, facilities and infrastructure is costly and labor intensive. Moreover, there can be no assurance that such measures will be sufficient to prevent security breaches from occurring. As cyber threats continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities.

Risks Relating to our Common Stock

We have not historically paid dividends on our common stock and, consequently, our stockholders' only opportunity to achieve a return on their investment is if the price of our stock appreciates.

We have not historically paid dividends on our common stock. Consequently, unless our board of directors authorizes the payment of dividends in the future, our stockholders' only opportunity to achieve a return on their investment in us will be if the market price of our common stock appreciates, which may not occur, and the stockholders sell their shares at a profit. There is no guarantee that the price of our common stock will ever exceed the price that the stockholders paid.

There may be circumstances in which the interests of our significant stockholders could be in conflict with the interests of our other stockholders.

Certain of our stockholders own a significant portion of our outstanding common stock. As of December 31, 2018, funds associated with Finepoint Capital LP and FS Investments collectively owned approximately 47% of our outstanding stock and as of September 7, 2018, CQS (UK) LLP owned approximately 15% of our outstanding stock. Circumstances

may arise in which these stockholders may have an interest in pursuing or preventing acquisitions, divestitures or other transactions, including the issuance of additional shares or debt, that, in their judgment, could enhance their investment in the Company. Such transactions might adversely affect us or other holders of our common stock.

Our significant concentration of share ownership may adversely affect the trading price of our common stock.

As of December 31, 2018, funds associated with Finepoint Capital LP and FS Investments collectively owned approximately 47% of our outstanding stock and as of September 7, 2018, CQS (UK) LLP owned approximately 15% of our outstanding stock, and Finepoint Capital LP and FS Investments each have a representative on our board of directors. Our significant concentration of share ownership may adversely affect the trading price of our common stock because of the lack of trading volume in our stock and because investors may perceive disadvantages in owning shares in companies with significant stockholders.

We have experienced recent volatility in the market price and trading volume of our common stock and may continue to do so in the future.

The trading price of shares of our common stock has fluctuated widely and in the future may be subject to similar fluctuations. The trading price of our common stock may be affected by a number of factors, including the volatility of oil, natural gas, and natural gas liquids prices, our operating results, changes in our earnings estimates, additions or departures of key personnel, our financial condition and liquidity, drilling activities, legislative and regulatory changes, general conditions in the oil and natural gas exploration and development industry, general economic conditions, and general conditions in the securities markets. In particular, a significant or extended decline in oil, natural gas and natural gas liquids prices could have a material adverse effect our sales price of our common stock. Other risks described in this annual report could also materially and adversely affect our share price.

Although our common stock is listed on the OTCQX U.S. Premier Marketplace, we cannot assure you that an active public market will continue for our common stock or that will be able to continue to meet the listing requirements of the OTCQX U.S. Premier Marketplace. If an active public market for our common stock does not continue, the trading price and liquidity of our common stock will be materially and adversely affected. If there is a thin trading market or "float" for our stock, the market price for our common stock may fluctuate significantly more than the stock market as a whole. Without a large float, our common stock would be less liquid than the stock of companies with broader public ownership and, as a result, the trading prices of our common stock may be more volatile. In addition, in the absence of an active public trading market, investors may be unable to liquidate their investment in us.

There is a limited trading market for our securities and the market price of our securities is subject to volatility.

Upon emergence from bankruptcy, the common units of the Predecessor were canceled and we issued new common stock. The market price of the new common stock could be subject to wide fluctuations in response to, and the level of trading that develops with the new common stock may be affected by, numerous factors, many of which are beyond our control. These factors include, among other things, our new capital structure as a result of the transactions contemplated by the reorganization plan, our limited trading history subsequent to our emergence from bankruptcy, our limited trading volume, the concentration of holdings of our new common stock, the lack of comparable historical financial information due to our adoption of fresh-start accounting, actual or anticipated variations in our operating results and cash flow, the nature and content of our earnings releases, announcements or events that impact our products, customers, competitors or markets, business conditions in our markets and the general state of the securities markets and the market for energy-related stocks, as well as general economic and market conditions and other factors that may affect our future results.

Our certificate of incorporation and bylaws, as well as Delaware law, contain provisions that could discourage acquisition bids or merger proposals, even if such acquisition or merger may be in our stockholders' best interests.

Our certificate of incorporation authorizes our board of directors to issue preferred stock without stockholder approval. If our board of directors elects to issue preferred stock, it could be more difficult for a third party to acquire us. In addition, some provisions of our certificate of incorporation and bylaws could make it more difficult for a third party to acquire control of us, even if the change of control would be beneficial to our stockholders, including:

- advance notice provisions for stockholder proposals and nominations for elections to the board of directors to be acted upon at meetings of stockholders; and

- limitations on the ability of our stockholders to call special meetings or act by written consent.

Delaware law prohibits us from engaging in any business combination with any "interested stockholder," meaning generally that a stockholder who beneficially owns more than 15% of our stock cannot acquire us for a period of three years from the date this person became an interested stockholder, unless various conditions are met, such as approval of the transaction by our board of directors.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Information regarding our properties is contained in "Item 1. Business — Overview," "Item 1. Business — Oil and Natural Gas Producing Activities" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Results of Operations" contained herein.

ITEM 3. LEGAL PROCEEDINGS

We are involved in disputes or legal actions arising in the ordinary course of business. We do not believe the outcome of such disputes or legal actions will have a material effect on our consolidated financial statements, and no amounts have been accrued at December 31, 2018.

In August 2018, the Company was notified by the Office of Natural Resources Revenue ("ONRR") of potential underpayments of royalties related to certain leases for the period of 2009 through 2018. The Company has submitted amended royalty filings for the period of 2009 to 2012, pursuant to which Harvest has an additional liability of approximately $2.0 million. This amount will be paid upon ONRR review and concurrence with the accuracy of royalties per the amended filings. The Company expects to submit amended royalty filings for the period of 2013 to 2018 later in 2019, pursuant to which Harvest may have an additional liability of approximately $3.0 million. The Company recognized an accrual for the estimated liability for the period of 2009 to 2018 as of December 31, 2018.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Market Information

Our common stock is traded on the OTCQX U.S. Premier Marketplace (the "OTCQX") under the symbol "HRST." As of March 22, 2019, we had 10,042,468 shares of common stock issued and outstanding, held by approximately 281 registered holders.

Issuer Purchases of Equity Securities

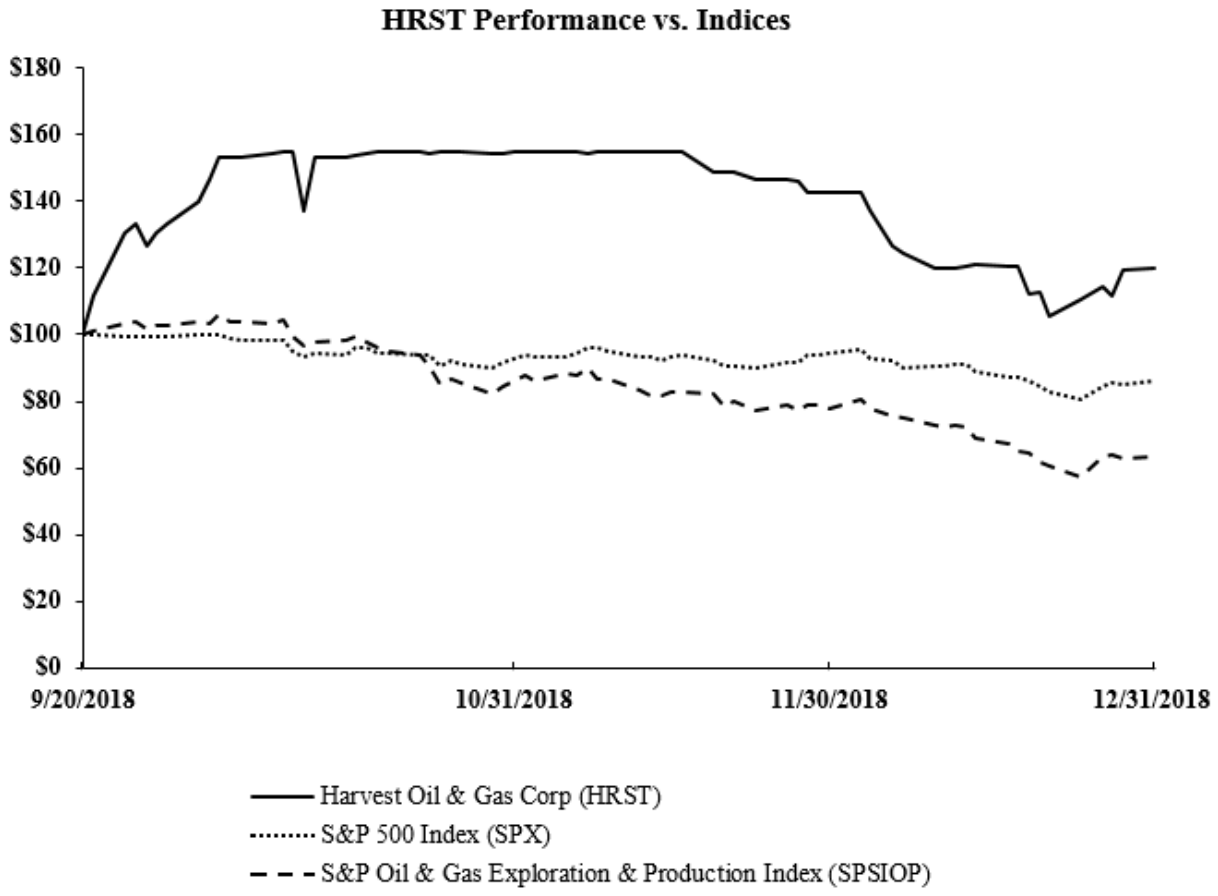
The Company repurchased the following shares from employees for the payment of withholding taxes due on vesting shares of restricted stock previously issued under our share-based compensation plan:

Period	Total Number of Shares Purchased	Average Price Pace Per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Approximate Dollar Value of Shares that may yet be Purchased Under Program
September 2018	12,348	$ 19.99	n/a	n/a

Stock Performance Graph

On September 20, 2018, our common stock began trading on the OTCQX under the symbol “HRST.” Prior to such time, there was no established trading market for our common stock. The following graph compares, since the inception of trading, the performance of our common stock to the S&P 500 Index and the S&P Oil & Gas Exploration & Production Index. The chart assumes that the value of the investment in our common stock and each index was $100 at September 20, 2018, and that all dividends were reinvested.

The stock performance graph is furnished and shall not be deemed "filed" with the SEC or subject to Section 18 of the Exchange Act, and such information shall not be incorporated by reference into any filing of the Company with the SEC, regardless of any general incorporation language in such filing. Also, the stock performance in the graph below is historical and not indicative of future stock price performance.



	9/20/2018	12/31/2018
Harvest Oil & Gas Corp.	$ 100	$ 120
S&P 500 Index	100	86
S&P Oil & Gas Exploration & Production Index	100	63

ITEM 6. SELECTED FINANCIAL DATA

Prior year financial statements are not comparable to our current year financial statements due to the adoption of fresh-start accounting. References to "Successor" relate to the financial position and results of operations of the reorganized Company subsequent to May 31, 2018. References to "Predecessor" relate to the financial position and results of operations of the Company prior to, and including, May 31, 2018.

The following table shows selected financial data for the periods and as of the dates indicated. The selected financial data as of and for the seven months ended December 31, 2018 have been derived from our consolidated financial statements. The selected financial data as of and for the five months ended May 31, 2018 and for the years ended December 31, 2017, 2016, 2015 and 2014 have been derived from the Predecessor's consolidated financial statements.

With the sale of interests in Cardinal Gas Services, LLC ("Cardinal") in October 2014 and in Utica East Ohio Midstream LLC ("UEO") in June 2015, the Predecessor no longer operated in the midstream segment and reclassified its consolidated financial statements for all periods presented to reflect the operations of the midstream segment as discontinued operations. The selected financial data should be read in conjunction with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Item 8. Financial Statements and Supplementary Data," both contained herein.

	Successor	Predecessor				
	Seven Months Ended December 31,	Five Months Ended	Year Ended December 31,			
	2018	May 31, 2018	2017 (1)	2016	2015 (1)	2014
Statement of Operations Data:						
Total revenues	$ 138,600	$ 111,031	$ 225,693	$ 184,894	$ 177,971	$ 339,405
Operating income (loss) [2]	27,389	(10,602)	(118,068)	(217,050)	(287,933)	(25,123)
Other income (expense), net	(1,019)	(12,432)	(16,343)	(28,220)	51,911	47,844
Reorganization items, net [3]	(2,323)	(587,325)	—	—	—	—
Income (loss) from continuing operations before income taxes	24,047	(610,359)	(134,411)	(245,270)	(236,022)	22,721
Income tax (expense) benefit	(78)	(166)	210	2,375	1,843	(476)
Income (loss) from continuing operations	23,969	(610,525)	(134,201)	(242,895)	(234,179)	22,245
Income from discontinued operations [4]	—	—	—	—	255,512	107,475
Net income (loss)	$ 23,969	$ (610,525)	$ (134,201)	$ (242,895)	$ 21,333	$ 129,720
Earnings per share / limited partner unit (basic):						
Income (loss) from continuing operations	$ 2.39	$ (12.12)	$ (2.66)	$ (4.85)	$ (4.72)	$ 0.41
Net income (loss)	$ 2.39	$ (12.12)	$ (2.66)	$ (4.85)	$ 0.41	$ 2.58
Earnings per share / limited partner unit (diluted):						
Income (loss) from continuing operations	$ 2.39	$ (12.12)	$ (2.66)	$ (4.85)	$ (4.72)	$ 0.41
Net income (loss)	$ 2.39	$ (12.12)	$ (2.66)	$ (4.85)	$ 0.41	$ 2.58
Distributions declared per share / limited partner unit	$ —	$ —	$ —	$ —	$ 1.575	$ 2.819
Financial Position (at end of period):						
Working capital	$ 88,522		$ (592,523)	$ (6,875)	$ 54,812	$ 428,965
Total assets	534,494		1,441,805	1,606,770	1,923,602	2,246,161
Current portion of long-term debt [5]	—		605,549	—	—	—
Long-term debt, net [5]	115,000		—	606,948	688,614	1,027,349
Stockholders' / owners' equity	273,539		628,012	758,407	998,559	1,066,113

(1) Includes the results of the following acquisitions of oil and natural gas properties:

- Karnes County, Texas in January 2017; and
- the Appalachian Basin, the San Juan Basin, Michigan and the Austin Chalk in October 2015.

(2) Includes impairments of oil and natural gas properties of $3.1 million, $93.6 million, $131.3 million, $136.7 million and $114.0 million in the seven months ended December 31, 2018 and in 2017, 2016, 2015 and 2014, respectively.

(3) Reorganization items, net, represent costs, gains and losses directly associated with the Chapter 11 proceedings since the Petition Date.

(4) Includes gain on sale of investment in UEO of $246.7 million and Cardinal of $92.1 million in 2015 and 2014, respectively.

(5) Due to the anticipated financial covenant violations as of December 31, 2017, the borrowings under the Predecessor's credit facility and senior notes were classified as current at December 31, 2017. There were no financial covenant violations as of December 31, 2018.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Management's Discussion and Analysis of Financial Condition and Results of Operations should be read in conjunction with "Item 8. Financial Statements and Supplementary Data" contained herein.

OVERVIEW

Harvest Oil & Gas Corp. ("Harvest" or "Successor") is an independent oil and natural gas company that was formed in 2018 in connection with the reorganization of EV Energy Partners, L.P. ("EVEP" or "Predecessor"). As used herein, the terms the "Company," "we," "our" or "us" refer to (i) Harvest Oil & Gas Corp. after the Effective Date (as defined below) and (ii) EVEP prior to, and including, the Effective Date, in each case, together with their respective consolidated subsidiaries or on an individual basis, depending on the context in which the statements are made.

We operate one reportable segment engaged in the development and production of oil and natural gas properties, and all of our operations are located in the United States. As of December 31, 2018, our oil and natural gas properties are located in the Barnett Shale, the San Juan Basin, the Appalachian Basin (which includes the Utica Shale), Michigan, the Mid–Continent areas in Oklahoma, Texas, Arkansas, Kansas and Louisiana, the Permian Basin and the Monroe Field in Northern Louisiana. As of December 31, 2018, we had estimated net proved reserves of 9.9 MMBbls of oil, 476.7 Bcf of natural gas and 29.3 MMBbls of natural gas liquids, or 711.9 Bcfe, and a standardized measure of $436.4 million. Of our total net proved reserves, 98% are proved developed and 53% are operated.

As a result of the ongoing review of our asset base in order to maximize shareholder value, we have initiated processes to divest certain assets and in the future, may look to divest additional assets or all of our remaining assets and use the proceeds to repay bank debt, return capital to shareholders, concentrate in existing positions or venture into new basins. In January and February 2019, we entered into definitive agreements to sell all of our oil and gas properties in the San Juan Basin and certain of our oil and gas properties in the Mid-Continent area. See "—Current Developments" below for additional information.

Current Developments

In August 2018, we closed the sale of certain oil and gas properties in Central Texas and Karnes County, Texas to Magnolia Oil & Gas Parent LLC and Magnolia Oil & Gas Corporation (collectively, "Magnolia") for total consideration of $134.4 million in cash, net of purchase price adjustments, and 4.2 million shares of common stock of Magnolia (NYSE: MGY). Based on the closing price for Magnolia's common stock on August 31, 2018, total consideration was $192.7 million, net of purchase price adjustments.

During January 2019, we sold all of our 4.2 million shares of common stock of Magnolia for net proceeds of $51.7 million.

In addition, in August 2018, we closed the sale of certain oil and gas properties in Central Texas to a third party for total consideration of $3.4 million, net of purchase price adjustments.

In December 2018, we closed the sale of certain oil and gas properties in Central Texas to a third party for total consideration of $2.6 million, net of preliminary purchase price adjustments.

In addition, in December 2018, we closed the sale of certain oil and gas properties in the Mid–Continent area to a third party for total consideration of $1.0 million, net of purchase price adjustments.

In January 2019, we closed the sale of certain oil and gas properties in the Mid-Continent area to a third party for total consideration of $1.7 million, net of preliminary purchase price adjustments.

In February 2019, we entered into a definitive agreement to sell all of our (i) oil and gas properties in the San Juan Basin and (ii) membership interests in EnerVest Mesa, LLC, a wholly-owned subsidiary of EV Properties, L.P., to a third party for total consideration of $42.8 million in cash, subject to purchase price adjustments. The transaction is expected to close in April 2019 and has an effective date of October 1, 2018. The net book value as of December 31, 2018 of the San Juan assets and liabilities to be divested was approximately $61 million. As a result, we expect to record an impairment related to the sale of our San Juan properties in 2019.

Also, in February 2019, we entered into a definitive agreement to sell certain oil and gas properties in the Mid-Continent area to a third party for total consideration of $2.5 million in cash, subject to purchase price adjustments. The transaction is expected to close in April 2019 and has an effective date of October 1, 2018.

See Note 8 of the Notes to Consolidated Financial Statements included under "Item 8. Financial Statements and Supplementary Data" contained herein for additional information.

Emergence from Voluntary Reorganization under Chapter 11

On March 13, 2018, EVEP and the other 13 affiliated debtors (collectively, the "Debtors") entered into a Restructuring Support Agreement (the "Restructuring Support Agreement") with certain holders of the Predecessor's outstanding notes (collectively, the "Supporting Noteholders"), certain lenders under the Predecessor's reserve-based lending facility, EnerVest, Ltd and EnerVest Operating, L.L.C. The Restructuring Support Agreement set forth, subject to certain conditions, the commitment of the Debtors and the consenting creditors to support a comprehensive restructuring of the Debtors' long-term debt (the "Restructuring"). On April 2, 2018 (the "Petition Date"), the Debtors each filed Chapter 11 proceedings under Chapter 11 in the United States Bankruptcy Court for the District of Delaware (the "Bankruptcy Court"). The Debtors' Chapter 11 proceedings were jointly administered under the caption *In re EV Energy Partners, L.P., et al*., Case No. 18-10814. During the pendency of the Chapter 11 proceedings, EVEP continued to operate its business and manage its properties under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code and orders of the Bankruptcy Court as "Debtors-in-Possession." On May 17, 2018, the Bankruptcy Court entered the Confirmation Order confirming the Plan.

On June 4, 2018, the Debtors satisfied the conditions to effectiveness of the Debtors' First Modified Joint Prepackaged Plan of Reorganization (as amended, modified and supplemented from time to time, the "Plan"), the Plan became effective in accordance with its terms. In accordance with the Plan, EVEP's equity was cancelled, EVEP transferred all of its assets and operations to Harvest, EVEP was dissolved and Harvest became and the successor reporting company to EVEP pursuant to Rule 15d-5 of the Securities Exchange Act of 1934, as amended.

Although we are not a debtor-in-possession, the Predecessor was a debtor-in-possession between April 2, 2018 and June 4, 2018. As such, certain aspects of the Chapter 11 proceedings and related matters are described below in order to provide context to the Company's financial condition and results of operations for the period presented. See Note 2 and

Note 3 of the Notes to Consolidated Financial Statements included under "Item 8. Financial Statements and Supplementary Data" contained herein for additional information.

Plan of Reorganization

In accordance with the Plan, on the Effective Date, among other things:

- The Predecessor transferred all of its assets and operations to the Successor, the Predecessor was dissolved and the Successor became the successor reporting company to the Predecessor pursuant to Rule 15d-5 of the Exchange Act;

- The Successor issued (i) 9,500,000 new shares of its common stock, par value $0.01 per share ("common stock"), pro rata to holders of the 8.0% senior unsecured notes due April 2019 (the "Senior Notes") with claims allowed under the Plan; (ii) 500,016 shares of common stock pro rata to holders of units of EVEP prior to the Effective Date; (iii) 800,000 warrants (the "Warrants") to purchase 800,000 shares of common stock to holders of units of EVEP prior to the Effective Date exercisable for a five-year period commencing on the Effective Date entitling their holders upon exercise thereof, on a pro rata basis, to 8% of the total issued and outstanding common stock (including common stock as of the Effective Date issuable upon full exercise of the Warrants, but excluding any common stock issuable under the Company's Management Incentive Plan (the "MIP")), at a per share exercise price of $37.48; (iv) 79,000 shares of 8% Cumulative Nonparticipating Redeemable Series A Preferred Stock (the "Series A Preferred Stock") to its indirectly wholly-owned subsidiary EV Midstream, L.P. for consideration of $790,000; and (v) 21,000 shares of Series A Preferred Stock to one employee of the Company and one employee of EnerVest for consideration of services to the Company, which vest on the earlier of (a) June 4, 2019 or (b) immediately prior to the consummation of a Sale Transaction as such term is defined in the Certificate of Designations, Preferences and Rights of the Series A Preferred Stock (the "Certificate of Designations");

- The holders of claims under the Predecessor's credit facility received full recovery, consisting of (i) their pro rata share of the $1 billion new reserve-based revolving loan (the "Exit Credit Facility"); (ii) cash in amount equal to the accrued but unpaid interest payable to such lenders under the credit facility as of the Effective Date; and (iii) unfunded commitments and letter of credit participation under the Exit Credit Facility equal to the unfunded commitments and letter of credit participation of such lender as of the Effective Date;

- The Senior Notes were cancelled and the Predecessor's liability thereunder discharged, and the holders of the Notes received (directly or indirectly) their pro rata share of common stock representing, in the aggregate, 95% of the common stock on the Effective Date (subject to dilution by the MIP and the common shares issuable upon exercise of the Warrants);

- The Predecessor's common units were cancelled, and each common unitholder received its pro rata share of: (i) 5% of the common stock and (ii) the Warrants;

- The holders of administrative expense claims, other priority claims and general unsecured creditors of the Predecessor received in exchange for their claims payment in full in cash or otherwise had their rights unimpaired under Title 11 of the United States Code;

- The Successor adopted the MIP, pursuant to which employees, directors, consultants and other service providers of the Company and its subsidiaries are eligible to receive stock options, stock appreciation rights, restricted stock, restricted stock units, other stock-based awards and cash-based awards. As of the Effective Date, an aggregate of 689,362 shares of common stock were reserved for issuance under the MIP, all of which may be granted in the form of incentive stock options; and

- General unsecured claims received (i) if such claim was due and payable on or before the Effective Date, payment in full, in cash, or the unpaid portion of its allowed general unsecured claim, (ii) if such claim was not due and payable before the Effective Date, payment in the ordinary course, and (iii) other treatment, as may be agreed upon by the Debtors, the Supporting Noteholders and the holder of such general unsecured claim.

Predecessor and Successor Reporting

Upon our emergence on the Effective Date, we elected to adopt fresh start accounting effective May 31, 2018 (the "convenience date") to coincide with the timing of our normal accounting period close. As a result of the adoption of fresh start accounting and the effects of the implementation of the Plan, the Company's consolidated financial statements and certain presentations are separated into two distinct periods, the period before the convenience date (labeled Predecessor) and the period after the convenience date (labeled Successor), to indicate the application of different basis of accounting between the periods presented. Despite the separate presentation, there was continuity of the Company's operations.

See Note 3 of the Notes to Consolidated Financial Statements included under "Item 8. Financial Statements and Supplementary Data" contained herein for additional information.

Our Operating Plan and Strategy

We focus our efforts on maintaining or minimizing the decline in our reserves and production while controlling costs at a level that is appropriate for long–term operations. Our future cash flows from operations are dependent upon our ability to manage our overall cost structure. As initial reservoir pressures are depleted, production from our wells decreases. We attempt to mitigate or reduce this natural decline through drilling and workover operations. We will maintain our focus on drilling costs as well as the costs necessary to produce our reserves. Our drilling program is dependent on our capital resources and the inventory and economics of drilling prospects and can be limited by many factors, including our ability to timely obtain drilling permits and regulatory approvals. Our overall operating plan also includes regular reviews of our asset base. As a result of this ongoing review, we have initiated processes to divest of certain assets, and in the future, we may look to divest additional assets or all of our remaining assets in order to maximize shareholder value.

In order to mitigate the impact of lower prices on our cash flows, we are a party to derivatives, and we intend to enter into derivatives in the future to reduce the impact of price volatility on our cash flows. Although we have entered into derivative contracts covering a portion of our future production through December 2020, a sustained lower price environment would result in lower prices for unprotected volumes and reduce the prices at which we can enter into derivative contracts for additional volumes in the future. We have mitigated, but not eliminated, the potential effects of changing prices on our cash flows from operations for those periods. An extended period of depressed commodity prices would alter our development plans, as well as adversely affect our ability to access additional capital in the capital markets. Please refer to Item 7A. "Quantitative And Qualitative Disclosures About Market Risk" contained herein for more information.

Critical Accounting Policies

The discussion and analysis of our financial condition and results of operations is based upon the consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP"). The preparation of these consolidated financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and related disclosures about contingent assets and liabilities. Certain of our accounting policies involve estimates and assumptions to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions or if different assumptions had been used. We base these estimates and assumptions on historical experience and on various other information and assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Estimates and assumptions about future events and their effects cannot be perceived with certainty and, accordingly, these estimates may change as additional information is obtained, as more experience is acquired, as our operating environment changes and as new events occur.

Our critical accounting policies are important to the portrayal of both our financial condition and results of operations and require us to make difficult, subjective or complex assumptions or estimates about matters that are uncertain. We would report different amounts in our consolidated financial statements, which could be material, if we used different

assumptions or estimates. We believe that the following are the critical accounting policies used in the preparation of our consolidated financial statements.

Bankruptcy Accounting

The consolidated financial statements have been prepared as if we are a going concern and reflect the application of Accounting Standards Codification 852 *Reorganizations* ("ASC 852"). ASC 852 requires that the financial statements, for periods subsequent to the Chapter 11 filing, distinguish transactions and events that are directly associated with the reorganization from the ongoing operations of the business. Accordingly, certain expenses, gains and losses that were realized or incurred related to the bankruptcy proceedings are recorded in "Reorganization items, net" on our consolidated statements of operations.

Upon emergence from bankruptcy on June 4, 2018, we elected to adopt and apply the relevant guidance provided in GAAP with respect to the accounting and financial statement disclosures for entities that have emerged from Chapter 11 ("fresh start accounting") effective May 31, 2018 to coincide with the timing of our normal accounting period close. This process required us to make assumptions around valuations which included estimates of future prices, production costs, development expenditures, anticipated production, appropriate risk-adjusted discount rates and other relevant data. As a result of the application of fresh start accounting and the effects of the implementation of the plan of reorganization, the consolidated financial statements as of or after May 31, 2018, are not comparable with the consolidated financial statements prior to that date. To facilitate the financial statement presentations, we refer to the reorganized company in our consolidated financial statements as the "Successor" for periods subsequent to May 31, 2018 and "Predecessor" for periods prior to June 1, 2018. Furthermore, the consolidated financial statements have been presented with a "black line" division to delineate the lack of comparability between the Predecessor and Successor. See Note 2 and Note 3 of the Notes to Consolidated Financial Statements included under "Item 8. Financial Statements and Supplementary Data" contained herein for additional information.

Oil and Natural Gas Properties

We account for our oil and natural gas properties using the successful efforts method of accounting. Under this method, costs of productive exploratory wells, development dry holes and productive wells and undeveloped leases are capitalized. Oil and natural gas lease acquisition costs are also capitalized. Exploration costs, including personnel costs, certain geological and geophysical expenses and delay rentals for oil and natural gas leases, are charged to expense during the period the costs are incurred. Exploratory drilling costs are initially capitalized, but charged to expense if and when the well is determined not to have found reserves in commercial quantities.

Sales proceeds are credited to the carrying value of the properties, and no gains or losses are recognized upon the disposition of proved oil and natural gas properties except in transactions such as the significant disposition of an amortizable base that significantly affects the unit–of–production amortization rate.

The application of the successful efforts method of accounting requires managerial judgment to determine the proper classification of wells designated as development or exploratory which will ultimately determine the proper accounting treatment of the costs incurred. The results from a drilling operation can take considerable time to analyze, and the determination that commercial reserves have been discovered requires both judgment and industry experience. Wells may be completed that are assumed to be productive and actually deliver oil, natural gas and natural gas liquids in quantities insufficient to be economic, which may result in the abandonment of the wells at a later date. Wells are drilled that have targeted geologic structures that are both developmental and exploratory in nature, and an allocation of costs is required to properly account for the results. Delineation seismic incurred to select development locations within an oil and natural gas field is typically considered a development cost and capitalized, but often these seismic programs extend beyond the reserve area considered proved and management must estimate the portion of the seismic costs to expense. The evaluation of oil and natural gas leasehold acquisition costs requires managerial judgment to estimate the fair value of these costs with reference to drilling activity in a given area. Drilling activities in an area by other companies may also effectively condemn leasehold positions.

The successful efforts method of accounting can have a significant impact on the operational results reported when we are entering a new exploratory area in hopes of finding an oil and natural gas field that will be the focus of future developmental drilling activity. The initial exploratory wells may be unsuccessful and will be expensed. Seismic costs can be substantial which will result in additional exploration expenses when incurred.

We assess our proved oil and natural gas properties for possible impairment whenever events or circumstances indicate that the recorded carrying value of the properties may not be recoverable. Such events include a projection of future reserves that will be produced from a field, the timing of this future production, future costs to produce the oil, natural gas and natural gas liquids and future inflation levels. If the carrying amount of a property exceeds the sum of the estimated undiscounted future net cash flows, we recognize an impairment expense equal to the difference between the carrying value and the fair value of the property, which is estimated to be the expected present value of the future net cash flows. Estimated future net cash flows are based on existing reserves, forecasted production and cost information and management's outlook of future commodity prices. Where probable and possible reserves exist, an appropriately risk adjusted amount of these reserves is included in the impairment evaluation. The underlying commodity prices used in the determination of our estimated future net cash flows are based on NYMEX forward strip prices at the end of the period, adjusted by field or area for estimated location and quality differentials, as well as other trends and factors that management believes will impact realizable prices. Future operating costs estimates, including appropriate escalators, are also developed based on a review of actual costs by field or area. Downward revisions in estimates of reserve quantities or expectations of falling commodity prices or rising operating costs could result in a reduction in undiscounted future cash flows and could indicate a property impairment.

Estimates of Oil, Natural Gas and Natural Gas Liquids Reserves

Our estimates of proved reserves are based on the quantities of oil, natural gas and natural gas liquids which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations – prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimate. Reserves for proved developed producing wells were estimated using production performance and material balance methods. Certain new producing properties with little production history were forecast using a combination of production performance and analogy to offset production, both of which provide accurate forecasts. Non–producing reserve estimates for both developed and undeveloped properties were forecast using either volumetric and/or analogy methods. These methods provide accurate forecasts due to the mature nature of the properties targeted for development and an abundance of subsurface control data.

The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. For example, we must estimate the amount and timing of future operating costs, severance taxes, development costs and workover costs, all of which may vary considerably from actual results. In addition, as prices and cost levels change from year to year, the estimate of proved reserves also changes. Any significant variance in these assumptions could materially affect the estimated quantity and value of our reserves. Independent reserve engineers prepare our reserve estimates at the end of each year.

Despite the inherent imprecision in these engineering estimates, our reserves are used throughout our financial statements. For example, since we use the units–of–production method to amortize the costs of our oil and natural gas properties, the quantity of reserves could significantly impact our depreciation, depletion and amortization expense. Our reserves are also the basis of our supplemental oil and natural gas disclosures.

Revenue Recognition

Oil, natural gas and natural gas liquids revenues are recognized at a point in time upon the transfer of control of the products to a purchaser. We must use judgement and consider a variety of facts and circumstances to assess when transfer of control occurs, including but not limited to: whether the purchaser can direct the use of the hydrocarbon, the transfer of significant risks and rewards, our right to payment and transfer of legal title. Transfer of control typically occurs when the products are delivered to the purchaser, title or risk of loss has transferred and collectability of the revenue is reasonably

assured. Revenue is recognized net of royalties due to third parties in an amount that reflects the consideration we expect to receive in exchange for those products. Virtually all of our contracts' pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of oil, natural gas and natural gas liquids and prevailing supply and demand conditions, so that prices fluctuate to remain competitive with other available suppliers.

We follow the sales method of accounting for natural gas revenues. Under this method of accounting, revenues are recognized based on volumes sold, which may differ from the volume to which we are entitled based on our working interest. An imbalance is recognized as a liability only when the estimated remaining reserves will not be sufficient to enable the under–produced owner(s) to recoup its entitled share through future production. Under the sales method, no receivables are recorded where we have taken less than our share of production.

We own and operate a network of natural gas gathering systems in the Appalachian Basin and the Monroe Field in Northern Louisiana which gather and transport owned natural gas and a small amount of third party natural gas to intrastate, interstate and local distribution pipelines. Natural gas gathering and transportation revenue is recognized when the natural gas has been delivered to a custody transfer point.

RESULTS OF OPERATIONS

References to "Successor" relate to the financial position and results of operations of the reorganized Company subsequent to May 31, 2018, and references to "Predecessor" relate to the financial position and results of operations of the Company prior to, and including, May 31, 2018.

In addition to presenting Successor and Predecessor results of operations, in the table and discussion below, we have presented the Company's operating results for the fiscal year ended December 31, 2018 on a combined basis (i.e., by combining the results of the applicable Predecessor and Successor periods). We believe that describing certain year-over-year variances and trends in our production, revenue and expenses for the year ended December 31, 2018 as compared to December 31, 2017 without regard to the concept of Successor and Predecessor (i.e., on a combined basis) facilitates a meaningful analysis of our results of operations and is useful in identifying current business trends. The combined results represent the sum of the reported amounts for the Predecessor period from January 1, 2018 through May 31, 2018 and the Successor period from June 1, 2018 through December 31, 2018. These combined results are not considered to be prepared in accordance with GAAP and have not been prepared as pro forma results under applicable regulations. The combined operating results may not reflect the actual results we would have achieved absent our emergence from bankruptcy and may not be indicative of future results.

Factors Affecting the Comparability of the Results

The impact to the comparability of the Predecessor and Successor results is generally limited to those areas associated with the basis in and accounting for our oil and gas properties (specifically depreciation, depletion and amortization ("DD&A") and impairments), exploration expense and income taxes (due to the change from a limited partnership to a corporation that occurred in connection with our emergence from bankruptcy). In addition, the comparability of our results for 2018 (combined) as compared to prior years may be limited by the effects of our emergence from bankruptcy and fresh-start reporting.

	Successor	Predecessor		Predecessor	
	Seven Months Ended December 31, 2018	Five Months Ended May 31, 2018	Combined Year Ended December 31, 2018	Year Ended December 31, 2017	Year Ended December 31, 2016
Oil, natural gas and natural gas liquids revenues:					
Oil	$ 41,411	$ 42,460	$ 83,871	$ 65,768	$ 47,139
Natural gas	63,460	40,951	104,411	111,204	99,840
Natural gas liquids [1]	32,298	26,896	59,194	46,325	35,717
Total [1]	$ 137,169	$ 110,307	$ 247,476	$ 223,297	$ 182,696
Production data:					
Oil (MBbls)	642	662	1,304	1,387	1,216
Natural gas (MMcf)	23,084	16,982	40,066	40,979	49,333
Natural gas liquids (MBbls)	1,348	1,040	2,388	2,165	2,331
Total (MMcfe)	35,029	27,193	62,222	62,293	70,612
Average sales price per unit:					
Oil (per Bbl)	$ 64.45	$ 64.14	$ 64.32	$ 47.41	$ 38.78
Natural gas (per Mcf)	2.75	2.41	2.61	2.71	2.02
Natural gas liquids (per Bbl) [1]	23.95	25.86	24.79	21.40	15.32
Total (per Mcfe) [1]	3.92	4.06	3.98	3.58	2.59
Expenses and Other:					
Lease operating expenses	$ 64,100	$ 45,372	$ 109,472	$ 101,591	$ 103,371
Cost of purchased natural gas	1,026	557	1,583	1,699	1,497
Dry hole and exploration costs	177	122	299	413	651
Production taxes	6,482	5,343	11,825	10,588	7,386
Accretion expense on obligations	5,420	3,176	8,596	7,653	8,225
Depreciation, depletion and amortization	16,012	46,196	62,208	96,901	119,171
General and administrative expenses	15,626	15,648	31,274	32,290	33,637
Restructuring costs	-	5,211	5,211	-	-
Impairment of oil and natural gas properties	3,065	3	3,068	93,607	131,260
Gain (loss) on sales of oil and natural gas properties	697	(5)	692	981	69
Gain (loss) on derivatives, net	16,962	444	17,406	22,854	(35,950)
Interest expense	7,225	13,652	20,877	40,903	42,487
Gain on early extinguishment of debt	-	-	-	-	47,695
Loss on equity securities	11,130	-	11,130	-	-
Reorganization items, net	2,323	587,325	589,648	-	-
Income tax expense (benefit)	78	166	244	(210)	(2,375)
Net income (loss)	$ 23,969	$ (610,525)	$ (586,556)	$ (134,201)	$ (242,895)

[1] Includes a royalty adjustment of $5.0 million during the seven months ended December 31, 2018. Excluding this royalty adjustment, revenues from natural gas liquids would have been $37.3 million, or $27.66 per Bbl, and total revenues from oil, natural gas and natural gas liquids would have been $142.2 million, or $4.06 per Mcfe, for the seven months ended December 31, 2018. See Note 13 of the Notes to Consolidated Financial Statements included under "Item 8. Financial Statements and Supplementary Data" contained herein for additional information.

	Successor	Predecessor		Predecessor	
	Seven Months Ended December 31, 2018	Five Months Ended May 31, 2018	Combined Year Ended December 31, 2018	Year Ended December 31, 2017	Year Ended December 31, 2016
Average unit cost per Mcfe:					
Production costs:					
Lease operating expenses	$ 1.83	$ 1.67	$ 1.76	$ 1.63	$ 1.46
Production taxes	0.19	0.20	0.19	0.17	0.10
Total	2.02	1.87	1.95	1.80	1.56
Depreciation, depletion and amortization	0.46	1.70	1.00	1.56	1.69
General and administrative expenses	0.45	0.58	0.50	0.52	0.48

Year Ended December 31, 2018 (Combined) Compared with the Year Ended December 31, 2017

Net loss for 2018 was $586.6 million compared with a net loss of $134.2 million for 2017. The significant factors in this change were (i) $589.6 million of reorganization costs incurred during 2018; (ii) $11.1 million loss on equity securities during 2018; (iii) a $7.9 million increase in lease operating expenses; (iv) a $5.4 million unfavorable change in gain on derivatives and (v) $5.2 million of restructuring costs incurred prior to the Petition Date. These factors were partially offset by (i) a $90.5 million decrease in impairment of oil and natural gas properties; (ii) a $34.7 million decrease in depreciation, depletion and amortization; (iii) a $23.9 million increase in revenues and (iv) a $20.0 million decrease in interest expense.

Oil, natural gas and natural gas liquids revenues for 2018 totaled $247.5 million, an increase of $24.2 million compared with 2017. This increase in revenues was the result of an increase of $32.9 million primarily related to higher oil and natural gas liquids prices and an increase of $5.0 million related to the impact of adopting ASU No. 2014-09, *Revenue from Contracts with Customers* ("Topic 606"), partially offset by a decrease of $8.7 million primarily related to decreased oil and natural gas production and a decrease of $5.0 million related to a royalty adjustment.

Lease operating expenses for 2018 increased $7.9 million compared with 2017 as the result of $6.3 million from a higher cost per Mcfe combined with $5.0 million related to the impact of adopting Topic 606, partially offset by $3.4 million from decreased production. The higher unit cost per Mcfe reflects lower production volumes. Lease operating expenses per Mcfe were $1.76 in 2018 compared with $1.63 in 2017.

Production taxes for 2018 increased $1.2 million compared with 2017 due to higher oil, natural gas and natural gas liquids revenues. Production taxes for 2018 were $0.19 per Mcfe compared with $0.17 per Mcfe for 2017.

DD&A for 2018 decreased $34.7 million compared with 2017 primarily due to a lower average DD&A rate per Mcfe as a result of the application of fresh start accounting in 2018. DD&A for 2018 was $1.00 per Mcfe compared with $1.56 per Mcfe for 2017.

General and administrative expenses for 2018 totaled $31.3 million, a decrease of $1.0 million compared with 2017. This decrease is primarily the result of lower legal and consulting fees partially offset by higher fees paid under the Services Agreement with EnerVest. General and administrative expenses were $0.50 per Mcfe in 2018 compared with $0.52 per Mcfe in 2017.

Restructuring expenses for 2018 totaled $5.2 million. These expenses are for professional services related to the Restructuring which were incurred prior to the Petition Date. For 2017, there were no restructuring expenses.

During 2018, we incurred proved property impairment of $3.1 million related to proved oil and natural gas properties located in Central Texas and Karnes County, Texas which were sold during August 2018. During 2017, we incurred impairment charges of $93.6 million. Of this 2017 amount, $69.9 million related to oil and natural gas properties that were written down to their fair value as determined based on the expected present value of the future net cash flows. Of this $69.9 million amount, $49.5 million related to properties located in the Mid-Continent area and the Permian Basin, $15.3 million related to properties located in the Monroe Field, $2.2 million related to properties in Central Texas and $2.9

million related to properties in East Texas which were sold during April 2017. Significant assumptions associated with the calculation of discounted cash flows used in the impairment analysis included estimates of future prices, production costs, development expenditures, anticipated production of our estimated reserves, appropriate risk–adjusted discount rates and other relevant data. The remainder of the impairment charges in 2017 consisted of $23.7 million of leasehold impairments.

Loss on equity securities was $11.1 million for 2018 compared with none for 2017. The loss in 2018 is attributable to the changes in the share price of the shares of common stock of Magnolia which were acquired in the Central Texas Divestiture.

Gain on derivatives, net, was $17.4 million for 2018 compared with $22.9 million for 2017. This change was attributable to changes in future oil and natural gas prices. The 12-month forward price at December 31, 2018 for oil averaged $47.09 per Bbl compared with $59.40 at December 31, 2017, and the 12-month forward prices at December 31, 2018 for natural gas averaged $2.85 per MMBtu compared with $2.86 at December 31, 2017. The 12-month forward price at December 31, 2017 for oil averaged $59.40 per Bbl compared with $56.19 at December 31, 2016, and the 12-month forward prices at December 31, 2017 for natural gas averaged $2.86 per MMBtu compared with $3.61 at December 31, 2016.

Interest expense for 2018 decreased $20.0 million compared with 2017. This change was primarily a result of $16.1 million related to a lower weighted average long-term debt balance, $4.7 million related to the suspension of interest for the Senior Notes as a result of the Chapter 11 proceedings and $0.5 million related to the write off of loan costs in the prior year, partially offset by $1.3 million from a higher weighted average effective interest rate.

We incurred significant costs in 2018 associated with the reorganization. Reorganization items, net, represent costs and gains directly associated with the Chapter 11 proceedings since the Petition Date, such as the gain on settlement of liabilities subject to compromise, fresh start valuation adjustments, issuance of common stock and warrants and settlement with Predecessor common unitholders. We incurred $589.6 million of reorganization items, net, during the year ended December 31, 2018 compared to none in 2017. See Note 2 and Note 3 of the Notes to Consolidated Financial Statements included under “Item 8. Financial Statements and Supplementary Data” contained herein for additional information.

Year Ended December 31, 2017 Compared with the Year Ended December 31, 2016

Net loss for 2017 was $134.2 million compared with a net loss of $242.9 million for 2016. The significant factors in this change were (i) a $58.8 million favorable change in gain (loss) on derivatives; (ii) a $40.8 million increase in revenues; (iii) a $37.7 million decrease in impairment of oil and natural gas properties; and (iv) a $22.3 million decrease in depreciation, depletion and amortization. These factors were partially offset by a $47.7 million decrease in gain on early extinguishment of debt that occurred in 2016 when we redeemed $74.0 million of our outstanding Senior Notes.

Oil, natural gas and natural gas liquids revenues for 2017 totaled $223.3 million, an increase of $40.6 million compared with 2016. This was the result of increases of $58.7 million related to higher prices for oil, natural gas and natural gas liquids partially offset by a decrease of $18.1 million primarily related to decreased natural gas and natural gas liquids production.

Lease operating expenses for 2017 decreased $1.8 million compared with 2016 as the result of $13.6 million from decreased production offset by $11.8 million from a higher cost per Mcfe. The higher unit cost per Mcfe reflects lower production volumes. Lease operating expenses per Mcfe were $1.63 in 2017 compared with $1.46 in 2016.

Production taxes for 2017 increased $3.2 million compared with 2016 due to higher oil, natural gas and natural gas liquids revenues. Production taxes for 2017 were $0.17 per Mcfe compared with $0.10 per Mcfe for 2016.

DD&A for 2017 decreased $22.3 million compared with 2016 due to $13.0 million of decreased production combined with $9.3 million from a lower average DD&A rate per Mcfe. The lower average DD&A rate per Mcfe reflects the change that prices had on our reserves estimates, as well as impairment of oil and gas properties during the first half of 2017. DD&A for 2017 was $1.56 per Mcfe compared with $1.69 per Mcfe for 2016.

General and administrative expenses for 2017 totaled $32.3 million, a decrease of $1.3 million compared with 2016. This decrease is primarily the result of $2.3 million of lower equity compensation costs and $1.8 million of lower fees paid to EnerVest under our omnibus agreement; these were partially offset by $1.8 million of increased legal fees and $1.4 million of increased compensation costs. General and administrative expenses were $0.52 per Mcfe in 2017 compared with $0.48 per Mcfe in 2016.

As a result of a reduction in estimated future net cash flows primarily caused by the decrease in prices for oil, natural gas and natural gas liquids and the disposition of oil and gas properties, we incurred impairment charges of $93.6 million and $131.3 million in 2017 and 2016, respectively. Of these amounts, $69.9 million and $89.5 million in 2017 and 2016, respectively, related to oil and natural gas properties that were written down to their fair value as determined based on the expected present value of the future net cash flows. Of the $69.9 million impairment charge for 2017, $49.5 million related to properties located in the Mid-Continent area and the Permian Basin, $15.3 million related to properties located in the Monroe Field, $2.2 million related to properties in Central Texas and $2.9 million related to properties in East Texas which were sold during April 2017. The $89.5 million impairment charge for 2016 related to oil and natural gas properties in the Barnett Shale that were sold during December 2016. Significant assumptions associated with the calculation of discounted cash flows used in the impairment analysis included estimates of future prices, production costs, development expenditures, anticipated production of our estimated reserves, appropriate risk–adjusted discount rates and other relevant data. The remainder of the impairment charges in 2017 consisted of $23.7 million of leasehold impairments. The remainder of the impairment charges in 2016 consisted of $41.8 million of leasehold impairments, of which $35.8 million related to a change in our development plans for acreage in the Appalachian Basin, primarily in the Utica Shale.

In 2017, we recognized a gain of $1.0 million on the sale of certain non–core oil and natural gas properties.

Gain on derivatives, net, was $22.9 million for 2017 compared with a loss on derivatives, net, of $36.0 million for 2016. This change was attributable to changes in future oil and natural gas prices. The 12-month forward price at December 31, 2017 for oil averaged $59.40 per Bbl compared with $56.19 at December 31, 2016, and the 12-month forward prices at December 31, 2017 for natural gas averaged $2.86 per MMBtu compared with $3.61 at December 31, 2016. The 12-month forward price at December 31, 2016 for oil averaged $56.19 per Bbl compared with $40.45 at December 31, 2015, and the 12-month forward prices at December 31, 2016 for natural gas averaged $3.61 per MMBtu compared with $2.49 at December 31, 2015.

Interest expense for 2017 decreased $1.5 million compared with 2016 due to $2.0 million attributed to a lower weighted average long-term debt balance and $1.0 million attributed to a lower write-off of loan costs in 2017 due to the reduction in the borrowing base, partially offset by $1.5 million from a higher weighted average effective interest rate.

In 2016, we recognized a $47.7 million gain on the early extinguishment of debt as we redeemed $82.7 million of our Senior Notes for $35.0 million.

In 2016, we recorded approximately $2.4 million of tax benefits as a result of tax refunds and lower taxes.

LIQUIDITY AND CAPITAL RESOURCES

Since our emergence from bankruptcy, our primary sources of liquidity and capital have consisted of cash flows from operations and proceeds from divestitures of oil and natural gas properties. As a result of divesting certain oil and natural gas properties, we received $140.5 million in cash proceeds, net of purchase price adjustments, and 4.2 million shares of Magnolia common stock during the seven months ended December 31, 2018. Our primary uses of cash have been to repay bank debt and fund capital expenditures, principally for the development of our oil and natural gas properties.

During the seven months ended December 31, 2018, we incurred $18.0 million for capital drilling and completing wells. For the five months ended May 31, 2018, we incurred $26.8 million for capital drilling and completing wells. For 2019, we plan to incur $3 million to $6 million of capital expenditures, which we expect to fund primarily from cash on hand, sales of assets and net cash flows generated from operations. As of December 31, 2018, we had approximately $153.5 million of liquidity between our borrowing base capacity and cash on hand.

For 2019, we believe that cash on hand, proceeds from sales of assets and net cash flows generated from operations will be adequate to fund our capital budget and satisfy our short–term liquidity needs. Thus far in 2019, we have sold all of our shares of Magnolia common stock for net proceeds of $51.7 million, we have entered into a definitive agreement to sell all of our oil and gas properties in the San Juan Basin for $42.8 million, subject to purchase price adjustments, and we have entered into other definitive agreements to sell certain oil and gas properties in the Mid-Continent area. The proceeds from these 2019 divestitures will be used to reduce outstanding borrowings under our credit facility. We will continue monitoring the commodity price environment and expect to retain the financial flexibility to adjust plans in response to market conditions as needed.

We may also utilize borrowings under our credit facility and various financing sources available to us, including the issuance of equity or debt securities through public offerings or private placements, to fund any acquisitions and long–term liquidity needs. Our ability to complete future offerings of equity or debt securities and the timing of these offerings will depend upon various factors including prevailing market conditions and our financial condition.

Long–term Debt

As of December 31, 2018, we had a $1.0 billion credit facility that will mature in February 2021. Borrowings under the credit facility may not exceed a "borrowing base" determined by the lenders based on our oil and natural gas reserves. As of December 31, 2018, the borrowing base was $262.3 million, and we had $115.0 million outstanding. On January 29, 2019 and February 8, 2019, we repaid $35.0 million and $25.0 million, respectively, of the outstanding amount. As of March 22, 2019, our outstanding debt balance was $55.0 million.

The credit facility requires the following (as defined in the credit facility):

- the Total Debt to EBITDAX ratio covenant to be no greater than 4.0 to 1.0;
- the current consolidated assets (including unused commitments under the Exit Credit Facility) to current consolidated liabilities be no less than 1.0 to 1.0;
- the percentage of Mortgaged Properties be no less than 95% of the total value of the Oil and Gas Properties evaluated in the most recent Reserve Report;
- no later than 60 days following the Effective Date, 70% of projected production volumes (excluding projected production volumes from certain properties) be hedged (as of the date such swap agreements were executed) for the 18 months following the Effective Date; and
- cash held by the Company be limited to the greater of 5% of the current borrowing base or $30.0 million.

As of December 31, 2018, the Company was in compliance with all of these financial covenants.

For additional information about our long–term debt, such as interest rates and covenants, please see "Item 8. Financial Statements and Supplementary Data" contained herein.

Cash and Short-term Investments

At December 31, 2018, we had $6.3 million of cash and short–term investments, which included $0.6 million of short–term investments. With regard to our short–term investments, we invest in money market accounts with major financial institutions.

On August 31, 2018, the Company received 4.2 million shares of common stock of Magnolia as part of the consideration for the Central Texas Divestiture. As of December 31, 2018, the shares had a value of $47.1 million. During January 2019, the Company sold all of the shares of common stock of Magnolia for net proceeds of $51.7 million.

Counterparty Exposure

All of our derivative contracts are with major financial institutions who are also lenders under our credit facility. Should one of these financial counterparties not perform, we may not realize the benefit of some of our derivative contracts and we could incur a loss. As of December 31, 2018, all of our counterparties have performed pursuant to their derivative contracts.

Cash Flows

References to "Successor" relate to the financial position and results of operations of the reorganized Company subsequent to May 31, 2018, and references to "Predecessor" relate to the financial position and results of operations of the Company prior to, and including, May 31, 2018.

In addition to presenting Successor and Predecessor results of operations, in the table and discussion below, we have presented the Company's cash flows by activity type for the fiscal year ended December 31, 2018 on a combined basis (i.e., by combining the results of applicable Predecessor and Successor periods). We believe that describing certain year-over-year variances and trends in cash flows for the year ended December 31, 2018 as compared to December 31, 2017 and 2016 without regard to the concept of Successor and Predecessor (i.e., on a combined basis) facilitates a meaningful analysis of our cash flow and is useful in identifying trends. The combined cash flow figures represent the sum of the reported amounts for the Predecessor period from January 1, 2018 through May 31, 2018 and the Successor period from June 1, 2018 through December 31, 2018. These combined cash flow figures are not considered to be prepared in accordance with GAAP and have not been prepared as pro forma results under applicable regulations. The combined cash flow figures may not reflect the cash flows we would have achieved absent our emergence from bankruptcy and may not be indicative of future results.

	Successor	Predecessor		Predecessor	
	Seven Months Ended December 31, 2018	Five Months Ended May 31, 2018	Combined Year Ended December 31, 2018	Year Ended December 31, 2017	Year Ended December 31, 2016
Operating activities	$ 45,557	$ 21,655	$ 67,212	$ 31,700	$ 33,875
Investing activities	114,279	(29,046)	85,233	(82,437)	42,310
Financing activities	(182,255)	31,227	(151,028)	(2,000)	(38,967)

Operating Activities

Cash flows from operating activities provided $67.2 million and $31.7 million in 2018 on a combined basis and 2017, respectively. The significant factors in the change were $23.9 million of increased revenues, $20.0 million of decreased interest expense and a $21.0 million change in working capital, partially offset by a $16.3 million increase associated with reorganization items, $7.9 million of increased lease operating expenses and $5.2 million of restructuring costs.

Cash flows from operating activities provided $31.7 million and $33.9 million in 2017 and 2016, respectively. The significant factors in the change were $57.1 million of decreased cash settlements from our matured derivative contracts and $3.2 million of decreased gain on settlement of contract, partially offset by $40.8 million of increased revenues, an $11.7 million federal tax payment in 2016 related to the conversion of an acquired corporation to a single member limited liability company and a $6.6 million change in working capital, primarily related to higher accounts receivable as a result of higher oil, natural gas and natural gas liquids revenues during 2017.

Investing Activities

During 2018, cash flows provided by investing activities totaled $85.2 million on a combined basis. This consisted of $140.3 million in proceeds from the sale of oil and natural gas properties and $1.9 million from reimbursements related to oil and natural gas properties, partially offset by the use of $57.1 million for additions to our oil and natural gas properties.

During 2017, cash flows used in investing activities totaled $82.4 million. This consisted of $61.4 million for acquisitions of oil and natural gas properties and $27.3 million for additions to our oil and natural gas properties, partially offset by $3.7 million from the sale of oil and natural gas properties and $2.5 million from reimbursements related to oil and natural gas properties.

During 2016, cash flows provided by investing activities totaled $42.3 million. This consisted of $54.5 million from the sale of oil and natural gas properties and $3.0 million in cash settlements from acquired derivative contracts partially offset by $15.3 million for additions to our oil and natural gas properties.

Financing Activities

During 2018, on a combined basis, we received $34.0 million from borrowings under our credit facility, repaid $182.0 million of long-term debt borrowings and paid $2.8 million of debt issuance costs.

During 2017, we received $26.0 million from borrowings under our credit facility and repaid $28.0 million of borrowings under our credit facility.

During 2016, we received $57.0 million from borrowings under our credit facility, repaid $57.0 million of borrowings under our credit facility, and paid distributions of $3.9 million to holders of our common units, phantom units and our general partner relating to fiscal year 2015. We also redeemed $82.7 million of our Senior Notes for $35.0 million.

Capital Requirements

We currently expect spending in 2019 for additions to our oil and natural gas properties to be between $3 million and $6 million, a decrease from the amounts spent in 2018.

We expect to fund these amounts with cash on hand, proceeds from sales of assets, net cash flows generated from operations and borrowings under our credit facility.

Contractual Obligations

	Payments Due by Period (amounts in thousands)				
	Total	2019	2020-2021	2022-2023	After 2023
Total debt [1]	$ 115,000	$ —	$ 115,000	$ —	$ —
Estimated interest payments [2]	11,608	5,363	6,245	—	—
Transportation commitments [3]	2,633	856	1,365	412	—
Purchase obligation [4]	13,739	13,739	—	—	—
Total	$ 142,980	$ 19,958	$ 122,610	$ 412	$ —

(1) Amounts represent the scheduled future maturities of principal amounts outstanding for the period indicated.

(2) Amounts represent the expected cash payments for interest based on the amount outstanding under our credit facility as of December 31, 2018 and the weighted average interest rate for 2018 of 4.60%. Maturities are shown at original maturity dates assuming no acceleration.

(3) Amounts represent commitments under a firm transportation agreement at current rates.

(4) Amounts represent payments to be made under our Service Agreement with EnerVest based on the amount paid in 2018 as an estimate for 2019. This amount will increase or decrease as we purchase or divest assets. While these payments will continue for periods subsequent to December 31, 2019, no amounts are shown as they cannot be quantified.

Our asset retirement obligations are not included in the table above given the uncertainty regarding the actual timing of such expenditures. The total amount of our asset retirement obligations at December 31, 2018 is $119.6 million.

In January 2019, we adopted ASU No. 2016-02, *Leases* ("ASU 2016-02"). The adoption of this standard will result in an increase in liabilities on our consolidated balance sheets. The quantitative impacts of the new standard are dependent on the leases in force at the time of adoption. At January 1, 2019, the operating lease liability is estimated to be insignificant. See Note 4 of the Notes to Consolidated Financial Statements included under "Item 8. Financial Statements and Supplementary Data" contained herein for additional information.

Off–Balance Sheet Arrangements

In the normal course of business, we may enter into off-balance sheet arrangements that give rise to off-balance sheet obligations. As of December 31, 2018, we have entered into off–balance sheet arrangements which totaled $0.2 million.

RECENT ACCOUNTING STANDARDS

Please see "Item 8. Financial Statements and Supplementary Data" contained herein for additional information.

CAUTIONARY NOTE REGARDING FORWARD–LOOKING STATEMENTS

This Form 10–K contains forward–looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Exchange Act (each a "forward–looking statement"). These forward–looking statements relate to, among other things, the following:

- our business strategy and plans, and future capital expenditures, including plans to optimize the value of our assets, including our business strategies following our emergence from bankruptcy;
- our future financial and operating performance and results;
- our estimated net proved reserves, PV–10 value and standardized measure;
- the effects of asset and property dispositions or acquisitions on our cash position and levels of indebtedness;
- costs of developing our properties and conducting other operations;
- our cash flows, liquidity and capital availability;
- market prices;
- our financial strategy;
- our production volumes;
- environmental liabilities;
- our ability to access the capital markets;
- our future derivative activities; and
- our plans and forecasts.

We have based these forward–looking statements on our current assumptions, expectations and projections about future events.

The words "anticipate," "believe," "ensure," "expect," "if," "intend," "estimate," "project," "forecasts," "predict," "outlook," "aim," "will," "could," "should," "would," "may," "likely," the negative of such terms and similar expressions,

and the negative thereof, are intended to identify forward–looking statements. These statements discuss future expectations, contain projections of results of operations or of financial condition or state other "forward–looking" information. We do not undertake any obligation to update or revise publicly any forward–looking statements, except as required by law. These statements also involve risks and uncertainties that could cause our actual results or financial condition to materially differ from our expectations in this Form 10–K including, but not limited to:

- our inability to maintain relationships with suppliers, customers, employees and other third parties as a result of our Chapter 11 filing;
- our inability to control our contract operator, EnerVest Operating, outside of the parameters of the Services Agreement;
- our need to make accretive acquisitions or substantial capital expenditures to maintain our asset base;
- the existence of unanticipated liabilities and problems related to acquired or divested businesses or properties;
- the potential for additional impairments due to continuing or future declines in oil, natural gas and natural gas liquids prices;
- risks relating to any of our unforeseen liabilities;
- fluctuations in prices of oil, natural gas and natural gas liquids and the length of time commodity prices remain depressed;
- significant disruptions in the financial markets;
- future capital requirements and availability of financing;
- uncertainty inherent in estimating our reserves;
- risks associated with drilling and operating wells;
- discovery, acquisition, development and replacement of reserves;
- liquidity and cash flows and their adequacy to fund our ongoing operations;
- consequences of changes we have made or may make from time to time in the future, to our capital expenditures budget, including the impact of those changes on our production levels, reserves, results of operations and liquidity;
- changes in the financial condition of counterparties;
- timing and amount of future production of oil, natural gas and natural gas liquids;
- availability of drilling and production equipment;
- marketing of oil, natural gas and natural gas liquids;
- developments in oil and natural gas producing countries;
- competition;
- general economic conditions;

- governmental regulations;
- activities taken or non–performance by third parties, including suppliers, contractors, operators, transporters and purchasers of our production and counterparties to our derivative financial instrument contracts;
- hedging decisions, including whether or not to enter into derivative financial instruments;
- actions of third party co–owners of interest in properties in which we also own an interest; and
- fluctuations in interest rates and the value of the US dollar in international currency markets.

All of our forward–looking information is subject to risks and uncertainties that could cause actual results to differ materially from the results expected. Although it is not possible to identify all factors, these risks and uncertainties include the risk factors and the timing of any of those risk factors identified in "Item 1A. Risk Factors."

Our revenues, operating results, financial condition and ability to borrow funds or obtain additional capital depend substantially on prevailing prices for oil, natural gas and natural gas liquids. Declines in prices may materially adversely affect our financial condition, liquidity, ability to obtain financing and operating results. Lower prices also may reduce the amount of oil, natural gas or natural gas liquids that we can produce economically. A decline in prices could have a material adverse effect on the estimated value and estimated quantities of our reserves, our ability to fund our operations and our financial condition, cash flows, results of operations and access to capital. Historically, prices and markets have been volatile, with prices fluctuating widely, and they are likely to continue to be volatile.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to certain market risks that are inherent in our financial statements that arise in the normal course of business. We may enter into derivatives to manage or reduce market risk, but do not enter into derivatives for speculative purposes.

We do not designate these or future derivatives as hedges for accounting purposes. Accordingly, the changes in the fair value of these derivatives are recognized currently in earnings.

Commodity Price Risk

Our major market risk exposure is to prices for oil, natural gas and natural gas liquids. These prices have historically been volatile. As such, future earnings are subject to change due to changes in these prices. Realized prices are primarily driven by the prevailing worldwide price for oil and regional spot prices for natural gas production. We have used, and expect to continue to use, derivatives to reduce our risk of changes in the prices of oil, natural gas and natural gas liquids. Pursuant to our risk management policy, we engage in these activities as a hedging mechanism against price volatility associated with pre–existing or anticipated sales of oil, natural gas and natural gas liquids. Under our credit facility, we are required to hedge (as of the date such swap agreements were executed) no less than 70% of our projected production volumes (excluding projected production volumes from certain properties) for the 18-month period following the Effective Date.

We have entered into commodity contracts to hedge a portion of our anticipated oil and natural gas production through December 2020. As of December 31, 2018, we have commodity contracts covering approximately 68% of our estimated production attributable to our net proved reserves from January 2019 through December 2020. For more information regarding our commodity derivative contracts, please see Note 9 of the Notes to Consolidated Financial Statements under "Item 8. Financial Statements and Supplementary Data." Our actual production will vary from the amounts estimated in our reserve reports, perhaps materially. Please read the disclosures under "Item 1A. Risk Factors – *Our estimated reserve quantities and future production rates are based on many assumptions that may prove to be inaccurate. Any material*

inaccuracies in these reserve estimates or the underlying assumptions will materially affect the quantities and present value of our reserves."

The fair value of our oil and natural gas derivatives at December 31, 2018 was positive, representing an asset of $22.8 million on our consolidated balance sheet as of that date. A 10% change in prices with all other factors held constant would result in a change in the fair value (generally correlated to our estimated future net cash flows from such instruments) of our commodity contracts of approximately $20.7 million. Please see "Item 8. Financial Statements and Supplementary Data" contained herein for additional information.

Interest Rate Risk

Our floating rate credit facility also exposes us to risks associated with changes in interest rates and as such, future earnings are subject to change due to changes in these interest rates. If interest rates on our facility increased by 1%, interest expense for the year ended December 31, 2018 would have increased by approximately $2.3 million.

In April 2018, in conjunction with our Restructuring, the Predecessor terminated its interest rate swaps for the period of April 2018 to September 2020, which resulted in a cash settlement received in April 2018 of $1.6 million. As of December 31, 2018, we did not have any interest rate swaps in place.

Please see Note 9 of the Notes to Consolidated Financial Statements included under "Item 8. Financial Statements and Supplementary Data" contained herein for additional information.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The Company's management, including our Chief Executive Officer and Chief Financial Officer, is responsible for establishing and maintaining effective internal control over our financial reporting. Our internal control system was designed to provide reasonable assurance to our Management and Directors regarding the preparation and fair presentation of published financial statements. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

The Company's management conducted an evaluation of the effectiveness of internal control over financial reporting based on the *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that Harvest Oil & Gas Corp.'s internal control over financial reporting was effective as of December 31, 2018.

/s/ MICHAEL E. MERCER	/s/ RYAN STASH
Michael E. Mercer	Ryan Stash
Chief Executive Officer	Vice President and Chief Financial Officer

Houston, TX
March 28, 2019

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of
Harvest Oil & Gas Corp.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Harvest Oil & Gas Corp. and its subsidiaries (the "Company") as of December 31, 2018 (Successor balance sheet) and 2017 (Predecessor balance sheet), the related consolidated statements of operations, cash flows, and equity for the seven months ended December 31, 2018 (Successor operations), the related consolidated statements of operations, cash flows, and changes in owners' equity for the five months ended May 31, 2018 and for the years ended December 31, 2017 and 2016 (Predecessor operations), and the related notes (collectively referred to as the "financial statements"). In our opinion, the Successor financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018, and the results of its operations and cash flows for the seven months ended December 31, 2018, in conformity with accounting principles generally accepted in the United States of America. Further, in our opinion, the Predecessor financial statements present fairly, in all material respects, the financial position of the Predecessor as of December 31, 2017, and the results of its operations and cash flows for the five months ended May 31, 2018 and for the years ended December 31, 2017 and 2016, in conformity with accounting principles generally accepted in the United States of America.

Fresh-Start Reporting

As discussed in Note 2 to the financial statements, the Predecessor filed voluntary petitions for reorganization under Chapter 11 of the United States Bankruptcy Code on April 2, 2018, and the Company emerged from bankruptcy on June 4, 2018. Accordingly, the accompanying financial statements have been prepared in conformity with FASB Accounting Standard Codification 852, *Reorganizations*, for the Successor as a new entity with assets, liabilities, and a capital structure having carrying values not comparable with prior periods as described in Note 3 to the financial statements.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/DELOITTE & TOUCHE LLP

Houston, Texas
March 28, 2019

We have served as the Company's auditor since 1998.

Harvest Oil & Gas Corp.
Consolidated Balance Sheets
(In thousands, except number of shares or units)

	Successor December 31, 2018	Predecessor December 31, 2017
ASSETS		
Current assets:		
Cash and cash equivalents	$ 6,313	$ 4,896
Equity securities	47,082	—
Accounts receivable:		
Oil, natural gas and natural gas liquids revenues	40,176	47,694
Other	4,496	78
Derivative asset	15,452	3,052
Other current assets	2,314	5,713
Total current assets	115,833	61,433
Oil and natural gas properties, net of accumulated depreciation, depletion and amortization; December 31, 2018, $12,950; December 31, 2017, $1,191,559	405,688	1,375,527
Long–term derivative asset	8,499	—
Other assets	4,474	4,845
Total assets	$ 534,494	$ 1,441,805
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities:		
Third party	$ 26,146	$ 43,817
Related party	—	4,194
Derivative liability	1,165	396
Current portion of long-term debt	—	605,549
Total current liabilities	27,311	653,956
Asset retirement obligations	117,529	158,793
Long–term debt, net	115,000	—
Other long–term liabilities	1,036	1,044
Commitments and contingencies (Note 13)		
Mezzanine equity	79	—
Stockholders' / owners' equity:		
Predecessor common unitholders – 49,368,869 units issued and outstanding as of December 31, 2017	—	648,371
Predecessor general partner interest	—	(20,359)
Successor common stock – $0.01 par value; 65,000,000 shares authorized; 10,054,816 shares issued and 10,042,468 shares outstanding as of December 31, 2018	100	—
Successor additional paid-in capital	249,717	—
Successor treasury stock at cost – 12,348 shares at December 31, 2018	(247)	—
Successor retained earnings	23,969	—
Total stockholders' / owners' equity	273,539	628,012
Total liabilities and equity	$ 534,494	$ 1,441,805

See accompanying notes to consolidated financial statements.

Harvest Oil & Gas Corp.
Consolidated Statements of Operations
(In thousands, except per share/unit data)

	Successor	Predecessor		
	Seven Months Ended December 31, 2018	Five Months Ended May 31, 2018	Year Ended December 31, 2017	Year Ended December 31, 2016
Revenues:				
Oil, natural gas and natural gas liquids revenues	$ 137,169	$ 110,307	$ 223,297	$ 182,696
Transportation and marketing–related revenues	1,431	724	2,396	2,198
Total revenues	138,600	111,031	225,693	184,894
Operating costs and expenses:				
Lease operating expenses	64,100	45,372	101,591	103,371
Cost of purchased natural gas	1,026	557	1,699	1,497
Dry hole and exploration costs	177	122	413	651
Production taxes	6,482	5,343	10,588	7,386
Accretion expense on obligations	5,420	3,176	7,653	8,225
Depreciation, depletion and amortization	16,012	46,196	96,901	119,171
General and administrative expenses	15,626	15,648	32,290	33,637
Restructuring costs	—	5,211	—	—
Impairment of oil and natural gas properties	3,065	3	93,607	131,260
Gain on settlement of contract	—	—	—	(3,185)
(Gain) loss on sales of oil and natural gas properties	(697)	5	(981)	(69)
Total operating costs and expenses	111,211	121,633	343,761	401,944
Operating income (loss)	27,389	(10,602)	(118,068)	(217,050)
Other income (expense), net:				
Gain (loss) on derivatives, net	16,962	444	22,854	(35,950)
Interest expense	(7,225)	(13,652)	(40,903)	(42,487)
Gain on early extinguishment of debt	—	—	—	47,695
Loss on equity securities	(11,130)	—	—	—
Other income, net	374	776	1,706	2,522
Total other income (expense), net	(1,019)	(12,432)	(16,343)	(28,220)
Reorganization items, net	(2,323)	(587,325)	—	—
Income (loss) before income taxes	24,047	(610,359)	(134,411)	(245,270)
Income tax (expense) benefit	(78)	(166)	210	2,375
Net income (loss)	$ 23,969	$ (610,525)	$ (134,201)	$ (242,895)
Basic and diluted earnings per share / unit:				
Net income (loss)	$ 2.39	$ (12.12)	$ (2.66)	$ (4.85)
Weighted average common shares / units outstanding:				
Basic	10,030	49,369	49,357	49,048
Diluted	10,032	49,369	49,357	49,048

See accompanying notes to consolidated financial statements.

Harvest Oil & Gas Corp.
Consolidated Statements of Cash Flows
(In thousands)

	Successor	Predecessor		
	Seven Months Ended December 31, 2018	Five Months Ended May 31, 2018	Year Ended December 31, 2017	Year Ended December 31, 2016
Cash flows from operating activities:				
Net income (loss)	$ 23,969	$ (610,525)	$ (134,201)	$ (242,895)
Adjustments to reconcile net income (loss) to net cash flows provided by operating activities:				
Amortization of volumetric production payment liability	—	—	—	(4,108)
Accretion expense on obligations	5,420	3,176	7,653	8,225
Depreciation, depletion and amortization	16,012	46,196	96,901	119,171
Share-based compensation cost	1,227	3,784	4,266	6,611
Impairment of oil and natural gas properties	3,065	3	93,607	131,260
(Gain) loss on sales of oil and natural gas properties	(697)	5	(981)	(69)
Loss on equity securities	11,130	—	—	—
(Gain) loss on derivatives, net	(16,962)	(444)	(22,854)	35,950
Cash settlements of matured derivative contracts	(5,824)	3,099	(2,235)	54,884
Gain on early extinguishment of debt	—	—	—	(47,695)
Deferred taxes	—	—	—	(404)
Reorganization items, net	—	573,304	—	—
Other	1,020	248	1,411	2,523
Changes in operating assets and liabilities:				
Accounts receivable	7,823	(3,518)	(2,670)	(11,403)
Other current assets	(53)	1,853	(1,585)	(361)
Accounts payable and accrued liabilities	(513)	4,405	(6,783)	(5,862)
Income taxes	—	—	—	(11,657)
Other, net	(60)	69	(829)	(295)
Net cash flows provided by operating activities	45,557	21,655	31,700	33,875
Cash flows from investing activities:				
Acquisition of oil and natural gas properties	—	—	(61,400)	—
Additions to oil and natural gas properties	(27,368)	(29,727)	(27,268)	(15,258)
Reimbursements related to oil and natural gas properties	1,294	652	2,517	—
Proceeds from sale of oil and natural gas properties	140,324	3	3,654	54,509
Cash settlements from acquired derivative contracts	—	—	—	3,003
Other	29	26	60	56
Net cash flows provided by (used in) investing activities	114,279	(29,046)	(82,437)	42,310
Cash flows from financing activities:				
Repayment of long–term debt borrowings	(182,000)	—	(28,000)	(57,000)
Long-term debt borrowings	—	34,000	26,000	57,000
Redemption of 8% Senior Notes due 2019	—	—	—	(34,978)
Loan costs incurred	—	(2,813)	—	(121)
Purchase of treasury stock	(247)	—	—	—
Contributions from general partner	—	40	—	—
Distributions paid	—	—	—	(3,868)
Other	(8)	—	—	—
Net cash flows provided by (used in) financing activities	(182,255)	31,227	(2,000)	(38,967)
Increase (decrease) in cash, cash equivalents and restricted cash	(22,419)	23,836	(52,737)	37,218
Cash, cash equivalents and restricted cash – beginning of period	28,732	4,896	57,633	20,415
Cash, cash equivalents and restricted cash – end of period	$ 6,313	$ 28,732	$ 4,896	$ 57,633

See accompanying notes to consolidated financial statements.

Harvest Oil & Gas Corp.
Consolidated Statements of Changes in Owners' Equity (Predecessor)
(In thousands)

	Common Unitholders	General Partner Interest	Total Owners' Equity
Balance, December 31, 2015 (Predecessor)	$ 1,011,509	$ (12,950)	$ 998,559
Distributions	(3,793)	(75)	(3,868)
Equity–based compensation	6,479	132	6,611
Net loss	(238,037)	(4,858)	(242,895)
Balance, December 31, 2016 (Predecessor)	776,158	(17,751)	758,407
Equity–based compensation	3,730	76	3,806
Net loss	(131,517)	(2,684)	(134,201)
Balance, December 31, 2017 (Predecessor)	648,371	(20,359)	628,012
Contribution from general partner	—	40	40
Equity–based compensation	3,708	76	3,784
Net loss	(598,314)	(12,211)	(610,525)
Issuance of common stock to Predecessor common unitholders	(11,967)	—	(11,967)
Issuance of warrants to Predecessor common unitholders	(9,345)	—	(9,345)
Cancellation of Predecessor common unitholders	(32,453)	—	(32,453)
Cancellation of Predecessor general partner interest	—	32,454	32,454
Balance, May 31, 2018 (Predecessor)	$ —	$ —	$ —

Consolidated Statements of Equity (Successor)
(In thousands)

	Common Stock		Additional Paid-in Capital	Treasury Stock	Retained Earnings	Total Stockholders' Equity
	Shares	Amount				
Issuance of successor common stock to holders of the Senior Notes	9,500	$ 95	$ 227,271	$ —	$ —	$ 227,366
Issuance of successor common stock to predecessor common unitholders	500	5	11,962	—	—	11,967
Issuance of warrants	—	—	9,345	—	—	9,345
Balance, May 31, 2018 (Successor)	10,000	100	248,578	—	—	248,678
Net income	—	—	—	—	23,969	23,969
Share–based compensation	—	—	1,139	—	—	1,139
Restricted shares vested	55	—	—	—	—	—
Purchase of treasury stock	(12)	—	—	(247)	—	(247)
Balance, December 31, 2018 (Successor)	10,043	$ 100	$ 249,717	$ (247)	$ 23,969	$ 273,539

See accompanying notes to consolidated financial statements.

Harvest Oil & Gas Corp.
Notes to Consolidated Financial Statements

NOTE 1. ORGANIZATION AND NATURE OF BUSINESS

Harvest Oil & Gas Corp. is a newly formed Delaware corporation and the successor reporting company to EV Energy Partners, L.P. ("EVEP") pursuant to Rule 15d-5 of the Securities Exchange Act of 1934, as amended. As used herein, the terms "Successor," "Harvest" or the "Company" refer to Harvest Oil & Gas Corp. and its consolidated subsidiaries as a whole or on an individual basis, depending on the context in which the statements are made. When referring to the "Predecessor" or the "Partnership" in reference to the period prior to the emergence from bankruptcy, the intent is to refer to EVEP, the predecessor that was dissolved following the Effective Date (as defined below) of the Plan (as defined below) and its consolidated subsidiaries as a whole or on an individual basis, depending on the context in which the statements are made.

Unless the context requires otherwise, references to: (i) the "Predecessor's general partner" and "EV Energy GP" refer to EV Energy GP, L.P., a Delaware limited partnership, the Predecessor's general partner, which was dissolved following the Effective Date of the Plan; (ii) "EV Management" refers to EV Management, LLC, a Delaware limited liability company, the former general partner of the Predecessor's general partner; and (iii) "EnerVest" refers to EnerVest, Ltd., a Texas limited partnership, the owner of EV Management.

Harvest is an independent oil and natural gas company that was formed in 2018, in connection with the reorganization of the Predecessor. The Predecessor was publicly traded from September 2006 to June 2018. As discussed further in Note 2, on April 2, 2018, EVEP, and 13 affiliated debtors (collectively, the "Debtors") each filed a voluntary petition (the cases commenced thereby, the "Chapter 11 proceedings") for relief under Chapter 11 of Title 11 of the United States Bankruptcy Code ("Chapter 11") for bankruptcy protection in the United States Bankruptcy Court for the District of Delaware (the "Bankruptcy Court") via Case No. 18-10814. The Debtors requested that their cases be jointly administered under Case No. 18-10814 to pursue the prepackaged plan of reorganization. During the pendency of the Chapter 11 proceedings, EVEP continued to operate its businesses and manage its properties under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code and orders of the Bankruptcy Court as a "Debtors-in-Possession." On May 17, 2018, the Bankruptcy Court entered an order (the "Confirmation Order") confirming the Debtors' First Modified Joint Prepackaged Plan of Reorganization (as amended, modified and supplemented from time to time, the "Plan"). The Plan became effective on June 4, 2018 (the "Effective Date"), when all remaining conditions to the effectiveness of the Plan were satisfied and the Company emerged from bankruptcy.

The Company operates one reportable segment engaged in the development and production of oil and natural gas properties, and all of its operations are located in the United States. As a result of the ongoing review of the Company's asset base in order to maximize shareholder value, the Company has initiated processes to divest certain assets and in the future may look to divest additional assets or all of its remaining assets and use the proceeds to repay bank debt, return capital to shareholders, concentrate in existing positions or ventures into new basins. The oil and natural gas properties of Harvest are located in the Barnett Shale, the San Juan Basin, the Appalachian Basin (which includes the Utica Shale), Michigan, the Mid–Continent areas in Oklahoma, Texas, Arkansas, Kansas and Louisiana, the Permian Basin and the Monroe Field in Northern Louisiana.

In the Notes to Consolidated Financial Statements, all dollar and share amounts in tabulations are in thousands of dollars and shares or units, respectively, unless otherwise indicated.

NOTE 2. EMERGENCE FROM VOLUNTARY REORGANIZATION UNDER CHAPTER 11

On March 13, 2018, the Debtors entered into a Restructuring Support Agreement (the "Restructuring Support Agreement") with (i) holders (collectively, the "Supporting Noteholders") of approximately 70% of the 8.0% senior unsecured notes due April 2019 (the "Senior Notes") issued pursuant to that certain indenture, dated as of March 22, 2011 (as amended, restated, supplemented or otherwise modified from time to time, the "Indenture"), among EVEP, EV Energy Finance Corp., each of the guarantors party thereto, and Delaware Trust Company, as indenture trustee (the "Notes Trustee"), that are signatories to the Restructuring Support Agreement; (ii) lenders (collectively, the "Supporting Lenders" and, together with the Supporting Noteholders, the "Supporting Parties") under the Company's reserve-based lending facility, by and among EVEP, EV Properties, L.P., JPMorgan Chase Bank, N.A., as administrative agent (the "Administrative Agent"), BNP Paribas and Wells Fargo, National Association, as co-syndication agents, the guarantors

party thereto (the "credit facility"), and the lenders signatory thereto, constituting approximately 94% of the principal amount outstanding thereunder; (iii) EnerVest; and (iv) EnerVest Operating, L.L.C. ("EnerVest Operating" and, together with EnerVest, the "EnerVest Parties"). The Restructuring Support Agreement sets forth, subject to certain conditions, the commitment of the Debtors and the Consenting Creditors to support a comprehensive restructuring of the Debtors' long-term debt (the "Restructuring").

On April 2, 2018 (the "Petition Date"), the Debtors commenced the Chapter 11 Cases in the Bankruptcy Court. The Debtors filed motions with the Bankruptcy Court seeking operational and procedural relief, including joint administration of their Chapter 11 Cases. The Debtors' Chapter 11 proceedings were jointly administered under the caption *In re EV Energy Partners, L.P., et al*., Case No. 18-10814.

On May 17, 2018, the Bankruptcy Court entered the Confirmation Order confirming the Debtors' Plan.

On June 4, 2018, the Debtors satisfied the conditions to effectiveness of the Plan, the Plan became effective in accordance with its terms and the Company emerged from bankruptcy. Although the Company is no longer a debtor-in-possession, the Company was a debtor-in-possession from April 2, 2018 through June 4, 2018. As such, certain aspects of the Chapter 11 proceedings and related matters are described below in order to provide context to the Company's financial condition and results of operations for the period presented.

Plan of Reorganization

In accordance with the Plan, on the Effective Date:

- The Successor issued (i) 9,500,000 new shares of its common stock, par value $0.01 per share ("common stock") pro rata to holders of the Senior Notes with claims allowed under the Plan; (ii) 500,016 shares of common stock pro rata to holders of units of EVEP prior to the Effective Date; (iii) 800,000 warrants (the "Warrants") to purchase 800,000 shares of the Company's common stock to holders of units of EVEP prior to the Effective Date exercisable for a five-year period commencing on the Effective Date entitling their holders upon exercise thereof, on a pro rata basis, to 8% of the total issued and outstanding common stock (including common stock as of the Effective Date issuable upon full exercise of the Warrants, but excluding any common stock issuable under the Company's Management Incentive Plan (the "MIP")), at a per share exercise price of $37.48; (iv) 79,000 shares of 8% Cumulative Nonparticipating Redeemable Series A Preferred Stock (the "Series A Preferred Stock") to its indirectly wholly-owned subsidiary EV Midstream, L.P. for consideration of $790,000; and (v) 21,000 shares of Series A Preferred Stock to one employee of the Company and one employee of EnerVest for consideration of services to the Company, which vest on the earlier of (i) June 4, 2019 or (ii) immediately prior to the consummation of a Sale Transaction as such term is defined in the Certificate of Designations, Preferences and Rights of the Series A Preferred Stock (the "Certificate of Designations");

- The holders of claims under the Predecessor's credit facility received full recovery, consisting of (i) their pro rata share of the $1 billion new reserve-based revolving loan (the "Exit Credit Facility"), as further discussed in Note 12; (ii) cash in amount equal to the accrued but unpaid interest payable to such lenders under the credit facility as of the Effective Date; and (iii) unfunded commitments and letter of credit participation under the Exit Credit Facility equal to the unfunded commitments and letter of credit participation of such lender as of the Effective Date;

- The Senior Notes were cancelled and the Predecessor's liability thereunder discharged, and the holders of the Notes received (directly or indirectly) their pro rata share of New Common Stock representing, in the aggregate, 95% of the New Common Stock on the Effective Date (subject to dilution by the MIP and the common shares issuable upon exercise of the Warrants);

- The Predecessor's common units were cancelled, and each common unitholder received its pro rata share of: (i) 5% of the New Common Shares and (ii) the Warrants;

- The holders of administrative expense claims, other priority claims and general unsecured creditors of the Predecessor received in exchange for their claims payment in full in cash or otherwise had their rights unimpaired under Title 11 of the United States Code;

- The Successor entered into a registration rights agreement (the "Registration Rights Agreement") with certain recipients of shares of its common stock pursuant to which the Successor agreed to, among other things, file a shelf registration statement (the "Initial Shelf Registration Statement") and use its reasonable best efforts to have the Initial Shelf Registration Statement declared effective as soon as possible after the date of its first Quarterly Report on Form 10-Q following the Effective Date;

- The Successor adopted the MIP, pursuant to which employees, directors, consultants and other service providers of the Company and its subsidiaries are eligible to receive stock options, stock appreciation rights, restricted stock, restricted stock units, other stock-based awards and cash-based awards. As of the Effective Date, an aggregate of 689,362 shares of common stock were reserved for issuance under the MIP, all of which may be granted in the form of incentive stock options;

- The terms of the Predecessor's board of directors automatically expired on the Effective Date. The Successor formed a new five-member board of directors consisting of the Chief Executive Officer and two new members designated by certain parties to the Restructuring Support Agreement and two independent members; and

- General unsecured claims received, (i) if such claim was due and payable on or before the Effective Date, payment in full, in cash, or the unpaid portion of its allowed general unsecured claim, (ii) if such claim was not due and payable before the Effective Date, payment in the ordinary course, and (iii) other treatment, as may be agreed upon by the Debtors, the Supporting Noteholders and the holder of such general unsecured claim; and

- The Company converted from a limited partnership to a corporation.

NOTE 3. FRESH START ACCOUNTING

In connection with emergence from the Chapter 11 proceedings on the Effective Date, the Company applied the provisions of fresh start accounting, pursuant to ASC 852, Reorganizations ("ASC 852"), to its consolidated financial statements, which resulted in the Company becoming a new entity for financial reporting purposes. Harvest qualified for fresh start accounting as (i) the holders of existing voting common units of the Predecessor received less than 50% of the voting shares of the emerged entity and (ii) the reorganization value of assets immediately prior to confirmation was less than the post-petition liabilities and allowed claims. ASC 852 requires that fresh start accounting be applied when the Bankruptcy Court enters the Confirmation Order confirming the Plan, or as of a later date when all material conditions precedent to the effectiveness of the Plan are resolved, which was June 4, 2018. The Company elected to apply fresh start accounting effective May 31, 2018, to coincide with the timing of its normal accounting period close. The Company evaluated the events between May 31, 2018 and June 4, 2018 and concluded that the use of an accounting convenience date of May 31, 2018 did not have a material impact on the results of operations or financial position.

Upon adoption of fresh start accounting, the reorganization value derived from the enterprise value was allocated to the Company's assets and liabilities based on their fair values (except for deferred income taxes) in accordance with Accounting Standards Codification 805 *Business Combinations* ("ASC 805"). The amount of deferred income taxes recorded was determined in accordance with Accounting Standards Codification 740 *Income Taxes* ("ASC 740"). The Effective Date fair values of the Company's assets and liabilities differed materially from their recorded values as reflected on the historical balance sheet of the Predecessor. The effects of the Plan and the application of fresh start accounting were reflected in the consolidated financial statements as of May 31, 2018, and the related adjustments thereto were recorded on the consolidated statement of operations for the five months ended May 31, 2018.

As a result of the adoption of fresh start accounting and the effects of the implementation of the Plan, the Company's consolidated financial statements subsequent to May 31, 2018, are not comparable to its consolidated financial statements prior to May 31, 2018. References to "Successor" relate to the financial position and results of operations of the reorganized Company as of and subsequent to May 31, 2018. References to "Predecessor" relate to the financial position of the Company prior to, and results of operations through and including, May 31, 2018.

The Company's consolidated financial statements and related notes are presented with a black line division, which delineates the lack of comparability between amounts presented after May 31, 2018, and amounts presented on or prior to May 31, 2018. The Company's financial results for future periods following the application of fresh start accounting will be different from historical trends and the differences may be material.

Reorganization Value

In the disclosure statement associated with the Plan, which was confirmed by the Bankruptcy Court, the Successor's enterprise value was estimated to be within a range of $450 million to $550 million, with a midpoint estimate of approximately $500 million. Enterprise value represents the estimated fair value of a company's interest-bearing debt, its stockholders' equity and working capital. Based on the estimates and assumptions utilized in the fresh start accounting process, the Company estimated the Successor's enterprise value to be approximately $524.6 million before the consideration of cash and cash equivalents on hand at the Effective Date. Reorganization value represents the fair value of the Successor's total assets prior to the consideration of liabilities and is intended to approximate the amount a willing buyer would pay for the assets immediately after a restructuring. The reorganization value, which was derived from the Successor's enterprise value, was allocated to the Company's individual assets based on their estimated fair values.

The following table is a reconciliation of the enterprise value to the estimated fair value of the Successor's common stock at the Effective Date (in thousands):

Enterprise Value	$	524,596
Plus: Cash and cash equivalents		21,082
Less: Fair value of debt		(297,000)
Fair value of successor equity	$	248,678

The following table is a reconciliation of the enterprise value to the reorganization value of the Successor assets at the Effective Date (in thousands):

Enterprise Value	$	524,596
Plus: Cash and cash equivalents		21,082
Plus: Other working capital liabilities		36,787
Plus: Other long-term liabilities		121,041
Reorganization value of Successor assets	$	703,506

The Company's assets consist primarily of producing oil and natural gas properties. The fair values of proved and unproved oil and natural gas properties were estimated using valuation techniques consistent with the income approach, converting future cash flows to a single discounted amount. The factors to determine fair value include, but are not limited to, estimates of: (i) economic reserves, (ii) future operating and development costs, (iii) future commodity prices and (iv) a market-based weighted average cost of capital. These inputs require significant judgments and estimates by the Company's management at the time of the valuation and are the most sensitive and subject to change. The underlying commodity prices embedded in the Company's estimated cash flows are the product of a process that incorporates forward commodity pricing, analyst pricing estimates and adjustments for estimated location and quality differentials, as well as other factors as necessary that the Company's management believes will impact realizable prices. The fair value of support equipment and facilities were estimated using a cost approach, based on current replacement costs of the assets less depreciation based on the estimated economic useful lives of the assets and age of the assets.

See below under the caption "Fresh Start Adjustments" for additional information regarding assumptions used in the valuation of the Company's various other significant assets and liabilities.

Condensed Consolidated Balance Sheet

The adjustments included in the following condensed consolidated balance sheet reflect the effect of the transactions contemplated by the Plan (reflected in the column "Reorganization Adjustments") as well as fair value and other required accounting adjustments resulting from the adoption of fresh start accounting (reflected in the column "Fresh Start Adjustments"). The explanatory notes provide additional information with regard to the adjustments recorded, the methods used to determine the fair values and significant assumptions.

	As of May 31, 2018			
	Predecessor	Reorganization Adjustments [1]	Fresh Start Adjustments	Successor
ASSETS				
Current assets:				
Cash and cash equivalents	$ 35,020	$ (13,938)[2]	$ —	$ 21,082
Restricted cash	—	7,650 [3]	—	7,650
Accounts receivable:				
Oil, natural gas and natural gas liquids revenues	48,986	1,261 [4]	—	50,247
Related party	1,503	(1,503)[4]	—	—
Other	800	—	—	800
Other current assets	4,580	(527)[5]	(1,791)[12]	2,262
Total current assets	90,889	(7,057)	(1,791)	82,041
Oil and natural gas properties, net	1,355,504	—	(739,486)[13]	616,018
Other assets	4,507	1,941 [6]	(1,001)[14]	5,447
Total assets	$ 1,450,900	$ (5,116)	$ (742,278)	$ 703,506
LIABILITIES AND EQUITY				
Current liabilities:				
Accounts payable and accrued liabilities	$ 34,922	$ 2,177 [7]	$ (312)[15]	$ 36,787
Current portion of long-term debt	297,000	(297,000)[8]	—	—
Total current liabilities	331,922	(294,823)	(312)	36,787
Liabilities subject to compromise	356,066	(356,066)[9]	—	—
Asset retirement obligations	161,661	—	(41,641)[15]	120,020
Long–term debt, net	—	297,000 [8]	—	297,000
Other long–term liabilities	1,021	—	—	1,021
Total liabilities	850,670	(353,889)	(41,953)	454,828
Commitments and contingencies (Note 13)				
Stockholders' / owners' equity:				
Predecessor common unitholders	621,144	65,175 [10]	(686,319)[16]	—
Predecessor general partner interest	(20,914)	34,920 [10]	(14,006)[16]	—
Successor common stock	—	100 [11]	—	100
Successor additional paid-in capital	—	248,578 [11]	—	248,578
Total stockholders' / owners' equity	600,230	348,773	(700,325)	248,678
Total liabilities and equity	$ 1,450,900	$ (5,116)	$ (742,278)	$ 703,506

Reorganization Adjustments

[1] Reflects amounts recorded as of the Effective Date for the implementation of the Plan, including among other items, settlement of the Predecessor's liabilities subject to compromise, cancellation of the Predecessor's equity, issuance of the Successor New Common Shares and the Warrants, repayment of certain of Predecessor's liabilities and settlement with holders of the Senior Notes.

(2) Reflects the changes in cash and cash equivalents, including the following:

Funding of the professional fees escrow account	$	(7,650)
Payment of debt issuance costs on the Successor Exit Credit Facility		(2,813)
Payment of professional fees		(1,591)
Payment of success fees		(1,573)
Payment of derivative settlement		(216)
Payment of accrued interest payable under the Predecessor credit facility		(135)
Transfer of funds from Predecessor's general partner		40
Changes in cash and cash equivalents	$	(13,938)

(3) Reflects the transfer of restricted cash to fund the professional fees escrow account.

(4) Primarily reflects the reclassification of the related party net receivable from EnerVest to a third party receivable as EnerVest is no longer a related party as result of the Restructuring. Also, reflects the cancellation of related party claims of $0.2 million with the general partner of EVEP as a result of the Debtor's emergence from Chapter 11 bankruptcy proceedings.

(5) Represents the expense of certain prepaid professional fees as a result of the Debtor's emergence from Chapter 11 bankruptcy proceedings.

(6) Reflects the capitalization of the deferred financing costs of $2.8 million related to the Successor's Exit Credit Facility, offset by the write-off of $0.8 million of deferred financing costs related to the Predecessor's credit facility.

(7) Net increase in accounts payable and accrued liabilities reflects the following:

Recognition of payables for success fees	$	4,086
Recognition of payables for professional fees		32
Payment of professional fees		(1,590)
Payment of derivative settlement		(216)
Payment of accrued interest payable under the Predecessor credit facility		(135)
Net increase in accounts payable and accrued liabilities	$	2,177

(8) Reflects the reclassification of $297.0 million in borrowings under the Exit Credit Facility to long-term debt.

(9) Settlement of liabilities subject to compromise and the resulting net gain were determined as follows:

Senior Notes	$	343,348
Accrued interest payable		12,718
Total liabilities subject to compromise of Predecessor		356,066
Issuance of common stock to holders of the Senior Notes		(227,366)
Gain on settlement of liabilities subject to compromise	$	128,700

The amount of disallowed interest during the period from the Petition Date through the Effective Date of emergence not included in the accrued interest payable in the table above was $4.7 million.

(10) Reflects the cancellation of the Predecessor company common unitholders and general partner interest.

	Common Unitholders	General Partner Interest
Net gain from reorganization adjustments	$ 118,940	$ 2,426
Contribution from general partner	—	40
Issuance of common stock to Predecessor common unitholders	(11,967)	—
Issuance of warrants to Predecessor common unitholders	(9,345)	—
Cancellation of Predecessor common unitholders / general partner interest	(32,453)	32,454
	$ 65,175	$ 34,920

(11) Reflects the issuance of 10,000,016 shares of common stock at a par value of $0.01 per share in accordance with the Plan, and the issuance of 800,000 warrants in accordance with the Plan. The fair value of the Warrants was determined by using the Black-Scholes model and were reasonably estimated to be approximately $11.68 per share. See Note 14 for additional information on the issuance of the Successor's Warrants.

Issuance of shares of Successor common stock at par value of $0.01 per share	$ 100
Additional paid-in capital from issuance of Successor common stock	239,233
Additional paid-in capital from issuance of Successor warrants	9,345
Fair value of Successor equity	$ 248,678

See Note 14 for additional information on the issuances of the Successor's equity.

Fresh Start Adjustments

(12) Reflects the adjustment to write-down certain other current assets to fair value.

(13) Reflects a decrease of oil and natural gas properties, net. In determining the fair value of the oil and gas properties both the income and market approach were utilized and the accumulated depreciation, depletion and impairment was eliminated. The following table summarizes the components of oil and natural gas properties as of the Effective Date: based on the methodology discussed above and the elimination of accumulated depreciation, depletion and impairment. The fresh start adjustments to oil and natural gas properties, net are as follows:

	Successor	Predecessor
	Fair Value	Historical Book Value
Proved oil and natural gas properties	$ 547,136	$ 2,593,249
Unproved oil and natural gas properties	68,882	—
	616,018	2,593,249
Accumulated depreciation, depletion and amortization	—	(1,237,745)
Net capitalized costs	$ 616,018	$ 1,355,504

(14) Reflects the write-off of immaterial other assets not anticipated to have value to Harvest.

(15) Reflects a decrease of $42.0 million for asset retirement obligations. The fair value of asset retirement obligations was estimated using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation include estimates of: (i) plugging and abandonment costs per well based on existing regulatory requirements, (ii) remaining life per well, (iii) future inflation factors and (iv) a credit-adjusted risk free rate.

(16) Reflects the cumulative impact of the fresh start adjustments discussed above.

Reorganization Items, Net

The Company has incurred significant costs associated with the reorganization. These costs, which are expensed as incurred, are expected to significantly affect the Company's results of operations. Reorganization items, net, represent costs, gains and losses directly associated with the Chapter 11 proceedings since the Petition Date.

The following table summarizes the components of reorganization items, net, included in the accompanying consolidated statements of operations:

	Successor	Predecessor
	Seven Months Ended December 31, 2018	Five Months Ended May 31, 2018
Gain on settlement of liabilities subject to compromise	$ —	$ 128,700
Fresh start valuation adjustments	—	(700,325)
Professional fees	(2,323)	(13,345)
Other	—	(2,355)
Reorganization items, net	$ (2,323)	$ (587,325)

NOTE 4. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The consolidated financial statements for the Successor and Predecessor include the operations of the Company and all of its wholly owned subsidiaries and the operations of the Partnership and all of its wholly owned subsidiaries, respectively. All intercompany accounts and transactions have been eliminated in consolidation.

Bankruptcy Accounting

The consolidated financial statements have been prepared as if the Company is a going concern and reflect the application of Accounting Standards Codification 852 *Reorganizations* ("ASC 852"). ASC 852 requires that the financial statements, for periods subsequent to the Chapter 11 filing, distinguish transactions and events that are directly associated with the reorganization from the ongoing operations of the business. Accordingly, certain expenses, gains and losses that were realized or incurred related to the bankruptcy proceedings are recorded in "Reorganization items, net" on the Company's consolidated statements of operations.

Upon emergence from bankruptcy on June 4, 2018, the Company elected to adopt and apply the relevant guidance provided in GAAP (as defined below) with respect to the accounting and financial statement disclosures for entities that have emerged from Chapter 11 ("fresh start accounting") effective May 31, 2018 to coincide with the timing of the Company's normal accounting period close. As a result of the application of fresh start accounting and the effects of the implementation of the plan of reorganization, the consolidated financial statements as of or after May 31, 2018, are not comparable with the consolidated financial statements prior to that date. To facilitate the financial statement presentations, the Company refers to the reorganized company in these consolidated financial statements and notes as the "Successor" for periods subsequent to May 31, 2018 and "Predecessor" for periods prior to June 1, 2018. Furthermore, the consolidated financial statements and notes have been presented with a "black line" division to delineate the lack of comparability between the Predecessor and Successor. See Note 2 and Note 3 for additional information.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America ("GAAP") requires management to make estimates and judgments that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The Company bases its estimates and judgments on

historical experience and on various other assumptions and information that are believed to be reasonable under the circumstances. Estimates and assumptions about future events and their effects cannot be perceived with certainty and, accordingly, these estimates may change as new events occur, as more experience is acquired, as additional information is obtained and as the operating environment changes. While the Company believes that the estimates and assumptions used in the preparation of the consolidated financial statements are appropriate, actual results could differ from those estimates.

Cash and Cash Equivalents

The Company considers all highly liquid investments with an original maturity of three months or less at the time of purchase to be cash equivalents. All of its cash and cash equivalents are maintained with several major financial institutions in the United States. Deposits with these financial institutions may exceed the amount of insurance provided on such deposits; however, the Company regularly monitors the financial stability of these financial institutions and believes that it is not exposed to any significant default risk.

Accounts Receivable

Accounts receivable from oil, natural gas and natural gas liquids sales are recorded at the invoiced amount and do not bear interest. The Company routinely assesses the financial strength of its customers and bad debts are recorded based on an account–by–account review after all means of collection have been exhausted, and the potential recovery is considered remote.

The Company did not have any reserves for doubtful accounts as of December 31, 2018, and did not incur any expense related to bad debts for the year ended December 31, 2018. The Predecessor did not have any reserves for doubtful accounts as of December 31, 2017, and did not incur any expense related to bad debts during the year ended December 31, 2017. The Company does not have any off–balance sheet credit exposure related to customers.

Property and Depreciation

Oil, natural gas and natural gas liquids producing activities are accounted for under the successful efforts method of accounting. Under this method, exploration costs, other than the costs of drilling exploratory wells, are charged to expense as incurred. Costs that are associated with the drilling of successful exploration wells are capitalized if proved reserves are found. Lease acquisition costs are capitalized when incurred. Capitalized costs associated with unproved properties totaled $8.5 million as of December 31, 2018. There were no capitalized costs associated with unproved properties as of December 31, 2017. Costs associated with the drilling of exploratory wells that do not find proved reserves, geological and geophysical costs and costs of certain non–producing leasehold costs are expensed as incurred.

Sales proceeds are credited to the carrying value of the properties, and no gains or losses are recognized upon the disposition of proved oil and natural gas properties except in transactions such as the significant disposition of an amortizable base that significantly affects the unit–of–production amortization rate.

The capitalized costs of producing oil and natural gas properties are depreciated and depleted by the units–of–production method based on the ratio of current production to estimated total net proved reserves as estimated by independent petroleum engineers. Proved developed reserves are used in computing unit rates for drilling and development costs and total proved reserves are used for depletion rates of leasehold and pipeline costs.

Other property is stated at cost less accumulated depreciation, which is computed using the straight–line method based on estimated economic lives ranging from three to 25 years. The Company expenses costs for maintenance and repairs in the period incurred. Significant improvements and betterments are capitalized if they extend the useful life of the asset.

Impairment of Oil and Natural Gas Properties

The Company evaluates its proved oil and natural gas properties and related equipment and facilities for impairment whenever events or changes in circumstances indicate that the carrying amounts of such properties may not be recoverable. The determination of recoverability is made based upon estimated undiscounted future net cash flows. The amount of impairment loss, if any, is determined by comparing the fair value, as determined by a discounted cash flow analysis, with the carrying value of the related asset. For the seven months ended December 31, 2018, the Company recorded impairment charges of $3.1 million related to proved oil and natural gas properties as the carrying amounts of such properties were determined not to be recoverable. For the five months ended May 31, 2018, the Predecessor did not record any impairment charges related to proved oil and natural gas properties. In 2017 and 2016, the Predecessor recorded impairment charges of $69.9 million and $89.5 million respectively, related to proved oil and natural gas properties as the carrying amounts of such properties were determined not to be recoverable. The $3.1 million of impairment during the seven months ended December 31, 2018, related to properties located in Central Texas and Karnes County, Texas which were sold in August 2018 (see Note 8). If commodity prices significantly decrease in future quarters, the Company could have additional impairments of oil and natural gas properties.

Unproved oil and natural gas properties are assessed periodically on a property–by–property basis, and any impairment in value is recognized. For the seven months ended December 31, 2018, the Company did not record any impairment charges related to unproved oil and natural gas properties. For the five months ended May 31, 2018, the Predecessor recorded an insignificant amount of impairment charges related to unproved oil and natural gas properties. For 2017 and 2016, the Predecessor recorded impairment charges of $23.7 million and $41.8 million, respectively, related to unproved oil and natural gas properties where it had a change in development plans for the acreage.

Asset Retirement Obligations

An asset retirement obligation ("ARO") represents the future abandonment costs of tangible assets, such as wells, service assets, and other facilities. The Company records an ARO and capitalizes the asset retirement cost in oil and natural gas properties in the period in which the retirement obligation is incurred based upon the fair value of an obligation to perform site reclamation, dismantle facilities or plug and abandon wells. After recording these amounts, the ARO is accreted to its future estimated value using an assumed cost of funds and the additional capitalized costs are depreciated on a unit–of–production basis. If the ARO is settled for an amount other than the recorded amount, a gain or loss is recognized.

Revenue Recognition

Oil, natural gas and natural gas liquids revenues are recognized upon the transfer of control of the products to a purchaser. Transfer of control typically occurs when the products are delivered to the purchaser, title and/or risk of loss has transferred and collectability of the revenue is reasonably assured. Revenue is recognized net of royalties due to third parties in an amount that reflects the consideration the Company expects to receive in exchange for those products.

The Company's oil production is primarily sold under market-sensitive contracts that are typically priced at a differential to the NYMEX price or at purchaser posted prices for the producing area. For oil contracts, the Company generally records sales based on the net amount received.

The Company's natural gas production is primarily sold under market-sensitive contracts that are typically priced at a differential to the published natural gas index price for the producing area due to the natural gas quality and the proximity to major consuming markets. For natural gas contracts, the Company generally records wet gas sales at the wellhead or inlet of the gas processing plant as revenues net of transportation, gathering and processing expenses if the processor is the customer and there is no redelivery of commodities to the Company at the tailgate of the plant. Conversely, the Company generally records residual natural gas and natural gas liquids sales at the tailgate of the plant on a gross basis along with the associated transportation, gathering and processing expenses if the processor is a service provider and there

is redelivery of commodities to the Company at the tailgate of the plant. All facts and circumstances of an arrangement are considered and judgment is often required in making this determination.

In addition, the Company recognizes processing expenses for commodities paid as noncash consideration in exchange for processing services and recognizes the associated revenues for those same commodities. This recognition results in an increase to revenues and expenses with no impact on net income.

The Company follows the sales method of accounting for natural gas revenues. Under this method of accounting, revenues are recognized based on volumes sold, which may differ from the volume to which the Company is entitled based on its working interest. An imbalance is recognized as a liability only when the estimated remaining reserves will not be sufficient to enable the under–produced owner(s) to recoup its entitled share through future production. Under the sales method, no receivables are recorded where the Company has taken less than its share of production. There were no significant gas imbalances at December 31, 2018 or 2017.

Harvest owns and operates a network of natural gas gathering systems in the Appalachian Basin and the Monroe Field in Northern Louisiana which gather and transport owned natural gas and a small amount of third party natural gas to intrastate, interstate and local distribution pipelines. Natural gas gathering and transportation revenue is recognized when the natural gas has been delivered to a custody transfer point.

See Note 5 for additional information regarding revenue recognition.

Income Taxes

Effective June 4, 2018, pursuant to the Plan, the Successor became a corporation subject to federal and state income taxes. Prior to the Plan being effective, the Predecessor was a limited partnership and organized as a pass-through entity for federal and most state income tax purposes. As a result, the Predecessor's limited partners were responsible for federal and state income taxes on their share of taxable income. The Predecessor was subject to the Texas margin tax for partnership activity in the state of Texas. See Note 15 for additional information regarding income taxes.

Earnings per Share / Limited Partner Unit

Basic earnings (loss) per share is computed by dividing net earnings attributable to stockholders by the weighted average number of shares outstanding during the period. Diluted earnings per share is computed by adjusting the average number of shares outstanding for the dilutive effect, if any, of potential common shares. The Company uses the treasury stock method to determine the dilutive effect.

The Predecessor used the two–class method to compute earnings per limited partner unit. The two-class method is an earnings allocation formula that determines earnings per unit for common units and participating securities as if all earnings for the period had been distributed. As the unvested phantom units and the earned but unvested performance units participated in dividends on an equal basis with the common units, they were considered to be participating securities. Earnings used in the determination of earnings per limited partner unit for the reporting period were reduced by the amount of earnings allocated to the general partner and available cash that would be distributed to the limited partners and the participating securities. The undistributed earnings, if any, were then allocated to the limited partners and the participating securities in accordance with the terms of the partnership agreement. Basic and diluted earnings per limited partner unit were then calculated by dividing earnings, after deducting the amount allocated to the general partner and the earnings attributable to the participating securities, by the weighted average number of outstanding limited partner units during the period.

Derivatives

The Company monitors its exposure to various business risks, including commodity price and interest rate risks, and uses derivatives to manage the impact of certain of these risks. The Company's policies do not permit the use of derivatives

for speculative purposes. Harvest uses energy derivatives for the purpose of mitigating risk resulting from fluctuations in the market price of oil, natural gas and natural gas liquids.

The Company has elected not to designate its derivatives as hedging instruments. Changes in the fair value of derivatives are recorded immediately to earnings as "Gain (loss) on derivatives, net" in the consolidated statements of operations.

Concentration of Credit Risk

All of the Company's derivative contracts are with major financial institutions who are also lenders under the Exit Credit Facility. Should one of these financial counterparties not perform, Harvest may not realize the benefit of some of its derivative contracts and could incur a loss. As of December 31, 2018, all of the Company's counterparties have performed pursuant to their derivative contracts.

Oil, natural gas and natural gas liquids revenues are derived principally from uncollateralized sales to numerous companies in the oil and natural gas industry; therefore, Harvest customers may be similarly affected by changes in economic and other conditions within the industry. The Company has experienced no significant credit losses on such sales in the past.

During 2018, one customer accounted for 15.5% of the consolidated oil, natural gas and natural gas liquids revenues. In 2017, two customers accounted for 15.5% and 11.0%, respectively, of the Predecessor's consolidated oil, natural gas and natural gas liquids revenues. In 2016, three customers accounted for 18.5%, 13.4% and 10.4%, respectively, of the Predecessor's consolidated oil, natural gas and natural gas liquids revenues. Harvest believes that the loss of a major customer would have a temporary effect on its revenues but, that over time, the Company would be able to replace its major customers.

Recent Accounting Standards

In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2014–09, *Revenue from Contracts with Customers* ("ASU 2014-09"). This ASU, as amended, superseded virtually all of the revenue recognition guidance in generally accepted accounting principles in the United States. The core principle of the five–step model is that an entity will recognize revenue when it transfers control of goods or services to customers at an amount that reflects the consideration to which it expects to be entitled in exchange for those goods or services. Entities can choose to apply the standard using either the full retrospective approach or a modified retrospective approach. The Partnership implemented ASU 2014-09 as of January 1, 2018 using the modified retrospective method. The adoption of this ASU did not have a material impact on the Company's consolidated financial statements. See Note 5 for additional details about the impact upon adoption and related disclosures.

In January 2016, the FASB issued ASU No. 2016–01, *Financial Instruments: Overall (Subtopic 825-10)* ("ASU 2016-01"). This main objective of this ASU was to enhance the reporting model for financial instruments to provide users of financial statements with more decision-useful information. One of the provisions of this ASU was to require equity investments (except those accounted for under the equity method of accounting or those that result in consolidation of the investee) to be measured at fair value with changes in fair value recognized in net income. The Company implemented ASU 2016-01 as of January 1, 2018. Changes in fair value of the Company's equity investments are included in "Gain on equity securities" in the consolidated statements of operations. See Note 10 for additional details regarding the fair value measurement of the equity securities.

In February 2016, the FASB issued ASU No. 2016-02, *Leases* ("ASU 2016-02"). The main objective of ASU 2016-02 is to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. The main difference between previous GAAP and Topic 842 is the recognition of lease assets and lease liabilities by lessees for those leases classified as operating leases. ASU 2016-02 requires lessees to recognize assets and liabilities arising from leases on the balance sheet. ASU

2016-02 further defines a lease as a contract that conveys the right to control the use of identified property, plant, or equipment for a period of time in exchange for consideration. Control over the use of the identified asset means that the customer has both (1) the right to obtain substantially all of the economic benefit from the use of the asset and (2) the right to direct the use of the asset. ASU 2016-02 requires disclosures by lessees and lessors to meet the objective of enabling users of financial statements to assess the amount, timing, and uncertainty of cash flows arising from leases. In January 2018, the FASB issued ASU 2018-01, *Leases (Topic 842), Land Easement Practical Expedient for Transition to Topic 842* ("ASU 2018-01"), which permits an entity an optional election to not evaluate under ASU 2016-02 those existing or expired land easements that were not previously accounted for as leases prior to the adoption of ASU 2016-02. In July 2018, the FASB issued ASU 2018-11, *Leases (Topic 842), Targeted Improvements* ("ASU 2018-11"), which permits an entity (i) to apply the provisions of ASU 2016-02 at the adoption date instead of the earliest period presented in the financial statements, and, as a lessor, (ii) to account for lease and nonlease components as a single component as the nonlease components would otherwise be accounted for under the provisions of ASU 2014-09. For public entities, ASU 2016-02 and other related ASUs are effective for financial statements issued for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. The Company will apply the new standard for its interim and annual reporting periods starting January 1, 2019 using a modified retrospective approach. The Company also plans to elect the package of practical expedients within ASU 2016-02 that allows an entity to not reassess prior to the effective date (i) whether any expired or existing contracts are or contain leases, (ii) the lease classification for any expired or existing leases or (iii) initial direct costs for any existing leases. Additionally, the Company plans to elect the practical expedient under ASU 2018-01 and not evaluate existing or expired land easements not previously accounted for as leases prior to the effective date. The adoption of this standard will result in an increase in the assets and liabilities on the Company's consolidated balance sheets. The quantitative impacts of the new standard are dependent on the leases in force at the time of adoption. At January 1, 2019, the operating lease liability is estimated to be insignificant. As a result, the adoption of this ASU is not expected to have a material impact on the consolidated financial statements.

In August 2016, the FASB issued ASU No. 2016–15, *Statement of Cash Flows* ("ASU 2016-15"). This ASU addresses certain cash flow issues with the objective of reducing the existing diversity in practice in how the cash receipts and cash payments are presented and classified in the statement of cash flows. The Partnership adopted ASU 2016-15 on January 1, 2018. The adoption of this ASU did not have a material impact on the Predecessor's consolidated financial statements.

In November 2016, the FASB issued ASU No. 2016-18: *Statement of Cash Flows– Restricted Cash* ("ASU 2016-18"). The main objective of ASU 2016-18 is to address the diversity that exists in the classification and presentation of changes in restricted cash on the statement of cash flows. The amendments in ASU 2016-18 require that a statement of cash flows explain the change during the period in the total of cash, cash equivalents and amounts generally described as restricted cash or restricted cash equivalents. Thus, amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning of period and end of period total amounts shown on the statement of cash flows. The Partnership adopted ASU 2016-18 on January 1, 2018. The adoption of this ASU resulted in a change to the consolidated statements of cash flows for the years ended December 31, 2017 and 2016. For the year ended December 31, 2017, the $5.5 million cash and cash equivalents – beginning of period was revised to $57.6 million cash, cash equivalents and restricted cash – beginning of period and the net cash used in investing activities was increased from $30.3 million to $82.4 million. For the year ended December 31, 2016, the $5.5 million cash and cash equivalents – end of period was revised to $57.6 million cash, cash equivalents and restricted cash – end of period and the net cash used in investing activities was revised from $9.8 million to net cash provided by investing activities of $42.3 million.

In January 2017, the FASB issued ASU No. 2017-01, *Business Combinations (Topic 805): Clarifying the Definition of a Business* ("ASU 2017-01"). The main objective of ASU 2017-01 is to clarify the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. The amendments of this ASU provide a screen to determine when a set is not a business. The screen requires that when substantially all of the fair value of the gross assets acquired (or disposed of) is concentrated in a single identifiable asset or a group of similar identifiable assets, the set is not a business. This screen reduces the number of transactions that need to be further evaluated. If the screen is not met, the amendments of this ASU (i) require that to be considered a business, a set must include, at a minimum, an input and a substantive process that

together significantly contribute to the ability to create output and (ii) remove the evaluation of whether a market participant could replace missing elements. The Partnership adopted ASU 2017-01 on January 1, 2018.

In August 2018, the FASB issued ASU No. 2018-13: *Fair Value Measurement (Topic 820): Disclosure Framework – Changes to the Disclosure Requirements for Fair Value Measurement* ("ASU 2018-13"). The FASB issued ASU 2018-13 as part of its disclosure framework project. The amendments of this ASU modify the disclosure requirements on fair value measurements in Topic 820, *Fair Value Measurement*. ASU 2018-13 is effective for financial statements issued for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years; early application is permitted. The Company does not expect that adopting this ASU will have a material impact on its consolidated financial statements.

No other new accounting pronouncements issued or effective during the year ended December 31, 2018 have had or are expected to have a material impact on the Company's consolidated financial statements.

Subsequent Events

Harvest evaluated subsequent events for appropriate accounting and disclosure through the date these consolidated financial statements were issued.

NOTE 5. REVENUE

On January 1, 2018, the Partnership adopted ASU No. 2014–09, *Revenue from Contracts with Customers* ("Topic 606"), using the modified retrospective method applied to contracts that were not completed as of January 1, 2018. Accordingly, the comparative information for the years ended December 31, 2017 and 2016, have not been adjusted and continue to be reported under the previous revenue standard. The adoption of this ASU did not have a material impact on the consolidated financial statements, and the primary impacts of this change in accounting policy for revenue recognition effective January 1, 2018, are detailed below.

There were no significant changes to the timing of revenue recognized for sales of production. However, as a result of management's evaluation under new considerations within Topic 606, the adoption did result in certain contracts being recorded on a net basis instead of a gross basis, as well as some contracts being recorded on a gross basis instead of a net basis, as a result of the determined delivery point. These presentation changes did not have an impact on income or loss from operations, earnings per share/unit or cash flows, but did increase oil, natural gas and natural gas liquids revenues and lease operating expenses in the consolidated financial statements as compared to what would have been recognized using the revenue recognition guidance that was in effect before the adoption of Topic 606.

The following table summarizes the impact of adopting Topic 606 on the consolidated financial statements:

	Without Adoption of Topic 606	Impact of Change in Accounting Policy	As Reported
Successor			
For the Seven Months Ended December 31, 2018:			
Oil, natural gas and natural gas liquids revenues	$ 134,232	$ 2,937	$ 137,169
Lease operating expenses	$ 61,163	$ 2,937	$ 64,100
Predecessor			
For the Five Months Ended May 31, 2018:			
Oil, natural gas and natural gas liquids revenues	$ 108,253	$ 2,054	$ 110,307
Lease operating expenses	$ 43,318	$ 2,054	$ 45,372

Revenue from contracts with customers includes the sale of oil, natural gas and natural gas liquids production (recorded in "Oil, natural gas and natural gas liquids revenues" in the consolidated statements of operations) and gathering and transportation revenues (recorded in "Transportation and marketing-related revenues" in the consolidated statements of operations). There was no impact to gathering and transportation revenues as a result of adopting Topic 606.

The following table disaggregates revenue by significant product and service type:

	Successor	Predecessor
	Seven Months Ended December 31, 2018	Five Months Ended May 31, 2018
Oil	$ 41,411	$ 42,460
Natural gas [1]	63,460	40,951
Natural gas liquids [1] [2]	32,298	26,896
Oil, natural gas and natural gas liquids revenues [2]	137,169	110,307
Transportation and marketing–related revenues	1,431	724
Total revenues [2]	$ 138,600	$ 111,031

[1] The Company recognizes wet gas revenues, which are recorded net of transportation, gathering and processing expenses, partially as natural gas revenues and partially as natural gas liquids revenues based on the end products after processing occurs. For the Successor period of the seven months ended December 31, 2018, wet gas revenues were $13.4 million which were recognized as $4.4 million of natural gas revenues and $9.0 million of natural gas liquids revenues. For the Predecessor period of the five months ended May 31, 2018, wet gas revenues were $8.4 million which were recognized as $3.2 million of natural gas revenues and $5.2 million of natural gas liquids revenues.

[2] Includes a royalty adjustment of $5.0 million during the seven months ended December 31, 2018. Excluding this royalty adjustment, revenues from natural gas liquids would have been $37.3 million; oil, natural gas and natural gas liquids revenues would have been $142.2 million; and total revenues would have been $143.6 million for the seven months ended December 31, 2018. See Note 13 for additional information.

Contract Balances

Customers are invoiced once the Company's performance obligations have been satisfied. Payment terms and conditions vary by contract type, although terms generally include a requirement of payment within 30 days. There are no significant judgments that significantly affect the amount or timing of revenue from contracts with customers. Accordingly, the Company's product sales contacts do not give rise to material contract assets or contract liabilities.

Accounts receivable are primarily from purchasers of oil, natural gas and natural gas liquids and from exploration and production companies that own interests in properties Harvest operates. As of December 31, 2018 and 2017, the Company and the Predecessor had receivables of $38.3 million and $47.7 million, respectively, due from purchasers of oil, natural gas and natural gas liquids. This industry concentration could affect overall exposure to credit risk, either positively or negatively, because the Company's purchasers and joint working interest owners may be similarly affected by changes in economic, industry or other conditions. The Company routinely assesses the financial strength of its customers and bad debts are recorded based on an account-by-account review specifically identifying receivables that the Company believes may be uncollectible after all means of collection have been exhausted, and the potential recovery is considered remote. As of December 31, 2018 and 2017, the Company and the Predecessor did not have any reserves for doubtful accounts, respectively.

Performance Obligations

The Company applies the optional exemptions in Topic 606 and does not disclose consideration for remaining performance obligations with an original expected duration of one year or less or for variable consideration related to unsatisfied performance obligations.

NOTE 6. SHARE–BASED COMPENSATION

On the Effective Date, in connection with the Plan, the Company adopted the MIP, pursuant to which employees, directors, consultants and other service providers of the Company and its subsidiaries are eligible to receive stock options, stock appreciation rights, restricted stock, restricted stock units, other stock-based awards and cash-based awards. An aggregate of 689,362 shares of the Company's common stock are reserved for issuance under the MIP. To the extent that an award under the MIP is expired, forfeited or cancelled for any reason without having been exercised in full, the unexercised award would then be available again for grant under the MIP.

The Compensation Committee of the Company's Board of Directors (the "Board") (or any properly delegated subcommittee thereof) or a committee of at least two people as the Board may appoint or, if no such committee or subcommittee has been appointed by the Board, the Board (the "Committee") will administer the MIP. The Committee has broad authority under the MIP to, among other things: (i) select participants; (ii) determine the types of awards that participants are to receive and the number of shares or the amount of cash that are to be subject to such awards and grant such awards; and (iii) determine the terms, conditions and restrictions of awards, including the applicable performance criteria relating to the award.

During the seven months ended December 31, 2018, the Company granted 54,800 shares of restricted stock under the MIP, which vested during September 2018 as a result of the closing of the Central Texas divestiture (defined in Note 8). See Note 8 for additional information about the divestiture. During the seven months ended December 31, 2018, the Company also granted 6,500 shares of restricted stock under the MIP to members of the Board which are scheduled to vest on June 5, 2019. The weighted average fair value of the restricted shares granted during the seven months ended December 31, 2018, was $20.33 with a total fair value of approximately $1.2 million. None of these shares were forfeited during the seven months ended December 31, 2018. Approximately 0.6 million shares remain available for grant under the MIP as of December 31, 2018.

Activity related to these restricted share awards is as follows:

	Number of Restricted Shares	Weighted Average Grant Date Fair Value
Nonvested awards as of June 1, 2018	—	$ —
Granted	61,300	20.33
Vested	(54,800)	19.99
Forfeited	—	—
Nonvested awards as of December 31, 2018	6,500	$ 23.20

The Company recognized compensation cost related to these restricted shares of $1.1 million for the seven months ended December 31, 2018. These costs are included in "General and administrative expenses" in the consolidated statements of operations. As of December 31, 2018, there was $0.1 million of total unrecognized compensation cost related to unvested restricted stock which is expected to be recognized over a weighted average period of 0.4 years.

Series A Preferred Stock

In connection with the Restructuring and in reliance on the exemption from the registration requirements of the Securities Act provided by Section 1145 of the Bankruptcy Code, Harvest issued 21,000 shares of Series A Preferred Stock

pursuant to Preferred Stock Purchase Agreements, dated as of the Effective Date. The Company estimated the fair value of the Series A Preferred Stock as of December 31, 2018 at $0.2 million. The fair value of the preferred stock award will be recognized on a straight–line basis over the service period, and the Company will account for forfeitures as they occur. During the seven months ended December 31, 2018, the Company recognized $88 thousand of compensation cost related to this preferred stock. These costs are included in "General and administrative expenses" in the consolidated statement of operations.

The Series A Preferred Stock is entitled to receive mandatory and cumulative dividends payable semi-annually in arrears with respect to each dividend period ending on and including the last calendar day of each six-month period ending June 4 and December 4, at a rate per share of Series A Preferred Stock equal to 8.0% per annum. In the event that dividends due to each share of Series A Preferred Stock have not been paid for a period of two consecutive Dividend Periods (as defined in the Certificate of Designations), the holders of the Series A Preferred Stock, as an independent class, shall be entitled to nominate and vote to appoint one director of the Board of Directors of the Company. Holders of shares of Series A Preferred Stock have no right, by virtue of their status as holders of shares of Series A Preferred Stock, to vote on any matters on which holders of shares of New Common Stock are entitled to vote.

Predecessor Equity-Based Compensation

EV Management has two long–term incentive plans, the 2006 Long-Term Incentive Plan (the "2006 Plan") and the 2016 Long-Term Incentive Plan (the "2016 Plan" and together, the "Plans") for employees, consultants and directors of EV Management and its affiliates who perform services for EVEP. The 2006 Plan expired on September 20, 2016, and on August 30, 2016, the unitholders approved the adoption of the 2016 Plan, which replaced the 2006 Plan with respect to future awards. The 2016 Plan provided for the issuance of up to 5,000,000 units and allowed for the award of unit options, phantom units, performance units, restricted units and deferred equity rights. These equity–based awards consisted only of phantom units as of May 31, 2018.

EVEP accounted for phantom units as equity awards since it had determined that these awards would likely be settled by issuing common units. Compensation cost was recognized for these phantom units on a straight–line basis over the service period and was net of forfeitures. These phantom units were subject to graded vesting over a four year period. However, the Partnership elected to settle the awards which vested in January 2018 with cash payments; as a result, the awards which vested in January 2018 were classified as liability awards as of December 31, 2017.

There were no phantom unit awards issued during the five months ended May 31, 2018 or the year ended December 31, 2017. The weighted average fair value of the phantom unit awards issued during the year ended December 31, 2016, was $2.05.

Activity related to these phantom units is as follows:

	Number of Phantom Units	Weighted Average Grant Date Fair Value
Nonvested phantom units as of December 31, 2017	1,511,920	$ 4.54
Granted	—	—
Vested	(1,460,234)	4.58
Forfeited	(51,686)	3.42
Nonvested phantom units as of May 31, 2018	—	$ —

For the Predecessor, the total grant date fair value of the phantom units vested in 2018, 2017 and 2016 was $6.7 million, $6.3 million and $8.4 million, respectively.

The Predecessor recognized compensation cost related to these phantom units of $1.0 million during the five months ended May 31, 2018, under the normal vesting schedule. The Predecessor recognized compensation cost related to these

phantom units of $4.3 million and $6.6 million in 2017 and 2016, respectively. These costs are included in "General and administrative expenses" in our consolidated statements of operations.

On June 4, 2018, EVEP's emergence from bankruptcy, which constituted a change of control, resulted in the immediate acceleration of all unvested phantom units. As a result, the total unrecognized compensation cost of $2.8 million was recognized as of May 31, 2018. These costs are included in "General and administrative expenses" in the consolidated statements of operations.

NOTE 7. ACQUISITIONS

2017

On January 31, 2017, EVEP acquired a 5.8% working interest in oil and gas properties in Karnes County, Texas for $58.7 million (net of post-closing purchase price adjustments) with the $52.1 million of proceeds from the divestiture of the Barnett Shale natural gas properties in December 2016 (see Note 8) and $6.6 million of borrowings under the Predecessor's credit facility (the "Eagle Ford Acquisition"). Certain EnerVest institutional partnerships owned an 87% working interest in, and EnerVest Operating, L.L.C. ("EnerVest Operating"), a wholly owned subsidiary of EnerVest and its affiliates, acted as operator of, the properties. The purchase price of $58.7 million was primarily allocated to proved oil and natural gas properties.

In August 2017, EVEP acquired a 40% working interest in oil and gas properties in Central Texas near the Austin Chalk position for $2.7 million (net of post-closing purchase price adjustments) from a third party.

NOTE 8. DIVESTITURES

2018

In August 2018, the Company closed the sale of certain oil and gas properties in Central Texas and Karnes County, Texas (the "Central Texas Divestiture") to Magnolia Oil & Gas Parent LLC and Magnolia Oil & Gas Corporation (collectively, "Magnolia") for total consideration of $134.4 million in cash, net of purchase price adjustments, and 4.2 million shares of common stock of Magnolia (NYSE: MGY). Based on the closing price for Magnolia's common stock on August 31, 2018, total consideration was $192.7 million, net of purchase price adjustments. The Company did not record a gain or loss on this sale. The Company recognized impairment expense of $2.9 million during the seven months ended December 31, 2018 related to the sale of these properties.

During January 2019, the Company sold all of its 4.2 million shares of common stock of Magnolia for net proceeds of $51.7 million.

In addition, in August 2018, the Company closed the sale of certain oil and gas properties in Central Texas to a third party for total consideration of $3.4 million, net of purchase price adjustments. The Company did not record a gain or loss on this sale. The Company recognized impairment expense of $0.2 million during the seven months ended December 31, 2018 related to the sale of these properties.

In December 2018, the Company closed the sale of certain oil and gas properties in Central Texas to a third party for total consideration of $2.6 million, net of preliminary purchase price adjustments. The Company recorded a gain of $0.7 million on this sale.

In addition, in December 2018, the Company closed the sale of certain oil and gas properties in the Mid–Continent area to a third party for total consideration of $1.0 million, net of preliminary purchase price adjustments. The Company did not record a gain, loss or impairment related to this sale.

In January 2019, the Company closed the sale of certain oil and gas properties in the Mid-Continent area to a third party for total consideration of $1.7 million, net of preliminary purchase price adjustments.

On February 13, 2019, the Company entered into a definitive agreement to sell all of its (i) oil and gas properties in the San Juan Basin and (ii) membership interests in EnerVest Mesa, LLC, a wholly-owned subsidiary of EV Properties, L.P., to a third party for total consideration of $42.8 million in cash, subject to purchase price adjustments. The transaction is expected to close in April 2019 and has an effective date of October 1, 2018. The net book value as of December 31, 2018 of the San Juan assets and liabilities to be divested was approximately $61 million. As a result, the Company expects to record an impairment related to the sale of its San Juan properties in 2019.

On February 27, 2019, the Company entered into a definitive agreement to sell certain oil and gas properties in the Mid-Continent area to a third party for total consideration of $2.5 million in cash, subject to purchase price adjustments. The transaction is expected to close in April 2019 and has an effective date of October 1, 2018.

2017

In February 2017, EVEP, along with certain institutional partnerships managed by EnerVest, entered into an Agreement of Sale and Purchase to sell certain oil and gas properties in Ohio and Pennsylvania to a third party. The transaction closed on April 10, 2017, and EVEP received net proceeds of $1.1 million. EVEP did not record a gain, loss or impairment related to this sale.

In April 2017, EVEP sold certain oil and gas properties in East Texas to a third party. The transaction closed on April 5, 2017, and EVEP received net proceeds of $0.6 million. EVEP did not record a gain or loss on this sale. The Company recognized impairment expense of $2.9 million during the year ended December 31, 2017 related to the sale of these properties.

In August 2017, EVEP sold certain acreage in the San Juan Basin to a third party. EVEP received net proceeds of $1.0 million and recorded a gain of $1.0 million on this sale.

2016

In December 2016, EVEP, along with certain institutional partnerships managed by EnerVest, closed on the sale of a portion of its Barnett Shale natural gas properties, and its share of the proceeds was $52.1 million (before post-closing adjustments). The Company recognized impairment expense of $89.5 million during the year ended December 31, 2016 related to the sale of these properties. Also, during 2016, EVEP received proceeds of $2.4 million for the sale of other oil and gas properties.

NOTE 9. RISK MANAGEMENT

The Company's business activities expose it to risks associated with changes in the market price of oil, natural gas and natural gas liquids. In addition, the Company's floating rate credit facility exposes it to risks associated with changes in interest rates. As such, future earnings are subject to fluctuation due to changes in the market price of oil, natural gas and natural gas liquids and interest rates. The Company uses derivatives to reduce its risk of volatility in the prices of oil,

natural gas and natural gas liquids and interest rates. The Company policies do not permit the use of derivatives for speculative purposes.

The Company has elected not to designate any of its derivatives as hedging instruments. Accordingly, changes in the fair value of its derivatives are recorded immediately to earnings as "Gain (loss) on derivatives, net" in the consolidated statements of operations.

In April 2018, in conjunction with the Chapter 11 proceedings, the Predecessor terminated its interest rate swaps for the period of April 2018 to September 2020, which resulted in a cash settlement received in April 2018 of $1.6 million.

After the Effective Date, the Company entered into new commodity derivative contracts. As of December 31, 2018, the Company had entered derivatives with the following terms:

Period Covered	Hedged Volume	Weighted Average Fixed Price
Oil (MBbls):		
Swaps - January 2019 to December 2019	1,022.0	$ 63.02
Swaps - January 2020 to December 2020	732.0	$ 60.51
Natural Gas (MMBtus):		
Swaps - January 2019 to December 2019	31,025.0	$ 2.77
Natural Gas Liquids (MBbls):		
Swaps - January 2019 to December 2019	1,095.0	$ 18.58
Swaps - January 2020 to December 2020	768.6	$ 17.68

During the first quarter of 2019, the Company entered into additional derivatives for 16,470 MMBtus of natural gas at a weighted average fixed price of $2.70 for the period of January 2020 to December 2020. Also, in January 2019, the Company terminated 167 MBbls of oil swaps for the period of February 2019 to December 2019 at a fixed price of $62.12; this termination resulted in a cash settlement received of $1.5 million.

The following table sets forth the fair values and classification of the Company's outstanding derivatives:

	Successor		
	Gross Amount of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Assets Presented in the Consolidated Balance Sheet
As of December 31, 2018:			
Derivative asset	$ 18,048	$ (2,596)	$ 15,452
Long-term derivative asset	8,565	(66)	8,499
Total	$ 26,613	$ (2,662)	$ 23,951
Derivative liability	$ 3,761	$ (2,596)	$ 1,165
Long-term derivative liability	66	(66)	—
Total	$ 3,827	$ (2,662)	$ 1,165

	Predecessor		
	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet
As of December 31, 2017:			
Derivative asset	$ 3,402	$ (350)	$ 3,052
Derivative liability	$ 746	$ (350)	$ 396

The Company has entered into master netting arrangements with its counterparties. The amounts above are presented on a net basis in the consolidated balance sheets when such amounts are with the same counterparty. In addition, the Company has recorded accounts payable and receivable balances related to settled derivatives that are subject to the master netting agreements. These amounts are not included in the above table; however, under the master netting agreements, the Company has the right to offset these positions against forward exposure related to outstanding derivatives.

The Company could be required to post cash collateral related to these derivatives under certain circumstances. As of December 31, 2018 and 2017, the Company and the Predecessor were not required to post any collateral nor did they hold any collateral associated with derivatives, respectively.

NOTE 10. FAIR VALUE MEASUREMENTS

The fair value hierarchy has three levels based on the reliability of the inputs used to determine fair value. Level 1 refers to fair values determined based on quoted prices in active markets for identical assets or liabilities. Level 2 refers to fair values determined based on quoted prices for similar assets and liabilities in active markets or inputs that are observable for the asset or liability, either directly or indirectly through market corroboration. Level 3 refers to fair values determined based on the Company's own assumptions used to measure assets and liabilities at fair value.

Recurring Basis

The following table presents the fair value hierarchy table for the Company's net assets and liabilities that are required to be measured at fair value on a recurring basis:

	Successor			
		Fair Value Measurements at the End of the Reporting Period		
	Fair Value	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
As of December 31, 2018:				
Assets:				
Oil, natural gas and natural gas liquids derivatives	$ 26,613	$ —	$ 26,613	$ —
Equity securities	47,082	47,082	—	—
	$ 73,695	$ 47,082	$ 26,613	$ —
Liabilities:				
Oil, natural gas and natural gas liquids derivatives	$ 3,827	$ —	$ 3,827	$ —

	Predecessor			
		Fair Value Measurements at the End of the Reporting Period		
	Fair Value	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
As of December 31, 2017:				
Assets:				
Oil, natural gas and natural gas liquids derivatives	$ 2,696	$ —	$ 2,696	$ —
Interest rate swaps	706	—	706	—
	$ 3,402	$ —	$ 3,402	$ —
Liabilities:				
Oil, natural gas and natural gas liquids derivatives	$ 721	$ —	$ 721	$ —
Interest rate swaps	25	—	25	—
	$ 746	$ —	$ 746	$ —

The Company's derivatives consist of over–the–counter ("OTC") contracts which are not traded on a public exchange. As the fair value of these derivatives is based on inputs using market prices obtained from independent brokers or determined using quantitative models that use as their basis readily observable market parameters that are actively quoted and can be validated through external sources, including third party pricing services, brokers and market transactions, the Company has categorized these derivatives as Level 2. The Company values these derivatives using the income approach using inputs such as the forward curve for commodity prices based on quoted market prices and prospective volatility factors related to changes in the forward curves and yield curves based on money market rates and interest rate swap data, such as forward LIBOR curves. The estimates of fair value have been determined at discrete points in time based on relevant market data. Furthermore, fair values are adjusted to reflect the credit risk inherent in the transaction, which may include amounts to reflect counterparty credit quality and/or the effect of the Company's creditworthiness. These assumed credit risk adjustments are based on published credit ratings, public bond yield spreads and credit default swap spreads. There were no changes in valuation techniques or related inputs in 2018.

At December 31, 2018, equity securities consisted of 4.2 million shares of common stock of Magnolia which are traded on a public exchange. The Company categorized these equity securities as Level 1, as the fair value of these shares is based market price and the 120-day lock up period upon issuance had expired.

Nonrecurring Basis

The following table presents the fair value hierarchy table for the Company's net assets and liabilities that are required to be measured at fair value on a nonrecurring basis:

		Fair Value Measurements			
	Fair Value	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Losses
Predecessor:					
Year Ending December 31, 2017:					
Long–lived assets held and used	$ 48,694	$ —	$ —	$ 48,694	$ 66,931

Long–lived Assets Held and Used

The Company did not incur any impairment charges during the seven months ended December 31, 2018 for any of its oil and natural gas properties that were held and used as of December 31, 2018. The Predecessor did not incur any impairment charges during the five months ended May 31, 2018 for any of its oil and natural gas properties that were held and used as of May 31, 2018. As a result of reductions in estimated future net cash flows primarily caused by the decrease in prices for oil, natural gas and natural gas liquids, the Company incurred impairment charges of $66.9 million in 2017 to write down oil and natural gas properties that were held and used to their fair value. These impairment charges were included in earnings in the periods indicated. The Predecessor did not incur any impairment charges during 2016 for any of its oil and natural gas properties that were held and used as of December 31, 2016.

The fair values were determined using the income approach and were based on the expected present value of the future net cash flows from reserves. Significant Level 3 assumptions associated with the calculation of discounted cash flows used in the impairment analysis included estimates of future prices, production costs, development expenditures, anticipated production, appropriate risk–adjusted discount rates and other relevant data.

Financial Instruments

The estimated fair values of the Company's financial instruments have been determined at discrete points in time based on relevant market information. The Company's financial instruments consist of cash and cash equivalents, restricted cash, accounts receivable, accounts payable and accrued liabilities, derivatives and long–term debt. The carrying amounts of the Company's financial instruments other than derivatives and long–term debt approximate fair value because of the short–term nature of the items. Derivatives are recorded at fair value (see above).

The carrying value of debt outstanding under the Company's Exit Credit Facility approximates fair value because the credit facility's variable interest rate resets frequently and approximates current market rates available to us. The estimated fair value of the Predecessor's Senior Notes was $176.8 million at December 31, 2017, which differed from the carrying value of $342.5 million at December 31, 2017. The fair value of the Senior Notes was determined using Level 2 inputs.

NOTE 11. ASSET RETIREMENT OBLIGATIONS

The changes in the aggregate ARO are as follows:

ARO as of December 31, 2016 (Predecessor)	$ 183,476
Liabilities incurred	671
Accretion expense	7,653
Revisions in estimated cash flows	(875)
Settlements and divestitures	(28,962)
ARO as of December 31, 2017 (Predecessor)	161,963
Liabilities incurred	77
Accretion expense	3,176
Settlements and divestitures	(385)
ARO as of May 31, 2018 (Predecessor)	164,831
Fresh start adjustments (1)	(41,953)
ARO as of May 31, 2018 (Successor)	122,878
Liabilities incurred	8
Accretion expense	5,420
Settlements and divestitures	(8,700)
ARO as of December 31, 2018 (Successor)	$ 119,606

(1) As a result of the application of fresh start accounting, the Successor recorded its asset retirement obligations at fair value as of the Effective Date.

As of December 31, 2018, $2.1 million of the Successor ARO and as of December 31, 2017, $3.2 million of the Predecessor ARO is classified as current and is included in "Accounts payable and accrued liabilities" in the consolidated balance sheets.

NOTE 12. LONG–TERM DEBT, NET

The following table presents the consolidated debt obligations at the dates indicated:

	Successor	Predecessor
	December 31, 2018	December 31, 2017
Successor Exit Credit Facility (1)	$ 115,000	$ —
Predecessor Credit facility	—	263,000
Predecessor 8.0% senior notes due April 2019:		
Principal outstanding	—	343,348
Unamortized discount and debt issuance costs (2)	—	(1,701)
Unaccreted premium (3)	—	902
	—	342,549
Total debt	115,000	605,549
Less: Current portion of long-term debt (4)	—	(605,549)
Long-term debt, net	$ 115,000	$ —

(1) On January 29, 2019 and February 8, 2019, the Company repaid $35.0 million and $25.0 million, respectively, of the outstanding amount under the Exit Credit Facility.

(2) Imputed interest rate of 8.49% for December 31, 2017.

(3) Imputed interest rate of 7.43% for December 31, 2017.

(4) Due to the anticipated financial covenant violations as of December 31, 2017, the borrowings under the Predecessor's credit facility and Senior Notes were classified as current at December 31, 2017. There were no financial covenant violations as of December 31, 2018.

Exit Credit Facility

In connection with the Company's emergence from bankruptcy, on the Effective Date, the Company entered into a Credit Agreement providing for a $1.0 billion new reserve-based revolving loan. The Exit Credit Facility matures on February 26, 2021. Borrowings under the Exit Credit Facility are secured by a first priority lien on substantially all of the Company's oil and natural gas properties. The Company may use borrowings under the Exit Credit Facility for acquiring and developing oil and natural gas properties, for working capital purposes and for general corporate purposes. The Company also may use up to $50.0 million of available borrowing capacity for letters of credit. As of December 31, 2018, the Company had a $0.2 million letter of credit outstanding.

The terms of the credit facility do not require any repayments of amounts outstanding until it matures in February 2021. Borrowings under the credit facility bear interest at a floating rate based on, at the Company's election, a base rate or the London Inter–Bank Offered Rate plus applicable premiums based on the percent of the borrowing base outstanding (weighted average effective interest rate of 5.10% at December 31, 2018).

Borrowings under the Exit Credit Facility may not exceed a "borrowing base" determined by the lenders under the credit facility based on the Company's oil and natural gas reserves. In August 2018, as a result of the Central Texas divestiture, the borrowing base was reduced by $60.3 million to $264.7 million. During the fourth quarter of 2018, as a result of other divestitures, the borrowing base was reduced by $2.4 million to $262.3 million as of December 31, 2018. In addition, during the first quarter of 2019, as a result of other divestitures, the borrowing base was reduced by an additional $2.0 million. The borrowing base is subject to scheduled redeterminations starting on April 1, 2019, and semi-annually as of April 1 and October 1 of each year thereafter with an additional redetermination once per calendar year at the election of either the Company or the lenders.

The Exit Credit Facility requires the following (as defined in the Credit Agreement):

- the Total Debt to EBITDAX ratio covenant to be no greater than 4.0 to 1.0;
- the current consolidated assets (including unused commitments under the Exit Credit Facility) to current consolidated liabilities be no less than 1.0 to 1.0;
- the percentage of Mortgaged Properties be no less than 95% of the total value of the Oil and Gas Properties evaluated in the most recent Reserve Report;
- no later than 60 days following the Effective Date, 70% of projected production volumes (excluding projected production volumes from certain properties) be hedged (as of the date such swap agreements were executed) for the 18 months following the Effective Date; and
- cash held by the Company be limited to the greater of 5% of the current borrowing base or $30.0 million.

As of December 31, 2018, the Company was in compliance with all of these financial covenants.

Predecessor's Credit Facility

The Predecessor was party to a $1.0 billion credit facility, which was scheduled to expire in February 2020. Borrowings under that credit facility were secured by a first priority lien on substantially all of the Predecessor's oil and natural gas properties. The Predecessor also had access to up to $100.0 million of available borrowing capacity for letters of credit. As of May 31, 2018 and December 31, 2017, the Predecessor had a $0.2 million letter of credit outstanding.

The terms of the Predecessor's credit facility did not require any repayments of amounts outstanding until it expired in February 2020. Borrowings under the credit facility bore interest at a floating rate based on, at the Partnership's election, a base rate or the London Inter–Bank Offered Rate plus applicable premiums based on the percent of the borrowing base that the Partnership had outstanding (weighted average effective interest rate of 5.47% and 4.82% at May 31, 2018 and December 31, 2017, respectively).

Borrowings under the credit facility could not exceed a "borrowing base" determined by the lenders under the credit facility based on the Partnership's oil and natural gas reserves. As of May 31, 2018 and December 31, 2017, the borrowing base under the credit facility was $325.0 million.

In connection with EVEP's emergence from bankruptcy on June 4, 2018, the holders of claims under the Predecessor's credit facility received full recovery, consisting of (i) their pro rata share of the $1 billion new reserve-based revolving loan; (ii) cash in amount equal to the accrued but unpaid interest payable to such lenders under the credit facility as of the Effective Date; and (iii) unfunded commitments and letter of credit participation under the Exit Credit Facility equal to the unfunded commitments and letter of credit participation of such lender as of the Effective Date.

Predecessor's 8.0% Senior Notes due April 2019

The Predecessor's Senior Notes were issued under the Indenture, would have matured April 15, 2019, and bore interest at 8.0%. The Senior Notes were general unsecured obligations and were effectively junior in right of payment to any of the Partnership's secured indebtedness to the extent of the value of the collateral securing such indebtedness.

The Senior Notes were fully and unconditionally guaranteed, jointly and severally, on a senior unsecured basis, by all of the Partnership's existing subsidiaries other than EV Energy Finance Corp. ("Finance"), which is a co–issuer of the Senior Notes. Neither EVEP nor Finance had independent assets or operations apart from the assets and operations of the Predecessor's subsidiaries.

In 2016, EVEP redeemed $82.7 million of the Senior Notes for $35.0 million, resulting in a gain on the early extinguishment of debt of $47.7 million.

As a result of EVEP's emergence from bankruptcy, the Senior Notes were cancelled and the Predecessor's liability thereunder discharged as of June 4, 2018, and the holders of the Notes received (directly or indirectly) their pro rata share of New Common Stock representing, in the aggregate, 95% of the New Common Stock on the Effective Date (subject to dilution by the MIP and the common shares issuable upon exercise of the Warrants). See also Note 2.

NOTE 13. COMMITMENTS AND CONTINGENCIES

On the Effective Date, Harvest entered into a Services Agreement (the "Services Agreement") with EnerVest, Ltd. and EnerVest Operating, L.L.C. (together, the "EnerVest Group"). Pursuant to the Services Agreement, the EnerVest Group will provide certain administrative, management, operating and other services and support to Harvest (the "Services") following the Effective Date. In addition, the EnerVest Group will also provide Harvest with sufficient office space, equipment and office supplies pursuant to the Services Agreement. The Services Agreement covers the people EnerVest employs who provide direct support to the Company's operations; however, the Services Agreement does not cover the five full-time employees of Harvest which include the Chief Executive Officer and the Chief Financial Officer. The management fee is subject to an annual redetermination by agreement of the parties and may also be adjusted for acquisitions or divestitures over $5 million. As of March 28, 2019, Harvest and EnerVest were in the process of negotiating the extension of the Services Agreement.

In August 2018, the Company was notified by the Office of Natural Resources Revenue ("ONRR") of potential underpayments of royalties related to certain leases for the period of 2009 through 2018. The Company has submitted amended royalty filings for the period of 2009 to 2012, pursuant to which Harvest has an additional liability of

approximately $2.0 million. This amount will be paid upon ONRR review and concurrence with the accuracy of royalties per the amended filings. The Company expects to submit amended royalty filings for the period of 2013 to 2018 later in 2019, pursuant to which Harvest may have an additional liability of approximately $3.0 million. The Company recognized an accrual for the estimated liability for the period of 2009 to 2018 as of December 31, 2018.

The Company is involved in other disputes or legal actions arising in the ordinary course of business. The Company does not believe the outcome of such disputes or legal actions, other than addressed above, will have a material effect on its consolidated financial statements. No amounts, other than as described above, were accrued at December 31, 2018 for the Successor, and no amounts were accrued at December 31, 2017 for the Predecessor.

The Company is subject to firm agreements for the future transportation and processing of natural gas. The Company is obligated to transport minimum daily natural gas volumes. As of December 31, 2018, the Company's future minimum transportation fees under these agreements are as follows for the years ended December 31:

2019	$ 856
2020	747
2021	618
2022	412
2023	—
Thereafter	—
	$ 2,633

NOTE 14. EQUITY

Issuance of Common Stock and Cancellation of Units

In accordance with the Plan, on the Effective Date:

- the Company issued a total of 10,000,016 shares of its common stock, which included the issuance of (i) 9,500,000 shares pro rata to holders of the Senior Notes with claims allowed under the Plan and (ii) 500,016 shares pro rata to holders of units of EVEP prior to the Effective Date;
- the Company issued 800,000 warrants to purchase 800,000 shares of the Company's common stock to holders of units of EVEP prior to the Effective Date;
- the Predecessor common units were cancelled; and
- each Predecessor common unitholder received its pro rata share of: (i) 5% of the New Common Stock and (ii) the Warrants as discussed above.

On the Effective Date, there were 10,000,016 shares of New Common Stock issued and outstanding. As of December 31, 2018, there were 10,054,816 shares issued and 10,042,468 shares outstanding.

Warrants

On the Effective Date, the Company entered into a warrant agreement with Computershare Trust Company N.A., as warrant agent, pursuant to which the Company issued Warrants to purchase up to 800,000 shares of the Company's common stock (representing 8% of the Company's outstanding total issued and outstanding common stock as of the Effective Date including shares of the Company's common stock issuable upon full exercise of the Warrants, but excluding any common stock issuable under the MIP), exercisable for a five year period commencing on the Effective Date at an exercise price of $37.48 per warrant.

The fair values for the Warrants upon issuance have been estimated using the Black-Scholes option pricing model using the following assumptions:

	Warrants Issued in Successor Period
Risk–free interest rate	2.8 %
Dividend yield	— %
Expected life (years)	5.0
Expected volatility	69.0 %
Strike price	$ 37.48
Calculated fair value	$ 9,345

Predecessor

At December 31, 2017, owner's equity consisted of 49,368,869 common units outstanding, representing a 98% limited partnership interest in the Predecessor and a 2% general partnership interest.

The common units had limited voting rights as set forth in the partnership agreement.

Pursuant to the partnership agreement, if at any time the general partner and its affiliates owned more than 80% of the common units outstanding, the general partner had the right, but not the obligation, to "call" or acquire all, but not less than all, of the common units held by unaffiliated persons at a price not less than their then current market value. The general partner had the right to assign this call right to any of its affiliates or to the Predecessor.

The general partner owned a 2% interest in the Predecessor. This interest entitled the general partner to receive distributions of available cash from operating surplus as discussed further below under "Cash Distributions." The partnership agreement set forth the calculation to be used to determine the amount and priority of cash distributions that the common unitholders, Class B unitholders and general partner would receive.

The general partner had the management rights as set forth in the partnership agreement.

Predecessor Allocations of Net Income

Net income was allocated between the general partner and the limited partners in accordance with the provisions of the partnership agreement. Net income was generally allocated first to the general partner and the limited partners in an amount equal to the net losses allocated to the general partner and the limited partners in the current and prior tax years under the partnership agreement. The remaining net income was allocated to the general partner and the limited partners in accordance with their respective percentage interests of the general partner and limited partners.

Predecessor Cash Distributions

The Predecessor's credit facility prohibited the Partnership from making cash distributions if any default or event of default, as defined in the credit facility, occurred or would result from the cash distribution.

Within 45 days after the end of each quarter, the Predecessor would distribute all of its available cash (as defined in the partnership agreement) to its general partner and unitholders of record on the applicable record date. The amount of available cash generally was all cash on hand at the end of the quarter; less the amount of cash reserves established by the general partner to provide for the proper conduct of business, to comply with applicable laws, any of the debt instruments, or other agreements or to provide funds for distributions to unitholders and to the general partner for any one or more of the next four quarters; plus all cash on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made after the end of the quarter. Working capital borrowings were generally borrowings that were made under the Partnership's credit facility and in all cases was used solely for working capital purposes or to pay distributions to partners.

The partnership agreement required that the Predecessor make distributions of available cash from operating surplus in the following manner:

- *first*, 98% to the unitholders, pro rata, and 2% to the general partner, until the Predecessor distributed for each outstanding common unit an amount equal to the minimum quarterly distribution for that quarter; and

- *thereafter*, cash in excess of the minimum quarterly distributions is distributed to the unitholders and the general partner based on the percentages below.

The minimum quarterly distribution was not guaranteed and distributions below the minimum quarterly distribution were not accrued in arrears.

The general partner was entitled to incentive distributions if the amount distributed with respect to one quarter exceeded specified target levels shown below:

		Marginal Percentage Interest in Distributions	
	Total Quarterly Distributions Target Amount	Limited Partner	General Partner
Minimum quarterly distribution	$0.7615	98 %	2 %
First target distribution	Up to $0.875725	98 %	2 %
Second target distribution	Above $0.875725, up to $0.951875	85 %	15 %
Thereafter	Above $0.951875	75 %	25 %

The Predecessor did not pay any distributions during the five months ended May 31, 2018 or during the year ended December 31, 2017. The following sets forth the distributions paid during the year ended December 31, 2016 (relating to the fourth quarter of 2015):

Date Paid	Period Covered	Distribution per Unit	Total Distribution
February 12, 2016	October 1, 2015 – December 31, 2015	$ 0.075	$ 3,868
			$ 3,868

During the five months ended May 31, 2018 and the years ended December 31, 2017 and 2016, the board of directors of EV Management announced that it had elected to suspend distributions for all quarters of those periods.

NOTE 15. INCOME TAXES

Effective June 4, 2018, pursuant to the Plan, the Successor became a corporation subject to federal and state income taxes. Prior to the Plan being effective, the Predecessor was a limited partnership and organized as a pass-through entity for federal and most state income tax purposes. As a result, the Predecessor's limited partners were responsible for federal and state income taxes on their share of taxable income. The Predecessor was subject to the Texas margin tax for partnership activity in the state of Texas. Tax obligations of the Predecessor and Successor are recorded as "Income taxes" in the consolidated statements of operations.

The income tax expense for the Successor period indicated is comprised of the following:

	Seven Months Ended December 31, 2018
Current tax expense:	
Federal	$ —
State	(78)
Total	(78)
Deferred tax expense:	
Federal	—
State	—
Total	—
Total tax expense:	
Federal	—
State	(78)
Total	$ (78)

During the five months ended May 31, 2018, the Predecessor recorded income tax expense of $0.2 million related to state income taxes. During the years ended December 31, 2017 and 2016, the Predecessor recognized approximately $0.2 million and $2.4 million, respectively, of tax benefits primarily as a result of tax refunds.

A reconciliation of the statutory federal income tax expense to the income tax expense or benefit from continuing operations provided for the Successor period is as follows:

	Seven Months Ended December 31, 2018
Tax expense at statutory rate	$ (5,050)
State income tax expense, net of federal benefit	(62)
Changes in valuation allowance	4,999
Other	35
Total income tax expense	$ (78)

The Successor's net deferred tax is comprised of the following:

	December 31, 2018
Deferred tax assets:	
Net operating loss carryforward	$ 19,086
Asset retirement obligation	26,948
Other	2,365
Total deferred tax assets before valuation allowance	48,399
Valuation allowance	(15,573)
Net deferred tax assets	32,826
Deferred tax liability:	
Oil and natural gas properties	30,200
Derivative instruments	2,626
Total deferred tax liability	32,826
Total net deferred tax	$ —

Management assesses the available positive and negative evidence to estimate whether it is more likely than not that sufficient future taxable income will be generated to realize the Company's deferred tax assets. In making this determination, Management considers all available positive and negative evidence and makes certain assumptions. Management considers, among other things, its deferred tax liabilities, the overall business environment, its historical earnings and losses, current industry trends and its outlook for future years. Due to significant negative evidence, the Company has established a valuation allowance against its net deferred tax asset of $15.6 million as of December 31, 2018.

As of December 31, 2018, the Company had federal net operating loss ("NOL") carryforwards of approximately $84.7 million, which can be carried forward indefinitely, and state NOLs of $22.2 million, which will expire in varying amounts beginning in 2029.

Accounting Standard Codification 740, *Income Taxes* ("ASC 740") prescribes a recognition threshold and a measurement attribute for the financial statement recognition and measurement of income tax positions taken or expected to be taken in an income tax return. For those benefits to be recognized, an income tax position must be more-likely-than-not to be sustained upon examination by taxing authorities. The Company must recognize the tax effects of any uncertain tax positions it may adopt, if the position taken is more likely than not sustainable based on its technical merits. The company had no unrecognized tax benefits as of December 31, 2018 and does not anticipate recognition of any significant liabilities for uncertain tax positions during the next 12 months. Interest and penalties related to uncertain tax positions are reported in income tax expense.

The Company's tax returns are subject to periodic audits by the various jurisdictions in which the Company operates. These audits can result in adjustments of taxes due or adjustments of the NOL carryforwards that are available to offset future taxable income.

NOTE 16. EARNINGS PER SHARE/UNIT

The following sets forth the calculation of earnings per share/unit for the periods indicated:

	Successor	Predecessor		
	Seven Months Ended December 31, 2018	Five Months Ended May 31, 2018	Year Ended December 31, 2017	Year Ended December 31, 2016
Net income (loss) attributable to Successor/Predecessor	$ 23,969	$ (610,525)	$ (134,201)	$ (242,895)
Predecessor's general partner's 2% interest in net loss	—	12,211	2,684	4,858
Earnings attributable to Predecessor's unvested phantom units	—	—	—	—
Net income (loss) available to common stockholders/limited partners	$ 23,969	$ (598,314)	$ (131,517)	$ (238,037)
Weighted average common shares/units outstanding:				
Basic	10,030	49,369	49,357	49,048
Dilutive effect of potential common shares/units	2	—	—	—
Diluted	10,032	49,369	49,357	49,048
Net earnings per share/unit:				
Basic	$ 2.39	$ (12.12)	$ (2.66)	$ (4.85)
Diluted	$ 2.39	$ (12.12)	$ (2.66)	$ (4.85)
Antidilutive warrants [1]	800,000	—	—	—

[1] Amount represents warrants to purchase common stock that are excluded from the diluted net earnings per share calculations because of their antidilutive effect.

NOTE 17. RELATED PARTY TRANSACTIONS

As a result of the Restructuring, EnerVest is no longer a related party to the Company. However, Harvest will continue its relationship with EnerVest through an agreement for EnerVest to operate its properties. See Note 13 for additional information regarding the Services Agreement.

Prior to emergence from bankruptcy, the Predecessor's general partner was EV Energy GP, and the general partner of its general partner was EV Management. EV Management is a wholly owned subsidiary of EnerVest. EnerVest and its affiliates also had a significant interest in the Partnership through their 71.25% ownership of EV Energy GP which, in turn, owned a 2% general partner interest in the Partnership and all of its incentive distribution rights. In addition, the Predecessor's board of directors included directors who were also executives of EnerVest. As a result, EnerVest was considered a related party to the Predecessor.

However, in accordance with the Plan, EV Energy GP, the Predecessor's general partner, was dissolved following the Effective Date, and the terms of the Predecessor's board of directors automatically expired on the Effective Date. The Successor formed a new five-member board of directors which does not consist of any members of EnerVest management. As a result, EnerVest is not considered a related party to the Successor.

Pursuant to a services agreement, referred to as an omnibus agreement , the Predecessor paid EnerVest $7.2 million for general and administrative services provided during the five months ended May 31, 2018. Under the omnibus

agreement, the Predecessor also paid EnerVest $14.1 million and $15.9 million during the years ended 2017 and 2016, respectively. These fees were based on an allocation of charges between EnerVest and EVEP based on the estimated use of such services by each party, and the Partnership believed that the allocation method employed by EnerVest was reasonable and reflective of the estimated level of costs the Partnership would have incurred on a standalone basis. These fees are included in "General and administrative expenses" in the consolidated statements of operations.

The Partnership also entered into operating agreements with EnerVest whereby EnerVest Operating, a subsidiary of EnerVest acted as contract operator of the oil and natural gas wells and related gathering systems and production facilities in which EVEP owned an interest. The Predecessor reimbursed EnerVest approximately $8.4 million in the five months ended May 31, 2018, for direct expenses incurred in the operation of its wells and related gathering systems and production facilities and for the allocable share of the costs of EnerVest employees who performed services on its properties. Under that operating agreement, the Predecessor also reimbursed EnerVest approximately $20.1 million and $21.2 million during the years ended December 31, 2017 and 2016, respectively, for direct expenses incurred. As the vast majority of such expenses were charged to the Partnership on an actual basis (i.e., no mark–up or subsidy is charged or received by EnerVest), EVEP believed that the aforementioned services were provided to the Partnership at fair and reasonable rates relative to the prevailing market and were representative of what the amounts would have been on a standalone basis. These costs are included in "Lease operating expenses" in the consolidated statements of operations. Additionally, in its role as contract operator, this EnerVest subsidiary also collected proceeds from oil, natural gas and natural gas liquids sales and distributed them to the Partnership and other working interest owners.

As of December 31, 2017, the Predecessor owed EnerVest Operating $4.2 million.

Effective November 1, 2011, EVEP, along with certain institutional partnerships managed by EnerVest, sold a portion of its unproved, undeveloped Utica acreage in ten Ohio counties to Total E&P USA, Inc. A portion of the purchase price was paid in cash with the balance payable in the form of a carried interest in future development activity. In early 2017, the allocated share of the Carry for one of the institutional partnerships was completely utilized. As such, that institutional partnership purchased Carry rights from us and the other institutional partnerships equal to the benefit to be received from Total for their continued participation in the Carry. EVEP's share of this benefit was $0.7 million for the five months ended May 31, 2018 and was $2.5 million for the year ended December 31, 2017. These purchased Carry rights were recorded as reimbursements to oil and gas properties.

In 2011, EVEP and certain institutional partnerships managed by EnerVest carved out 7.5% overriding royalty interests from certain acres in Ohio (the "Underlying Properties"), which the Partnership believed may be prospective for the Utica Shale, and contributed the ORRI to a newly formed limited partnership. EnerVest is the general partner of this partnership. The ORRI entitles the partnership to an average approximate 5.64% of the gross revenues from the Underlying Properties. EVEP owned a 48% limited partner interest in the partnership and account for the investment using the equity method of accounting. EVEP recognized $0.1 million, $0.5 million and $0.1 million of income during the five months ended May 31, 2018 and the years ended December 31, 2017 and 2016, respectively, and EVEP received $0.3 million, $0.3 million and $0.1 million of distributions during the five months ended May 31, 2018 and the years ended December 31, 2017 and 2016, respectively. This income is included in "Other income, net" in the consolidated statements of operations.

NOTE 18. OTHER SUPPLEMENTAL INFORMATION

Supplemental cash flows and non–cash transactions were as follows as of and for the periods indicated:

	Successor	Predecessor		
	Seven Months Ended December 31, 2018	Five Months Ended May 31, 2018	Year Ended December 31, 2017	Year Ended December 31, 2016
Supplemental cash flows information:				
Cash paid for interest	$ 6,110	$ 6,008	$ 38,758	$ 39,807
Cash paid for income taxes	—	—	—	10,942
Cash paid for reorganization items [1]	9,021	6,691	—	—

[1] Includes approximately $6.9 million disbursed from the restricted cash account during the seven months ended December 31, 2018.

	Successor	Predecessor
	December 31, 2018	December 31, 2017
Non–cash transactions:		
Costs for additions to oil and natural gas properties in accounts payable and accrued liabilities	$ 419	$ 12,748
Shares of common stock of Magnolia received in Central Texas Divestiture	58,212	—

Accounts payable and accrued liabilities consisted of the following as of December 31:

	Successor	Predecessor
	December 31, 2018	December 31, 2017
Lease operating expenses	$ 10,035	$ 11,411
San Juan royalties	5,000	—
Production and ad valorem taxes	4,680	6,351
General and administrative expenses	3,321	3,331
Current portion of ARO	2,077	3,170
Costs for additions to oil and natural gas properties	419	12,748
Interest	12	5,820
Derivative settlements	—	573
Other	602	413
Total	$ 26,146	$ 43,817

NOTE 19. QUARTERLY DATA (UNAUDITED)

	Predecessor		Successor		
	First Quarter	Two Months Ended May 31, 2018	One Month Ended June 30, 2018	Third Quarter	Fourth Quarter
2018					
Revenues [1]	$ 67,942	$ 43,089	$ 21,720	$ 68,966	$ 47,914
Gross profit [2]	36,558	23,201	11,246	37,319	18,427
Net income (loss) [3]	(15,449)	(595,076)	(538)	(9,760)	34,267
Net income (loss) per share/unit:					
Basic	$ (0.31)	$ (11.81)	$ (0.05)	$ (0.97)	$ 3.41
Diluted	$ (0.31)	$ (11.81)	$ (0.05)	$ (0.97)	$ 3.41

	Predecessor			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2017				
Revenues	$ 56,987	$ 56,052	$ 52,651	$ 60,003
Gross profit [2]	29,809	26,861	23,026	32,119
Net loss [4]	(50,831)	(25,161)	(17,888)	(40,321)
Net loss per unit:				
Basic	$ (1.01)	$ (0.50)	$ (0.36)	$ (0.80)
Diluted	$ (1.01)	$ (0.50)	$ (0.36)	$ (0.80)

(1) Includes a royalty adjustment of $5.0 million during the fourth quarter of 2018. Excluding this royalty adjustment, revenues would have been $52.9 million for the fourth quarter of 2018. See Note 13 for additional information.

(2) Represents total revenues less lease operating expenses, cost of purchased natural gas and production taxes.

(3) Includes significant costs associated with the reorganization. Reorganization items, net represent costs and gains directly associated with the Chapter 11 proceedings since the Petition Date, such as the gain on settlement of liabilities subject to compromise, fresh start valuation adjustments, issuance of common stock and warrants and settlement with Predecessor common unitholders. The Predecessor incurred $587.3 million of reorganization items, net during the five months ended May 31, 2018. See Note 2 and Note 3.

(4) Includes impairment charges of $93.6 million, primarily in the third and fourth quarters of 2017. Of this amount, $69.9 million related to oil and natural gas properties that were written down to their fair value as determined based on the expected present value of future net cash flows. Of the $69.9 million, $49.5 million related to oil and natural gas properties located in the Mid-Continent area and the Permian Basin, $15.3 million related to properties located in the Monroe Field, $2.2 million related to properties located in Central Texas and $2.9 million related to properties in East Texas which were sold in April 2017. The remainder of the impairment charges in 2017 consisted of $23.7 million of leasehold impairments.

NOTE 20. SUPPLEMENTARY INFORMATION ON OIL AND NATURAL GAS ACTIVITIES (UNAUDITED)

Capitalized costs relating to oil and natural gas producing activities are as follows at December 31:

	Successor	Predecessor
	2018	2017
Proved oil and natural gas properties	$ 410,184	$ 2,567,086
Unproved oil and natural gas properties	8,454	—
	418,638	2,567,086
Accumulated depreciation, depletion and amortization	(12,950)	(1,191,559)
Net capitalized costs	$ 405,688	$ 1,375,527

Costs incurred in oil and natural gas property acquisition and development activities are as follows for the periods indicated:

	Successor	Predecessor		
	Seven Months Ended December 31, 2018	Five Months Ended May 31, 2018	Year Ended December 31, 2017	Year Ended December 31, 2016
Acquisition of oil and natural gas properties:				
Proved	$ —	$ —	$ 58,230	$ —
Unproved	—	—	3,170	—
Exploration costs	177	122	413	651
Development costs	17,925	26,841	39,348	10,712
Total	$ 18,102	$ 26,963	$ 101,161	$ 11,363

NOTE 21. ESTIMATED PROVED OIL, NATURAL GAS AND NATURAL GAS LIQUIDS RESERVES (UNAUDITED)

The Company's estimated proved reserves are all located within the United States. The Company cautions that there are many uncertainties inherent in estimating proved reserve quantities and in projecting future production rates and the timing of development expenditures. Accordingly, these estimates are expected to change as further information becomes available. Material revisions of reserve estimates may occur in the future, development and production of the oil, natural gas and natural gas liquids reserves may not occur in the periods assumed, and actual prices realized and actual costs incurred may vary significantly from those used in these estimates. The estimates of the Company's proved reserves as of December 31, 2018, and the estimates of the Predecessor's proved reserves as of December 31, 2017 and 2016 have been prepared by Cawley, Gillespie & Associates, Inc. and Wright & Company, Inc., independent petroleum consultants.

The following table sets forth changes in estimated proved and estimated proved developed reserves for the periods indicated.

	Oil (MBbls) [1]	Natural Gas (Mmcf) [2]	Natural Gas Liquids (MBbls) [1]	Mmcfe [3]
Proved developed and undeveloped reserves:				
As of December 31, 2015 (Predecessor)	21,995	747,015	36,294	1,096,753
Revisions of previous estimates [4]	(8,163)	(57,723)	(1,223)	(114,041)
Extensions and discoveries [5]	61	10,255	736	15,038
Production	(1,216)	(49,333)	(2,331)	(70,612)
Sales of minerals in place [6]	(85)	(74,916)	(81)	(75,919)
As of December 31, 2016 (Predecessor)	12,592	575,298	33,395	851,219
Revisions of previous estimates [7]	1,141	3,558	(422)	7,867
Purchases of minerals in place	1,228	6,578	415	16,444
Extensions and discoveries [8]	105	3,035	398	6,053
Production	(1,387)	(40,979)	(2,165)	(62,293)
Sales of minerals in place [9]	(286)	(3,784)	(27)	(5,663)
As of December 31, 2017 (Predecessor)	13,393	543,706	31,594	813,627
Revisions of previous estimates [10]	4,640	7,641	4,518	62,600
Extensions and discoveries [11]	7	4,192	104	4,859
Production	(1,304)	(40,066)	(2,388)	(62,222)
Sales of minerals in place [12]	(6,823)	(38,785)	(4,544)	(106,994)
As of December 31, 2018 (Successor)	9,913	476,688	29,284	711,870
Proved developed reserves:				
December 31, 2015 (Predecessor)	13,919	644,984	30,091	909,047
December 31, 2016 (Predecessor)	11,954	523,113	28,218	764,149
December 31, 2017 (Predecessor)	13,393	543,706	31,594	813,627
December 31, 2018 (Successor)	9,881	468,510	28,442	698,445
Proved undeveloped reserves:				
December 31, 2015 (Predecessor)	8,076	102,031	6,203	187,706
December 31, 2016 (Predecessor)	638	52,185	5,177	87,070
December 31, 2017 (Predecessor)	—	—	—	—
December 31, 2018 (Successor)	32	8,178	842	13,425

(1) Thousands of barrels.

(2) Million cubic feet.

(3) Million cubic feet equivalent; barrels are converted to Mcfe based on one barrel of oil or natural gas liquids to six Mcf of natural gas equivalent.

(4) Revisions were primarily attributable to reductions in the Appalachian Basin (51.8 Bcfe), the Barnett Shale (39.9 Bcfe) and Central Texas (13.5 Bcfe) and were the result of the decrease in prices for oil, natural gas and natural gas liquids used in the December 31, 2016 reserve estimates from prices used in the December 31, 2015 reserve estimates.

(5) Extensions and discoveries were primarily associated with drilling success in the Barnett Shale (13.0 Bcfe).

(6) Sales of minerals in place were primarily associated with the sale of a portion of the Barnett Shale natural gas properties (74.2 Bcfe) in December 2016.

(7) Revisions were attributable to a combination of reserve increases (81.8 Bcfe) resulting from improvements in SEC pricing from December 31, 2016 to December 31, 2017, reductions (85.0 Bcfe) due to the removal of all PUD reserves and an aggregate increase from various other revisions (11.0 Bcfe).

(8) Extensions and discoveries were primarily associated with drilling success in the Barnett Shale (4.2 Bcfe) and Mid-Continent area (1.5 Bcfe).

(9) Sales of minerals in place were primarily associated with the sale of properties in the Appalachian Basin (4.6 Bcfe), Central Texas (0.6 Bcfe) and San Juan Basin (0.5 Bcfe).

(10) Revisions were attributable to a combination of reserve increases (66.7 Bcfe) resulting from our emergence from bankruptcy on June 4, 2018 and the availability of capital required to develop the PUDs within the SEC five-year development limitation on PUDs, reserve increases (24.3 Bcfe) resulting from improvements in SEC pricing from December 31, 2017 to December 31, 2018, reductions (20.8 Bcfe) primarily due to negative revisions in Appalachian and San Juan basins, and an aggregate decrease (7.6 Bcfe) from various other revisions.

(11) Extensions and discoveries were primarily associated with drilling success in the Barnett Shale (4.8 Bcfe).

(12) Sales of minerals in place were primarily associated with the sale of all properties in Central Texas (106.1 Bcfe) with smaller sales in the Mid-Continent area (0.8 Bcfe) and other areas.

NOTE 22. STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS RELATING TO PROVED OIL, NATURAL GAS AND NATURAL GAS LIQUIDS RESERVES (UNAUDITED)

The following tables present a standardized measure of discounted future net cash flows and changes therein relating to estimated proved oil, natural gas and natural gas liquids reserves. In computing this data, assumptions other than those required by the SEC could produce different results. Accordingly, the data should not be construed as representative of the fair market value of the Company's estimated proved oil, natural gas and natural gas liquids reserves. The following assumptions have been made:

- Future cash inflows were based on prices used in estimating the Company's proved oil, natural gas and natural gas liquids reserves. Future price changes were included only to the extent provided by existing contractual agreements.
- Future development and production costs were computed using year end costs assuming no change in present economic conditions.
- Future net cash flows were discounted at an annual rate of 10%.

The standardized measure of discounted future net cash flows relating to estimated proved oil, natural gas and natural gas liquids reserves is presented below for the years ended December 31:

	2018	2017	2016
Future cash inflows	$ 2,710,234	$ 2,778,662	$ 2,261,520
Future production and development costs	(1,622,040)	(1,603,373)	(1,480,900)
Future income tax expenses	(167,692)	(6,022)	(5,442)
Future net cash flows	920,502	1,169,267	775,178
10% annual discount for estimated timing of cash flows	(484,069)	(589,862)	(404,061)
Standardized measure of discounted future net cash flows	$ 436,433	$ 579,405	$ 371,117

As specified by the SEC, the prices for oil, natural gas and natural gas liquids used in this calculation were the average prices during the year determined using the price on the first day of each month, except for volumes subject to fixed price

contracts. The prices utilized in calculating the Company's total estimated proved reserves at December 31, 2018, 2017 and 2016 were $65.56 per Bbl of oil, $3.10 per MMBtu of natural gas; $51.34 per Bbl of oil, $2.976 per MMBtu of natural gas; and $42.75 per Bbl of oil, $2.481 per MMBtu of natural gas, respectively. The Company does not include its commodity derivatives in the determination of its oil, natural gas and natural gas liquids reserves.

The principal sources of changes in the standardized measure of future net cash flows are as follows for the years ended December 31:

	2018	2017	2016
Standardized measure at beginning of period	$ 579,405	$ 371,117	$ 536,450
Sales and transfers of oil, natural gas and natural gas liquids produced, net of production costs	(126,181)	(111,118)	(71,939)
Net changes in prices and production costs	48,322	202,810	(83,146)
Extensions, discoveries and improved recovery, less related costs	3,148	5,451	1,712
Development costs incurred during the period	16	2,261	2,065
Revisions and other	88,587	13,516	(23,328)
Accretion of 10% timing discount	58,222	37,356	53,998
Changes in income taxes	(70,390)	(371)	1,093
Changes in estimated future development costs	3,174	20,177	3,976
Changes in timing and other	21,551	8,302	(26,920)
Purchase of minerals in place	—	32,949	—
Sales of minerals in place	(169,421)	(3,045)	(22,844)
Standardized measure of discounted future net cash flows	$ 436,433	$ 579,405	$ 371,117

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

In accordance with Exchange Act Rule 13a–15 and 15d–15, the Company carried out an evaluation, under the supervision and with the participation of management, including the Chief Executive Officer and the Chief Financial Officer, of the effectiveness of disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the disclosure controls and procedures were effective as of December 31, 2018 to provide reasonable assurance that information required to be disclosed in the reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. The Company's disclosure controls and procedures include controls and procedures designed to provide reasonable assurance that information required to be disclosed in reports filed or submitted under the Exchange Act is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Management's Report on Internal Control Over Financial Reporting

Pursuant to Section 404 of the Sarbanes–Oxley Act of 2002, management included a report of their assessment of the design and effectiveness of internal control over financial reporting as part of this Annual Report on Form 10–K for the fiscal year ended December 31, 2018. Management's report is included under "Item 8. Financial Statements and Supplementary Data – Management's Report on Internal Control Over Financial Reporting" and is incorporated herein by reference.

Change in Internal Controls Over Financial Reporting

There have not been any changes in the Company's internal control over financial reporting that occurred during the quarterly period ended December 31, 2018 that have materially affected, or is reasonably likely to materially affect, internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information regarding directors, executive officers, promoters and control persons required under Item 10 of Form 10-K will be contained in our Definitive Proxy Statement for our 2019 Annual Meeting of Stockholders (the "Proxy Statement") under the headings "Proposal 1: Election of Directors," "Executive Compensation" and "Corporate Governance and our Board" and is incorporated herein by reference. The Proxy Statement will be filed with the SEC pursuant to Regulation 14A of the Exchange Act, not later than 120 days after December 31, 2018.

ITEM 11. EXECUTIVE COMPENSATION

The information required under Item 11 of Form 10-K will be contained in the Proxy Statement under the heading "Executive Compensation" and is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required under Item 12 of Form 10-K will be contained in the Proxy Statement under the heading "Security Ownership of Certain Other Beneficial Owners and Management" and is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required under Item 13 of Form 10-K will be contained in the Proxy Statement under the headings "Corporate Governance and our Board," "Transactions with Related Persons" and "Executive Compensation" and is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required under Item 14 of Form 10-K will be contained in the Proxy Statement under the subheading "Principal Accountant Fees and Services" and is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) List of Documents filed as part of this Report

(1) Financial Statements

All financial statements of the Registrant as set forth under Item 8 of this Annual Report on Form 10–K.

(2) Financial Statement Schedules

Financial statement schedules have been omitted because they are either not required, not applicable or the information required to be presented is included in our consolidated financial statements and related notes.

(3) Exhibits

The exhibits listed below are filed or furnished as part of this report:

2.1 First Modified Joint Prepackaged Chapter 11 Plan of Reorganization of EV Energy Partners, L.P. and Its Debtor Affiliates, dated May 17, 2018 (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by EV Energy Partners, L.P. on May 18, 2018).

3.1 Amended and Restated Certificate of Incorporation of Harvest Oil & Gas Corp. (incorporated by reference to Exhibit 4.1 of the Company's registration statement on Form S-8 filed on June 4, 2018).

3.2 Certificate of Designations, Preferences and Rights of 8% Cumulative Nonparticipating Redeemable Series A Preferred Stock of Harvest Oil & Gas Corp. (incorporated by reference to Exhibit 3.2 to Current Report on Form 8-K filed on June 4, 2018).

3.3 Amended and Restated Bylaws of Harvest Oil & Gas Corp. (incorporated by reference to Exhibit 4.2 of the Company's registration statement on Form S-8 filed on June 4, 2018).

3.4 State of Delaware Certificate of Change of Registered Agent and/or Registered Office, dated August 1, 2018 (incorporated by reference to Exhibit 3.4 to Quarterly Report on Form 10-Q filed on August 20, 2018).

4.1 Form of specimen New Common Stock certificate of Harvest Oil & Gas Corp. (incorporated by reference to Exhibit 4.3 of the Company's registration statement on Form S-8 filed on June 4, 2018).

10.1 Registration Rights Agreement dated as of June 4, 2018 by and among Harvest Oil & Gas Corp., and the other parties signatory thereto (incorporated by reference to Exhibit 10.2 to Current Report on Form 8-K filed on June 4, 2018).

10.2 Warrant Agreement, dated as of June 4, 2018, between Harvest Oil & Gas Corp., Computershare Inc. and its wholly owned subsidiary Computershare Trust Company, N.A. (incorporated by reference to Exhibit 10.4 to Current Report on Form 8-K filed on June 4, 2018).

10.3 Services Agreement, dated as of June 4, 2018, by and among EnerVest, Ltd., EnerVest Operating, L.L.C. and Harvest Oil & Gas Corp. (incorporated by reference to Exhibit 10.5 to Current Report on Form 8-K filed on June 4, 2018).

10.4 First Amendment to Services Agreement, dated August 17, 2018, by and between Harvest Oil & Gas Corp., EnerVest, Ltd. and EnerVest Operating, L.L.C. (incorporated by reference to Exhibit 10.2 to Current Report on Form 8-K filed on August 21, 2018).

10.5 Third Amended and Restated Credit Agreement dated as of June 4, 2018, is among Harvest Oil & Gas Corp., EV Properties, L.P., JPMorgan Chase Bank, N.A., as administrative agent, and each of the Lenders from time to time party thereto (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed on June 4, 2018).

10.6 Contribution and Membership Interest Purchase Agreement, dated August 20, 2018 (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed on August 21, 2018).

10.7 Contract Operating Agreement, dated September 29, 2006, by and among EnerVest Operating, L.L.C. and EnerVest Production Partners, L.P. (incorporated by reference from Exhibit 10.2 to EV Energy Partners, L.P.'s current report on Form 8–K filed with the SEC on October 5, 2006).

10.8 Contract Operating Agreement, dated September 29, 2006, by and among EnerVest Operating, L.L.C. and CGAS Properties, L.P. (incorporated by reference from Exhibit 10.3 to EV Energy Partners, L.P.'s current report on Form 8–K filed with the SEC on October 5, 2006).

*10.9 Harvest Oil & Gas Corp. 2018 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.1 of the Company's registration statement on Form S-8 filed on June 4, 2018).

*10.10 Form of Restricted Stock Unit Agreement under the 2018 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.3 to Current Report on Form 8-K filed on August 21, 2018).

*10.11 Form of Indemnification Agreement between Harvest Oil & Gas Corp. and the directors and officers of Harvest Oil & Gas Corp. (incorporated by reference to Exhibit 10.2 of the Company's registration statement on Form S-8 filed on June 4, 2018).

*10.12 Employee Agreement, dated November 17, 2017, by and between EV Management, LLC and Michael E. Mercer (incorporated by reference from Exhibit 10.1 to EV Energy Partners, L.P.'s current report on Form 8-K filed with the SEC on November 24, 2017).

*10.13 Amended and Restated Employment Agreement of Michael E. Mercer, dated June 4, 2018 (incorporated by reference to Exhibit 10.7 to Current Report on Form 8-K filed on June 4, 2018).

*10.14 Employee Agreement, dated November 17, 2017, by and between EV Management, LLC and Nicholas Bobrowski (incorporated by reference from Exhibit 10.2 to EV Energy Partners, L.P.'s current report on Form 8-K filed with the SEC on November 24, 2017).

*10.15 Amended and Restated Employment Agreement of Nicholas Bobrowski, dated June 4, 2018 (incorporated by reference to Exhibit 10.8 to Current Report on Form 8-K filed on June 4, 2018).

*10.16 Employment Agreement between the Company and Ryan Stash, dated October 26, 2018 (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed on October 29, 2018).

*10.17 EV Management, LLC 2017-2018 Key Employee Incentive Plan (incorporated by reference from Exhibit 10.3 to EV Energy Partners, L.P.'s current report on Form 8-K filed with the SEC on November 24, 2017).

*10.18 Retention Bonus Agreement, by and between EV Management, LLC and Michael E. Mercer (incorporated by reference from Exhibit 10.4 to EV Energy Partners, L.P.'s current report on Form 8-K filed with the SEC on November 24, 2017).

*10.19 Retention Bonus Agreement, by and between EV Management, LLC and Nicholas Bobrowski (incorporated by reference from Exhibit 10.5 to EV Energy Partners, L.P.'s current report on Form 8-K filed with the SEC on November 24, 2017).

10.20 Restructuring Support Agreement, dated as of March 13, 2018, among the Debtors, the Supporting Parties and the EnerVest Parties (incorporated by reference from Exhibit 10.1 to EV Energy Partners, L.P.'s current report on Form 8-K filed with the SEC on March 14, 2018).

+21.1 Subsidiaries of Harvest Oil & Gas Corp.

+23.1 Consent of Cawley, Gillespie & Associates, Inc.

+23.2 Consent of Wright & Company, Inc.

+23.3 Consent of Deloitte & Touche LLP.

+31.1 Rule 13a-14(a)/15d-14(a) Certification of Chief Executive Officer.

+31.2 Rule 13a-14(a)/15d-14(a) Certification of Chief Financial Officer.

++32 .1 Section 1350 Certification of Chief Executive Officer.

++32.2 Section 1350 Certification of Chief Financial Officer.

+99.1 Cawley, Gillespie and Associates, Inc. Reserve Report.

+99.2 Wright & Company, Inc. Reserve Report.

+101 Interactive Data Files.

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* Management contract or compensatory plan or arrangement
\+ Filed herewith
++ Furnished herewith

ITEM 16. FORM 10-K SUMMARY

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Harvest Oil & Gas Corp.
(Registrant)

Date: March 28, 2019

By: /s/ RYAN STASH
Ryan Stash
Vice President and Chief Financial Officer

Pursuant to the requirement of the Securities Exchange Act of 1934, as amended, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/MICHAEL E. MERCER Michael E. Mercer	President, Chief Executive Officer and Director (Principal Executive Officer)	March 28, 2019
/s/RYAN STASH Ryan Stash	Vice President and Chief Financial Officer (Principal Financial Officer)	March 28, 2019
/s/RYAN J. FLORY Ryan J. Flory	Controller (Principal Accounting Officer)	March 28, 2019
/s/TIM CAFLISCH Tim Caflisch	Director	March 28, 2019
/s/PATRICK HICKEY Patrick Hickey	Director	March 28, 2019
/s/JAMES F. MURCHISON James F. Murchison	Director	March 28, 2019
/s/STEVEN J. PULLY Steven J. Pully	Director	March 28, 2019