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

Form 10–K

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

For the fiscal year ended December 31, 2017

OR

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

Commission File Number
001-33024

EV Energy Partners, L.P.

(Exact name of registrant as specified in its charter)

Delaware	**20–4745690**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1001 Fannin, Suite 800, Houston, Texas	**77002**
(Address of principal executive offices)	(Zip Code)

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

Securities registered pursuant to Section 12(b) of the Act:

Common Units Representing Limited Partner Interests	**NASDAQ Capital Market**
(Title of each class)	(Name of each exchange on which registered)

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 o NO þ

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 o NO þ

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 þ NO o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). YES þ NO o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S–K 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. þ

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. Check one:

Large accelerated filer ¨	Accelerated filer ¨
Non-accelerated filer þ (Do not check if a smaller reporting company)	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 þ

The aggregate market value of the common units held by non–affiliates at June 30, 2017 based on the closing price on the NASDAQ Global Market on June 30, 2017 was $27,781,981.

As of March 27, 2018, the registrant had 49,368,869 common units outstanding.

Documents Incorporated by Reference: None

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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 standardized measure of discounted future net cash flows, or “standardized measure,” is the 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 Securities and Exchange Commission (the “SEC”), without giving effect to non–property related expenses such as certain general and administrative expenses, debt service and future federal income tax expenses or to depreciation, depletion and amortization and discounted using an annual discount rate of 10%. Our standardized measure includes future obligations under the Texas gross margin tax, but it does not include future federal income tax expenses because we are a partnership and are not subject to federal income taxes.

Tcfe. One trillion 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.

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

EV Energy Partners, L.P. ("we," "our," "us" or the "Partnership") is a publicly held Delaware limited partnership formed in 2006. Our general partner is EV Energy GP, L.P. ("EV Energy GP"), a Delaware limited partnership, and the general partner of our general partner is EV Management, LLC ("EV Management"), a Delaware limited liability company. EV Management is a wholly owned subsidiary of EnerVest, Ltd. ("EnerVest"), a Texas limited partnership. EnerVest and its affiliates have a significant interest in us through their 71.25% ownership of EV Energy GP which, in turn, owns a 2% general partner interest in us and all of our incentive distribution rights ("IDRs"). Our business activities are primarily conducted through wholly owned subsidiaries.

As of December 31, 2017, 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, Central Texas (which includes the Austin Chalk area), the Mid–Continent areas in Oklahoma, Texas, Arkansas, Kansas and Louisiana, the Permian Basin, the Monroe Field in Northern Louisiana and Karnes County, Texas (which includes the Eagle Ford Shale).

Oil, natural gas and natural gas liquids reserve information 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 summarizes information about our proved reserves by geographic region as of December 31, 2017:

	Estimated Net Proved Reserves				
	Oil (MMBbls)	Natural Gas (Bcf)	Natural Gas Liquids (MMBbls)	Bcfe	PV10 (1) ($ in millions)
Barnett Shale	0.3	186.5	17.2	291.1	$ 184.9
San Juan Basin	1.4	107.6	8.2	165.3	83.8
Appalachian Basin	6.9	99.7	0.5	144.3	133.8
Michigan	0.1	69.8	0.3	72.1	36.4
Central Texas	1.9	22.5	2.0	46.2	63.5
Mid–Continent area	1.4	21.6	0.6	33.5	31.2
Permian Basin	0.4	9.7	2.5	27.1	17.9
Monroe Field	-	24.1	-	24.1	1.5
Karnes County, Texas	1.0	2.2	0.3	9.9	29.2
Total	13.4	543.7	31.6	813.6	$ 582.2

(1) At December 31, 2017, our standardized measure of discounted future net cash flows was $579.4 million. Because we are a limited partnership, we made no provision for federal income taxes in the calculation of standardized measure; however, we made a provision for future obligations under the Texas gross margin tax. The present value of future net pre–tax cash flows attributable to estimated net proved reserves, discounted at 10% per annum ("PV–10"), is a computation of the standardized measure of discounted future net cash flows on a pre–tax basis. PV–10 is computed on the same basis as standardized measure but does not include a provision for federal income taxes or the Texas gross margin tax. PV–10 is considered a non–GAAP financial measure under the regulations of the Securities and Exchange Commission (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 the 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, 2017 (dollars in millions):

Standardized measure	$ 579.4
Future Texas gross margin taxes, discounted at 10%	2.8

PV-10	$ 582.2

Restructuring and Bankruptcy Proceedings under Chapter 11

As discussed under "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations," continued low oil and natural gas prices have had a significant adverse impact on our business, and, as a result of our financial condition, substantial doubt exists that we will be able to continue as a going concern.

On March 13, 2018, EVEP, EV Energy GP, EV Management and certain of EVEP's wholly owned subsidiaries (each a "Debtor" and, collectively, 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 our 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").

The prepackaged plan of reorganization (the "Plan") which remains subject to confirmation by the Bankruptcy Court and other closing conditions, provides that, among other things, on the effective date of the Plan (the "Effective Date"), subject to the occurrence and completion of certain structuring steps:

- the lenders under the credit facility that vote to accept the Plan will receive (a) pro rata loans under an amendment to the credit facility (the "Exit Credit Facility"), (b) cash in an amount equal to the accrued but unpaid interest payable to such lenders under the credit facility as of the Effective Date, and (c) 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;

- lenders under the credit facility that vote to reject the Plan will receive (a) term loans under a new term loan facility and (b) cash in an amount equal to the accrued and unpaid interest payable to such lender under the credit facility as of the Effective Date;

- the holders of the Senior Notes will receive 95% of the new common stock (subject to dilution) in the new, reorganized company, on a pro rata basis;

- the holders of general unsecured claims, including customers, will be paid in full or will otherwise be unimpaired; and

- the holders of the existing common interests in EVEP will receive 5% of the new common stock (subject to dilution) and five-year warrants for 8% of the new common stock (subject to dilution) in the new, reorganized company, on a pro rata basis, with an exercise price set at an equity value at which the holders of the Senior Notes would receive a recovery equal to par plus accrued and unpaid interest as of the Petition Date in respect of the Senior Notes (after taking into account value dilution on account of the three percent of the new common stock to be allocated to the participants in the management incentive plan on the Effective Date pursuant to a management incentive plan).

On March 14, 2018, the Debtors commenced the solicitation of votes from the holders of the Senior Notes to accept or reject the Plan in accordance with the terms of the Restructuring Support Agreement.

On April 2, 2018, the Debtors commenced cases (the "Chapter 11 Cases") under Chapter 11 of the United States Bankruptcy Code (the "Bankruptcy Code") in the US Bankruptcy Court for the District of Delaware (the "Bankruptcy Court"). The Debtors have filed motions with the Bankruptcy Court seeking operational and procedural relief, including joint administration of their Chapter 11 Cases. The Debtors have also filed a motion requesting that the Bankruptcy Court schedule a hearing to confirm the Plan. If the Plan is confirmed by the Bankruptcy Court and becomes effective, then the claims of the lenders under the credit facility and the holders of the Senior Notes will be discharged. There can be no assurance regarding the Partnership's ability to obtain confirmation of the Plan or approval of other relief in the Chapter 11 Cases, the Bankruptcy Court's rulings in the Chapter 11

Cases or the ultimate outcome of the Chapter 11 Cases in general.

As of April 2, 2018, the Partnership was in default under certain of its debt instruments. The Partnership's filing of the Chapter 11 Cases described above accelerated the Partnership's obligations under its credit facility and the Senior Notes. Additionally, events of default, including cross-defaults, including the receipt of a going concern explanatory paragraph from the Partnership's independent registered public accounting firm on the Partnership's consolidated financial statements, which is subject to a 30 day grace period. Under the Bankruptcy Code, the creditors under these debt agreements are stayed from taking any action against the Partnership as a result of an event of default.

For the duration of the Restructuring and after the Chapter 11 Cases, our operations and our ability to develop and execute our business plan are subject to risks and uncertainties associated with the Restructuring and Chapter 11 Cases. As a result of these risks and uncertainties, our assets, liabilities, officers and/or directors could be significantly different following the outcome of the Chapter 11 Cases, and the description of our operations, properties and capital plans included in these financial statements may not accurately reflect our operations, properties and capital plans following the Chapter 11 Cases.

The Partnership expects to continue its operations without interruption during the pendency of the Chapter 11 Cases. See Note 2 of the Notes to Consolidated Financial Statements included under "Item 8. Financial Statements and Supplementary Data" for additional information.

Current Developments

NASDAQ Delisting

Our common units are traded on the NASDAQ Capital Market (the "NASDAQ") under the symbol "EVEP." On July 17, 2017, we received a letter from the NASDAQ notifying us that we were not in compliance with the NASDAQ Global Market's rules that require the minimum bid price of our units to be at least $1.00 per share over a consecutive 30-trading-day period. On December 27, 2017, we applied to transfer from the NASDAQ Global Market to the NASDAQ Capital Market and requested an additional 180-day grace period to regain compliance with the NASDAQ Capital Market's minimum bid price requirement because our common units have continued to trade below the $1.00 minimum closing bid price. In January 2018, the NASDAQ approved both the transfer and the extension of the 180-day grace period, which will end on July 16, 2018. This notice from the NASDAQ does not affect our business operations or trigger any default or other violation of our debt or other material obligations.

In connection with filing the Chapter 11 Cases, we expect to receive a notice from the NASDAQ stating that our units will be delisted from the NASDAQ Capital Market. The delisting decision will be reached under the NASDAQ Listing Rules 5101, 5110(b), and IM-5101-1 following our announcement that the Debtors filed the Chapter 11 Cases. Trading of our common units will be suspended by the NASDAQ, and a Form 25-NSE will be filed with the Securities and Exchange Commission, which will remove our securities from listing and registration on the NASDAQ Capital Market.

Following the expected delisting from the NASDAQ, our units will commence trading on the OTC Pink Marketplace under the symbol "EVEPQ". We can provide no assurance that its units will commence or continue to trade on this market, whether broker-dealers will continue to provide public quotes of the units on this market, whether the trading volume of the units will be sufficient to provide for an efficient trading market or whether quotes for the units will continue on this market in the future.

Industry Conditions and Our Financial Position

Oil, natural gas and natural gas liquids prices are determined by many factors that are outside of our control. Historically, these prices have been volatile, and we expect them to remain volatile. In late 2014, prices for oil, natural gas and natural gas liquids declined precipitously, and prices remained low through 2015 and most of 2016. While prices showed some improvement during the second half of 2016 and 2017, they continue to fluctuate.

Factors contributing to lower oil prices in recent years have included real or perceived geopolitical risks in oil producing regions of the world, particularly the Middle East; excess global supply and buildup of oil inventory levels above the historical norm; actions taken by the Organization of Petroleum Exporting Countries; and the strength of the US dollar in international currency markets. Factors contributing to lower natural gas prices include increased supplies of natural gas due to greater exploration and development activities; higher levels of natural gas in storage; and competition from other energy sources. Prices for natural gas liquids generally correlate to the price of oil and are likely to continue to directionally follow the market for oil.

In 2017, oil, natural gas and natural gas liquids prices increased relative to previous years, but did not reach a level for our revenues and cash flows to sufficiently reduce our total leverage ratio to meet the longer term level required by our credit agreement, which have a material adverse effect on our liquidity. Continued volatility or further declines in prices could also have a significant adverse impact on the value and quantities of our reserves.

In response, we took a number of actions in 2017 to preserve our liquidity and financial flexibility, including:

- negotiating and pursuing consummation of the Restructuring, which is expected to substantially deleverage our balance sheet and reduce debt service obligations;
- focusing on managing and enhancing our base business through continued reductions in operating costs;
- increasing our capital spending in 2017 to $39.3 million from $10.7 million in 2016, in an effort to maintain production levels;
- concentrating on maintaining sufficient liquidity;
- continuing to evaluate strategic acquisitions of long–life, producing oil and natural gas properties; and
- seeking opportunities to further realize the value of our undeveloped acreage through either alternative sources of capital (including farmouts, production payments and joint ventures) or monetization of acreage.

As a result of the steps above, at December 31, 2017, we had over $66 million of liquidity available between our borrowing base capacity and cash on hand. However, our current leverage position, covenant defaults under our credit facility and our Indenture governing our Senior Notes and the fact that we have less production hedged at lower prices in 2018 relative to previous years, has required us to take additional steps going forward into 2018 to continue to preserve our liquidity and financial flexibility. These steps include:

- focusing on managing and enhancing our base business through continued reductions in operating costs;
- increasing our capital spending budget to $55 - $65 million from $39.3 million in 2017, in an effort to maintain current production levels;
- continuing to evaluate strategic acquisitions of long–life, producing oil and natural gas properties such as our Eagle Ford Acquisition described below; and
- realizing the value of our undeveloped acreage through either alternative sources of capital, including farmouts, production payments and joint ventures, or potential monetization of acreage.

During 2016 and 2017, the board of directors of EV Management announced that it had elected to suspend distributions for those fiscal years. The Partnership continues to generate positive distributable cash flow, albeit at significantly lower levels than previous years. However, to reinstate distributions, we must be in compliance with the covenants contained in our current credit agreement. We do not anticipate that we will be able to reinstate distributions in the foreseeable future, given that our operating cash flows have not increased, and are currently unlikely to increase, to a level that can support a sustainable distribution in compliance with theses covenants.

Furthermore, as of April 2, 2018, the Partnership was in default under certain of its debt instruments. The Partnership's filing of the Chapter 11 Cases accelerated the Partnership's obligations under its credit facility and the Senior Notes. Additionally, events of default, including cross-defaults, are present, including the receipt of a going concern explanatory paragraph from the Partnership's independent registered public accounting firm on the Partnership's consolidated financial statements, subject to a 30 day grace period. As a result, our credit facility could become due and payable because of this event of default. This has a material, adverse effect on our business, including our ability to resume and sustain distributions. See "Item 1A. Risk Factors - *Covenants in our credit agreement may restrict our ability to resume and sustain distributions*."

Acquisition of Eagle Ford Shale Properties

In December 2016, we sold a portion of our Barnett Shale natural gas properties for $52.1 million (before post-closing adjustments), which proceeds were deposited with a qualified intermediary to facilitate a like-kind exchange transaction pursuant to Section 1031 of the Internal Revenue Code. On January 31, 2017, we acquired a 5.8% working interest in 9,151 gross acres (529 net acres) in Karnes County, Texas for $58.7 million (before post-closing purchase price adjustments) with the proceeds and $6.6 million of borrowings under our credit facility (the "Eagle Ford Acquisition"). Certain EnerVest institutional partnerships own an 87% working interest in, and EnerVest acts as operator of, the properties.

Our Relationship with EnerVest

Our general partner is and historically has been EV Energy GP. Its general partner is EV Management, which is a wholly owned subsidiary of EnerVest. Through our omnibus agreement with EnerVest, EnerVest agrees to make available to us its personnel to permit us to carry on our business. We therefore benefit from the technical expertise of EnerVest, which we believe would generally not otherwise be available to a company of our size.

EnerVest's principal business is to act as general partner or manager of EnerVest partnerships, formed to acquire, explore, develop and produce oil and natural gas properties. A primary investment objective of the EnerVest partnerships is to make periodic cash distributions. EnerVest was formed in 1992 and is one of the 25 largest oil and natural gas companies in the United States, with more than 36,500 wells across 15 states, 8.0 million acres under lease and 4.4 Tcfe of proved reserves under management.

While our relationship with EnerVest is a significant attribute, it is also a source of potential conflicts. For example, we have acquired oil and natural gas properties from partnerships formed by EnerVest and partnerships in which EnerVest has an interest, and we may do so in the future. We have also acquired interests in oil and natural gas properties in conjunction with institutional partnerships managed by EnerVest. In these acquisitions, we and the institutional partnerships managed by EnerVest each acquire an interest in all of the properties subject to the acquisition. The purchase is allocated among us and the institutional partnerships managed by EnerVest based on the interest acquired. In the future, it is possible that we would vary the manner in which we jointly acquire oil and natural gas properties with the institutional partnerships managed by EnerVest.

EnerVest currently operates oil and natural gas properties representing 93% of our proved oil and gas reserves as of December 31, 2017. The EnerVest partnerships own interests in oil and gas properties in which we own interests. The properties are primarily located in the Barnett Shale, the Appalachian Basin and the San Juan Basin, and these properties represent approximately 74% of our net proved reserves at December 31, 2017. The investment strategy of the EnerVest partnerships is to typically divest their properties in three to five years, while our strategy contemplates holding such properties for a longer term. If the EnerVest partnerships were to sell their interests in these properties to an entity not affiliated with EnerVest, we may not have a sufficient working interest to cause EnerVest to remain operator of the property. The EnerVest partnerships are under no obligation to us with respect to their sale of the properties they own.

EnerVest is not restricted from competing with us. It may acquire, develop or dispose of oil and natural gas properties or other assets in the future without any obligation to offer us the opportunity to purchase or participate in the development of those assets. In addition, the principal business of the EnerVest partnerships is to acquire and develop oil and natural gas properties. The agreements for certain of our EnerVest partnerships, however, provide that if EnerVest becomes aware, other than in its capacity as an owner of our general partner, of acquisition opportunities that are suitable for purchase by the EnerVest partnerships during their investment periods, EnerVest must first offer those opportunities to those EnerVest partnerships, in which case we would be offered the opportunities only if the EnerVest partnerships chose not to pursue the acquisition. EnerVest's obligation to offer acquisition opportunities to its existing EnerVest partnership will not apply to acquisition opportunities which we generate internally, and EnerVest has agreed with us that for so long as it controls our general partner it will not enter into any agreements which would limit our ability to pursue acquisition opportunities that we generate internally.

On March 8, 2018, our Board of Directors, after receiving the recommendation of our conflicts committee, approved an extension of our Omnibus Agreement with EnerVest through the end of 2018, at a monthly fee of $1,433,333.

As a result of the Restructuring, we anticipate that EV Energy GP and EV Management will be dissolved. Pursuant to the Restructuring Support Agreement, EnerVest has agreed to continue to satisfy, consistent with past practice, all obligations to the Debtors under the existing omnibus agreement and any joint operating agreements and other operating agreements to which the Debtors and EnerVest are party and has agreed to negotiate in good faith the terms of a new omnibus agreement and any modifications to the joint operating agreements and other operating agreements to which the Debtors and EnerVest are party.

Oil and Natural Gas Producing Activities

At December 31, 2017, 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, Central Texas (which includes the Austin Chalk area), the Mid–Continent areas in Oklahoma, Texas, Arkansas, Kansas and Louisiana, the Permian Basin, the Monroe Field in Northern Louisiana and Karnes County, Texas.

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, 2017 were 291.1 Bcfe, 64% of which is natural gas. During 2017, we drilled 9 gross wells (2.5 net wells) in the Barnett Shale, which were successfully completed. EnerVest operates wells representing 98% of our estimated net proved reserves in this area, and we own an average 27% working interest in 1,398 gross productive wells.

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, 2017 were 165.3 Bcfe, 65% of which is natural gas. During 2017, we did not drill any wells in the San Juan Basin. EnerVest operates wells representing 98% of our estimated net proved reserves in this area, and we own an average 79% working interest in 502 gross productive wells.

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, 2017 were 144.3 Bcfe, 69% of which is natural gas. During 2017, we did not drill any wells in the Appalachian Basin. EnerVest operates wells representing 86% of our estimated net proved reserves in this area, and we own an average 63% working interest in 9,876 gross productive wells.

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, 2017 were 72.1 Bcfe, 97% of which is natural gas. During 2017, we did not drill any wells in Michigan. EnerVest operates wells representing 99% of our estimated net proved reserves in this area, and we own an average 61% working interest in 1,625 gross productive wells.

Central Texas

Our properties produce primarily from the Austin Chalk formation and are located in 16 counties in Central Texas. Our portion of the estimated net proved reserves as of December 31, 2017 was 46.2 Bcfe, 49% of which is natural gas. During 2017, we drilled 2 gross wells (0.3 net wells) in Central Texas, which were successfully completed. In August 2017, we acquired a 40% working interest in additional oil and gas properties in central Texas for $2.7 million (net of post-closing purchase price adjustments) from a third party. EnerVest operates wells representing 98% of our estimated net proved reserves in this area, and we own an average 22% working interest in 1,544 gross productive wells.

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, 2017 were 33.5 Bcfe, 65% of which is natural gas. During 2017, we did not drill any wells in the Mid-Continent area. EnerVest operates wells representing 15% of our estimated net proved reserves in this area, and we own an average 16% working interest in 1,610 gross productive wells.

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, 2017 were 27.1 Bcfe, 36% of which is natural gas. During 2017, we did not drill any wells in the Permian Basin. EnerVest operates wells representing 99% of our estimated net proved reserves in this area, and we own an average 95% working interest in 136 gross productive wells.

Monroe Field

Our properties are primarily located in two parishes in Northeast Louisiana. Our estimated net proved reserves as of December 31, 2017 were 24.1 Bcfe, 100% of which is natural gas. During 2017, we did not drill any wells in the Monroe Field. EnerVest operates wells representing 100% of our estimated net proved reserves in this area, and we own an average 98% working interest in 3,851 gross productive wells.

Karnes County, Texas

On January 31, 2017, we acquired an additional 5.8% working interest in certain oil and gas properties in Karnes County, Texas for $58.7 million (net of post-closing purchase price adjustments). Our estimated net proved reserves as of December 31, 2017 were 9.9 Bcfe, 22% of which is natural gas. During 2017, we drilled 22 gross wells (1.0 net wells) in Karnes County, which were successfully completed. EnerVest operates wells representing 94% of our estimated net proved reserves in this area, and we own an average 6% working interest in 127 gross productive wells.

Our Oil, Natural Gas and Natural Gas Liquids Data

Our Reserves

The following table presents our estimated net proved reserves at December 31, 2017:

	Oil (MMBbls)	Natural Gas (Bcf)	Natural Gas Liquids (MMBbls)	Bcfe
Proved reserves:				
Developed	13.4	543.7	31.6	813.6
Undeveloped	-	-	-	-
Total	13.4	543.7	31.6	813.6

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 table 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 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%. Because we are a limited partnership which passes through our taxable income to our unitholders, we have made no provisions for federal income taxes in the calculation of standardized measure; however, we have made a provision for future obligations under the Texas gross margin tax. 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.

Our Proved Undeveloped Reserves

We annually review all PUDs to ensure an appropriate plan for development exists. As of December 31, 2017, we have no reportable estimated PUDs with respect to any of our properties due to uncertainty regarding our ability to continue as a going concern and the availability of capital that would be required to develop the PUD reserves. We previously reported estimated PUDs in SEC filings, and, if in the future we can satisfy the reasonable certainty criteria for recording PUDs as prescribed under the SEC requirements, we will likely report estimated PUDs in future filings.

At December 31, 2017, we had no PUDs compared with 87.1 Bcfe of PUDs at December 31, 2016. The following table describes the changes in our PUDs during 2017:

	Bcfe
PUDs as of December 31, 2016	87.1
Revisions of previous estimates	(85.0)
Converted to proved developed reserves	(2.1)
PUDs as of December 31, 2017	-

The following describes the material changes to our PUDs during 2017:

Revisions of previous estimates. The annual review of our PUDs for 2017 resulted in a negative revision of 85.0 Bcfe. This change from prior estimates results from uncertainty regarding our ability to continue as a going concern and the availability of capital that would be required to develop the PUDs within the SEC five-year development limitation on PUDs. Further, decreases in prices for oil, natural gas and natural gas liquids have delayed the development of certain PUDs.

Converted to proved developed reserves. In 2017, we developed approximately 2.8% of our PUD volume and 2.5% of our PUD locations booked as of December 31, 2016 through the drilling of 4 gross (0.7 net) development wells. Of these reserves and wells, 1.4 Bcfe and 2 gross (0.4 net) wells are located in the Barnett Shale and the remaining 0.7 Bcfe and 2 gross (0.3 net) wells produce from the Austin Chalk located in the Central Texas area. Costs incurred relating to the development of PUDs were approximately $3.6 million during 2017.

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 88% and 12%, 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 43 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, 2017. 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	10	1,254	1,264	3	364	367
Non–operated	9	125	134	-	9	9
San Juan Basin:						
Operated	20	408	428	20	367	387
Non–operated	23	51	74	2	7	9
Appalachian Basin:						
Operated	1,545	6,179	7,724	1,491	4,550	6,041
Non–operated	343	1,809	2,152	29	176	205
Michigan:						
Operated	1	1,223	1,224	1	969	970
Non–operated	32	369	401	1	18	19
Central Texas:						
Operated	612	660	1,272	193	133	326
Non–operated	40	232	272	1	14	15
Mid–Continent area:						
Operated	52	97	149	43	72	115
Non–operated	629	832	1,461	46	104	150
Permian Basin:						
Operated	1	132	133	1	127	128
Non–operated	3	-	3	1	-	1
Monroe Field:						
Operated	-	3,851	3,851	-	3,764	3,764
Non–operated	-	-	-	-	-	-
Karnes County, Texas:						
Operated	94	10	104	5	1	6
Non–operated	19	4	23	1	-	1
Total [(1)]	3,433	17,236	20,669	1,838	10,675	12,513

(1) 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, 2017:

	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
Barnett Shale	145,986	38,222	13,738	3,240
San Juan Basin	166,844	73,365	49,508	33,793
Appalachian Basin	651,108	463,903	383,757	268,496
Michigan	266,266	67,938	2,806	1,175
Central Texas	756,222	122,507	1,423	268
Mid–Continent area	389,363	56,265	10,315	493
Permian Basin	11,415	10,868	520	385
Monroe Field (1)	5,904	5,904	170,346	145,666
Karnes County, Texas	7,771	381	1,921	123
Total	2,400,879	839,353	634,334	453,639

(1) 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 2017, 2016 and 2015 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, 2017 attributable to the field represented 15% or more of our total estimated net proved reserves at December 31, 2017:

	Year Ended December 31,		
	2017	2016	2015
Oil			
Production (MBbls):			
Barnett Shale	35	39	65
Appalachian Basin	541	611	420
San Juan Basin	74	75	53
Average sales price per Bbl:			
Barnett Shale	$ 48.74	$ 36.96	$ 43.64
Appalachian Basin	$ 47.29	$ 39.59	$ 42.99
San Juan Basin	$ 38.20	$ 31.01	$ 34.82
Natural Gas			
Production (MMcf):			
Barnett Shale	12,948	19,936	22,249
Appalachian Basin	11,465	12,097	7,553
San Juan Basin	5,336	3,751	1,949
Average sales price per Mcf:			
Barnett Shale	$ 2.70	$ 1.93	$ 2.22
Appalachian Basin	$ 2.45	$ 1.70	$ 1.79
San Juan Basin	$ 2.82	$ 2.37	$ 2.48
Natural Gas Liquids			
Production (MBbls):			
Barnett Shale	1,183	1,320	1,593
Appalachian Basin	43	59	43
San Juan Basin	390	405	203
Average sales price per Bbl:			
Barnett Shale	$ 19.91	$ 14.01	$ 13.50
Appalachian Basin	$ 15.53	$ 14.12	$ 2.51
San Juan Basin	$ 27.34	$ 20.94	$ 17.22
Average unit costs per Mcfe:			
Lease operating expenses per Mcfe (1)			
Barnett Shale	$ 1.25	$ 0.95	$ 1.15
Appalachian Basin	$ 1.85	$ 1.65	$ 1.73
San Juan Basin	$ 1.59	$ 1.80	$ 1.70

(1) 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 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 by us during 2017, 2016 and 2015, 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,		
	2017	2016	2015
Gross wells:			
Productive	33.0	9.0	62.0
Dry	-	-	-
Total	33.0	9.0	62.0
Net wells:			
Productive	3.8	2.6	14.6
Dry	-	-	-
Total	3.8	2.6	14.6

As of December 31, 2017, we were participating in the drilling of 17 gross (1.9 net) development wells.

We did not drill any exploratory wells in 2017 or in 2016. We drilled three gross (1.7 net) exploratory wells in 2015, all of which were successfully completed as producers.

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.

In 2017, Energy Transfer Partners, L.P. and EnLink Midstream Partners, L.P. accounted for 15.5% and 11.0%, respectively, of our 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 our consolidated oil, natural gas and natural gas liquids revenues. In 2015, Energy Transfer Partners, L.P. and EnLink Midstream Partners, L.P. accounted for 17.1% and 10.8%, respectively, of our 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 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. The US Environmental Protection Agency (the "EPA") has identified environmental compliance by the energy extraction sector as one of its enforcement initiatives for fiscal years 2018 and 2019 although it is unclear whether the Trump Administration will implement this initiative. 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 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. To our knowledge, neither we nor our predecessors have been designated as a PRP by the EPA under CERCLA; we also do not know of any prior owners or operators of our properties that are named as PRPs related to their ownership or operation of such properties. 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. In the future, 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 EPA has issued final rules outlining its position on the federal jurisdictional reach over waters of the United States. Litigation surrounding this rule is ongoing. 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 but not at the federal level, as the federal Safe Drinking Water Act expressly excludes regulation of these fracturing activities (except for fracturing activities involving the use of diesel). Due to public concerns raised regarding potential impacts of hydraulic fracturing on groundwater quality, there have been recent developments at the federal, state, regional and local levels that 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 Safe Drinking Water Act, 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 chemical 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. Further, the EPA 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.

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 ("NESHAPS") programs under the CAA, and to impose new and amended requirements under both programs. The EPA rules include NSPS standards for completions of hydraulically fractured natural gas wells. Beginning 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 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. 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 rules governing flaring and venting on public and tribal lands, which could require additional equipment and emissions controls as well as inspection requirements. These rules have been challenged in court and remain in litigation. Additionally, the US House of Representatives has passed a resolution under the Congressional Review Act disapproving the rules; Senate action remains pending. If allowed to stand, these additional regulations on our air emissions is 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 GHG reporting program as recently amended will have a material adverse effect on our results of operations or financial position. We have submitted annual reports for emissions starting with our 2012 GHG emissions.

The EPA has adopted rules to regulate methane emissions, including from new and modified oil and gas production sources and natural gas processing and transmission sources. The EPA attempted to suspend enforcement of its methane rule, but this action was challenged on appeal and ruled improper. The EPA is reported to be considering rulemaking to rescind or revise the rule. 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, which became effective on January 17, 2017, 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 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. Just as the EPA has proposed a temporary stay of some of its requirements contained in NSPS Subpart OOOOa, as the EPA reconsiders some of these requirements, the BLM issued a proposed rule on February 12, 2018, that concludes that the costs the rule would impose would exceed the benefits it is expected to generate and therefore reduces those unnecessary compliance burdens, including requirements to write waste minimization plans, meet methane capture targets and use equipment that meets certain technical standards. It is too recent an event to determine the impact these proposed regulatory changes may have on oil and gas producers.

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. 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 the act. 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, 2017, 2016 and 2015. Additionally, we are not aware of any environmental issues or claims that will require material capital expenditures during 2018 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 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 unitholders 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 ("GHG") 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 unitholders.

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

EV Management, the general partner of our general partner, has six full–time employees who spend a significant amount of their time on our operations. At December 31, 2017, EnerVest, the sole member of EV Management, had 1,179 full–time employees, including over 89 geologists, engineers and land professionals. To carry out our operations, EnerVest employs the people who will provide direct support to our operations. None of these employees are covered by collective bargaining agreements. We consider EV Management's relationship with its employees to be good, and EnerVest considers its relationship with its employees to be good.

Offices

We do not have any material owned or leased property (other than our interests in oil and gas properties). Under our omnibus 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 Securities Exchange Act of 1934, as amended (the "Exchange Act"), are made available free of charge on our website at www.evenergypartners.com as soon as reasonably practicable after these reports have been electronically filed with, or furnished to, the SEC. These documents are also available on the SEC's website at www.sec.gov or you may read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington DC 20549. Our website also includes our Code of Business Conduct and the charters of our audit committee and compensation committee. No information from either the SEC's website or 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 Restructuring and our Indebtedness

On April 2, 2018, we filed voluntary petitions commencing the Chapter 11 Cases under the Bankruptcy Code. The Chapter 11 Cases and the Restructuring may have a material adverse impact on our business, financial condition, results of operations, and cash flows. In addition, the Chapter 11 Cases and the Restructuring may have a material adverse impact on the trading price and ultimately are expected to result in the cancelation and discharge of our securities, including our equity units. Our proposed Plan, if confirmed by the Bankruptcy Court and consummated, will govern distributions to and the recoveries of holders of our securities.

We have engaged financial and legal advisors to assist us in, among other things, analyzing various strategic alternatives to address our liquidity and capital structure, including strategic and refinancing alternatives to restructure our indebtedness in private transactions. These restructuring efforts led to the execution of the Restructuring Support Agreement on March 13, 2018. Consistent with the Restructuring Support Agreement, on April 2, 2018, we commenced the Chapter 11 Cases in the Bankruptcy Court.

Commencing the Chapter 11 Cases could have a material adverse effect on our business, financial condition, results of operations and liquidity. So long as the Chapter 11 Cases continue, our senior management may be required to spend a significant amount of time and effort dealing with the reorganization instead of focusing on our business operations. Bankruptcy Court protection also may make it more difficult to retain management and the key personnel necessary to the success and growth of our business. In addition, during the period of time we are involved in a bankruptcy proceeding, our customers and suppliers might lose confidence in our ability to reorganize our business successfully and may seek to establish alternative commercial relationships.

Additionally, all of our indebtedness is senior to the existing common units in our capital structure. As a result, if the Bankruptcy Court confirms the Plan, then our common units will be canceled, resulting in a limited recovery for unitholders, and would place unitholders at a significant risk of losing all of their investment in our units. More specifically, pursuant to the Plan, existing common units would be canceled and would receive 5% of the new common stock (subject to dilution) and five-year warrants for 8% of the new common stock (subject to dilution) in the new, reorganized company, on a pro rata basis, with an exercise price set at an equity value at which the holders of the Senior Notes would receive a recovery equal to par plus accrued and unpaid interest as of the Petition Date in respect of the Senior Notes (after taking into account value dilution on account of the three percent of the new common stock to be allocated to the participants in the management incentive plan on the Effective Date pursuant to a management incentive plan).

Other significant risks include the following:

- our ability to prosecute, confirm and consummate the Plan;
- our ability to obtain Bankruptcy Court approval of operational and procedural motions in the Chapter 11 Cases and the outcomes of Bankruptcy Court rulings and of the Chapter 11 Cases in general;
- risks associated with third party motions or objections in the Chapter 11 Cases, which may interfere with our business operations or our ability to confirm the Plan;
- the high costs of bankruptcy and related fees;
- our ability to obtain sufficient financing to emerge from bankruptcy and execute our business plan post-emergence;
- our ability to maintain our relationships with our suppliers, service providers, customers and other third parties;
- potential increased difficulty in retaining and motivating our key employees through the process of reorganization, and potential increased difficulty in attracting new employees;

- significant time and effort required to be spent by our senior management in dealing with the bankruptcy and restructuring activities rather than focusing exclusively on business operations; and

- the actions and decisions of the holders of our existing indebtedness and other third parties who have interests in our Chapter 11 Cases that may be inconsistent with our plans.

Because of the risks and uncertainties associated with Chapter 11 Cases, we cannot predict or quantify the ultimate impact that events occurring during the Chapter 11 Cases may have on our business, cash flows, liquidity, financial condition and results of operations, nor can we predict the ultimate impact that events occurring during the Chapter 11 Cases may have on our corporate or capital structure.

Any Partnership de-levering transaction or change in the Partnership's capital structure, including in connection with a plan of reorganization in the Chapter 11 Cases, may involve significant taxable cancellation-of-debt or other income, such that the Partnership's unitholders may be required to pay taxes on their share of such income even if they do not receive any cash distributions from the Partnership.

Our unitholders, as the owners of the Partnership, are allocated the taxable income (or loss) of the Partnership for income tax purposes. Each unitholder is required to report its share of our taxable income on its federal and applicable state and local income tax returns. Accordingly, depending on their individual tax position, each unitholder may be required to pay income taxes on its share of our taxable income, even if the unitholder receives no cash distributions from the Partnership, which could happen.

The Restructuring pursuant to the Plan is intended to be structured in a manner that minimizes, to the extent possible, the negative tax impact of cancellation of debt income ("CODI") to our unitholders. Nevertheless, such transaction and any or other transactions we may engage in to de-lever the Partnership and manage its liquidity could result in the allocation of substantial taxable income to our unitholders without a corresponding cash distribution and possibly without any cash distribution. CODI may or may not be generated. The generation of CODI will depend on whether the principal amount of the outstanding Senior Notes, plus accrued and unpaid interest, exceeds the fair value of the equity received by the noteholders upon emergence from bankruptcy. Because the valuation upon emergence from bankruptcy is something determined in the future, we are currently unable to determine whether, and by how much, if any, the principal amount, plus accrued and unpaid interest, of the outstanding Senior Notes will exceed such valuation. If CODI is generated, it would be allocated to the unitholders of record as of the opening of the first NYSE trading day of the month we emerge from bankruptcy (the "CODI Allocation Date"). No CODI should be allocated to a unitholder with respect to units which are sold prior to the CODI Allocation Date. In certain cases, CODI can be realized even when existing debt is modified with no reduction in such debt's stated principal amount. We will not make a corresponding cash distribution with respect to such allocation of CODI. Therefore, any CODI will cause a unitholder to be allocated income with respect to our units with no corresponding distribution of cash to fund the payment of the resulting tax liability to such unitholder. Such CODI, like other items of our income, gain, loss, and deduction that are allocated to our unitholders, will be taken into account in the taxable income of the holders of our units as appropriate. CODI is not itself an additional tax due but is an amount that must be reported as ordinary income by the unitholder, potentially increasing such unitholder's tax liabilities.

Our unitholders may not have sufficient tax attributes (including allocated past and current losses from our activities) available to offset such allocated CODI. Moreover, CODI that is allocated to our unitholders will be ordinary income, and, as a result, it may not be possible for our unitholders to offset such CODI by claiming capital losses with respect to their units, even if such units are cancelled for no consideration in connection with such a restructuring. Importantly, certain exclusions that are available with respect to CODI generally do not apply at the partnership level, and any solvent unitholder that is not in a Chapter 11 proceeding will be unable to rely on such exclusions.

Each unitholder's tax situation is different. The ultimate effect to each unitholder will depend on the unitholder's individual tax position with respect to its units. Additionally, certain of our unitholders may have more losses available than other of our unitholders, and such losses may be available to offset some or all of the CODI that could be generated in a strategic transaction involving our debt. Accordingly, unitholders are highly encouraged to consult, and depend on, their own tax advisors in making such evaluation.

Additionally, the Partnership expects to emerge from the Chapter 11 Cases as a corporation, including for US federal income tax purposes.

During the existence of an event of default and the Chapter 11 Cases, we have no borrowing capacity under our credit agreement. Unless we are able to successfully restructure our existing indebtedness we may not be able to continue as a going concern.

Over the periods presented in the accompanying financial statements, our growth has been funded through a combination of borrowings under our credit agreement, the sale of assets and cash flows from operating activities. We currently have limited access to additional capital. During the existence of an event of default, we have no availability under our credit agreement.

The accompanying Consolidated Financial Statements have been prepared on a going concern basis which contemplates continuity of operations, realization of assets and liquidation of liabilities in the ordinary course of business. As a result of losses incurred, there is no assurance that the carrying amounts of assets will be realized or that liabilities will be settled for the amounts recorded. Unless we are able to successfully restructure our existing indebtedness under the Chapter 11 Cases we may not be able to continue as a going concern. There can be no assurance that the Plan as outlined in the Restructuring Support Agreement (or any other plan of reorganization) will be confirmed by the Bankruptcy Court and consummated.

Delays in our Chapter 11 Cases may increase the risks of our being unable to reorganize our business and emerge from bankruptcy and increase our costs associated with the bankruptcy process.

Our Restructuring Support Agreement contemplates the confirmation of the Plan through an orderly prepackaged plan of reorganization, but there can be no assurance that we will be able to confirm and consummate the Plan. In addition to obtaining the required votes of stakeholders (which requirement we believe we satisfied before commencing the Chapter 11 Cases), the requirements for the Bankruptcy Court to confirm a plan of reorganization include, among other judicial findings, that:

- we acted in accordance with the applicable provisions of the Bankruptcy Code; and

- the plan of reorganization has been proposed in good faith and not by any means forbidden by law; and

- the plan of reorganization does not unfairly discriminate and is fair and equitable with respect to those classes of claims and interests that did not vote to accept the plan of reorganization.

We may not be able to confirm the Plan promptly, if at all. In such event, a prolonged Chapter 11 bankruptcy proceeding could adversely affect our relationships with customers, suppliers and employees, among other parties, which in turn could adversely affect our business, competitive position, financial condition, liquidity and results of operations and our ability to continue as a going concern. A weakening of our financial condition, liquidity and results of operations could adversely affect our ability to implement our proposed Plan (or any other plan of reorganization). If no plan is confirmed by the Bankruptcy Court, we may be forced to liquidate our assets.

In addition, the confirmation and effectiveness of the Plan is subject to certain conditions and requirements in addition to those described above that may not be satisfied.

We believe it is likely that our common units will substantially decrease in value in our Chapter 11 Cases.

We have a significant amount of indebtedness that is senior to our common units in our capital structure. We believe that the existing common units will substantially decrease in value during and after emergence from the Chapter 11 Cases. Accordingly, any trading in our common units during the pendency of our Chapter 11 Cases is highly speculative and poses substantial risks to purchasers of our common units.

Pursuant to the Plan, existing common units will be canceled and will receive 5% of the new common stock (subject to dilution) and five-year warrants for 8% of the new common stock (subject to dilution) in the new, reorganized company, on a pro rata basis, with an exercise price set at an equity value at which the holders of the Senior Notes would receive a recovery equal to par plus accrued and unpaid interest as of the Petition Date in respect of the Senior Notes (after taking into account value dilution on account of the three percent of the new common stock to be allocated to the participants in the management incentive plan on the Effective Date pursuant to a management incentive plan).

The Restructuring Support Agreement is subject to significant conditions and milestones that may be difficult for us to satisfy.

There are certain material conditions we must satisfy under the Restructuring Support Agreement, including the timely satisfaction of milestones in the Chapter 11 Cases, including for confirmation and consummation of the Plan. Our ability to timely complete such milestones is subject to risks and uncertainties, many of which are beyond our control.

We may not be able to obtain confirmation of the Plan.

There can be no assurance that the Plan as outlined in the Restructuring Support Agreement (or any other plan of reorganization) will be confirmed by the Bankruptcy Court. As a result, investors should exercise caution with respect to existing and future investments in our securities. The success of any reorganization will depend on approval by the Bankruptcy Court, and there can be no guarantee of success with respect to the Plan or any other plan of reorganization. For instance, we might receive objections from stakeholders to confirmation of the Plan or other relief we seek in the Chapter 11 Cases. We cannot predict the impact of any such objections. Any objection may cause us to devote significant resources in response which could materially and adversely affect our business, financial condition and results of operations.

If the Plan is not confirmed by the Bankruptcy Court, it is unclear whether we would be able to reorganize our business and what, if any, distributions holders of claims against us, including holders of our existing indebtedness, would ultimately receive with respect to their claims. The Plan provides for a recovery to our public unitholders. If the Plan is not confirmed, we believe that any other plan is likely to provide a reduced recovery (or no recovery at all) to our unitholders and will place them at significant risk of losing most or all of their investments in the Partnership. See Note 2 of the Notes to Consolidated Financial Statements included under "Item 8. Financial Statements and Supplementary Data."

There can be no assurance to whether we will successfully reorganize and emerge from the Chapter 11 Cases or, if we do successfully reorganize, as to when we would emerge from the Chapter 11 Cases. If we are unable to successfully reorganize, we may not be able to continue our operations.

If the Restructuring Support Agreement is terminated, our ability to confirm and consummate the Plan could be materially and adversely affected.

The Restructuring Support Agreement contains a number of termination events, upon the occurrence of which certain parties to the Restructuring Support Agreement may terminate the agreement. If the Restructuring Support Agreement is terminated, each of the parties thereto will be released from their obligations in accordance with the terms of the Restructuring Support Agreement. Such termination may result in the loss of support for the Plan by the parties to the Restructuring Support Agreement, which could adversely affect our ability to confirm and consummate the Plan. If the Plan is not consummated, there can be no assurance that any new Chapter 11 plan of reorganization would be as favorable to holders of claims and units as the current Plan.

Even if a Chapter 11 plan of reorganization is consummated, we may not be able to achieve our stated goals and there is substantial doubt regarding our ability to continue as a going concern.

Even if the Plan or any other Chapter 11 plan of reorganization is consummated, we may continue to face a number of risks, such as further deterioration in commodity prices or other changes in economic conditions, changes in our industry, changes in demand for our oil and gas and increasing expenses. Some of these risks become more acute when a case under the Bankruptcy Code continues for a protracted period without indication of how or when the case may be completed. As a result of these risks and others, we cannot guarantee that any Chapter 11 plan of reorganization will achieve our stated goals.

In addition, at the outset of the Chapter 11 Cases, the Bankruptcy Code gives the Debtors the exclusive right to propose a plan of reorganization and prohibits creditors, equity security holders and others from proposing a plan. Accordingly, we currently have the exclusive right to propose a plan of reorganization. If that right is terminated, however, or the exclusivity period expires, there could be a material adverse effect on our ability to achieve confirmation of a plan of reorganization in order to achieve our stated goals.

Furthermore, even if our debts are reduced or discharged through a plan of reorganization, we may need to raise additional funds through public or private debt or equity financing or other various means to fund our business after the completion of the Chapter 11 Cases. Our access to additional financing may be limited, if it is available at all. Therefore, adequate funds may not be available when needed or may not be available on favorable terms, if they are available at all.

As a result of the entry into the Chapter 11 Cases, even with the creditor support for the restructuring under the Restructuring Support Agreement, there is substantial doubt regarding our ability to continue as a going concern. As a result, we cannot give any assurance of our ability to continue as a going concern, even if a plan of reorganization is confirmed.

Our common units will be delisted from trading on the NASDAQ Capital Market, and no longer been listed on a national securities exchange effective following the commencement of the Chapter 11 Cases, and will be quoted only in the over-the-counter market, which could negatively affect the price and liquidity of our common units.

In connection with filing the Chapter 11 Cases, we expect to receive a notice from the NASDAQ stating that our units will be delisted from the NASDAQ Capital Market. The delisting decision will be reached under the NASDAQ Listing Rules 5101, 5110(b), and IM-5101-1 following our announcement that the Debtors filed the Chapter 11 Cases. Trading of our common units will be suspended by the NASDAQ, and a Form 25-NSE will be filed with the Securities and Exchange Commission, which will remove our securities from listing and registration on the NASDAQ Capital Market.

Following the expected delisting from the NASDAQ Capital Market, our units will commence trading on the OTC Pink Marketplace under the symbol "EVEPQ". We can provide no assurance that its units will commence or continue to trade on this market, whether broker-dealers will continue to provide public quotes of the units on this market, whether the trading volume of the units will be sufficient to provide for an efficient trading market or whether quotes for the units will continue on this market in the future.

The OTC Pink is a significantly more limited market than the NASDAQ Capital Market, and the quotation of our common units on the OTC Pink Marketplace may result in a less liquid market available for existing and potential shareholders to trade our common units. This could further depress the trading price of our common units and could also have a long-term adverse effect on our ability to raise capital. There can be no assurance that any public market for our common units will exist in the future or that we will be able to relist our common units on a national securities exchange. In connection with the delisting of our common units, there may also be other negative implications, including the potential loss of confidence in us by suppliers, customers and employees and the loss of institutional investor interest in our common units

In certain instances, a Chapter 11 case may be converted to a case under Chapter 7 of the Bankruptcy Code.

Upon a showing of cause, the Bankruptcy Court may convert our Chapter 11 Cases to a case under Chapter 7 of the Bankruptcy Code. In such event, a Chapter 7 trustee would be appointed or elected to liquidate our assets for distribution in accordance with the priorities established by the Bankruptcy Code. We believe that liquidation under chapter 7 would result in significantly smaller distributions being made to our creditors than those provided for in our Plan because of (i) the likelihood that the assets would have to be sold or otherwise disposed of in a distressed fashion over a short period of time rather than in a controlled manner and as a going concern, (ii) additional administrative expenses involved in the appointment of a Chapter 7 trustee, and (iii) additional expenses and claims, some of which would be entitled to priority, that would be generated during the liquidation and from the rejection of leases and other executory contracts in connection with a cessation of operations.

As a result of the Chapter 11 Cases, our historical financial information may not be indicative of our future performance, which may be volatile.

During the Chapter 11 Cases, we expect our financial results to continue to be volatile as restructuring activities and expenses, contract terminations and rejections, and claims assessments significantly impact our consolidated financial statements. As a result, our historical financial performance is likely not indicative of our financial performance after the date of the filing of the Chapter 11 Cases. In addition, if we emerge from Chapter 11, the amounts reported in subsequent consolidated financial statements may materially change relative to historical consolidated financial statements, including as a result of revisions to our operating plans pursuant to the Plan. We also may be required to adopt fresh start accounting, in which case our assets and liabilities will be recorded at fair value as of the fresh start reporting date, which may differ materially from the recorded values of assets and liabilities on our consolidated balance sheets. Our financial results after the application of fresh start accounting also may be different from historical trends.

We may be subject to claims that will not be discharged in the Chapter 11 Cases, which could have a material adverse effect on our financial condition and results of operations.

The Bankruptcy Court provides that the confirmation of a plan of reorganization discharges a debtor from substantially all debts arising prior to confirmation. With few exceptions, all claims that arose prior to April 2, 2018, or before confirmation of the Plan (i) would be subject to compromise and/or treatment under the Plan and/or (ii) would be discharged in accordance with the Bankruptcy Code and the terms of the Plan. Any claims not ultimately discharged pursuant to the Plan could be asserted against the reorganized entities and may have an adverse effect on our financial condition and results of operations on a post-reorganization basis.

We have significant exposure to fluctuations in commodity prices since none of our estimated future production is covered by commodity derivative contracts and we may not be able to enter into commodity derivative contracts covering our estimated future production on favorable terms or at all.

During the Chapter 11 Cases, our ability to enter into commodity derivative contracts covering estimated future production will be limited. As a result, we may not be able to enter into commodity derivative contracts covering our production in future periods on favorable terms or at all. If we cannot or choose not to enter into commodity derivative contracts in the future, we could be more affected by changes in commodity prices. Our inability to hedge the risk of low commodity prices in the future, on favorable terms or at all, could have a material adverse impact on our business, financial condition and results of operations.

We may experience employee attrition as a result of the Chapter 11 Cases.

As a result of the Chapter 11 Cases, we may experience employee attrition, and our employees may face considerable distraction and uncertainty. A loss of key personnel or material erosion of employee morale could adversely affect our business and results of operations. Our ability to engage, motivate and retain key employees or take other measures intended to motivate and incentivize key employees to remain with us through the pendency of the Chapter 11 Cases is limited by restrictions on implementation of incentive programs under the Bankruptcy Code. The loss of services of members of our senior management team could impair our ability to execute our strategy and implement operational initiatives, which would be likely to have a material adverse effect on our financial condition, liquidity and results of operations.

Risks Related to Our Business

The board of directors of our general partner has suspended quarterly cash distributions on our common units and, in connection with the transactions contemplated by the Plan in the Chapter 11 Cases, we will convert into an entity that will not seek to pay a quarterly cash distribution or any other amount to equity holders.

Since 2016, we have suspended cash distributions to the holders of our common units in order to conserve cash and improve our liquidity. In connection with the transactions contemplated by the Plan in the Chapter 11 Cases, the Partnership will convert into a corporation or other entity with a primary business objective other than generating stable cash flows that will allow for quarterly cash distributions to equity holders.

If we were to resume quarterly cash distributions, the cash available to service our indebtedness or otherwise operate our business may be limited and we may be required to incur additional debt to enable us to pay such quarterly distributions.

If we were to resume quarterly cash distributions, we may not accumulate significant amounts of cash. These distributions could significantly reduce the cash available to us in subsequent periods to make payments on our indebtedness or otherwise operate our business. For more information, see below "—- Covenants in our credit agreement may restrict our ability to resume and sustain distributions."

Covenants in our credit agreement may restrict our ability to resume and sustain distributions.

The terms of our credit agreement may restrict our ability to pay distributions if we do not satisfy the financial and other covenants in the credit facility. Prior to reinstating distributions, we will ensure that we are, and will continue to be, in compliance with the covenants contained in our credit agreement. As of April 2, 2018, the Partnership was in default under certain of its debt instruments. The Partnership's filing of the Chapter 11 Cases accelerated the Partnership's obligations under its credit facility and the Senior Notes. Additionally, events of default, including cross-defaults, are present, including the receipt of a going concern explanatory paragraph from the Partnership's independent registered public accounting firm on the Partnership's consolidated financial statements, subject to a 30 day grace period. As a result, our credit facility could become due and payable because of this event of default. This has a material, adverse effect on our business, including our ability to resume and sustain distributions.

Oil, natural gas and natural gas liquids prices are highly volatile and depressed prices can significantly and adversely affect our cash flows from operations and our ability to service our debt obligations.

Our revenue, profitability and cash flow 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. The prices we receive for our production are volatile and a drop in prices can significantly affect our financial results and impede our growth, including our ability to maintain or increase our borrowing capacity, to repay current or future indebtedness and to obtain additional capital on attractive terms. Changes in prices have a significant impact on the value of our reserves and on our cash flows. Prices 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 U.S 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 proximity and capacity of natural gas pipelines and other transportation facilities to our production; and
- the price and availability of alternative fuels.

Low prices will decrease our revenues, but may also 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. 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. We may incur impairment charges in the future, which could have a material adverse effect on our results of operations in the period taken and our ability to borrow funds under our credit facility, which may adversely affect our ability to service our debt obligations.

Low commodity prices or further declines would have a material adverse effect on our business.

Our financial position, results of operations, access to capital and the quantities of oil and natural gas that may be economically produced would be negatively impacted if oil and natural gas prices decrease further or remain depressed for an extended period of time. The ways in which such price decreases could have a material negative effect 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 for capital expenditures employed to replace reserves and maintain or increase production;
- a decrease in future undiscounted and discounted net cash flows from producing properties, possibly resulting in impairment expense that may be significant;
- lower proved reserves, production and cash flow as certain reserves may no longer be economic to produce;
- 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 on our credit facility or our Exit Credit Facility.

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 any future financing agreements may restrict our ability to finance future operations or capital needs or to engage, expand or pursue our business activities or to pay distributions to our unitholders. 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:

- 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.

We expect our Exit Credit Facility to be at least as restrictive as our revolving credit facility.

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

Our credit facility allowed, and we expect our Exit Credit Facility will allow, 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 NGL reserves, which takes into account the prevailing natural gas, oil and NGL 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 required, and we expect our Exit Credit Facility will require, 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.

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 substantial 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 or our Exit 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 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 and cash available for servicing our indebtedness would decrease. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk — Interest Price Risk" included under Part II of this annual report for further information regarding interest rate sensitivity.

The board of directors of our general partner has suspended quarterly cash distributions on common units and, in connection with the transactions contemplated by the plan of reorganization in the Chapter 11 Cases, we will convert into an entity that will not seek to pay a quarterly cash distribution or any other amount to equity holders.

Under the terms of our partnership agreement, we distribute all of our available cash to our unitholders after reserves established by our general partner. The amount of cash available for distribution is reduced by our operating expenses and the amount of any cash reserves established by our general partner to provide for future operations, future capital expenditures, including acquisitions of additional oil and natural gas properties, and future debt service requirements. In 2016, the board of directors of our general partner suspended and has not reinstated distributions on common units primarily due to the current and expected commodity price environment and market conditions and their impact on our future business as well as restrictions imposed by our debt instruments, including our credit facility.

In connection with the transactions contemplated by the plan of reorganization in the Chapter 11 Cases, the Partnership will convert into a corporation or other entity with a primary business objective other than generating stable cash flows that will allow for quarterly cash distributions to equity holders.

If we were to resume quarterly cash distributions, the cash available to service our indebtedness or otherwise operate our business may be limited and we may incur additional debt to enable us to pay such quarterly distributions.

If we were to resume quarterly cash distributions, we may not accumulate significant amounts of cash. These distributions could significantly reduce the cash available to us in subsequent periods to make payments on our indebtedness or otherwise operate our business.

In addition, we may be unable to pay the quarterly cash distribution, if resumed, without borrowing under our credit facility or otherwise. If we use borrowings to pay distributions to our equity holders for an extended period of time rather than to fund capital expenditures and other activities relating to our operations, we may be unable to maintain or grow our business. Such a curtailment of our business activities, combined with our payment of principal and interest on our future indebtedness incurred to pay these distributions, will reduce our cash available for distribution on our equity and will have a material adverse effect on our business, financial condition and results of operations.

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. During 2017, we recorded impairment charges of approximately $93.6 million. The impairment charges during 2017 included $69.9 million of proved oil and natural gas properties, of which, $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 located in Central Texas and $2.9 million related to properties in East Texas which were sold during April 2017. We also may incur impairment charges in the future, which could have a material adverse effect on our results of operations in the period incurred. Since December 31, 2017, commodity prices have continued to fluctuate. If commodity prices significantly decrease in future quarters, we could have additional impairments of our oil and natural gas properties.

As of December 31, 2017, we had no estimated proved undeveloped reserves ("PUDs").

As of December 31, 2017, we did not report any estimated PUDs with respect to any of our properties due to uncertainty regarding our ability to continue as a going concern and the availability of capital that would be required to develop the PUDs. These undeveloped properties may not be ultimately developed by us. We previously reported estimated PUDs in our SEC filings, and, if in the future we can satisfy the reasonable certainty criteria for recording PUDs as prescribed under the SEC requirements, we would likely report estimated PUDs in future filings.

Identified potential drilling locations, which are part of our anticipated future drilling plans, 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.

As of December 31, 2017, we had over 3,374 gross identified potential drilling locations, of which approximately 1,360 were located in the Barnett Shale and approximately 1,100 were located in the Appalachian Basin. This inventory was developed using data gathered from our appraisal efforts and development drilling, along with offset operators drilling activities. As noted above, we did not include any reserves attributable to our identified potential drilling as PUDs.

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. Further, our identified potential drilling locations are in various stages of evaluation, ranging from locations that are ready to drill to locations that will require substantial additional interpretation. We cannot predict 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. Because of these uncertainties, we do not know if the potential drilling 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 currently own interests in oil and natural gas properties in which partnerships managed by EnerVest also own an interest and we may acquire properties in which the EnerVest managed partnerships own an interest in the future. 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, and we expect to make acquisitions of properties jointly with EnerVest partnerships in the future. These properties are primarily in the Barnett Shale and San Juan Basin, and these properties represent approximately 56% of our estimated net proved reserves as of December 31, 2017. The EnerVest partnerships generally have an investment strategy to typically divest properties in three to five years, while our strategy is to hold properties for the longer term. We own less than a majority working interest in the properties in which the EnerVest partnerships also own an interest. If the EnerVest partnerships were to sell their interest in these properties 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.

We depend on EnerVest to provide us services necessary to operate our business. 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 an omnibus agreement, EnerVest provides services to us such as accounting, human resources, office space and other administrative services, and under an operating agreement, EnerVest operates our properties for us. 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.

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.

While we currently have no commodity price derivative hedges in place, 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. 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 ability to use hedging transactions to protect us from future price declines will be dependent upon oil and natural gas prices at the time we enter into future hedging transactions and our future levels of hedging, and as a result our future net cash flows may be more sensitive to commodity price changes. In addition, as substantial doubt exists that we will be able to continue as a going concern, finding counterparties for commodity hedges has proven difficult.

Our policy has been to hedge a significant portion of our near–term estimated production. However, our price hedging strategy and future hedging transactions will be determined at the discretion of our general partner, which is not under an obligation to hedge a specific portion of our production except that the Exit Credit Facility will require the Partnership to hedge no less than 70% of forecasted proved developed producing production not later than the closing date and for the 18-month period thereafter. 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, 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. Relative to previous years, we have less volumes hedged at lower prices. This makes our near-term oil, natural gas and natural gas liquids revenues more sensitive to changes in commodity prices.

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 limits our ability to hedge our natural gas liquids production effectively or at all. 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 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 unable to integrate successfully the operations of our recent or future acquisitions with our operations and we may not realize all the anticipated benefits of the recent acquisitions or any future acquisition.

Integration of our recent acquisitions with our business and operations has been a complex, time consuming and costly process. Failure to successfully assimilate our past or future acquisitions could adversely affect our financial condition and results of operations.

Our acquisitions involve numerous risks, including:

- operating a significantly larger combined organization and adding operations;
- difficulties in the assimilation of the assets and operations of the acquired business, especially if the assets acquired are in a new business segment or geographic area;
- the risk that reserves acquired may not be of the anticipated magnitude or may not be developed as anticipated;
- the loss of significant key employees from the acquired business;
- the diversion of management's attention from other business concerns;
- the failure to realize expected profitability or growth;
- the failure to realize expected synergies and cost savings;
- coordinating geographically disparate organizations, systems and facilities; and
- coordinating or consolidating corporate and administrative functions.

Further, unexpected costs and challenges may arise whenever businesses with different operations or management are combined, and we may experience unanticipated delays in realizing the benefits of an acquisition. If we consummate any future acquisition, our capitalization and results of operation may change significantly, and you may not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in evaluating future acquisitions.

Properties that we buy may not produce as projected and we may be unable to determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against such liabilities, which could adversely affect our liquidity and results of operations.

One of our strategies is to capitalize on opportunistic acquisitions of oil, natural gas and natural gas liquids reserves. Any future acquisition will require an assessment of recoverable reserves, title, future oil, natural gas and natural gas liquids prices, operating costs, potential environmental hazards, potential tax and ERISA liabilities, and other liabilities and similar factors. Ordinarily, our review efforts are focused on the higher valued properties and are inherently incomplete because it generally is not feasible to review in depth every individual property involved in each acquisition. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well, and potential problems, such as ground water contamination and other environmental conditions and deficiencies in the mechanical integrity of equipment are not necessarily observable even when an inspection is undertaken. Any unidentified problems could result in material liabilities and costs that negatively impact our financial condition and results of operations and our ability to service our debt obligations.

Additional potential risks related to acquisitions include, among other things:

- incorrect assumptions regarding the future prices of oil, natural gas and natural gas liquids or the future operating or development costs of properties acquired;
- incorrect estimates of the reserves attributable to a property we acquire;
- an inability to integrate successfully the businesses we acquire;
- the assumption of liabilities;
- limitations on rights to indemnity from the seller;
- the diversion of management's attention from other business concerns; and
- losses of key employees at the acquired businesses.

If we consummate any future acquisitions, our capitalization and results of operations may change significantly.

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 and our ability to resume, maintain and increase distributions to unitholders 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 acquisition and development operations will 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 make and expect to continue to make substantial capital expenditures in our business 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 with cash flows from operations, borrowings under our Exit Credit Facility, as amended and restated upon approval of the Plan in the Chapter 11 Cases and 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, financial conditions and ability to make distributions to our unitholders. 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 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 NGL 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.

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. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Many of our larger competitors not only drill for and produce oil, natural gas and natural gas liquids, but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for oil and natural gas properties and evaluate, bid for and purchase a greater number of properties than our financial or human resources permit. In addition, 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. In addition, competition is strong for attractive oil and natural gas producing properties, oil and natural gas companies, and undeveloped leases and drilling rights. We may be often outbid by competitors in our attempts to acquire properties or companies. 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 pay distributions to our unitholders and 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 NGLs 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 CAA 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, or RCRA, and comparable state laws that impose requirements for the handling and disposal of waste from our facilities;

- 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 and state or local laws and regulations related to hydraulic fracturing;

- the OPA which subjects responsible parties to liability for removal costs and damages arising from an oil spill in waters of the US;

- EPA community right to know regulations under the Title III of CERCLA and similar state statutes 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 area.

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 the 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 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 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, although it remains unclear the status of future rulemaking under the new administration. This rule is also the subject of pending appeals. In late 2016, BLM adopted rules 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. These rules have been challenged in court and remain in litigation. Additionally, the US House of Representatives has passed a resolution under the Congressional Review Act disapproving the rules; Senate action remains pending. As noted elsewhere in this report, both the EPA and BLM have proposed regulatory changes that would reduce the burdens of the above-described GHG emission regulations on new and existing sources, but it is too recent an event to know for certain the impact of these proposed rule changes.

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 in 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 but the EPA has asserted federal regulatory authority pursuant to the Safe Drinking Water Act 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 Safe Drinking Water Act 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 such things as 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 has issued final rules outlining its position on the federal jurisdictional reach over waters of the United States. This interpretation by the EPA may constitute an expansion of federal jurisdiction over waters of the United States. Litigation surrounding this rule is ongoing. 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. This 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 Safe Drinking Water Act or other regulatory programs.

We are now subject to regulation under NSPS and NESHAPS 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.

Changes in interest rates could adversely impact our ability to issue additional debt.

Interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. As with other yield oriented securities, our unit price is impacted by the level of our cash distributions and implied distribution yield. The distribution yield is often used by investors to compare and rank related yield oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our units, and a rising interest rate environment could have an adverse impact on our unit price and our ability to issue additional equity to make acquisitions, incur debt or for other purposes.

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 units and our ability to pay distributions on our units and 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 acquisition and development 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, 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 Inherent in an Investment in Us

EnerVest controls our general partner, which has sole responsibility for conducting our business and managing our operations. EnerVest, EV Investors, L.P. ("EV Investors") and EnCap Investments, L.P. ("EnCap"), which are limited partners of our general partner, have conflicts of interest, which may permit them to favor their own interests to your detriment.

EnerVest owns and controls our general partner, and EnCap owns a 23.75% limited partnership interest in our general partner. Conflicts of interest may arise between EnerVest, EnCap and their respective affiliates, including our general partner, on the one hand, and us, our unitholders and the holders of our debt obligations, on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of its owners over the interests of our unitholders and the holders of our debt obligations. These conflicts include, among others, the following situations:

- we have acquired oil and natural gas properties from partnerships formed by EnerVest and partnerships and companies in which EnerVest and EnCap have an interest, and we may do so in the future;
- neither our partnership agreement nor any other agreement requires EnerVest or EnCap to pursue a business strategy that favors us or to refer any business opportunity to us;
- our general partner is allowed to take into account the interests of parties other than us, such as EnerVest and EnCap, in resolving conflicts of interest;
- our general partner determines the amount and timing of our drilling program and related capital expenditures, asset purchases and sales, borrowings, issuance of additional partnership securities and reserves, each of which can affect the amount of cash that is distributed to unitholders and used to service our debt obligations;
- our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;
- our general partner controls the enforcement of obligations owed to us by our general partner and its affiliates; and
- our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

Many of the directors and officers who have responsibility for our management have significant duties with, and will spend significant time serving, entities that compete with us in seeking out acquisitions and business opportunities and, accordingly, may have conflicts of interest in allocating time or pursuing business opportunities.

In order to maintain and increase our levels of production, we will need to acquire oil and natural gas properties. Several of the officers and directors of EV Management, the general partner of our general partner, who have responsibilities for managing our operations and activities hold similar positions with other entities that are in the business of identifying and acquiring oil and natural gas properties. For example, Mr. John B. Walker is Executive Chairman of EV Management and Chief Executive Officer of EnerVest, which is in the business of acquiring oil and natural gas properties and managing the EnerVest partnerships that are in that business. We cannot assure you that these conflicts will be resolved in our favor. Mr. Gary R. Petersen, a director of EV Management, is also a senior managing director of EnCap, which is in the business of investing in oil and natural gas companies with independent management which in turn is in the business of acquiring oil and natural gas properties. Mr. Petersen is also a director of several oil and natural gas producing entities that are in the business of acquiring oil and natural gas properties. The existing positions of these directors and officers may give rise to fiduciary obligations that are in conflict with fiduciary obligations owed to us. The EV Management officers and directors may become aware of business opportunities that may be appropriate for presentation to us as well as the other entities with which they are or may be affiliated. Due to these existing and potential future affiliations with these and other entities, they may have fiduciary obligations to present potential business opportunities to those entities prior to presenting them to us, which could cause additional conflicts of interest. They may also decide that the opportunities are more appropriate for other entities which they serve and elect not to present them to us.

Neither EnerVest nor EnCap is limited in its ability to compete with us for acquisition or drilling opportunities. This could cause conflicts of interest and limit our ability to acquire additional assets or businesses which in turn could adversely affect our ability to replace reserves, results of operations and cash available for servicing our debt obligations.

Neither our partnership agreement nor the omnibus agreement between EnerVest and us prohibits EnerVest, EnCap and their affiliates from owning assets or engaging in businesses that compete directly or indirectly with us. For instance, EnerVest, EnCap and their respective affiliates may acquire, develop or dispose of additional oil or natural gas properties or other assets in the future, without any obligation to offer us the opportunity to purchase or develop any of those assets. Each of these entities is a large, established participant in the energy business, and each has significantly greater resources and experience than we have, which factors may make it more difficult for us to compete with these entities with respect to commercial activities as well as for acquisition candidates. As a result, competition from these entities could adversely impact our results of operations and accordingly cash available for servicing our debt obligations.

Cost reimbursements due to our general partner and its affiliates for services provided may be substantial and will reduce our cash available for servicing our debt obligations.

Pursuant to the omnibus agreement between EnerVest and us, EnerVest will receive reimbursement for the provision of various general and administrative services for our benefit. In addition, we entered into contract operating agreements with a subsidiary of EnerVest pursuant to which the subsidiary will be the contract operator of all of the wells for which we have the right to appoint an operator. Payments for these services will be substantial. In addition, under Delaware partnership law, our general partner has unlimited liability for our obligations, such as our debts and environmental liabilities, except for our contractual obligations that are expressly made without recourse to our general partner. To the extent our general partner incurs obligations on our behalf, we are obligated to reimburse or indemnify it. If we are unable or unwilling to reimburse or indemnify our general partner, our general partner may take actions to cause us to make payments of these obligations and liabilities. Any such payments could reduce the amount of cash otherwise available for distribution to our unitholders.

Our partnership agreement limits our general partner's fiduciary duties to holders of our common units.

Although our general partner has a fiduciary duty to manage us in a manner beneficial to us and our unitholders, the directors and officers of EV Management, the general partner of our general partner, have a fiduciary duty to manage our general partner in a manner beneficial to its owners. Our partnership agreement contains provisions that reduce the standards to which our general partner and its affiliates would otherwise be held by state fiduciary duty laws. For example, our partnership agreement permits our general partner and its affiliates to make a number of decisions either in their individual capacities, as opposed to in its capacity as our general partner, or otherwise free of fiduciary duties to us and our unitholders. This entitles our general partner and its affiliates to consider only the interests and factors that they desire, and they have no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner. Examples include:

- whether or not to exercise its right to reset the target distribution levels of its incentive distribution rights at higher levels and receive, in connection with this reset, a number of Class B units that are convertible at any time following the first anniversary of the issuance of these Class B units into common units;
- whether or not to exercise its limited call right;
- how to exercise its voting rights with respect to the units it owns;
- whether or not to exercise its registration rights; and
- whether or not to consent to any merger or consolidation of the partnership or amendment to the partnership agreement.

Our partnership agreement restricts the remedies available to holders of our common units for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions restricting the remedies available to unitholders for actions taken by our general partner or its affiliates that might otherwise constitute breaches of fiduciary duty. For example, our partnership agreement:

- provides that our general partner will not have any liability to us or our unitholders for decisions made in its capacity as a general partner so long as it acted in good faith, meaning it believed the decision was in the best interests of our partnership;

- generally provides that affiliated transactions and resolutions of conflicts of interest not approved by the conflicts committee of the board of directors of the general partner of our general partner and not involving a vote of unitholders must be on terms no less favorable to us than those generally being provided to or available from unrelated third parties or must be "fair and reasonable" to us, as determined by our general partner in good faith and that, in determining whether a transaction or resolution is "fair and reasonable," our general partner may consider the totality of the relationships between the parties involved, including other transactions that may be particularly advantageous or beneficial to us; and

- provides that our general partner and its officers and directors will not be liable for monetary damages to us, our limited partners or assignees for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that the general partner or those other persons acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal.

Holders of our common units have limited voting rights and are not entitled to elect our general partner or the board of directors of its general partner.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Unitholders will not elect our general partner, its general partner or the members of its board of directors, and will have no right to elect our general partner, its general partner or its board of directors on an annual or other continuing basis. The board of directors of EV Management is chosen by EnerVest, the sole member of EV Management. Furthermore, if the unitholders were dissatisfied with the performance of our general partner, they will have only a limited ability to remove our general partner. As a result of these limitations, the price at which the common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

Control of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, our partnership agreement does not restrict the ability of the owners of our general partner or EV Management, from transferring all or a portion of their respective ownership interest in our general partner or EV Management to a third party. The new owners of our general partner or EV Management would then be in a position to replace the board of directors and officers of EV Management with its own choices and thereby influence the decisions taken by the board of directors and officers.

Your liability may not be limited if a court finds that unitholder action constitutes control of our business.

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law, and we conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business. You could be liable for any and all of our obligations as if you were a general partner if:

- a court or government agency determined that we were conducting business in a state but had not complied with that particular state's partnership statute; or

- your right to act with other unitholders to remove or replace the general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitutes "control" of our business.

Unitholders may have liability to repay distributions that were wrongfully distributed to them.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17–607 of the Delaware Revised Uniform Limited Partnership Act, we may not make a distribution to you if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of the impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Substituted limited partners are liable for the obligations of the assignor to make contributions to the partnership that are known to the substituted limited partner at the time it became a limited partner and for unknown obligations if the liabilities could be determined from the partnership agreement. Liabilities to partners on account of their partnership interest and liabilities that are non–recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

If we fail to maintain an effective system of internal controls, we may not be able to accurately report our financial results or prevent fraud. As a result, current and potential unitholders could lose confidence in our financial reporting, which would harm our business and the trading price of our units.

Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and operate successfully as a public company. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results would be harmed. We cannot be certain that our efforts to maintain our internal controls will be successful, that we will be able to maintain adequate controls over our financial processes and reporting in the future or that we will be able to continue to comply with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002. Any failure to maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet our reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the trading price of our units.

Tax Risks to Common Unitholders

An IRS contest of our US federal income tax positions may adversely affect the market for our common units, and the cost of any IRS contest may be substantial.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel's conclusions or the positions we take. A court may not agree with all of our counsel's conclusions or positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade.

You may be required to pay taxes on income from us even if you do not receive any cash distributions from us.

Because our unitholders will be treated as partners to whom we will allocate taxable income which could be different in amount than the cash we distribute, you will be required to pay any federal income taxes and, in some cases, state and local income taxes on your share of our taxable income even if you receive no cash distributions from us. You may not receive cash distributions from us equal to your share of our taxable income or even equal to the tax liability that results from that income.

Tax gain or loss on disposition of common units could be more or less than expected.

If you sell your common units, you will recognize a gain or loss equal to the difference between the amount realized and your tax basis in those common units. Prior distributions to you in excess of the total net taxable income you were allocated for a common unit, which decreased your tax basis in that common unit, will, in effect, become taxable income to you if the common unit is sold at a price greater than your tax basis in that common unit, even if the price is less than your original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income. In addition, if you sell your units, you may incur a tax liability in excess of the amount of cash you receive from the sale.

Tax–exempt entities and foreign persons face unique tax issues from owning common units that may result in adverse tax consequences to them.

Investment in common units by tax–exempt entities, such as individual retirement accounts (known as IRAs), other retirement plans and non–US persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non–US persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non–US persons will be required to file US federal tax returns and pay tax on their share of our taxable income.

We will treat each purchaser of our common units as having the same tax benefits without regard to the actual common units purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.

Because we cannot match transferors and transferees of common units and because of other reasons, we will take depreciation and amortization positions that may not conform to all aspects of existing Treasury regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to you. It also could affect the timing of these tax benefits or the amount of gain from the sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to your tax returns.

Unitholders may be subject to state and local taxes and tax return filing requirements in states where they do not live as a result of investing in our common units.

In addition to federal income taxes, you will likely be subject to other taxes, including Medicare, state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property, even if you do not live in any of those jurisdictions. You will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these jurisdictions. Further, you may be subject to penalties for failure to comply with those requirements. We own assets and do business in the states of Texas, Louisiana, Oklahoma, Arkansas, New Mexico, Colorado, Kansas, Michigan, Ohio, West Virginia and Pennsylvania. Each of these states, other than Texas, currently imposes a personal income tax. As we make acquisitions or expand our business, we may own assets or do business in additional states that impose a personal income tax. It is your responsibility to file all US federal, foreign, state and local tax returns.

The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by legislative, judicial or administrative changes and differing interpretations at any time. Specifically, from time to time, members of Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships. If successful, such a proposal could eliminate the qualifying income exception to the treatment of all publicly traded partnerships as corporations upon which we rely for our treatment as a partnership for US federal income tax purposes. Any modification to the US federal income tax laws may be applied retroactively and could make it more difficult or impossible for us to meet the exception for certain publicly traded partnerships to be treated as partnerships for US federal income tax purposes. We are unable to predict whether any of these changes or other proposals will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Information regarding our properties is contained in "Item 1. Business — Oil and Natural Gas Producing Activities" and "Item 1. Business — Our Oil and Natural Gas Data" 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, 2017.

Please see “Item 1. Business — Restructuring and Bankruptcy Proceedings under Chapter 11” contained herein.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

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

Our common units are traded on the NASDAQ Capital Market (the "NASDAQ") under the symbol "EVEP." At the close of business on March 27, 2018, based upon information received from our transfer agent and brokers and nominees, there were 49,368,869 common units outstanding and we had 290 common unitholders of record. This number does not include owners for whom common units are held in "street" names.

The following table sets forth the range of the daily high and low sales prices per common unit and cash distributions to common unitholders for 2017 and 2016:

	Price Range		Cash Distribution per
	High	Low	Common Unit (1)
2017			
First Quarter	$ 2.21	$ 1.43	$ -
Second Quarter	1.68	0.53	-
Third Quarter	0.72	0.37	-
Fourth Quarter	1.46	0.45	-
2016			
First Quarter	$ 3.05	$ 1.60	$ -
Second Quarter	3.59	1.82	-
Third Quarter	2.65	2.10	-
Fourth Quarter	2.72	1.51	-

(1) When cash distributions are declared, they are declared and paid in the following calendar quarter. However, during 2017 and 2016, the board of directors of EV Management elected to suspend distributions for all four quarters of 2017 and 2016.

On July 17, 2017, we received a letter from the NASDAQ notifying us that we were not in compliance with the NASDAQ Global Market's rules that require the minimum bid price of our units to be at least $1.00 per share over a consecutive 30-trading-day period. On December 27, 2017, we applied to transfer from the NASDAQ Global Market to the NASDAQ Capital Market and requested an additional 180-day grace period to regain compliance with the NASDAQ Capital Market's minimum bid price requirement because our common units have continued to trade below the $1.00 minimum closing bid price. In January 2018, NASDAQ approved both the transfer and the extension of the 180-day grace period, which will end on July 16, 2018. This notice from NASDAQ does not affect our business operations or trigger any default or other violation of our debt or other material obligations.

In connection with filing the Chapter 11 Cases, we expect to receive a notice from the NASDAQ stating that our units will be delisted from the NASDAQ Capital Market. The delisting decision will be reached under NASDAQ Listing Rules 5101, 5110(b), and IM-5101-1 following our announcement that the Debtors filed the Chapter 11 Cases. Trading of our common units will be suspended by the NASDAQ, and a Form 25-NSE will be filed with the Securities and Exchange Commission, which will remove our securities from listing and registration on the NASDAQ Capital Market.

Following the expected delisting from the NASDAQ, our units will commence trading on the OTC Pink Marketplace under the symbol "EVEPQ". We can provide no assurance that its units will commence or continue to trade on this market, whether broker-dealers will continue to provide public quotes of the units on this market, whether the trading volume of the units will be sufficient to provide for an efficient trading market or whether quotes for the units will continue on this market in the future.

Cash Distributions to Unitholders

Suspension of Cash Distribution

The board of directors of EV Management elected to suspend cash distributions to our unitholders in 2017 and 2016, in order to conserve cash and improve liquidity.

As of April 2, 2018, the Partnership was in default under certain of its debt instruments. The Partnership's filing of the Chapter 11 Cases accelerated the Partnership's obligations under its credit facility and the Senior Notes. Additionally, events of default, including cross-defaults, are present, including the receipt of a going concern explanatory paragraph from the Partnership's independent registered public accounting firm on the Partnership's consolidated financial statements, subject to a 30 day grace period. As a result, our credit facility could become due and payable because of this event of default. This has a material, adverse effect on our business, including our ability to resume and sustain distributions.

Distribution Mechanics

Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all of our available cash (as defined in our partnership agreement) to unitholders of record on the applicable record date. The amount of available cash generally is all cash on hand at the end of the quarter:

- *less* the amount of cash reserves established by our general partner to:
  - provide for the proper conduct of our business;
  - comply with applicable law, any of our debt instruments or other agreements; or
  - provide funds for distributions to our unitholders and to our general partner for any one or more of the next four quarters;
- *plus,* if our general partner so determines, all or a portion of cash on hand on the date of determination of available cash for the quarter including cash from working capital borrowings.

Working capital borrowings are borrowings used solely for working capital purposes or to pay distributions to unitholders.

Our general partner is entitled to 2% of all quarterly distributions that we make prior to our liquidation. Our general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its current general partner interest. The general partner's initial 2% interest in these distributions will be reduced if we issue additional units in the future and our general partner does not contribute a proportionate share of capital to us to maintain its 2% general partnership interest. When we issued common units in the past, our general partner contributed to us an amount of cash necessary to maintain its 2% interest.

Our general partner also holds IDRs that entitle it to receive increasing percentages, up to a maximum of 25%, of the cash we distribute from operating surplus (as defined in our partnership agreement) in excess of the minimum quarterly distribution rate per unit per quarter. The maximum distribution percentage of 25% includes distributions paid to our general partner on its 2% general partner interest and assumes that our general partner maintains its general partner interest at 2%. The maximum distribution percentage of 25% does not include any distributions that our general partner may receive on common units that it owns. For additional information on our distributions, please see Note 12 of the Notes to Consolidated Financial Statements in "Item 8. Financial Statements and Supplementary Data."

Our partnership agreement requires that we make distributions of available cash from operating surplus for any quarter in the following manner:

- *first*, 98% to the common unitholders, pro rata, and 2% to the general partner, until we distribute 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 in the table below.

Our general partner is entitled to incentive distributions if the amount we distribute with respect to one quarter exceeds 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%

Unregistered Sales of Equity Securities

None.

Issuer Purchases of Equity Securities

None.

ITEM 6. SELECTED FINANCIAL DATA

The following table shows selected financial data for the periods and as of the dates indicated. The selected financial data are derived from our financial statements. With the sale of our interests in Cardinal Gas Services, LLC ("Cardinal") in October 2014 and in Utica East Ohio Midstream LLC ("UEO") in June 2015, we no longer operate in the midstream segment, and we have reclassified our consolidated financial statements for all periods presented to reflect the operations of our midstream segment as discontinued operations. Accordingly, in the consolidated statements of operations, amounts previously included in "Equity in income of unconsolidated affiliates" have been reclassified to "Income from 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.

	Year Ended December 31,				
	2017 (1)	2016	2015 (1)	2014	2013 (1)
Statement of Operations Data:					
Total revenues	$ 225,693	$ 184,894	$ 177,971	$ 339,405	$ 315,312
Operating income (loss) (2)	(118,068)	(217,050)	(287,933)	(25,123)	(9,703)
Other income (expense), net	(16,343)	(28,220)	51,911	47,844	(65,788)
Income (loss) from continuing operations before income taxes	(134,411)	(245,270)	(236,022)	22,721	(75,491)
Income taxes	210	2,375	1,843	(476)	(133)
Income (loss) from continuing operations	(134,201)	(242,895)	(234,179)	22,245	(75,624)
Income (loss) from discontinued operations (3)	-	-	255,512	107,475	(603)
Net income (loss)	$ (134,201)	$ (242,895)	$ 21,333	$ 129,720	$ (76,227)
Earnings per limited partner unit (basic):					
Income (loss) from continuing operations	$ (2.66)	$ (4.85)	$ (4.72)	$ 0.41	$ (1.75)
Net income (loss)	$ (2.66)	$ (4.85)	$ 0.41	$ 2.58	$ (1.76)
Earnings per limited partner unit (diluted):					
Income (loss) from continuing operations	$ (2.66)	$ (4.85)	$ (4.72)	$ 0.41	$ (1.75)
Net income (loss)	$ (2.66)	$ (4.85)	$ 0.41	$ 2.58	$ (1.76)
Distributions declared per limited partner unit	$ -	$ -	$ 1.575	$ 2.819	$ 3.078
Financial Position (at end of period):					
Working capital	$ (592,523)	$ (6,875)	$ 54,812	$ 428,965	$ 29,435
Total assets	1,441,805	1,606,770	1,923,602	2,246,161	2,201,225
Current portion of long-term debt (4)	605,549	-	-	-	-
Long-term debt, net (4)	-	606,948	688,614	1,027,349	976,539
Owners' equity	628,012	758,407	998,559	1,066,113	1,071,933

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

- Karnes County, Texas in January 2017;
- the Appalachian Basin, the San Juan Basin, Michigan and the Austin Chalk in October 2015; and
- the Barnett Shale in September 2013; and

(2) Includes impairments of oil and natural gas properties of $93.6 million, $131.3 million, $136.7 million, $114.0 million and $85.3 million in 2017, 2016, 2015, 2014 and 2013, respectively.

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

(4) Reduction in long-term debt and related increase in current portion of long-term debt is due to the the Partnership's event of default as discussed in Note 2 of the Notes to Consolidated Financial Statements included under "Item 8. Financial Statements and Supplementary Data" and the default or cross-default provisions in the indentures governing the 8.0% senior notes due April 2019.

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

We are a Delaware limited partnership formed in April 2006 by EnerVest. Our general partner is EV Energy GP, a Delaware limited partnership, and the general partner of our general partner is EV Management, a Delaware limited liability company.

As of December 31, 2017, 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, Central Texas (which includes the Austin Chalk area), the Mid-Continent area in Oklahoma, Texas, Arkansas, Kansas and Louisiana, the Permian Basin, the Monroe Field in Northern Louisiana and Karnes County. As of December 31, 2017, we had estimated net proved reserves of 13.4 MMBbls of oil, 543.7 Bcf of natural gas and 31.6 MMBbls of natural gas liquids, or 813.6 Bcfe, and a standardized measure of $579.4 million.

Restructuring and Bankruptcy Proceedings under Chapter 11

Continued low oil and natural gas prices have had a significant adverse impact on our business, and, as a result of our financial condition, we were not able to continue as a going concern without restructuring our capital structure.

On March 13, 2018, the Debtors entered into the Restructuring Support Agreement with (i) the Supporting Noteholders of approximately 70% of the Senior Notes issued pursuant to the Indenture; (ii) the Supporting Lenders constituting approximately 94% of the principal amount outstanding under the credit facility; (iii) EnerVest; and (iv) EnerVest Operating.

The Plan, which remains subject to confirmation by the Bankruptcy Court and other closing conditions, provides that, among other things, on the effective date of the Plan (the "Effective Date"), subject to the occurrence and completion of certain structuring steps:

- the lenders under the credit facility that vote to accept the Plan will receive (a) pro rata loans under an amendment to the credit facility (the "Exit Credit Facility"), (b) cash in an amount equal to the accrued but unpaid interest payable to such lenders under the credit facility as of the Effective Date, and (c) 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;

- lenders under the credit facility that vote to reject the Plan will receive (a) term loans under a new term loan facility and (b) cash in an amount equal to the accrued and unpaid interest payable to such lender under the credit facility as of the Effective Date;

- the holders of the Senior Notes will receive 95% of the new common stock (subject to dilution) in the new, reorganized company, on a pro rata basis;

- the holders of general unsecured claims, including customers, will be paid in full or will otherwise be unimpaired; and

- the holders of the existing common interests in EVEP will receive 5% of the new common stock (subject to dilution) and five-year warrants for 8% of the new common stock (subject to dilution) in the new, reorganized company, on a pro rata basis, with an exercise price set at an equity value at which the holders of the Senior Notes would receive a recovery equal to par plus accrued and unpaid interest as of the Petition Date in respect of the Senior Notes (after taking into account value dilution on account of the three percent of the new common stock to be allocated to the participants in the management incentive plan on the Effective Date pursuant to a management incentive plan).

On March 14, 2018 the Debtors commenced the solicitation of votes from the holders of the Senior Notes to accept or reject the Plan in accordance with the terms of the Restructuring Support Agreement.

On April 2, 2018, the Debtors commenced the Chapter 11 Cases in the Bankruptcy Court. The Debtors have filed motions with the Bankruptcy Court seeking operational and procedural relief, including joint administration of their Chapter 11 Cases. The Debtors have also filed a motion requesting that the Bankruptcy Court schedule a hearing to confirm the Plan. If the Plan is confirmed by the Bankruptcy Court and becomes effective, then the claims of the lenders under the credit facility and the holders of the Senior Notes will be discharged. There can be no assurance regarding the Partnership's ability to obtain confirmation of the Plan or approval of other relief in the Chapter 11 Cases, the Bankruptcy Court's rulings in the Chapter 11 Cases or the ultimate outcome of the Chapter 11 Cases in general.

As of April 2, 2018, the Partnership was in default under certain of its debt instruments. The Partnership's filing of the Chapter 11 Cases described above accelerated the Partnership's obligations under its credit facility and the Indenture governing the Senior Notes. Additionally, events of default, including cross-defaults, including the receipt of a going concern explanatory paragraph from the Partnership's independent registered public accounting firm on the Partnership's consolidated financial statements, which is subject to a 30 day grace period. Under the Bankruptcy Code, the creditors under these debt agreements are stayed from taking any action against the Partnership as a result of an event of default.

For the duration of the Restructuring and after the Chapter 11 Cases, our operations and our ability to develop and execute our business plan are subject to risks and uncertainties associated with the Restructuring and Chapter 11 Cases. As a result of these risks and uncertainties, our assets, liabilities, officers and/or directors could be significantly different following the outcome of the Chapter 11 Cases, and the description of our operations, properties and capital plans included in these financial statements may not accurately reflect our operations, properties and capital plans following the Chapter 11 Cases.

The Partnership expects to continue its operations without interruption during the pendency of the Chapter 11 Cases. See Note 2 of the Notes to Consolidated Financial Statements included under "Item 8. Financial Statements and Supplementary Data" for additional information.

Ability to Continue as a Going Concern

As discussed above, as of April 2, 2018, the Partnership was in default under certain of its debt instruments. The Partnership's filing of the Chapter 11 Cases accelerated the Partnership's obligations under its credit facility and the Senior Notes. Additionally, events of default, including cross-defaults, are present, including the receipt of a going concern explanatory paragraph from the Partnership's independent registered public accounting firm on the Partnership's consolidated financial statements, subject to a 30 day grace period. As a result, our credit facility could become due and payable because of this event of default.

Throughout 2017, our management, along with our legal and financial advisors, explored strategic alternatives to maintain sufficient liquidity and to address the credit agreement covenant compliance issue. We specifically evaluated options with the lenders under our credit facility and the holders of our Senior Notes that would improve liquidity and deleverage the Partnership. Our ability to access the capital markets has been extremely limited. In addition, our credit facility is subject to scheduled redeterminations of its borrowing base, semi-annually as of April 1 and October 1. We do not have sufficient liquidity to repay amounts due under the credit agreement and the Senior Notes.

The significant risks and uncertainties related to our liquidity and the Chapter 11 Cases described above raise substantial doubt about our ability to continue as a going concern. The audited consolidated financial statements for the year ended December 31, 2017 have been prepared on a going concern basis of accounting, which contemplates continuity of operations, realization of assets, and satisfaction of liabilities and commitments in the normal course of business. The audited consolidated financial statements do not include any adjustments that might result from the outcome of the going concern uncertainty. If we cannot continue as a going concern, adjustments to the carrying values and classification of our assets and liabilities and the reported amounts of income and expenses could be required and could be material.

In order to decrease the Partnership's level of indebtedness and maintain the Partnership's liquidity at levels sufficient to meet its commitments, the Partnership has undertaken a number of actions, including minimizing capital expenditures and further reducing its recurring operating expenses. The Partnership believes that even after taking these actions, it will not have sufficient liquidity to satisfy its debt service obligations, meet other financial obligations and comply with its debt covenants. As a result, the Debtors filed petitions for reorganization under Chapter 11 of the Bankruptcy Code.

See Note 2 and 10 of the Notes to Consolidated Financial Statements included under "Item 8. Financial Statements and Supplementary Data" and "Item 1A. Risk Factors" for additional information regarding our debt instruments and bankruptcy proceedings under Chapter 11.

Operating Environment

Oil, natural gas and natural gas liquids prices are determined by many factors that are outside of our control. Historically, these prices have been volatile, and we expect them to remain volatile. In late 2014, prices for oil, natural gas and natural gas liquids declined precipitously, and prices remained low through 2015 and most of 2016. While prices showed some improvement during the second half of 2016 and 2017, they have continued to fluctuate.

Factors contributing to lower oil prices in recent years have included real or perceived geopolitical risks in oil producing regions of the world, particularly the Middle East; excess global supply and buildup of oil inventory levels above the historical norm; actions taken by the Organization of Petroleum Exporting Countries; and the strength of the US dollar in international currency markets. Factors contributing to lower natural gas prices include increased supplies of natural gas due to greater exploration and development activities; higher levels of natural gas in storage; and competition from other energy sources. Prices for natural gas liquids generally correlate to the price of oil and are likely to continue to directionally follow the market for oil.

In 2017, oil, natural gas and natural gas liquids prices increased relative to previous years, but did not reach a level for our revenues and cash flows to sufficiently reduce our total leverage ratio to meet the longer term level required by our credit agreement. The continuation of these lower prices, coupled with our levels of leverage, has negatively affected our revenues, earnings and cash flows. Continued volatility in prices for oil, natural gas and natural gas liquids could have a material adverse effect on our liquidity. Continued volatility or additional declines in prices could also have a significant adverse impact on the value and quantities of our reserves, assuming no other changes in our development plans.

As specified by the SEC, the prices for oil, natural gas and natural gas liquids used to calculate our reserves were the average prices during the year determined using the price on the first day of each month. The prices utilized in calculating our total estimated proved reserves at December 31, 2017 were $51.34 per Bbl of oil and $2.976 per MMBtu of natural gas, which is lower than current forward strip prices. Had we used the forward strip prices at December 31, 2017 through December 2030, we estimate that the present value (discounted at 10% per annum) of estimated future net revenues of our proved reserves would have been approximately 6.0% higher and that our reserves on an Mcfe basis would have been approximately 2.6% higher than our reserves calculated using SEC prices.

Our Responses to the Operating Environment in 2017 and Our Operating Plan for 2018

In 2017 and through April 2, 2018, we took a number of actions to preserve our liquidity and financial flexibility, including:

- negotiating and pursuing consummation of the Restructuring, which is expected to substantially deleverage our balance sheet and reduce debt service obligations;
- focusing on managing and enhancing our base business through continued reductions in operating costs;
- increasing our capital spending to $39.3 million in 2017 from $10.7 million in 2016, in an effort to maintain current production levels;
- concentrating on maintaining sufficient liquidity;
- continuing to evaluate strategic acquisitions of long–life, producing oil and natural gas properties such as our Eagle Ford Acquisition in January 2017; and
- attempting to further realize the value of our undeveloped acreage through either acquiring alternative sources of capital (including farmouts, production payments and joint ventures) or monetization of acreage.

In December 2016, we sold a portion of our Barnett Shale natural gas properties for $52.1 million (before post-closing adjustments), which proceeds were deposited into a 1031 'like-kind' exchange account. On January 31, 2017, we completed the Eagle Ford Acquisition. Certain EnerVest institutional partnerships own an 87% working interest in, and EnerVest acts as operator of, the properties.

As a result of the steps above, as of December 31, 2017, we have over $66 million of liquidity between our borrowing base capacity and cash on hand. We expect to continue operations without interruption during the pendency of the Chapter 11 Cases. Going forward into 2018, we plan to take additional steps to continue to preserve our liquidity and financial flexibility. These steps include:

- focusing on managing and enhancing our base business through continued reductions in operating costs;
- increasing our capital spending budget to $55 - $65 million from $39.3 million in 2017, in an effort to maintain current production levels;
- continuing to evaluate strategic acquisitions of long–life, producing oil and natural gas properties such as our Eagle Ford Acquisition; and
- realizing the value of our undeveloped acreage through either alternative sources of capital, including farmouts, production payments and joint ventures, or potential monetization of acreage.

During 2017, the board of directors of EV Management announced that it had elected to suspend distributions to our common unitholders for each quarter during the fiscal year. A distribution will not be made to our unitholders with respect to the first quarter of 2018. While we continue to generate positive distributable cash flow, the levels of cash flow are significantly less than we generated in prior years, and not adequate presently to repay our outstanding indebtedness and make distributions to our unitholders.

As of April 2, 2018, the Partnership was in default under certain of its debt instruments. The Partnership's filing of the Chapter 11 Cases accelerated the Partnership's obligations under its credit facility and the Senior Notes. Additionally, events of default, including cross-defaults, are present, including the receipt of a going concern explanatory paragraph from the Partnership's independent registered public accounting firm on the Partnership's consolidated financial statements, subject to a 30 day grace period. As a result, our credit facility could become due and payable because of this event of default. This has a material, adverse effect on our business.

We typically enter into derivative instruments to reduce the impact of price volatility on our cash flows. As of December 31, 2017, we were a party to derivative contracts covering approximately 44% of our production attributable to our estimated net proved reserves through March 2018. Please refer to Item 7A. "Quantitative And Qualitative Disclosures About Market Risk" in this annual report for more information.

The primary factors affecting our production levels are capital availability, our ability to make accretive acquisitions, the success of our drilling program and our inventory of drilling prospects. In addition, as initial reservoir pressures are depleted, production from our wells decreases. We attempt to overcome this natural decline through a combination of drilling and acquisitions. Our future growth will depend on our ability to continue to add reserves through drilling and acquisitions in excess of production. We will maintain our focus on the costs to add reserves through drilling and acquisitions as well as the costs necessary to produce such reserves. Our ability to add reserves through drilling is dependent on our capital resources and can be limited by many factors, including our ability to timely obtain drilling permits and regulatory approvals. Any delays in drilling, completion or connection to gathering lines of our new wells will negatively impact our production, which may have an adverse effect on our revenues.

We focus our efforts on increasing 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.

In 2017, we spent $39.3 million of capital drilling and completing wells, a decline relative to our average capital expenditures for drilling and completion activities in previous years. As a result, we saw our total production decline throughout the year. For 2018, we plan to spend $55 - $65 million of capital in an effort to keep our production flat, or to achieve moderate growth. We will continue monitoring the ongoing commodity price environment and expect to retain the financial flexibility to adjust plans in response to market conditions as needed.

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 US generally accepted accounting principles. 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.

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.

Derivatives

We use derivatives to hedge against the variability in cash flows associated with the forecasted sale of our anticipated future oil, natural gas and natural gas liquids production. We have historically hedged a substantial, but varying, portion of our anticipated production for the next 12 – 36 months. We do not use derivatives for trading purposes. We have elected not to apply hedge accounting to our derivatives. Accordingly, we carry our derivatives at fair value on our consolidated balance sheet, with the changes in the fair value included in our consolidated statement of operations in the period in which the change occurs. Our current results of operations would potentially have been significantly different had we elected and qualified for hedge accounting on our derivatives.

In determining the amounts to be recorded, we are required to estimate the fair values of the derivatives. We base our estimates of fair value upon various factors that include closing prices on the NYMEX, volatility, the time value of options, our credit worthiness and the credit worthiness of the counterparties to our derivative instruments. These pricing and discounting variables are sensitive to market volatility as well as changes in future price forecasts and interest rates.

Goodwill

Goodwill is an asset representing the future economic benefits arising from other assets acquired in a business combination that are not individually identified and separately recognized. In accounting for a business combination, the purchase price is allocated to the identifiable assets and liabilities based upon the estimated fair values as of the acquisition date. Goodwill is the excess of the purchase price over the estimated fair values of the assets acquired net of the liabilities assumed in the acquisition. Goodwill is not amortized, but is evaluated for impairment at the reporting unit level.

We have the option of performing either a qualitative or quantitative assessment to determine if impairment may have occurred. If the qualitative assessment indicates that it is more likely than not that the fair value of our reporting unit is less than its carrying amount, then we would be required to perform the two step impairment test.

Under the first step in the impairment test, we compare the fair value of our reporting unit with its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, the second step of the goodwill impairment test is performed. Under the second step in the impairment test, the implied fair value of goodwill is compared with its carrying amount. The implied fair value of goodwill is calculated by subtracting the estimated fair values of our reporting unit's assets net of liabilities from the fair value of our reporting unit. If the carrying amount of goodwill exceeds its implied fair value, an impairment loss shall be recognized in an amount equal to that excess.

We determine the fair value of the reporting unit using a combination of the market approach and the income approach. Under the market approach, the fair value is based on the quoted market price for our common units adjusted for a control premium, which is the premium over current market price a market participant may be willing to pay to obtain the synergies and other benefits that control would provide. Under the income approach, the fair value was based on the expected present value of the future net cash flows. Significant assumptions associated with the calculation of the fair value include estimates of the appropriate control premium, future prices, production costs, development expenditures, anticipated production, appropriate risk–adjusted discount rates and other relevant data. Given the nature of these estimates and their application to specific assets and liabilities and time frames, it is not possible to reasonably quantify the impact of changes in these assumptions.

Asset Retirement Obligations

We have significant obligations to remove tangible equipment and facilities and restore land at the end of oil and natural gas production operations. Our removal and restoration obligations are primarily associated with site reclamation, dismantling facilities and plugging and abandoning wells. Estimating the future restoration and removal costs is difficult and requires management to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations.

We record an asset retirement obligation ("ARO") and capitalize 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.

Inherent in the present value calculation are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions of these assumptions impact the present value of the existing asset retirement obligation, a corresponding adjustment is made to the oil and natural gas property balance.

Revenue Recognition

Oil, natural gas and natural gas liquids revenues are recognized when production is sold to a purchaser at fixed or determinable prices, when delivery has occurred and title has transferred and collectibility of the revenue is reasonably assured. 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.

There are two principal accounting practices to account for natural gas imbalances. These methods differ as to whether revenue is recognized based on the actual sale of natural gas (sales method) or an owner's entitled share of the current period's production (entitlement method). 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 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

	Year Ended December 31,		
	2017	2016	2015
Production data:			
Oil (MBbls)	1,387	1,216	1,041
Natural gas liquids (MBbls)	2,165	2,331	2,326
Natural gas (MMcf)	40,979	49,333	43,592
Net production (MMcfe)	62,293	70,612	63,792
Average sales price per unit:			
Oil (Bbl)	$ 47.41	$ 38.78	$ 43.67
Natural gas liquids (Bbl)	21.40	15.32	14.04
Natural gas (Mcf)	2.71	2.02	2.23
Mcfe	3.58	2.59	2.74
Average unit cost per Mcfe:			
Production costs:			
Lease operating expenses	$ 1.63	$ 1.46	$ 1.56
Production taxes	0.17	0.10	0.11
Total	1.80	1.56	1.67
Depreciation, depletion and amortization	1.56	1.69	1.66
General and administrative expenses	0.52	0.48	0.62

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.

Depreciation, depletion and amortization ("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.

Year Ended December 31, 2016 Compared with the Year Ended December 31, 2015

Net loss for 2016 was $242.9 million compared with net income of $21.3 million for 2015. The significant factors in this change were (i) a $255.5 million decrease in income from discontinued operations; (ii) a $114.1 million unfavorable change in gain (loss) on derivatives; partially offset by (iii) a $65.9 million decrease in impairment of goodwill; and (iv) a $23.7 million increase in gain on early extinguishment of debt.

Oil, natural gas and natural gas liquids revenues for 2016 totaled $182.7 million, an increase of $7.6 million compared with 2015. This was the result of increases of $18.5 million related to increased oil, natural gas and natural gas liquids production as a result of the October 2015 acquisitions offset by decreases of $10.9 million related to lower prices for oil, natural gas and natural gas liquids.

Lease operating expenses for 2016 increased $3.7 million compared with 2015 as the result of $9.9 million from increased oil and natural gas production offset by $6.2 million from a lower cost per Mcfe. The lower unit cost per Mcfe reflects the downward trend in operating costs throughout the oil and natural gas industry. Lease operating expenses per Mcfe were $1.46 in 2016 compared with $1.56 in 2015.

Dry hole and exploration costs for 2016 decreased $3.0 million compared with 2015 as a result of our decreased drilling program during 2016.

Production taxes for 2016 increased $0.6 million compared with 2015 due to higher oil, natural gas and natural gas liquids revenues. Production taxes for 2016 were $0.10 per Mcfe compared with $0.11 per Mcfe for 2015.

DD&A for 2016 increased $13.2 million compared with 2015 due to $11.5 million of increased oil and natural gas production combined with $1.7 million from a higher average DD&A rate per Mcfe. The higher average DD&A rate per Mcfe reflects the change that prices had on our reserves estimates. DD&A for 2016 was $1.69 per Mcfe compared with $1.66 per Mcfe for 2015.

General and administrative expenses for 2016 totaled $33.6 million, a decrease of $5.4 million compared with 2015. This decrease is primarily the result of (i) $5.4 million of lower equity compensation costs, of which $2.3 million related to the accelerated vesting of the phantom units of a former officer in 2015; (ii) $1.3 million of decreased compensation costs, of which $0.8 million related to the vesting of our phantom units under our equity compensation plan; partially offset by (iii) $1.7 million of higher fees paid to EnerVest under the omnibus agreement related to our October 2015 acquisition. General and administrative expenses were $0.48 per Mcfe in 2016 compared with $0.62 per Mcfe in 2015.

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 $131.3 million and $136.7 million in 2016 and 2015, respectively. Of these amounts, $89.5 million and $86.9 million in 2016 and 2015, 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. The $89.5 million of impairment for 2016 related to oil and natural gas properties in the Barnett Shale which were sold during December 2016 (see Note 6). 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 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. The remainder of the impairment charges in 2015 consisted of $49.8 million of leasehold impairments, of which $49.2 million related to a change in our development plans for acreage in the Utica Shale.

In conjunction with our October 2015 acquisitions of oil and natural gas properties, we recorded $65.9 million of goodwill. As of December 31, 2015, we determined that the carrying amount of goodwill was impaired due to the continued decline in oil, natural gas and natural gas liquids prices. We determined the fair value of the reporting unit using a combination of the market approach and the income approach. Significant assumptions associated with the calculation of the fair value included estimates of future prices, production costs, development expenditures, anticipated production, appropriate risk–adjusted discount rates and other relevant data. We then determined the implied fair value of goodwill by subtracting the estimated fair values of the reporting unit's assets net of liabilities from the fair value of the reporting unit. As the carrying amount of the goodwill exceeded the implied fair value of the goodwill, we recognized a $65.9 million impairment loss for the difference between the carrying amount and the implied fair value of goodwill.

In 2015, we recognized a gain of $0.6 million on the sale of certain non–core oil and natural gas properties.

Loss on derivatives, net was $36.0 million for 2016 compared with a gain on derivatives, net of $78.1 million for 2015. This change was attributable to changes in future oil and natural gas prices. 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. The 12-month forward price at December 31, 2015 for oil averaged $40.45 per Bbl compared with $56.46 per Bbl at December 31, 2014, and the 12-month forward price at December 31, 2015 for natural gas averaged $2.49 per MmBtu compared with $3.03 at December 31, 2014.

Interest expense for 2016 decreased $7.8 million compared with 2015 due to $9.4 million attributed to a lower weighted average long-term debt balance, partially offset by $0.1 million from a higher weighted average effective interest rate and the write-off of $1.5 million of loan costs due to the reduction in the borrowing base and the redemption of the Senior Notes.

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 2015, we recognized a $24.0 million gain on the early extinguishment of debt as we redeemed $74.0 million of our Senior Notes for $50.0 million.

In 2016, we recorded approximately $2.4 million of tax benefits as a result of tax refunds and lower taxes. In December 2015, we converted our wholly owned subsidiary Belden and Blake Corporation ("Belden") from a corporation into a single member limited liability company. As a result, the $13.4 million of deferred taxes recorded in the acquisition of Belden were realized. The benefit was offset by an $11.7 million current tax liability for the estimated federal and state taxes based on the fair value of Belden as of the date of conversion.

Income from discontinued operations was $255.5 million in 2015. Included in 2015 was the $246.7 million gain on the sale of Utica East Ohio Midsteram LLC (“UEO”).

LIQUIDITY AND CAPITAL RESOURCES

Historically, our primary sources of liquidity and capital have been issuances of equity and debt securities, borrowings under our credit facility and cash flows from operations. Our primary uses of cash have been acquisitions of oil and natural gas properties and related assets, development of our oil and natural gas properties, distributions to our unitholders and general partner and meeting our working capital needs.

In 2017, in response to continued lower prices, we took a number of actions, including suspending distributions on our common units and strategic divestitures of non-core assets, to preserve our liquidity and financial flexibility. As a result of these steps, as of December 31, 2017, we have over $66 million of liquidity between our borrowing base capacity and cash on hand.

For 2018, we believe that cash on hand, proceeds from sales of assets, net cash flows generated from operations and borrowings under our expected Exit Credit Facility will be adequate to fund our capital budget and satisfy our short–term liquidity needs.

We may also utilize borrowings under our expected Exit 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 our 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, 2017, the credit facility had a capitalization of $1.0 billion and will expire in February 2020. 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, 2017, the borrowing base was $325.0 million, and we had $263.0 million of indebtedness under the credit facility outstanding.

In October 2017, we entered into the tenth amendment (“Tenth Amendment”) to our credit agreement governing the credit facility. Specifically, the amendment:

- decreased the borrowing base to $325.0 million;
- increased the required percentage of mortgaged properties from 85% to 95%;
- amended and restated the guaranty and collateral agreement to substantially increase the collateral securing the credit facility to cover all personal property;
- allowed for the maintenance of deposit and securities accounts at the facility lenders’ financial institutions subject to a deposit account control agreement on such accounts; and
- within 15 days of the closing of the Tenth Amendment, required mortgaged properties to represent at least 98% of the total value of the oil and gas properties evaluated in the most recently completed reserve report.

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

- the senior secured funded debt to earnings plus interest expense, taxes, depreciation, depletion and amortization expense and exploration expense (“EBITDAX”) ratio covenant to be no greater than (a) for the fiscal quarters ending March 31, 2017 and June 30, 2017, 3.5 to 1.0 and (b) for the fiscal quarter ending September 30, 2017 and December 31, 2017, 4.0 to 1.0;

- total funded debt to EBITDAX ratio covenant to be no greater than (a) for the fiscal quarters ending March 31, 2018, 5.50 to 1.0, (b) for the fiscal quarters ending June 30, 2018 and September 30, 2018, 5.25 to 1.0 and (c) for the fiscal quarter ending December 31, 2018 and thereafter, 4.25 to 1.0;

- the EBITDAX to cash interest expense ratio covenant to be no less than (a) for the fiscal quarters ending March 31, 2017 and June 30, 2017, 2.0 to 1.0 and (c) for the fiscal quarter ending September 30, 2017 and thereafter, 1.5 to 1.0; and

- limits cash held by us to the greater of 5% of the current borrowing base or $30.0 million.

As of December 31, 2017, we had $343.3 million in aggregate principal amount outstanding of our Senior Notes. As of December 31, 2017, the aggregate carrying amount of the Senior Notes was $342.5 million.

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.

If the Partnership effectuates the Restructuring pursuant to the Restructuring Support Agreement and the Plan, then the claims of the lenders under the credit facility and the holders of the Senior Notes will be cancelled. See Note 2 of the Notes to Consolidated Financial Statements included under “Item 8. Financial Statements and Supplementary Data” for additional information on the terms of the Restructuring Support Agreement.

Cash and Cash Equivalents

At December 31, 2017, we had $4.9 million of cash and cash equivalents, 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.

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, 2017, all of our counterparties have performed pursuant to their derivative contracts.

Cash Flows

	2017	2016	2015
Operating activities	$ 31,700	$ 33,875	$ 141,283
Investing activities	(30,361)	(9,766)	291,793
Financing activities	(2,000)	(38,967)	(420,916)

Operating Activities

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.

Cash flows from operating activities provided $33.9 million and $141.3 million in 2016 and 2015, respectively. The significant factors in the change were $85.8 million of decreased cash settlements from our matured derivative contracts, an $11.7 million federal tax payment related to the conversion of an acquired corporation to a single member LLC and a $28.9 million change in working capital, primarily related to higher accounts receivable as a result of higher oil, natural gas and natural gas liquids production during 2016.

Investing Activities

During 2017, cash flows used in investing activities totaled $30.4 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 the use of $52.1 million of restricted cash for acquisitions, $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 used in investing activities totaled $9.8 million. This consisted of $52.1 million of restricted cash deposited with a qualified intermediary to facilitate like–kind exchange transactions pursuant to Section 1031 of the Internal Revenue Code and $15.3 million for additions to our oil and natural gas properties offset by $54.5 million from the sale of oil and natural gas properties and $3.0 million in cash settlements from acquired derivative contracts.

During 2015, cash flows used in investing activities from continuing operations totaled $280.4 million. This consisted of $250.4 million for acquisitions of oil and natural gas properties, $67.9 million for additions to our oil and natural gas properties offset by $33.8 million from the release of cash deposited with a qualified intermediary to facilitate like–kind exchange transactions pursuant to Section 1031 of the Internal Revenue Code, $2.6 million in cash settlements from acquired derivative contracts and $1.5 million in proceeds from the sales of oil and natural gas properties. Net cash flows provided by investing activities from discontinued operations of $572.2 million consisted of the proceeds from the sale of our interest in UEO.

Financing Activities

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.

During 2015, we repaid $561.0 million of borrowings under our credit facility with proceeds from the sale of our investment in UEO and the release of our restricted cash. We also redeemed $74.0 million of our Senior Notes for $50.0 million, received $295.0 million from borrowings under our credit facility, incurred loan costs of $4.1 million related to the amendments of our credit facility and paid distributions of $101.0 million to holders of our common units, phantom units and our general partner.

Capital Requirements

We currently expect spending in 2018 for additions to our oil and natural gas properties to be between $55 and $65 million, an increase from the amounts spent in 2017.

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 expected Exit Credit Facility upon approval of the Plan in the Chapter 11 Cases.

We are actively engaged in the acquisition of oil and natural gas properties. We expect to finance any acquisitions in 2018 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	**2018**	**2019 - 2020**	**2021 - 2022**	**After 2022**
Total debt [1]	$ 606,348	$ -	$ 606,348	$ -	$ -
Estimated interest payments [2]	58,504	38,197	20,307	-	-
Transportation commitments [3]	12,711	3,324	4,675	2,992	1,720
Purchase obligation [4]	17,200	17,200	-	-	-
Total	$ 694,763	$ 58,721	$ 631,330	$ 2,992	$ 1,720

(1) Amounts represent the scheduled future maturities of principal amounts outstanding for the period indicated. Maturities are shown at original maturity dates assuming no acceleration; however, due to the event of default, the Partnership's entire long-term debt was classified as current at December 31, 2017. See Note 10 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for additional information.

(2) Amounts represent the expected cash payments for interest based on (i) the amount outstanding under our credit facility as of December 31, 2017 and the weighted average interest rate for 2017 of 4.08%, and (ii) our $343.3 million in aggregate principal amount of Senior Notes. Such amounts do not include the effects of our interest rate swaps. Maturities are shown at original maturity dates assuming no acceleration: however, due to the event of default, the Partnership's entire long-term debt was classified as current at December 31, 2017. See Note 10 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for additional information.

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

(4) Amounts represent payments to be made under our omnibus agreement with EnerVest based on the amount that we will pay in 2018. This amount will increase or decrease as we purchase or divest assets. While these payments will continue for periods subsequent to December 31, 2018, 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, 2017 is $162.0 million.

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, 2017, 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.

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:

- bankruptcy proceedings and the effect of those proceedings on our ongoing and future operations;
- our future financial and operating performance and results, and our ability to resume and sustain distributions;
- our business strategy and plans, and future capital expenditures, including plans to optimize the value of our assets, including our business strategies post-emergence from bankruptcy;
- our estimated net proved reserves, PV–10 value and standardized measure;
- our liquidity and capital availability;
- market prices;
- 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:

- risks and uncertainties associated with the Chapter 11 Cases described in this annual report, including our ability to develop, confirm and consummate a plan under Chapter 11 or an alternative restructuring transaction, including a sale of all or substantially all of our assets, which may be necessary to continue as a going concern;
- our inability to maintain relationships with suppliers, customers, employees and other third parties as a result of our Chapter 11 filing;
- our ability to obtain the approval of the Bankruptcy Court with respect to motions or other requests made to the Bankruptcy Court in the Chapter 11 Cases, including maintaining strategic control as debtor-in-possession;
- our ability to obtain sufficient financing to allow us to emerge from bankruptcy and execute our business plan post-emergence;
- the effects of the Chapter 11 Cases on the Partnership and on the interests of various constituents, including holders of our common units;
- Bankruptcy Court rulings in the Chapter 11 Cases as well as the outcome of all other pending litigation and the outcome of the Chapter 11 Cases in general;
- the length of time that the Partnership will operate under Chapter 11 protection and the continued availability of operating capital during the pendency of the proceedings;
- risks associated with third-party motions in the Chapter 11 Cases, which may interfere with our ability to confirm and consummate the Plan;
- the potential adverse effects of the Chapter 11 Cases on our liquidity and results of operations;
- increased advisory costs to execute a reorganization;
- the impact of the NASDAQ's delisting of our common units on the liquidity and market price of our common units and on our ability to access the public capital markets;
- 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;
- cash flows and liquidity;
- 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;
- fluctuations in interest rates and the value of the US dollar in international currency markets; and
- our ability to effectively integrate companies and properties that we acquire.

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. As substantial doubt exists that we will be able to continue as a going concern, finding counterparties for commodity hedges has proven difficult. Under the expected Exit Credit Facility, we will be required to hedge no less than 70% of our forecasted proved developed producing production not later than the closing date and for the 18-month period thereafter.

We currently do not have any commodity hedges in place. We entered into derivatives to hedge a portion of our anticipated production through March 2018. As of December 31, 2017, we had derivatives covering approximately 44% of our production attributable to our estimated net proved reserves through March 2018, as estimated in our reserve report prepared by third party engineers using prices, costs and other assumptions required by SEC rules. 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, 2017 was positive, representing an asset of $2.0 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 $2.5 million. Please see “Item 8. Financial Statements and Supplementary Data” contained herein for additional information.

Interest Rate Risk

Our floating rate credit facility and interest rate derivatives also expose 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 2017 would have increased by approximately $2.7 million. The fair value of our interest rate derivatives at December 31, 2017 was positive, representing an asset of $0.7 million. A 1% change in interest rates 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 interest rate swaps) of our interest rate derivatives of approximately $0.4 million. Please see “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 Partnership'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 Partnership'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 EV Energy Partners, L.P.'s internal control over financial reporting was effective as of December 31, 2017.

/s/ MICHAEL E. MERCER
Michael E. Mercer
Chief Executive Officer of EV Management, LLC,
general partner of EV Energy, GP, L.P.,
general partner of EV Energy Partners, L.P.

/s/ NICHOLAS BOBROWSKI
Nicholas Bobrowski
Chief Financial Officer of EV Management, LLC,
general partner of EV Energy GP, L.P.,
general partner of EV Energy Partners, L.P.

Houston, TX
April 2, 2018

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of EV Management, LLC and
Unitholders of EV Energy Partners, L.P. and Subsidiaries
Houston, Texas

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of EV Energy Partners, L.P. and subsidiaries (the "Partnership") as of December 31, 2017 and 2016, the related consolidated statements of operations, cash flows and changes in owners' equity for each of the three years in the period ended December 31, 2017, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Partnership as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

Emphasis of Matter Regarding Going Concern

The accompanying financial statements have been prepared assuming that the Partnership will continue as a going concern. As discussed in Note 2 to the financial statements, the Partnership filed voluntary petitions for reorganization under Chapter 11 of the United States Bankruptcy Code on April 2, 2018, which raises substantial doubt about its ability to continue as a going concern. Management's plans in regard to these matters are also described in Note 2. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

Basis for Opinion

These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on the Partnership'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 Partnership 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 Partnership 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 Partnership'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
April 2, 2018

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

EV Energy Partners, L.P.
Consolidated Balance Sheets
(In thousands, except number of units)

	December 31, 2017	December 31, 2016
ASSETS		
Current assets:		
Cash and cash equivalents	$ 4,896	$ 5,557
Accounts receivable:		
Oil, natural gas and natural gas liquids revenues	47,694	39,629
Related party	-	745
Other	78	2,451
Derivative asset	3,052	201
Other current assets	5,713	3,718
Total current assets	61,433	52,301
Oil and natural gas properties, net of accumulated depreciation, depletion and amortization; December 31, 2017, $1,191,559; December 31, 2016, $1,051,600	1,375,527	1,497,211
Other property, net of accumulated depreciation and amortization; December 31, 2017, $1,049; December 31, 2016, $1,002	997	996
Restricted cash	-	52,076
Other assets	3,848	4,186
Total assets	$ 1,441,805	$ 1,606,770
LIABILITIES AND OWNERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities		
Third party	$ 43,817	$ 31,700
Related party	4,194	5,797
Derivative liability	396	21,679
Current portion of long-term debt	605,549	-
Total current liabilities	653,956	59,176
Asset retirement obligations	158,793	180,241
Long–term debt, net	-	606,948
Long–term derivative liability	-	955
Other long–term liabilities	1,044	1,043
Commitments and contingencies (Note 11)		
Owners' equity:		
Common unitholders – 49,368,869 units and 49,055,214 units issued and outstanding as of December 31, 2017 and 2016, respectively	648,371	776,158
General partner interest	(20,359)	(17,751)
Total owners' equity	628,012	758,407
Total liabilities and owners' equity	$ 1,441,805	$ 1,606,770

See accompanying notes to consolidated financial statements.

EV Energy Partners, L.P.
Consolidated Statements of Operations
(In thousands, except per unit data)

	Year Ended December 31, 2017	2016	2015
Revenues:			
Oil, natural gas and natural gas liquids revenues	$ 223,297	$ 182,696	$ 175,088
Transportation and marketing–related revenues	2,396	2,198	2,883
Total revenues	225,693	184,894	177,971
Operating costs and expenses:			
Lease operating expenses	101,591	103,371	99,626
Cost of purchased natural gas	1,699	1,497	1,988
Dry hole and exploration costs	413	651	3,695
Production taxes	10,588	7,386	6,784
Accretion expense on obligations	7,653	8,225	5,598
Depreciation, depletion and amortization	96,901	119,171	105,969
General and administrative expenses	32,290	33,637	38,994
Impairment of oil and natural gas properties	93,607	131,260	136,667
Impairment of goodwill	-	-	65,924
Loss (gain) on settlement of contract	-	(3,185)	1,210
Gain on sales of oil and natural gas properties	(981)	(69)	(551)
Total operating costs and expenses	343,761	401,944	465,904
Operating loss	(118,068)	(217,050)	(287,933)
Other income (expense), net:			
Gain (loss) on derivatives, net	22,854	(35,950)	78,145
Interest expense	(40,903)	(42,487)	(50,336)
Gain on early extinguishment of debt	-	47,695	24,024
Other income, net	1,706	2,522	78
Total other income (expense), net	(16,343)	(28,220)	51,911
Loss from continuing operations before income taxes	(134,411)	(245,270)	(236,022)
Income tax benefits	210	2,375	1,843
Loss from continuing operations	(134,201)	(242,895)	(234,179)
Income from discontinued operations	-	-	255,512
Net income (loss)	$ (134,201)	$ (242,895)	$ 21,333
Earnings per limited partner unit (basic and diluted):			
Loss from continuing operations	$ (2.66)	$ (4.85)	$ (4.72)
Income from discontinued operations	$ -	$ -	$ 5.13
Net income (loss)	$ (2.66)	$ (4.85)	$ 0.41
Weighted average limited partner units outstanding (basic and diluted)	49,357	49,048	48,853
Distributions declared per common unit	$ -	$ -	$ 1.575

See accompanying notes to consolidated financial statements.

EV Energy Partners, L.P.
Consolidated Statements of Cash Flows
(In thousands)

	Year Ended December 31,		
	2017	**2016**	**2015**
Cash flows from operating activities:			
Net income (loss)	$ (134,201)	$ (242,895)	$ 21,333
Adjustments to reconcile net income (loss) to net cash flows provided by operating activities:			
Income from discontinued operations	-	-	(255,512)
Amortization of volumetric production payment liability	-	(4,108)	(1,196)
Accretion expense on obligations	7,653	8,225	5,598
Depreciation, depletion and amortization	96,901	119,171	105,969
Equity–based compensation	4,266	6,611	12,001
Impairment of oil and natural gas properties	93,607	131,260	136,667
Impairment of goodwill	-	-	65,924
Gain on sales of oil and natural gas properties	(981)	(69)	(551)
Loss (gain) on derivatives, net	(22,854)	35,950	(78,145)
Cash settlements of matured derivative contracts	(2,235)	54,884	140,657
Gain on early extinguishment of debt	-	(47,695)	(24,024)
Deferred taxes	-	(404)	(13,285)
Other	1,411	2,523	4,487
Changes in operating assets and liabilities, net of effects of amounts acquired:			
Accounts receivable	(2,670)	(11,403)	14,850
Other current assets	(1,585)	(361)	511
Accounts payable and accrued liabilities	(6,783)	(5,862)	(4,067)
Income taxes	-	(11,657)	10,683
Other, net	(829)	(295)	(245)
Net cash flows provided by operating activities from continuing operations	31,700	33,875	141,655
Net cash flows used in operating activities from discontinued operations	-	-	(372)
Net cash flows provided by operating activities	31,700	33,875	141,283
Cash flows from investing activities:			
Acquisitions of oil and natural gas properties, net of cash acquired	(61,400)	-	(250,357)
Additions to oil and natural gas properties	(27,268)	(15,258)	(67,923)
Reimbursements related to oil and natural gas properties	2,517	-	-
Proceeds from sales of oil and natural gas properties	3,654	54,509	1,457
Restricted cash	52,076	(52,076)	33,768
Cash settlements from acquired derivative contracts	-	3,003	2,615
Other	60	56	73
Net cash flows used in investing activities from continuing operations	(30,361)	(9,766)	(280,367)
Net cash flows provided by investing activities from discontinued operations	-	-	572,160
Net cash flows (used in) provided by investing activities	(30,361)	(9,766)	291,793

(Continued)

EV Energy Partners, L.P.
Consolidated Statements of Cash Flows (continued)
(In thousands)

	Year Ended December 31,		
	2017	2016	2015
Cash flows from financing activities:			
Long–term debt borrowings	26,000	57,000	295,000
Repayments of long–term debt borrowings	(28,000)	(57,000)	(561,000)
Redemption of 8% Senior Notes due 2019	-	(34,978)	(49,954)
Loan costs paid	-	(121)	(4,074)
Contributions from general partner	-	-	91
Distributions paid	-	(3,868)	(100,979)
Net cash flows used in financing activities	(2,000)	(38,967)	(420,916)
(Decrease) increase in cash and cash equivalents	(661)	(14,858)	12,160
Cash and cash equivalents – beginning of year	5,557	20,415	8,255
Cash and cash equivalents – end of year	$ 4,896	$ 5,557	$ 20,415

(Concluded)

See accompanying notes to consolidated financial statements.

EV Energy Partners, L.P.
Consolidated Statements of Changes in Owners' Equity
(In thousands, except number of units)

	Common Unitholders	General Partner Interest	Total Owners' Equity
Balance, December 31, 2014	$ 1,077,826	$ (11,713)	$ 1,066,113
Contributions from general partner	-	91	91
Distributions	(98,985)	(1,994)	(100,979)
Equity–based compensation	11,761	240	12,001
Net income	20,907	426	21,333
Balance, December 31, 2015	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	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	$ 648,371	$ (20,359)	$ 628,012

See accompanying notes to consolidated financial statements.

EV Energy Partners, L.P.
Notes to Consolidated Financial Statements

NOTE 1. ORGANIZATION AND NATURE OF BUSINESS

EV Energy Partners, L.P. (the "Parent" or "EVEP") and its wholly owned subsidiaries (collectively, the "Partnership") are a publicly held limited partnership. The Partnership's general partner is EV Energy GP, L.P. ("EV Energy GP"), a Delaware limited partnership, and the general partner of its general partner is EV Management, LLC ("EV Management"), a Delaware limited liability company. EV Management is a wholly owned subsidiary of EnerVest, Ltd. ("EnerVest"), a Texas limited partnership. EnerVest and its affiliates also have a significant interest in the Partnership through their 71.25% ownership of EV Energy GP which, in turn, owns a 2% general partner interest in the Partnership and all of its incentive distribution rights.

The Partnership operates one reportable segment engaged in the acquisition, development and production of oil and natural gas properties and all of our operations are located in the United States.

NOTE 2. CHAPTER 11 CASES, ABILITY TO CONTINUE AS A GOING CONCERN AND COVENANT VIOLATIONS

Voluntary Reorganization under Chapter 11

On March 13, 2018, EVEP, EV Energy GP, EV Management and certain of EVEP's wholly owned subsidiaries (each a "Debtor" and, collectively, 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 our 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 March 14, 2018 the Partnership commenced the solicitation of votes from the holders of the Senior Notes to accept or reject the prepackaged plan of reorganization (the "Plan"). If the Partnership effectuates the Restructuring pursuant to the Restructuring Support Agreement and the Plan, and the Plan is approved by the Bankruptcy Court, then the claims of the lenders under the credit facility and the holders of the Senior Notes will be cancelled.

On April 2, 2018, the Debtors commenced the Chapter 11 Cases in the Bankruptcy Court. The Debtors have filed motions with the Bankruptcy Court seeking operational and procedural relief, including joint administration of their Chapter 11 Cases. The Debtors have also filed a motion requesting that the Bankruptcy Court schedule a hearing to confirm the Plan. If the Plan is confirmed by the Bankruptcy Court and becomes effective, then the claims of the lenders under the credit facility and the holders of the Senior Notes will be discharged. There can be no assurance regarding the Partnership's ability to obtain confirmation of the Plan or approval of other relief in the Chapter 11 Cases, the Bankruptcy Court's rulings in the Chapter 11 Cases or the ultimate outcome of the Chapter 11 Cases in general.

For the duration of the Restructuring and after the Chapter 11 Cases, our operations and our ability to develop and execute our business plan are subject to risks and uncertainties associated with the Restructuring and Chapter 11 Cases. As a result of these risks and uncertainties, our assets, liabilities, officers and/or directors could be significantly different following the outcome of the Chapter 11 Cases, and the description of our operations, properties and capital plans included in these financial statements may not accurately reflect our operations, properties and capital plans following the Chapter 11 Cases.

The Partnership expects to continue its operations without interruption during the pendency of the Chapter 11 Cases.

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Notes to Consolidated Financial Statements (continued)

The Restructuring Support Agreement sets forth, subject to certain conditions, the commitment of the Debtors and the Consenting Creditors to support the Restructuring. The Restructuring Support Agreement obligates the Debtors and the Consenting Creditors to, among other things, support and not interfere with consummation of the Restructuring and, as to the Consenting Creditors, vote their claims in favor of the Plan. The Restructuring Support Agreement may be terminated upon the occurrence of certain events, including the failure to meet specified milestones relating to the filing, confirmation and consummation of the Plan, among other requirements, and in the event of certain breaches by the parties under the Restructuring Support Agreement. The Restructuring Support Agreement is subject to termination if the effective date of the Plan has not occurred within 250 days of the bankruptcy filing. There can be no assurances that the Restructuring will be consummated.

Under the terms of the Restructuring Support Agreement, the financial restructuring would be effectuated through the Plan, which was filed contemporaneously with the Debtors' voluntary petitions. Pursuant to the terms of the Plan, as approved by the Bankruptcy Court, it is anticipated that, among other things:

- On or prior to the Effective Date of the Plan (the "Effective Date"), the Supporting Holders that hold the Senior Notes will contribute their Senior Notes (the "Contributed Notes") to a newly formed C-corporation ("New EVEP Parent Inc.") in exchange for pro rata share of 95% of the shares of common stock of New EVEP Parent Inc. (the "New Equity Interests");

- On the Effective Date, New EVEP Parent Inc. would contribute to a newly formed subsidiary ("Acquisition Inc.") (i) the Contributed Notes, (ii) a number of shares of New Equity Interests sufficient to satisfy (a) the claims of the holders of the Senior Notes (the "Notes Claims") other than the Notes Claims in respect of the Contributed Notes and (b) shares of New Equity Interests to be distributed to the holders of existing equity interests in the Partnership (the "Existing Unitholders") and (iii) 5-year warrants for 8% of the New Equity Interests (subject to dilution by the shares (the "MIP Shares") reserved to participants in the new management incentive plan (the "MIP")), with a strike price set at an equity value at which the Supporting Holders would receive a recovery equal to par plus accrued and unpaid interest as of the petition date of the Chapter 11 Cases in respect of the Senior Notes (after taking into account value dilution on account of the initial distribution of participants in the MIP), (the "New Warrants") New EVEP Parent Inc. will receive all of the equity interests of Acquisition Inc.;

- On the Effective Date, Acquisition Inc. will acquire all of the assets of the Partnership and certain liabilities not discharged, satisfied or as otherwise provided for under the Plan in exchange for (i) the Contributed Notes and (ii) the New Equity Interests it received from New EVEP Parent Inc.;

- New EVEP Parent Inc. will distribute the New Equity Shares it received from Acquisition Inc. to the (i) holders of the Senior Notes that did not contribute Contributed Notes and (ii) Existing Unitholders;

- At the conclusion of these steps, the Supporting Holders will directly own 95% of the New Equity Interests and 5% will be owned by the Existing Unitholders, subject in each case to the dilution by the MIP Shares and New Equity Interest issued in respect of the New Warrants;

- The Senior Notes will be cancelled and discharged and the holders of those Notes will receive (directly or indirectly) New Equity Interests representing, in the aggregate, 95% of the New Equity Interests issued on the Effective Date (subject to dilution by the MIP Shares and the New Equity Interests issuable upon exercise of the New Warrants);

- Each Existing Unitholder will receive its pro rata share of (i) New Equity Interests representing, in the aggregate, 5% of the New Equity Interests issued on the Effective Date and (ii) the New Warrants (in each case, subject to dilution by the MIP Shares and, in the case of the New Equity Interests, subject to dilution by the New Warrants);

- General unsecured claims will receive, (i) if such claim is 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 is 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

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Notes to Consolidated Financial Statements (continued)

- The lenders under the credit facility that vote to accept the Plan will receive (a) pro rata loans under an amendment to the credit facility (the "Exit Credit Facility"), (b) cash in an amount equal to the accrued but unpaid interest payable to such lenders under the credit facility as of the Effective Date, and (c) 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 lenders under the credit facility that vote to reject the Plan will receive (a) term loans under a new term loan facility and (b) cash in an amount equal to the accrued and unpaid interest payable to such lender under the credit facility as of the Effective Date.

The Partnership expects to emerge from the Chapter 11 Cases as a corporation, including for US federal income tax purposes.

Subject to certain exceptions, under the Bankruptcy Code, the filing of the Chapter 11 Cases automatically enjoined, or stayed, the continuation of most judicial or administrative proceedings or filing of other actions against the Debtors or their property to recover, collect or secure a claim arising prior to the date of the Chaper 11 Cases. Accordingly, although the filing of the Chapter 11 Cases triggered defaults on the Debtors' debt obligations, creditors are stayed from taking any actions against the Debtors as a result of such defaults, subject to certain limited exceptions permitted by the Bankruptcy Code. Absent an order of the Bankruptcy Court, substantially all of the Debtors' pre-petition liabilities are subject to settlement under the Bankruptcy Code.

Subject to certain exceptions, under the Bankruptcy Code, the Debtors may assume, assign or reject certain executory contracts and unexpired leases subject to the approval of the Court and certain other conditions. Generally, the rejection of an executory contract or unexpired lease is treated as a pre-petition breach of such executory contract or unexpired lease and, subject to certain exceptions, relieves the Debtors of performing their future obligations under such executory contract or unexpired lease but entitles the contract counterparty or lessor to a pre-petition general unsecured claim for damages caused by such deemed breach. Counterparties to such rejected contracts or leases may assert unsecured claims in the Bankruptcy Court against the applicable Debtors' estate for such damages. Generally, the assumption of an executory contract or unexpired lease requires the Debtors to cure existing monetary defaults under such executory contract or unexpired lease and provide adequate assurance of future performance. Accordingly, any description of an executory contract or unexpired lease with the Debtor in these financial statements, including where applicable a quantification of the Partnership's obligations under any such executory contract or unexpired lease with the Debtor is qualified by any overriding rejection rights the Partnership has under the Bankruptcy Code. Further, nothing herein is or shall be deemed an admission with respect to any claim amounts or calculations arising from the rejection of any executory contract or unexpired lease and the Debtors expressly preserve all of their rights with respect thereto.

The Partnership also entered into a Plan Support Agreement (the "PSA") with lenders holding 94% of the loans under our credit facility. The PSA was entered into on terms substantially similar to those of the Restructuring Support Agreement. In addition, among other things, the PSA provided that (i) the consenting lenders (as defined in the PSA) may terminate the PSA upon the termination of the Restructuring Support Agreement or if there is an amendment to the Restructuring Support Agreement that is, or would reasonably be expected to be, adverse to the administrative agent under our credit facility or the consenting lenders and (ii) the Debtors agreed to not file a voluntary petition for relief under the Bankruptcy Code until the Debtors terminated certain swap agreements identified in the PSA and used the net proceeds thereof to repay outstanding amounts under the credit facility.

An indicative summary of the expected terms and conditions of the Exit Credit Facility is set forth below, which terms and conditions may include (but are not limited to) the following:

- a senior secured revolving credit facility with maximum aggregate commitments of $1 billion, subject to a borrowing base;

- an expected initial borrowing base of approximately $325 million based on a May 2018 emergence date to be effective upon consummation of the Restructuring, subject to certain automatic deductions between redeterminations;

- the first scheduled borrowing base redetermination will occur no later than April 1, 2019;

- a maturity date of February 26, 2021; and

EV Energy Partners, L.P.
Notes to Consolidated Financial Statements (continued)

- proceeds of the revolving credit facility will be used to amend and restate the credit agreement to finance the emergence from the Chapter 11 Cases and for general corporate purposes (including financing working capital needs).

Ability to Continue as a Going Concern

As of April 2, 2018, the Partnership was in default under certain of its debt instruments. The Partnership's filing of the Chapter 11 Cases described above constitutes an event of default that accelerated the Partnership's obligations under its credit facility and the Indenture governing the Senior Notes. Additionally, other events of default, including cross-defaults, are present, including the receipt of a going concern explanatory paragraph from the Partnership's independent registered public accounting firm on the Partnership's consolidated financial statements, subject to a 30 day grace period. Under the Bankruptcy Code, the creditors under these debt agreements are stayed from taking any action against the Partnership as a result of an event of default.

Throughout 2017, management, along with its legal and financial advisors, explored strategic alternatives to maintain sufficient liquidity and to address the credit agreement covenant compliance issue. The Partnership specifically evaluated options with the lenders under the credit facility and holders of the Senior Notes under the Indenture that would improve liquidity and deleverage the Partnership. Continued low commodity prices are expected to result in significantly lower levels of cash flow from operating activities in the future and have limited the Partnership's ability to access the capital markets. In addition, the Partnership's credit facility is subject to scheduled redeterminations of its borrowing base, semi-annually as of April 1 and October 1. The Partnership's filing of the Chapter 11 Cases described above accelerated the Partnership's obligations under its credit facility and under the Indenture governing the Senior Notes.

The significant risks and uncertainties related to the Partnership's liquidity and Chapter 11 Cases described above raise substantial doubt about the Partnership's ability to continue as a going concern. The audited consolidated financial statements have been prepared on a going concern basis of accounting, which contemplates continuity of operations, realization of assets, and satisfaction of liabilities and commitments in the normal course of business. The audited consolidated financial statements do not include any adjustments that might result from the outcome of the going concern uncertainty. If the Partnership cannot continue as a going concern, adjustments to the carrying values and classification of its assets and liabilities and the reported amounts of income and expenses could be required and could be material.

In order to decrease the Partnership's level of indebtedness and maintain the Partnership's liquidity at levels sufficient to meet its commitments, the Partnership has undertaken a number of actions, including minimizing capital expenditures and further reducing its recurring operating expenses. The Partnership believes that even after taking these actions, it will not have sufficient liquidity to satisfy its debt service obligations, meet other financial obligations and comply with its debt covenants. As a result, the Debtors filed petitions for reorganization under Chapter 11 of the Bankruptcy Code.

Covenant Violations

As of April 2, 2018, the Partnership was in default under certain of its debt instruments. The Partnership's filing of the Chapter 11 Cases described above constitutes an event of default that accelerated the Partnership's obligations under its credit facility and the Indenture governing the Senior Notes. Additionally, other events of default, including cross-defaults, are present, including the receipt of a going concern explanatory paragraph from the Partnership's independent registered public accounting firm on the Partnership's consolidated financial statements, subject to a 30 day grace period. Under the Bankruptcy Code, the creditors under these debt agreements are stayed from taking any action against the Partnership as a result of an event of default. See Note 10 for additional details about the Partnership's debt.

EV Energy Partners, L.P.
Notes to Consolidated Financial Statements (continued)

NOTE 3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The consolidated financial statements include the operations of the Partnership and all of its wholly owned subsidiaries ("we," "our" or "us"). All intercompany accounts and transactions have been eliminated in consolidation. In the Notes to Consolidated Financial Statements, all dollar and share amounts in tabulations are in thousands of dollars and units, respectively, unless otherwise indicated.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America 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. We base our 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 our operating environment changes. While we believe 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

We consider all highly liquid investments with an original maturity of three months or less at the time of purchase to be cash equivalents. All of our 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, we regularly monitor the financial stability of these financial institutions and believe that we are 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. We routinely assess the financial strength of our 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.

As of December 31, 2017 and 2016, we did not have any reserves for doubtful accounts, and we did not incur any expense related to bad debts. We do not have any off–balance sheet credit exposure related to our customers

Property and Depreciation

Our 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. There were no capitalized costs associated with unproved properties as of December 31, 2017. Capitalized costs associated with unproved properties totaled $20.9 million as of December 31, 2016. 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. For 2017, 2016 and 2015, we recorded dry hole and exploration costs of $0.4 million, $0.7 million and $3.7 million, respectively.

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Notes to Consolidated Financial Statements (continued)

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 our 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. We expense 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

We evaluate our 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 2017, 2016 and 2015, we recorded impairment charges of $69.9 million, $89.5 million and $86.9 million, respectively, related to proved oil and natural gas properties as the carrying amounts of such properties were determined not to be recoverable (see Note 8). The $69.9 million of impairment for 2017 consisted of $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 located in Central Texas and $2.9 million related to properties in East Texas which were sold during April 2017 (see Note 6). Since December 31, 2017, commodity prices have continued to fluctuate. If commodity prices significantly decrease in future quarters, we could have additional impairments of our 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 2017, 2016 and 2015, we recorded impairment charges of $23.7 million, $41.8 million and $49.8 million, respectively, related to unproved oil and natural gas properties where we had a change in development plans for the acreage.

Goodwill

We recorded $65.9 million of goodwill in conjunction with our October 2015 acquisitions (see Note 5). Goodwill was calculated as the excess of the purchase price over the estimated fair values of the assets acquired net of the liabilities assumed in the acquisitions. The goodwill was not amortized, but was evaluated for impairment as the declining oil and natural price environment indicated the carrying value of goodwill may not be recoverable (see Note 8).

The changes in the carrying amount of goodwill are as follows:

Balance as of January 1, 2015	$ -
Goodwill acquired during the year	65,924
Impairment losses	(65,924)
Balance as of December 31, 2015	$ -

Restricted Cash

Restricted cash represents proceeds from the sale of certain oil and natural gas properties we deposited with a qualified intermediary to facilitate like–kind exchange transactions pursuant to Section 1031 of the Internal Revenue Code.

Asset Retirement Obligations

An asset retirement obligation (“ARO”) represents the future abandonment costs of tangible assets, such as wells, service assets, and other facilities. We record an ARO and capitalize 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.

EV Energy Partners, L.P.
Notes to Consolidated Financial Statements (continued)

Revenue Recognition

Oil, natural gas and natural gas liquids revenues are recognized when production is sold to a purchaser at fixed or determinable prices, when delivery has occurred and title has transferred and collectability of the revenue is reasonably assured. 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. There were no significant gas imbalances at December 31, 2017 or 2016.

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.

Income Taxes

We are a partnership that is not taxable for federal income tax purposes. As such, we do not directly pay federal income tax. As appropriate, our taxable income or loss is includable in the federal income tax returns of our partners. Since we do not have access to information regarding each partner's tax basis, we cannot readily determine the total difference in the basis of our net assets for financial and tax reporting purposes.

We record our obligations under the Texas gross margin tax as "Income taxes" in our consolidated statements of operations.

In October 2015, we acquired Belden & Blake Corporation ("Belden"), a taxable entity (see Note 5). We used the asset and liability method of accounting for income taxes. Under this method, deferred taxes were provided for temporary differences as of the date of acquisition between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. In December 2015, Belden was converted from a corporation into a single member limited liability company (see Note 13).

Earnings per Limited Partner Unit

We use 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 our common units and participating securities as if all earnings for the period had been distributed. As our unvested phantom units and our earned but unvested performance units participate in dividends on an equal basis with our common units, they are considered to be participating securities. Earnings used in the determination of earnings per limited partner unit for the current reporting period are reduced by the amount of earnings allocated to the general partner and available cash that will be distributed to the limited partners and the participating securities. The undistributed earnings, if any, are 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 are 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

We monitor our exposure to various business risks, including commodity price and interest rate risks, and use derivatives to manage the impact of certain of these risks. Our policies do not permit the use of derivatives for speculative purposes. We use energy derivatives for the purpose of mitigating risk resulting from fluctuations in the market price of oil, natural gas and natural gas liquids.

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Notes to Consolidated Financial Statements (continued)

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

Concentration of Credit Risk

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, 2017, all of our counterparties have performed pursuant to their derivative contracts.

Our 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, our customers may be similarly affected by changes in economic and other conditions within the industry. We have experienced no significant credit losses on such sales in the past.

In 2017, two customers accounted for 15.5% and 11.0%, respectively, of our consolidated oil, natural gas and natural gas liquids revenues. In 2016, three customers accounted for 18.5%, 13.4% and 10.4%, respectively, of our consolidated oil, natural gas and natural gas liquids revenues. In 2015, two customers accounted for 17.1% and 10.8%, respectively, of our 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.

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.* 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 provisions of ASU 2014–09 are applicable to annual reporting periods beginning after December 15, 2017 and interim periods within those annual periods. We plan to implement ASU 2014-09 as of January 1, 2018 using the modified retrospective method with the cumulative effect of initial adoption, if any, recognized in retained earnings at the date of initial application. We have evaluated the impact of the new standard on our accounting policies, processes, system requirements and financial reporting. Based on the evaluation performed, we have identified similar performance obligations as compared with deliverables and separate units of account previously identified, and the change related to allocation of the transaction price and the timing of our revenue does not have a material impact on our consolidated financial statements. While we currently do not expect our net income to be materially impacted, our gross revenues and expenses are expected to be impacted based on the determination of when control of the commodity is transferred in certain transactions; This recognition will result in an increase to revenues and expenses with no impact on net income. Thus, we have concluded that the adoption of this new accounting standard will not have a material impact on the consolidated financial statements.

In February 2016, the FASB issued ASU No. 2016-02, *Leases*. 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 transition, lessees and lessors are required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. For public entities, ASU 2016-02 is effective for financial statements issued for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years; early application is permitted. The Partnership will not early adopt this standard. The Partnership will apply the new standard for our interim and annual reporting periods starting January 1, 2019 using a modified retrospective approach, including several optional practical expedients related to leases commenced before the effective date. The Partnership is currently evaluating the impact of this standard on its financial statements and has started the assessment process by evaluating the population of leases under the revised definition. The adoption of this standard will result in an increase in the assets and liabilities on the Partnership’s consolidated balance sheets. The quantitative impacts of the new standard are dependent on the leases in force at the time of adoption. As a result, the evaluation of the effect of the new standards will extend over future periods.

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Notes to Consolidated Financial Statements (continued)

In March 2016, the FASB issued ASU No. 2016–09, *Compensation – Stock Compensation*. This ASU simplifies several aspects of the accounting for employee share–based payment transactions, including the accounting for income taxes, forfeitures and statutory withholding requirements, as well as classification in the statement of cash flows. We adopted the provisions of ASU 2016–09 on January 1, 2017. The adoption of this ASU did not have a material impact on our consolidated financial statements.

In August 2016, the FASB issued ASU No. 2016–15, *Statement of Cash Flows*. 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 provisions of ASU 2016–15 are applicable to annual reporting periods beginning after December 15, 2017 and interim periods within those annual periods. We do not expect that adopting this ASU will have a material impact on our consolidated financial statements.

In November 2016, the FASB issued ASU No. 2016-18: *Statement of Cash Flows– Restricted Cash*. 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. For public entities, ASU 2016-18 is effective for financial statements issued for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. We do not expect that adopting this ASU will have a material impact on our consolidated financial statements.

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. For public entities, ASU 2017-01 is effective for financial statements issued for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. We do not expect that adopting this ASU will have a material impact on our consolidated financial statements.

No other new accounting pronouncements issued or effective during the year ended December 31, 2017 have had or are expected to have a material impact on our consolidated financial statements.

Subsequent Events

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

NOTE 4. 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 us. 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 provides for the issuance of up to 5,000,000 units and allows for the award of unit options, phantom units, performance units, restricted units and deferred equity rights. As of December 31, 2017, the aggregate amount of our common units that may be awarded under the 2016 Plan was 4.2 million units. The compensation committee of the board of directors administers the Plans.

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Notes to Consolidated Financial Statements (continued)

Phantom Units

Equity Awards

We account for phantom units as equity awards since we have determined that these awards will likely be settled by issuing common units. Compensation cost is recognized for these phantom units on a straight–line basis over the service period and is net of forfeitures. These phantom units are 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.

We estimated the fair value of these phantom units using the Black–Scholes option pricing model. There were no phantom unit awards issued during the year ended December 31, 2017. The following assumptions were used to estimate the weighted average fair value of the phantom units awarded for the years ended December 31, 2016 and 2015:

	2016	2015
Weighted average fair value of phantom units	$ 2.05	$ 2.61
Expected volatility	83.41%	62.33%
Risk–free interest rate	1.30%	1.13%
Dividend yield	0.0%	0.0%
Expected life (years)	4.0	4.1

We calculated estimated volatility using historical daily prices for two years prior to the grant date. The risk–free interest rate was based on US Treasury yield curves. The dividend yield is not taken into account as recipients are entitled to receive all distributions underlying the phantom units.

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, 2016	2,225,877	$ 6.31
Granted	-	-
Vested	(459,505)	13.67
Forfeited	(254,452)	3.50
Nonvested phantom units as of December 31, 2017	1,511,920	$ 4.54

The total grant date fair value of the phantom units vested in 2017, 2016 and 2015 was $6.3 million, $8.4 million and $15.2 million, respectively.

We recognized compensation cost related to these phantom units of $4.3 million, $6.6 million and $11.8 million in 2017, 2016 and 2015, respectively. These costs are included in "General and administrative expenses" in our consolidated statements of operations.

As of December 31, 2017, there was $4.0 million of total unrecognized compensation cost related to unvested phantom units which is expected to be recognized over a weighted average period of 1.9 years.

Performance Units

In September 2011, we issued 0.3 million performance units to certain employees and executive officers of EV Management and its affiliates. These performance units vested 25% each year beginning in January 2012 subject to our common units achieving certain market prices. We accounted for the performance units as equity awards. We estimated the fair value of 0.1 million of the performance units using the Black–Scholes option pricing model, as the market price had already been achieved for those performance units. We estimated the fair value of the remainder of the market condition performance units using the Monte Carlo simulation model. These performance units were fully vested as of January 2015.

The total grant date fair value of the performance units vested in 2015 was $1.6 million.

We recognized compensation cost related to our performance units of $0.2 million in 2015. These costs are included in “General and administrative expenses” in our consolidated statements of operations.

EV Energy Partners, L.P.
Notes to Consolidated Financial Statements (continued)

NOTE 5. ACQUISITIONS

2017

On January 31, 2017, we 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 our Barnett Shale natural gas properties in December 2016 (see Note 6) and $6.6 million of borrowings under our credit facility (the "Eagle Ford Acquisition"). Certain EnerVest institutional partnerships own an 87% working interest in, and EnerVest Operating, L.L.C. ("EnerVest Operating"), a wholly owned subsidiary of EnerVest and its affiliates, acts as operator of, the properties. The purchase price of $58.7 million was primarily allocated to proved oil and natural gas properties, and we recognized $13.9 million of oil, natural gas and natural gas liquids revenues related to this acquisition in our consolidated statement of operations for 2017. This acquisition has an immaterial impact on our financial statements.

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

2015

In October 2015, we made the following acquisitions from certain institutional partnerships managed by EnerVest, a related party:

- we acquired Belden for $111.1 million, and we recognized $5.6 million of oil, natural gas and natural gas liquids revenues related to this acquisition in our consolidated statement of operations for 2015;

- we acquired oil and natural gas properties in the Austin Chalk for $25.9 million, and we recognized $4.9 million of oil, natural gas and natural gas liquids revenues related to this acquisition in our consolidated statement of operations for 2015; and

- we acquired oil and natural gas properties in the Appalachian Basin and the San Juan Basin for $122.0 million, and we recognized $4.5 million of oil, natural gas and natural gas liquids revenues related to this acquisition in our consolidated statement of operations for 2015.

These acquisitions were not accounted for as common control transactions as EnerVest does not control the institutional partnerships that sold the oil and natural gas properties.

As part of the acquisition of oil and natural gas properties in the San Juan Basin, we assumed an obligation to deliver approximately 2.4 billion cubic feet ("Bcf") of natural gas through December 31, 2016 under previously existing volumetric production payment ("VPP") agreements. Under these agreements, certain of these oil and natural gas properties are subject to fixed–term overriding royalty interests which had been conveyed to the VPP purchaser. While we were obligated under these agreements to produce and deliver to the purchaser its portion of natural gas production from these oil and natural gas properties, we retain control of these oil and natural gas properties and rights to future development drilling. If production from the oil and natural gas properties subject to the VPP were inadequate to deliver the natural gas provided for in the VPP, we had an obligation to make up the shortfall in accordance with the provisions of the agreements.

At December 31, 2016, we had no remaining obligation under these agreements and no liability for the cost to produce and deliver to the VPP purchasers their portion of future natural gas production from these oil and natural gas properties. At December 31, 2015, the remaining obligation under these agreements was approximately 1.9 Bcf of natural gas, and we had a liability of $4.0 million for the cost to produce and deliver to the VPP purchasers their portion of future natural gas production from these oil and natural gas properties. In 2016 and 2015, we recorded $0.1 million and $0.1 million, respectively, of accretion expense related to this VPP obligation.

EV Energy Partners, L.P.
Notes to Consolidated Financial Statements (continued)

We accounted for these acquisitions as business combinations. The following table reflects pro forma revenues and net income for the year ended December 31, 2015 as if these acquisitions had taken place on January 1, 2015. These unaudited pro forma amounts do not purport to be indicative of the results that would have actually been obtained during the periods presented or that may be obtained in the future.

	2015
Revenues:	
Historical	$ 177,971
Belden	24,292
Austin Chalk	9,235
Appalachian and San Juan Basins	23,738
Pro forma revenues	$ 235,236
Net income (loss):	
Historical	$ 21,333
Belden	(76,910)
Austin Chalk	1,217
Appalachian and San Juan Basins	414
Pro forma net income	$ (53,946)

The recognized fair values of the identifiable assets acquired and liabilities assumed in connection with these acquisitions are as follows:

	Belden	Austin Chalk	Appalachian and San Juan Basins	Total
Cash	$ 8,665	$ -	$ -	$ 8,665
Accounts receivable	7,901	-	-	7,901
Derivative asset	2,711	-	-	2,711
Other current assets	1,053	318	1,318	2,689
Proved oil and natural gas properties	105,626	28,513	136,176	270,315
Unproved oil and natural gas properties	-	1,020	-	1,020
Goodwill	45,681	-	20,243	65,924
Long-term derivative assets	128	-	-	128
Other assets	1,150	-	-	1,150
Accounts payable and accrued liabilities	(11,308)	(256)	(5,456)	(17,020)
Income taxes	(974)	-	-	(974)
Deferred taxes	(13,409)	-	-	(13,409)
Asset retirement obligations	(35,551)	(3,698)	(30,260)	(69,509)
Other long-term liabilities	(569)	-	-	(569)
	$ 111,104	$ 25,897	$ 122,021	$ 259,022

The amounts allocated to goodwill represent the future benefits arising from acquiring these assets from EnerVest, which has experience operating these properties, and from adding balance to our existing portfolio by increasing our positions in the Appalachian Basin, Michigan, the San Juan Basin and the Austin Chalk. Of the $65.9 million allocated to goodwill, $20.2 of the amount will be deductible for income tax purposes.

NOTE 6. DIVESTITURES

2017

Effective November 1, 2011, we, along with certain institutional partnerships managed by EnerVest, sold a portion of our 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 (the "Carry"). 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 in the amount of $9.0 million for their continued participation in the Carry. Our share of this benefit was $2.5 million. These purchased Carry rights were recorded as reimbursements to oil and gas properties.

EV Energy Partners, L.P.
Notes to Consolidated Financial Statements (continued)

In February 2017, we, 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 we received net proceeds of $1.1 million. We did not record a gain or loss on this sale.

In April 2017, we sold certain oil and gas properties in East Texas to a third party. The transaction closed on April 5, 2017, and we received net proceeds of $0.6 million. We did not record a gain or loss on this sale.

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

2016

In December 2016, we, along with certain institutional partnerships managed by EnerVest, closed on the sale of a portion of our Barnett Shale natural gas properties, and our share of the proceeds was $52.1 million (before post-closing adjustments). Also, during 2016, we received proceeds of $2.4 million for the sale of other oil and gas properties.

2015

In 2015, we closed on the sale of non–core oil and natural gas properties for aggregate proceeds of $1.5 million.

NOTE 7. RISK MANAGEMENT

Our business activities expose us to risks associated with changes in the market price of oil, natural gas and natural gas liquids. In addition, our floating rate credit facility exposes us 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. We use derivatives to reduce our risk of volatility in the prices of oil, natural gas and natural gas liquids and interest rates. Our policies do not permit the use of derivatives for speculative purposes. As substantial doubt exists that we will be able to continue as a going concern, finding counterparties for commodity hedges has proven difficult.

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

As of December 31, 2017, we had entered into oil, natural gas and natural gas liquids derivatives with the following terms:

Period Covered	Hedged Volume	Weighted Average Fixed Price
Oil (MBbls):		
Swaps – January 2018 to March 2018	117.0	$ 57.40
Natural Gas (MmmBtus):		
Swaps – January 2018 to March 2018	4,500.0	3.46
Natural Gas Liquids (MBbls):		
Swaps – January 2018 to March 2018	117.0	36.12

As of December 31, 2017, we had also entered into interest rate swaps with the following terms:

Period Covered	Notional Amount	Floating Rate	Fixed Rate
January 2018 – September 2020	100,000	1 Month LIBOR	1.795%

EV Energy Partners, L.P.
Notes to Consolidated Financial Statements (continued)

As of December 31, 2017, in connection with the Partnership's filing of the Chapter 11 Cases, all outstanding derivatives were classified as current. The following table sets forth the fair values and classification of our outstanding derivatives:

	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts of Assets Presented in the Consolidated Balance Sheets
Derivatives:			
As of December 31, 2017:			
Derivative asset	$ 3,402	$ (350)	$ 3,052
As of December 31, 2016:			
Derivative asset	$ 201	$ -	$ 201

	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts of Liabilities Presented in the Consolidated Balance Sheets
Derivatives:			
As of December 31, 2017:			
Derivative liability	$ 746	$ (350)	$ 396
As of December 31, 2016:			
Derivative liability	$ 21,679	$ -	$ 21,679
Long–term derivative liability	955	-	955
Total	$ 22,634	$ -	$ 22,634

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

As of April 2, 2018, the Partnership was in default under certain of its debt instruments. The Partnership's filing of the Chapter 11 Cases accelerated the Partnership's obligations under its credit facility and the Senior Notes. Additionally, events of default, including cross-defaults, are present, including the receipt of a going concern explanatory paragraph from the Partnership's independent registered public accounting firm on the Partnership's consolidated financial statements, subject to a 30 day grace period. As a result, our credit facility could become due and payable because of this event of default, our derivatives that are in a net liability position could also become due and payable. We could also be required to post cash collateral related to these derivatives under certain circumstances. As of December 31, 2017 and 2016, we were not required to post any collateral nor did we hold any collateral associated with our derivatives.

NOTE 8. 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 our own assumptions used to measure assets and liabilities at fair value.

EV Energy Partners, L.P.
Notes to Consolidated Financial Statements (continued)

Recurring Basis

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

		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	$ -
As of December 31, 2016:				
Assets:				
Oil, natural gas and natural gas liquids derivatives	$ -	$ -	$ -	$ -
Interest rate swaps	201	-	201	-
	$ 201	$ -	$ 201	$ -
Liabilities:				
Oil, natural gas and natural gas liquids derivatives	$ 22,588	$ -	$ 22,588	$ -
Interest rate swaps	46	-	46	-
	$ 22,634	$ -	$ 22,634	$ -

Our 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, we have categorized these derivatives as Level 2. We value 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. Our 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 our own 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 2017.

EV Energy Partners, L.P.
Notes to Consolidated Financial Statements (continued)

Nonrecurring Basis

The following table presents the fair value hierarchy table for our 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
Year ending December 31:					
2017:					
Long–lived assets held and used	$ 48,694	$ -	$ -	$ 48,694	$ 66,931
2015:					
Long–lived assets held and used	$ 52,406	$ -	$ -	$ 52,406	$ 86,892
Goodwill	-	-	-	-	65,924
	$ 52,406	$ -	$ -	$ 52,406	$ 152,816

Long–lived Assets Held and Used

We did not incur any impairment charges in 2016 for any of our oil and natural gas properties that were held and used as of December 31, 2016. 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, we incurred impairment charges of $66.9 million and $86.9 million in 2017 and 2015, respectively, to write down oil and natural gas properties to their fair value. These impairment charges were included in earnings in 2017 and 2015.

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.

Goodwill

In 2015, we determined that the carrying amount of goodwill was impaired due to the continued decline in oil, natural gas and natural gas liquids prices. We have only one reporting unit, and we determined the fair value of the reporting unit using a combination of the market approach and the income approach. Under the market approach, the fair value was based on the quoted market price for our common units as of December 31, 2015 (our market capitalization), adjusted for a control premium. The determination of the control premium was based on our judgment as to what we believe would be standard in our industry. Under the income approach, the fair value was based on the expected present value of the future net cash flows. Significant Level 3 assumptions associated with the calculation of the fair value included estimates of future prices, production costs, development expenditures, anticipated production, appropriate risk–adjusted discount rates and other relevant data. We then determined the implied fair value of goodwill by subtracting the estimated fair values of the reporting unit's assets net of liabilities from the fair value of the reporting unit. As the carrying amount of the goodwill exceeded the implied fair value of the goodwill, we recognized a $65.9 million impairment loss for the difference between the carrying amount and the implied fair value of goodwill.

Financial Instruments

The estimated fair values of our financial instruments have been determined at discrete points in time based on relevant market information. Our 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 our 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).

EV Energy Partners, L.P.
Notes to Consolidated Financial Statements (continued)

The carrying value of debt outstanding under our credit facility approximates fair value because the credit facility's variable interest rate resets frequently and approximates current market rates available to us. As of December 31, 2017 and 2016, the estimated fair value of the Senior Notes was $176.8 million and $242.6 million, respectively, which differs from the carrying value of $342.5 million and $341.9 million, respectively. The fair value of the Senior Notes was determined using Level 2 inputs.

NOTE 9. ASSET RETIREMENT OBLIGATIONS

The changes in the aggregate asset retirement obligations ("ARO") are as follows:

Balance as of December 31, 2015	$ 176,933
Liabilities incurred	1,223
Accretion expense	8,101
Revisions in estimated cash flows	820
Settlements and divestitures	(3,601)
Balance as of December 31, 2016	183,476
Liabilities incurred	671
Accretion expense	7,653
Revisions in estimated cash flows	(875)
Settlements and divestitures	(28,962)
Balance as of December 31, 2017	$ 161,963

As of December 31, 2017 and 2016, $3.2 million and $3.2 million, respectively, of our ARO is classified as current and is included in "Accounts payable and accrued liabilities" in our consolidated balance sheets.

NOTE 10. LONG–TERM DEBT, NET

The Partnership's long-term debt was classified as current at December 31, 2017 due to an event of default. See Note 2 for additional information. The current portion of long-term debt and long–term debt, net as of December 31, 2017 and 2016, respectively, consisted of the following:

	2017	2016
Credit facility	$ 263,000	$ 265,000
8.0% Senior Notes due April 2019:		
Principal outstanding	343,348	343,348
Unamortized discount and debt issuance costs (1)	(1,701)	(2,946)
Unaccreted premium (2)	902	1,546
	342,549	341,948
Total	$ 605,549	$ 606,948

(1) Imputed interest rate of 8.49% and 8.99% for 2017 and 2016, respectively.

(2) Imputed interest rate of 7.43% and 7.22% for 2017 and 2016, respectively.

Credit Facility

As of December 31, 2017, the credit facility had a capitalization of $1.0 billion and will expire in February 2020. Borrowings under the credit facility are secured by a first priority lien on substantially all of our oil and natural gas properties. We may use borrowings under the credit facility for acquiring and developing oil and natural gas properties, for working capital purposes, for general corporate purposes and for funding distributions to partners. We also may use up to $100.0 million of available borrowing capacity for letters of credit. As of December 31, 2017, we have a $0.2 million letter of credit outstanding.

Borrowings under the credit facility bear interest at a floating rate based on, at our election, a base rate or the London Inter–Bank Offered Rate plus applicable premiums based on the percent of the borrowing base that we have outstanding (weighted average effective interest rate of 4.82% and 3.75% at December 31, 2017 and 2016, respectively).

EV Energy Partners, L.P.
Notes to Consolidated Financial Statements (continued)

Borrowings under the credit facility may not exceed a "borrowing base" determined by the lenders under the credit facility based on our oil and natural gas reserves. As of December 31, 2017, the borrowing base under the credit facility was $325.0 million. The borrowing base is subject to scheduled redeterminations as of April 1 and October 1 of each year with an additional redetermination once per calendar year at our request or at the request of the lenders and with one calculation that may be made at our request during each calendar year in connection with material acquisitions or divestitures of properties.

In October 2017, we entered into the tenth amendment ("Tenth Amendment") to our credit agreement governing the credit facility ("credit agreement"). Specifically, the amendment:

- decreased the borrowing base to $325.0 million;
- increased the required percentage of mortgaged properties from 85% to 95%;
- amended and restated the guaranty and collateral agreement to substantially increase the collateral securing the credit facility to cover all personal property;
- allowed for the maintenance of deposit and securities accounts at Lender financial institutions subject to a deposit account control agreement on such accounts; and
- required mortgaged properties to represent at least 98% of the total value of the oil and gas properties evaluated in the most recently completed reserve report.

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

- the senior secured funded debt to earnings plus interest expense, taxes, depreciation, depletion and amortization expense and exploration expense ("EBITDAX") ratio covenant to be no greater than (a) for the fiscal quarters ended March 31, 2017 and June 30, 2017, 3.5 to 1.0 and (b) for the fiscal quarter ended September 30, 2017 and December 31, 2017, 4.0 to 1.0;
- the total funded debt to EBITDAX ratio covenant to be no greater than (a) for the fiscal quarters ending March 31, 2018, 5.50 to 1.0, (b) for the fiscal quarters ending June 30, 2018 and September 30, 2018, 5.25 to 1.0 and (c) for the fiscal quarter ending December 31, 2018 and thereafter, 4.25 to 1.0;
- the EBITDAX to cash interest expense ratio covenant to be no less than (a) for the fiscal quarters March 31, 2017 and June 30, 2017, 2.0 to 1.0 and (b) for the fiscal quarter ending September 30, 2017 and thereafter, 1.5 to 1.0;
- limits cash held by us to the greater of 5% of the current borrowing base or $30.0 million.

As of April 2, 2018, the Partnership was in default under certain of its debt instruments. The Partnership's filing of the Chapter 11 Cases described above accelerated the Partnership's obligations under its credit facility and the Senior Notes. Additionally, events of default, including cross-defaults, are present, including the receipt of a going concern explanatory paragraph from the Partnership's independent registered public accounting firm on the Partnership's consolidated financial statements, subject to a 30 day grace period. Under the Bankruptcy Code, the creditors under these debt agreements are stayed from taking any action against the Partnership as a result of an event of default.

The filing of the Chapter 11 Cases constitutes an event of default that accelerated the Partnership's obligations under the credit facility. However, under the Bankruptcy Code, the creditors under these debt agreements are stayed from taking any action against the Partnership as a result of the default.

8.0% Senior Notes due April 2019

Our Senior Notes were issued under the Indenture, mature April 15, 2019, and bear interest at 8.0%. Interest is payable semi–annually. The Senior Notes are general unsecured obligations and are effectively junior in right of payment to any of our secured indebtedness to the extent of the value of the collateral securing such indebtedness.

The Senior Notes are fully and unconditionally guaranteed, jointly and severally, on a senior unsecured basis, by all of our existing subsidiaries other than EV Energy Finance Corp. (“Finance”), which is a co–issuer of the Senior Notes. Neither the Parent nor Finance have independent assets or operations apart from the assets and operations of our subsidiaries.

EV Energy Partners, L.P.
Notes to Consolidated Financial Statements (continued)

In 2016, we 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. In 2015, we redeemed $74.0 million of the Senior Notes for $50.0 million, resulting in a gain on the early extinguishment of debt of $24.0 million.

The remaining Senior Notes are currently subject to redemption, at our option, at par, plus accrued and unpaid interest, if any, on the Senior Notes to be redeemed to the applicable redemption date.

The Indenture also provides that, if a change of control (as defined in the Indenture) occurs, the holders have a right to require us to repurchase all or part of the Senior Notes at a redemption price equal to 101%, plus accrued and unpaid interest.

The Indenture contains covenants that, among other things, limit our ability to: (i) pay distributions on, purchase or redeem our common units or redeem our subordinated debt; (ii) make investments; (iii) incur or guarantee additional indebtedness or issue certain types of equity securities; (iv) create certain liens; (v) sell assets; (vi) consolidate, merge or transfer all or substantially all of our assets; (vii) enter into intercompany agreements that restrict distributions or other payments from our restricted subsidiaries to us; (viii) engage in transactions with affiliates; and (ix) create unrestricted subsidiaries.

The filing of the Bankruptcy Petition constitutes an event of default that accelerated the Partnership's obligations under the indentures governing the Senior Notes. However, under the Bankruptcy Code, holders of the Senior Notes are stayed from taking any action against the Partnership as a result of the default. See also Note 2 of the Notes to Consolidated Financial Statements included above.

NOTE 11. COMMITMENTS AND CONTINGENCIES

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, 2017 and 2016.

We are subject to firm agreements for the future transportation and processing of natural gas. We are obligated to transport minimum daily natural gas volumes. As of December 31, 2017, our future minimum transportation fees under these agreements are as follows for the years ended December 31:

2018	$ 3,324
2019	2,944
2020	1,731
2021	1,599
2022	1,393
Thereafter	1,720
	$ 12,711

NOTE 12. OWNERS' EQUITY

Units Outstanding

At December 31, 2017, owner's equity consists of 49,368,869 common units outstanding (including 5,270,487 common units held by our executive officers and directors), collectively representing a 98% limited partnership interest in us and a 2% general partnership interest.

Common Units

The common units have limited voting rights as set forth in our partnership agreement.

EV Energy Partners, L.P.
Notes to Consolidated Financial Statements (continued)

Pursuant to our partnership agreement, if at any time our general partner and its affiliates own more than 80% of the common units outstanding, our general partner has 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. Our general partner may assign this call right to any of its affiliates or to us.

General Partner Interest

Our general partner owns a 2% interest in us. This interest entitles our general partner to receive distributions of available cash from operating surplus as discussed further below under "Cash Distributions". Our partnership agreement sets 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 will receive.

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

Allocations of Net Income

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

Cash Distributions

There is no assurance as to the future cash distributions since they are dependent upon future earnings, cash flows, capital requirements, financial condition and other factors. Our credit facility prohibits us from making cash distributions if any default or event of default, as defined in our credit facility, occurs or would result from the cash distribution.

Within 45 days after the end of each quarter, we will distribute all of our available cash (as defined in our partnership agreement) to our general partner and unitholders of record on the applicable record date. The amount of available cash generally is all cash on hand at the end of the quarter; less the amount of cash reserves established by our general partner to provide for the proper conduct of our business, to comply with applicable laws, any of our debt instruments, or other agreements or to provide funds for distributions to unitholders and to our 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 are generally borrowings that are made under our credit facility and in all cases are used solely for working capital purposes or to pay distributions to partners.

Our partnership agreement requires that we 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 we distribute 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 is not guaranteed and distributions below the minimum quarterly distribution will not be accrued in arrears.

EV Energy Partners, L.P.
Notes to Consolidated Financial Statements (continued)

Our general partner is entitled to incentive distributions if the amount we distribute with respect to one quarter exceeds specified target levels shown below:

	Total Quarterly Distributions Target Amount	Marginal Percentage Interest in Distributions: Limited Partner	Marginal Percentage Interest in Distributions: 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%

We did not pay any distributions during the year ended December 31, 2017. The following sets forth the distributions we 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 2017 and 2016, the board of directors of EV Management announced that it had elected to suspend distributions for all four quarters of both 2017 and 2016.

NOTE 13. INCOME TAXES

In December 2015, we converted Belden from a corporation into a single member limited liability company. As a result, the $13.4 million of deferred taxes recorded in the acquisition of Belden were realized. The benefit was offset by an $11.7 million current tax liability for the estimated federal and state taxes based on the fair value of Belden as of the date of conversion. As of December 31, 2015, Belden is no longer a tax paying entity.

Income taxes were as follows for the year ended December 31, 2015:

Current:	
Federal	$ 11,207
State	235
	11,442
Deferred:	
Federal	(12,482)
State	(803)
	(13,285)
	$ (1,843)

Of the $236.0 million of loss from continuing operations before income taxes for the year ended December 31, 2015, $45.7 million represents the loss that is subject to federal taxation.

The effective tax rate on the loss subject to federal taxation differs from the US statutory rate as follows for 2015:

Income taxes at US statutory income tax rate	$ (15,986)
Impairment of Belden goodwill	15,989
Belden deferred tax liability released at conversion	(2,070)
State income taxes, net of federal tax benefit	224
Income taxes	$ (1,843)

EV Energy Partners, L.P.
Notes to Consolidated Financial Statements (continued)

Our tax filings for four years are subject to examination by federal and state tax authorities where we conduct our business. These examinations may result in assessments of additional tax that are resolved with the authorities or through the courts. We have evaluated whether any material tax position we have taken will more likely than not be sustained upon examination by the appropriate taxing authority. As we believe that all such material tax positions we have taken are supportable by existing laws and related interpretations, we believe there are no material uncertain tax positions to consider.

In 2017 and 2016, we recorded approximately $0.2 million and $2.4 million, respectively, of tax benefits as a result of tax refunds and lower taxes.

NOTE 14. DISCONTINUED OPERATIONS

Our former midstream segment, which included our investment in Utica East Ohio Midstream LLC (“UEO”), was engaged in the construction and operation of natural gas processing, natural gas liquids fractionation, connecting pipeline infrastructure and gathering systems to serve production in the Utica Shale area in Ohio. In June 2015, we sold our interest in UEO and received net proceeds of $572.2 million and recognized a gain of $246.7 million. This gain is included in “Income from discontinued operations.” As a result of this sale, the Partnership no longer operates in the midstream segment.

As a result of the reduction in the borrowing base under our facility upon the sale of our interest in UEO, we were required to repay $25.0 million of outstanding borrowings. Accordingly, $1.5 million of interest related to this $25.0 million and the write off of deferred financing costs related to the reduction in the borrowing base have been allocated to “Income from discontinued operations” in 2015.

Summarized financial information for our discontinued operations was as follows:

	2015 [(1)]
Revenues	$ 93,726
Operating income	49,171
Net income	49,525

(1) Information is for UEO on a stand–alone basis through the date of divestiture.

EV Energy Partners, L.P.
Notes to Consolidated Financial Statements (continued)

NOTE 15. EARNINGS PER LIMITED PARTNER UNIT

The following sets forth the calculation of earnings per limited partner unit for the years ended December 31:

	2017	2016	2015
Loss from continuing operations	$ (134,201)	$ (242,895)	$ (234,179)
General partner's 2% interest in loss from continuing operations	2,684	4,858	4,684
Earnings attributable to unvested phantom units	-	-	(1,076)
Limited partners' interest in loss from continuing operations	$ (131,517)	$ (238,037)	$ (230,571)
Loss per limited partner unit (basic and diluted)	$ (2.66)	$ (4.85)	$ (4.72)
Income from discontinued operations	$ -	$ -	$ 255,512
General partner's 2% interest in income from discontinued operations	-	-	(5,110)
Earnings attributable to unvested phantom units	-	-	-
Limited partners' interest in income from discontinued operations	$ -	$ -	$ 250,402
Earnings per limited partner unit (basic and diluted)	$ -	$ -	$ 5.13
Net income (loss)	$ (134,201)	$ (242,895)	$ 21,333
General partner's 2% interest in net (income) loss	2,684	4,858	(426)
Earnings attributable to unvested phantom units	-	-	(1,076)
Limited partners' interest in net income (loss)	$ (131,517)	$ (238,037)	$ 19,831
Earnings (loss) per limited partner unit (basic and diluted)	$ (2.66)	$ (4.85)	$ 0.41
Weighted average limited partner units outstanding (basic and diluted)	49,357	49,048	48,853

As of December 31, 2017, 2016 and 2015, there were no unearned performance units outstanding.

NOTE 16. RELATED PARTY TRANSACTIONS

Pursuant to our omnibus agreement with EnerVest, we paid EnerVest $14.1 million, $15.9 million and $14.2 million in 2017, 2016 and 2015, respectively, in monthly administrative fees for providing us general and administrative services. These fees are based on an allocation of charges between EnerVest and us based on the estimated use of such services by each party, and we believe that the allocation method employed by EnerVest is reasonable and reflective of the estimated level of costs we would have incurred on a standalone basis. These fees are included in general and administrative expenses in our consolidated statements of operations.

We have entered into operating agreements with EnerVest whereby EnerVest Operating, a subsidiary of 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. During 2017, 2016 and 2015, we reimbursed EnerVest approximately $20.1 million, $21.2 million and $17.2 million, respectively, for direct expenses incurred in the operation of our wells and related gathering systems and production facilities and for the allocable share of the costs of EnerVest employees who performed services on our properties. As the vast majority of such expenses are charged to us on an actual basis (i.e., no mark–up or subsidy is charged or received by EnerVest), we believe that the aforementioned services were provided to us at fair and reasonable rates relative to the prevailing market and are representative of what the amounts would have been on a standalone basis. These costs are included in lease operating expenses in our consolidated statements of operations. Additionally, in its role as contract operator, this EnerVest subsidiary also collects proceeds from oil, natural gas and natural gas liquids sales and distributes them to us and other working interest owners.

As of December 31, 2017, we owed EnerVest Operating $4.2 million. As of December 31, 2016, we owed EnerVest Operating $5.8 million and partnerships managed by EnerVest owed us $0.7 million.

EV Energy Partners, L.P.
Notes to Consolidated Financial Statements (continued)

In October 2015, we acquired oil and natural gas properties in the Appalachian Basin, the San Juan Basin, Michigan and the Austin Chalk from certain institutional partnerships managed by EnerVest for a combined cash consideration of $259.0 million (see Note 5).

Effective November 1, 2011, we, along with certain institutional partnerships managed by EnerVest, sold a portion of our 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 in the amount of $9.0 million for their continued participation in the Carry. Our share of this benefit was $2.5 million. These purchased Carry rights were recorded as reimbursements to oil and gas properties.

In 2011, we and certain institutional partnerships managed by EnerVest carved out 7.5% overriding royalty interests (“ORRI”) from certain acres in Ohio (the "Underlying Properties"), which we believe 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. We own a 48% limited partner interest in the partnership and account for our investment using the equity method of accounting. We recognized $0.5 million, $0.1 million and $0.2 million of income in 2017, 2016 and 2015, respectively, and we received $0.3 million, $0.1 million and $0.2 million of distributions in 2017, 2016 and 2015, respectively. This income is included in Other income, net in our consolidated statements of operations.

NOTE 17. OTHER SUPPLEMENTAL INFORMATION

Supplemental cash flows and non–cash transactions were as follows as of and for the years ended December 31:

	2017	2016	2015
Supplemental cash flows information:			
Cash paid for interest	$ 38,758	$ 39,807	$ 48,344
Cash (refunded) paid for income taxes	-	10,942	(115)
Non–cash transactions:			
Costs for additions to oil and natural gas properties in accounts payable and accrued liabilities	12,748	668	5,212
Post-closing adjustments for sales of oil and natural gas properties in accounts payable and accrued liabilities	-	1,752	-

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

	2017	2016
Costs for additions to oil and natural gas properties	$ 12,748	$ 668
Lease operating expenses	11,411	9,835
Production and ad valorem taxes	6,351	7,382
Interest	5,820	6,029
General and administrative expenses	3,331	3,095
Current portion of ARO	3,170	3,235
Derivative settlements	573	106
Other	413	1,350
Total	$ 43,817	$ 31,700

EV Energy Partners, L.P.
Notes to Consolidated Financial Statements (continued)

NOTE 18. QUARTERLY DATA (UNAUDITED)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2017				
Revenues	$ 56,987	$ 56,052	$ 52,651	$ 60,003
Gross profit [1]	29,809	26,861	23,026	32,119
Net loss [2]	(50,831)	(25,161)	(17,888)	(40,321)
Net loss per limited partner unit:				
Basic	$ (1.01)	$ (0.50)	$ (0.36)	$ (0.80)
Diluted	$ (1.01)	$ (0.50)	$ (0.36)	$ (0.80)
2016				
Revenues	$ 38,250	$ 42,831	$ 51,372	$ 52,441
Gross profit [1]	7,328	14,776	23,240	27,296
Net loss [3]	(29,000)	(28,993)	(19,230)	(165,672)
Net loss per limited partner unit:				
Basic	$ (0.58)	$ (0.58)	$ (0.38)	$ (3.31)
Diluted	$ (0.58)	$ (0.58)	$ (0.38)	$ (3.31)

(1) Represents total revenues less lease operating expenses, cost of purchased natural gas and production taxes.

(2) 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.

(3) Includes impairment charges of $131.3 million, primarily in the fourth quarter of 2016. Of this amount, $89.5 million related to oil and natural gas properties in the Barnett Shale that were written down to their fair value as determined based on the expected present value of the future net cash flows. 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.

NOTE 19. 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:

	2017	2016
Proved oil and natural gas properties	$ 2,567,086	$ 2,527,927
Unproved oil and natural gas properties	-	20,884
	2,567,086	2,548,811
Accumulated depreciation, depletion and amortization	(1,191,559)	(1,051,600)
Net capitalized costs	$ 1,375,527	$ 1,497,211

Costs incurred in oil and natural gas property acquisition and development activities are as follows for the years ended December 31:

	2017	2016	2015
Acquisition of oil and natural gas properties:			
Proved	$ 58,230	$ -	$ 236,356

Unproved	3,170	-	1,020
Exploration costs	413	651	2,193
Development costs	39,348	10,712	55,109
Total	$ 101,161	$ 11,363	$ 294,678

EV Energy Partners, L.P.
Notes to Consolidated Financial Statements (continued)

NOTE 20. ESTIMATED PROVED OIL, NATURAL GAS AND NATURAL GAS LIQUIDS RESERVES (UNAUDITED)

Our estimated proved reserves are all located within the United States. We caution 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 our proved reserves as of December 31, 2017, 2016 and 2015 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, 2014	11,908	712,192	36,143	1,000,496
Revisions of previous estimates (4)	(3,319)	(194,442)	(9,028)	(268,522)
Purchases of minerals in place	11,852	214,578	7,468	330,504
Extensions and discoveries (5)	2,636	60,197	4,106	100,647
Production	(1,041)	(43,592)	(2,326)	(63,792)
Sales of minerals in place	(41)	(1,918)	(69)	(2,580)
As of December 31, 2015	21,995	747,015	36,294	1,096,753
Revisions of previous estimates (6)	(8,163)	(57,723)	(1,223)	(114,041)
Extensions and discoveries (7)	61	10,255	736	15,038
Production	(1,216)	(49,333)	(2,331)	(70,612)
Sales of minerals in place (8)	(85)	(74,916)	(81)	(75,919)
As of December 31, 2016	12,592	575,298	33,395	851,219
Revisions of previous estimates (9)	1,141	3,558	(422)	7,867
Purchases of minerals in place	1,228	6,578	415	16,444
Extensions and discoveries (10)	105	3,035	398	6,053
Production	(1,387)	(40,979)	(2,165)	(62,293)
Sales of minerals in place (11)	(286)	(3,784)	(27)	(5,663)
As of December 31, 2017	13,393	543,706	31,594	813,627
Proved developed reserves:				
December 31, 2014	9,783	599,664	30,766	842,956
December 31, 2015	13,919	644,984	30,091	909,047
December 31, 2016	11,954	523,113	28,218	764,149
December 31, 2017	13,393	543,706	31,594	813,627
Proved undeveloped reserves:				
December 31, 2014	2,125	112,528	5,377	157,540
December 31, 2015	8,076	102,031	6,203	187,706
December 31, 2016	638	52,185	5,177	87,070
December 31, 2017	-	-	-	-

(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 the Barnett Shale (120.7 Bcfe) and the Appalachian Basin (76.9 Bcfe) and are the result of the decrease in prices for oil, natural gas and natural gas liquids used in our December 31, 2015 reserve estimates from prices used in our December 31, 2014 reserve estimates.

EV Energy Partners, L.P.
Notes to Consolidated Financial Statements (continued)

(5) Extensions and discoveries were primarily associated with drilling success in the Barnett Shale (72.6 Bcfe) and the Appalachian Basin (16.9 Bcfe).

(6) 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 are the result of the decrease in prices for oil, natural gas and natural gas liquids used in our December 31, 2016 reserve estimates from prices used in our December 31, 2015 reserve estimates.

(7) Extensions and discoveries were primarily associated with drilling success in the Barnett Shale (13.0 Bcfe).

(8) Sales of minerals in place were primarily associated with the sale of a portion of our Barnett Shale natural gas properties (74.2 Bcfe) in December 2016.

(9) 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).

(10) Extensions and discoveries were primarily associated with drilling success in the Barnett Shale (4.2 Bcfe) and Mid-Continent area (1.5 Bcfe).

(11) Sales of minerals in place were primarily associated with the sale of non-core properties in the Appalachian Basin (4.6 Bcfe), Central Texas (0.6 Bcfe) and San Juan Basin (0.5 Bcfe).

NOTE 21. 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 our 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 our 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.

· In accordance with our standing as a nontaxable entity, no provisions for future federal income taxes were computed; however, provisions for future obligations under the Texas gross margin tax were computed.

· 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:

	2017	2016	2015
Future cash inflows	$ 2,778,662	$ 2,261,520	$ 3,285,271
Future production and development costs	(1,603,373)	(1,480,900)	(2,029,001)
Future income tax expenses	(6,022)	(5,442)	(7,769)
Future net cash flows	1,169,267	775,178	1,248,501
10% annual discount for estimated timing of cash flows	(589,862)	(404,061)	(712,051)
Standardized measure of discounted future net cash flows	$ 579,405	$ 371,117	$ 536,450

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 our total estimated proved reserves at December 31, 2017, 2016 and 2015 were $51.34 per Bbl of oil, $2.976 per MMBtu of natural gas; $42.75 per Bbl of oil, $2.481 per MMBtu of natural gas; and $50.28 per Bbl of oil, $2.587 per MMBtu of natural gas, respectively. We do not include our commodity derivatives in the determination of our oil, natural gas and natural gas liquids reserves.

EV Energy Partners, L.P.
Notes to Consolidated Financial Statements (continued)

The principal sources of changes in the standardized measure of future net cash flows are as follows for the years ended December 31:

	2017	2016	2015
Standardized measure at beginning of period	$ 371,117	$ 536,450	$ 1,093,303
Sales and transfers of oil, natural gas and natural gas liquids produced, net of production costs	(111,118)	(71,939)	(68,479)
Net changes in prices and production costs	202,810	(83,146)	(682,598)
Extensions, discoveries and improved recovery, less related costs	5,451	1,712	26,082
Development costs incurred during the period	2,261	2,065	21,441
Revisions and other	13,516	(23,328)	(205,821)
Accretion of 10% timing discount	37,356	53,998	110,120
Changes in income taxes	(371)	1,093	4,362
Changes in estimated future development costs	20,177	3,976	19,925
Changes in timing and other	8,302	(26,920)	(31,118)
Purchase of minerals in place	32,949	-	250,646
Sales of minerals in place	(3,045)	(22,844)	(1,413)
Standardized measure of discounted future net cash flows	$ 579,405	$ 371,117	$ 536,450

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, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and our Chief Financial Officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2017 to provide reasonable assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms. Our 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 our management, including our 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, our management included a report of their assessment of the design and effectiveness of our internal control over financial reporting as part of this Annual Report on Form 10–K for the fiscal year ended December 31, 2017. Management's report and 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 our internal control over financial reporting that occurred during the quarterly period ended December 31, 2017 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

On March 8, 2018, our Board of Directors, after receiving the recommendation of our conflicts committee, approved an extension of our Omnibus Agreement with EnerVest through the end of 2018, at a monthly fee of $1,433,333. A copy of the extension agreement is filed as Exhibit 10.5 to this annual report on Form 10–K and incorporated herein by reference.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

As is the case with many publicly traded partnerships, we do not directly employ officers, directors or employees. Our operations and activities are managed by EV Management, the general partner of our general partner. EV Management is a wholly owned subsidiary of EnerVest. References to our officers, directors and employees are references to the officers, directors and employees of EV Management.

Our general partner is not elected by our unitholders and will not be subject to re–election on a regular basis in the future. Unitholders will not be entitled to elect the directors of EV Management or directly or indirectly participate in our management or operation. Our general partner is owned 71.25% by EnerVest, 23.75% by EnCap and 5.00% by EV Investors, which is owned 70% by EnerVest and 30% by our senior management.

Our general partner owes a fiduciary duty to our unitholders. Our general partner will be liable, as general partner, for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made expressly nonrecourse to it. Our general partner therefore may cause us to incur indebtedness or other obligations that are nonrecourse to it.

Board Leadership Structure

Our board of directors has no policy regarding the separation of the positions of chief executive officer and chairman. We do not have a lead independent director. EnCap is entitled to designate one director, and EnerVest appoints the remainder. Holders of our common units have limited voting rights on matters affecting our governance or business, subject to any unitholder rights set forth in our partnership agreement.

In selecting our independent board members, EnerVest sought candidates with experience in the energy business and in developing and implementing successful growth strategies and who have diverse expertise in areas important to our success. Directors were selected with strong professional reputations, a history of success, and who exemplify the highest standards of personal and professional integrity. Our independent directors were selected because they could be expected to constructively challenge management through their participation on our board of directors and its committees.

Historically, the owners of our general partner did not apply a formal diversity policy or set of guidelines in selecting and appointing directors of the board of directors. However, when appointing new directors, the owners of our general partner considered each individual director’s qualifications, skills, business experience and capacity to serve as a director, as described above, and the diversity of these attributes for the board of directors as a whole. When considering new director nominees, our board of directors will utilize these same considerations.

Board Oversight of Risk

Like all businesses, we face risks in our business activities. Many of these risks are discussed under the caption “Risk Factors” elsewhere in this annual report. Our board of directors has oversight of our risk management program, working directly with senior management. Our senior management, subject to board oversight, is responsible for ensuring that our risk management program, comprised of strategic, operational, financial, and legal risk identification and prioritization, is reflected in our policies and actions. Our senior management, subject to board oversight, is also responsible for day to day risk management and implementation of our risk management policies.

In addition, our audit committee considers our practices regarding risk assessment and risk management, reviews our contingent liabilities, reviews our reserve estimation practices, as well as major legislative and regulatory developments that could affect us. Our audit committee also oversees our code of business conduct and responses to any alleged violations of our policies made by whistleblowers. Our compensation committee reviews and attempts to mitigate risks which may result from our compensation policies, including working directly with senior management to determine whether such programs improperly encourage management to take risks relating to the business or whether risks arising from our compensation programs are likely to have a material adverse effect on us. Our conflicts committee reviews transactions in which we engage with affiliates of EnerVest or EnCap, and, if appropriate, approves these transactions or the manner in which any conflicts were resolved. The strategic advisory committee reviews and advises management on potential strategic transactions to reduce debt leverage at the partnership.

Our board of directors believes that this division of risk management related roles among our independent directors fosters an atmosphere of significant involvement in the oversight of risk and that this shared oversight is appropriate for us.

Directors and Executive Officers

All of our executive management personnel, other than Messrs. Mercer and Bobrowski, are employees of EnerVest. Messrs. Mercer and Bobrowski are employees of EV Management and devote all of their time to our business and affairs.

We estimate that Messrs. Walker and Flory devote approximately 27% and 30%, respectively, of their time to our business. We also utilize a significant number of employees of EnerVest to operate our properties and provide us with certain general and administrative services. Under the omnibus agreement, we pay EnerVest a fee for its operational personnel who perform services for our benefit. During 2017, we paid EnerVest $14.1 million for general and administrative services, which fee will increase or decrease as we purchase or divest assets or as the costs to provide these services increase or decrease.

The following table shows information as of March 27, 2018 regarding members of our Board of Directors and executive officers of EV Management. Members of our Board of Directors are elected for one–year terms.

Name	Age	Position with EV Management
John B. Walker	72	Executive Chairman and Director
Michael E. Mercer	59	President, Chief Executive Officer and Director
Nicholas P. Bobrowski	40	Vice President and Chief Financial Officer
Ryan J. Flory	41	Controller
Mark A. Houser	56	Director
Kenneth Mariani	56	Director
Victor Burk (1) (2) (3) (4)	68	Director
James R. Larson (1) (2) (4)	68	Director
George Lindahl III (1) (2) (3) (4)	71	Director
Gary R. Petersen (3)	71	Director
Daniel J. Churay (2) (3) (4)	55	Director

(1) Member of the audit committee.

(2) Member of the conflicts committee.

(3) Member of the compensation committee.

(4) Member of the strategic advisory committee.

John B. Walker has served as our Executive Chairman since January 2012 and has been a director since 2006. Prior to serving as Executive Chairman, he served as our Chairman and Chief Executive Officer since 2006. Mr. Walker also serves as the Chief Executive Officer of EnerVest from its inception in 1992, and was the President of EnerVest from its formation in 1992 until 2014. He has been Chief Executive Officer of EnerVest since 2014. Prior to that, Mr. Walker was President and Chief Operating Officer of Torch Energy Advisors Incorporated, a company which formed and managed partnerships for institutional investors in the oil and natural gas business, and Chief Executive Officer of Walker Energy Partners, a master limited partnership engaged in the exploration and production business. In his early career on Wall Street, Mr. Walker was selected by Institutional Investor as an “All American” energy analyst for six years in a row. He served the Independent Petroleum Association of America (IPAA) as Chairman from 2003 – 2005. In November 2007, he received the oil and natural gas industry’s highest award, the Chief Roughneck Award. He is a member of the National Petroleum Council and All–American Wildcatters. He serves or has served on the boards of the Houston Producers’ Forum, Foundation for Energy Education, Petroleum Club of Houston, and the Texas Independent Producers and Royalty Owners Association. His civic activities currently include serving on the Board of Stewards of Chapelwood United Methodist Church, the Board of Directors of the Sam Houston Area Council of the Boy Scouts of America and the Board of Directors of Stoney Creek Ranch. In 2001, he received the Silver Beaver Award and in May 2007 the Distinguished Eagle from the Boy Scouts of America. In 2004, he was named Distinguished Alumni at Texas Tech University and, in January 2012, he was appointed by Gov. Rick Perry to serve on the Board of Regents. He holds a BBA with Honors from Texas Tech University and an MBA (with distinction) from New York University.

Michael E. Mercer has served as our President and Chief Executive Officer since March 2015. Prior to that, he was our Senior Vice President and Chief Financial Officer since 2006. He was a consultant to EnerVest from 2001 to 2006. Prior to that, Mr. Mercer was an investment banker for 12 years. He was a Director in the Energy Group at Credit Suisse First Boston in Houston and a Director in the Energy Group at Salomon Smith Barney in New York and London. He holds a BBA in Petroleum Land Management from the University of Texas at Austin and an MBA from the University of Chicago Booth School of Business. Mr. Mercer was appointed our President and Chief Executive Officer, and director, effective March 1, 2015.

Nicholas P. Bobrowski has served as Vice President and Chief Financial Officer since March 2015. Prior to that, Mr. Bobrowski served as Director of Finance of EV Management since 2013. From 2007 to 2012, he was an energy investment banker with Citigroup Global Markets, where he rose to the level of Vice President in the Financial Strategy Group advising clients on valuation, liability, risk management and capital structure. Prior to that, he rose to the rank of Captain in the 25th Infantry Division of the United States Army after graduating with a BS in Economics from the United States Military Academy at West Point. Mr. Bobrowski also holds an MBA from the Sloan School of Management at MIT.

Ryan J. Flory has served as Controller of EV Management since February 2014 and as Senior Vice President and Chief Accounting Officer of EnerVest since January 2017. Prior to that, Mr. Flory served as Vice President and Controller of EnerVest since January 2014 and Corporate Controller since 2013. From 2005 to 2013, he served as Manager of Financial Reporting for EnerVest and from 2003 to 2005, he worked for Belden & Blake Corporation where he held various management and supervisory positions. Mr. Flory began his career with Deloitte & Touche. He holds a Bachelor's of Business Administration, Accounting, from Kent State University and is a CPA and a member of the American Institute of Certified Public Accountants.

Mark A. Houser has been a member of our board since 2006. He was named Chief Executive Officer of University Lands in March 2015, where he oversees activities on 2.1 million acres of Permanent University lands that serve as a resource for both the University of Texas and Texas A&M University. Before joining University Lands, Mr. Houser served as our President and Chief Executive Officer from January 2012 through February 2015. Prior to that, he served as our President and Chief Operating Officer since 2006. He also served as Executive Vice President and Chief Operating Officer of EnerVest from 1999 through 2015. Prior to that, Mr. Houser was Vice President, United States Exploration and Production, for Occidental Petroleum Corporation ("Oxy"), where he helped lead Oxy's reorganization of its domestic reserve base, including the successful $3.65 billion acquisition of the Elk Hills Naval Petroleum Reserve. In 1989 he joined Canadian Occidental Petroleum, Ltd. (now Nexen Inc.), where he held positions of increasing responsibility, including Vice President of Corporate Planning and Investor Relations in Calgary and Vice President of Exploration for CXY Energy, Canadian Oxy's United States subsidiary. Mr. Houser began his career as an engineer with Kerr–McGee Corporation. He holds a petroleum engineering degree from Texas A&M University and an MBA from Southern Methodist University. Mr. Houser serves as the chairman of the industry board of the Texas A&M University Department of Petroleum Engineering and is a member of the Society of Petroleum Engineers. Mr. Houser was recently inducted into the Texas A&M Petroleum Engineering Academy of Distinguished Graduates. Additionally, he serves on the board of directors for the Methodist Hospital System and on the administrative board of Chapelwood United Methodist Church.

Kenneth Mariani was appointed to the board in February 2015. Mr. Mariani served as the President of EnerVest from January 2014 through December 2017. Prior to that, he served as Executive Vice President of EnerVest and President and Chief Executive Officer of EnerVest Operating Company from January 2012 to January 2014. Mr. Mariani joined EnerVest in 2000 and was Senior Vice President and General Manager – Eastern Division for 11 years. Prior to joining EnerVest, from 1991 to 2000, he served as Vice President of Operations for Energy Corporation of America ("ECA"), a privately held exploration and production company, and was responsible for engineering, land, geology and production operations. Prior to his role at ECA, he held various engineering positions at Conoco, Inc., in the Midland, TX, and Rocky Mountain Divisions. Mr. Mariani holds a degree in Chemical Engineering from the University of Pittsburgh, graduating cum laude with a petroleum option. He received his Master of Business Administration from The University of Texas of the Permian Basin and is a licensed Professional Engineer.

Victor Burk was appointed to our board of directors in September 2006. Since 2009, Mr. Burk has been a Managing Director for Alvarez and Marsal, a privately owned professional services firm. From 2005 to 2009, Mr. Burk was the global energy practice leader for Spencer Stuart, a privately owned executive recruiting firm. Prior to joining Spencer Stuart, Mr. Burk served as managing partner of Deloitte & Touche's global oil and natural gas group from 2002 to 2005. He began his professional career in 1972 with Arthur Andersen and served as managing partner of Arthur Andersen's global oil and natural gas group from 1989 until 2002. Mr. Burk is a current board member of the general partner of Plains GP Holdings, L.P. (NYSE: PAGP) and Plains All American Pipeline, L.P. (NYSE: PAA). He is also a board member of the Sam Houston Area Council of the Boy Scouts of America. He holds a BBA in Accounting from Stephen F. Austin University, graduating with highest honors. Mr. Burk has over 30 years of experience in the oil and natural gas industry, with extensive experience in public accounting and consulting. Mr. Burk brings to our board wide expertise in financial and accounting matters relating to the oil and natural gas industry as well as providing leadership in complex business organizations.

James R. Larson was appointed to our board of directors in September 2006. Since January 1, 2006, Mr. Larson has been retired. From September 2005 until January 1, 2006, Mr. Larson served as Senior Vice President of Anadarko Petroleum Corporation. From December 2003 to September 2005, Mr. Larson served as Senior Vice President, Finance and Chief Financial Officer of Anadarko. From 2002 to 2003, Mr. Larson served as Senior Vice President, Finance of Anadarko where he oversaw treasury, investor relations, internal audits and acquisitions and divestitures. From 1995 to 2002, Mr. Larson served as Vice President and Controller of Anadarko where he was responsible for accounting, financial reporting, budgeting, forecasting and tax. Prior to that, he held various tax and financial positions within Anadarko after joining the company in 1981. Mr. Larson is a current member of the American Institute of Certified Public Accountants, Financial Executives International, Tax Executives Institute and the National Association of Corporate Directors. Mr. Larson also serves on the board of CSI Compressco GP Inc., general partner of CSI Compressco L.P. He holds a BBA in Business from the University of Iowa. Mr. Larson has over 30 years of experience in the oil and natural gas business, and has served as chief financial officer of a large independent oil and natural gas company. We believe that his knowledge of the industry and finance and accounting provide a critical resource and skill set to our board of directors.

George Lindahl III was appointed to our board of directors in September 2006. From 2007 to the present, Mr. Lindahl manages GL III Investments. From 2001 to 2007, he was a Managing Partner for Sandefer Capital Partners. From 2000 to 2001 he served as Vice Chairman of Anadarko Petroleum Corporation. From 1987 to 2000, he was with Union Pacific Resources, serving as President and Chief Operating Officer from 1996 to 1999 and as Chairman, President and CEO from 1999 to 2000. He holds a BS in Geology from the University of Alabama and has completed the Advanced Management program at Harvard Business School. Mr. Lindahl has extensive geological and engineering experience, as well as leadership skills and a proven track record of successful investments in the oil and natural gas business. We believe that Mr. Lindahl's technical knowledge and experience and his leadership skills provide an important resource to our board of directors.

Gary R. Petersen was appointed to our board of directors in September 2006. Mr. Petersen is a Managing Partner and co–founder of EnCap Investments L.P., an investment manager and leading provider of private equity capital to the upstream and midstream sectors of the oil and natural gas industry. The firm has raised 17 institutional oil and natural gas investment funds totaling approximately $18 billion and currently manages capital on behalf of more than 250 US and institutional investors. Prior to the formation of EnCap Investments in 1988, Mr. Petersen was a Senior Vice President and Manager of the Corporate Finance Division of the Energy Banking Group for Republic Bank Corporation from 1985 to 1988. His duties and responsibilities included mergers and acquisitions, financial advisory services and institutional fund raising activities for the energy industry. Prior to his position at Republic Bank, Mr. Petersen was an Executive Vice President and a member of the board of directors of Nicklos Oil & Gas Company in Houston from 1979 to 1984. Previously, Mr. Petersen was a Group Vice President in the Petroleum and Minerals Division of Republic Bank Dallas. He served from 1970 to 1971 in the US Army in Washington D.C. as a First Lieutenant in the Finance Corps and as an Army Officer in the Army Security Agency. Mr. Petersen is a distinguished Alumni of Texas Tech University and holds B.B.A. and M.B.A. degrees in Finance. He has also done post-graduate work at American University and the Stonier Graduate School of Banking at Rutgers University. Mr. Petersen serves on the board of multiple EnCap portfolio companies and is a member of the board of directors of the general partner of Plains GP Holdings, L.P. (NYSE: PAGP) and Plains All American Pipeline, L.P. (NYSE: PAA) and Canacol Energy Ltd. (TSXV: CNE). He is a member of the Independent Petroleum Association of America, the Houston Producers' Forum and the Petroleum Club of Houston. He is also a member and past Chairman of Chapelwood United Methodist Church, Chairman of the Memorial Hermann Healthcare Foundation and a past Chairman of the Council on Alcohol and Drugs in Houston. Mr. Petersen brings to our board the expertise he has acquired from being involved in the energy sector for more than 30 years, including extensive knowledge of the energy sector's various cycles, as well as the current market and industry knowledge that comes with management of approximately $11 billion of energy-related investments.

Daniel J. Churay was appointed to our board of directors in November 2017. Mr. Churay has served since 2011 as executive vice president-corporate affairs, general counsel and corporate secretary of MRC Global Inc., the leading distributor of pipe, valves, fittings and infrastructure supplies to the energy industry. In his current role, Mr. Churay manages the company's human resources, legal, risk compliance, corporate services and external and government affairs functions. He also acts as corporate secretary to the company's board of directors. Prior to joining MRC Global, he served as president and CEO of Rex Energy Corporation, an independent oil and gas company, and was a member of its board of directors from 2007 to 2011. Mr. Churay's executive experience prior to Rex Energy includes his serving as executive vice president, general counsel and secretary of YRC Worldwide Inc., a Fortune 500 transportation and logistics company; and deputy general counsel and assistant secretary of Baker Hughes Incorporated, a Fortune 500 company that provides products and services to the petroleum and continuous process industries. He was also a senior counsel at Fulbright & Jaworski LLP, now part of Norton Rose Fulbright. Mr. Churay received his bachelor's degree in economics from the University of Texas and a juris doctorate from the University of Houston Law Center, where he was a member of the Law Review. Mr. Churay is a Leadership Fellow with the National Association of Corporate Directors and a member of the board of directors of the Sam Houston Area Council of the Boy Scouts of America. We believe that Mr. Churay's legal background, understanding of the industry and previous restructuring experience greatly enhances our board of directors.

Composition of the Board of Directors

Effective November 28, 2017, EV Management's board of directors was expanded from eight to nine members with the addition of Mr. Churay. EnerVest appointed eight of the members and EnCap appointed Mr. Petersen.

EV Management's board of directors holds regular and special meetings at any time as may be necessary. Regular meetings may be held without notice on dates set by the board from time to time. Special meetings of the board may be called with reasonable notice to each member upon request of the chairman of the board or upon the written request of any three board members. A quorum for a regular or special meeting will exist when a majority of the members are participating in the meeting either in person or by telephone conference. Any action required or permitted to be taken at a board meeting may be taken without a meeting, without prior notice and without a vote if all of the members sign a written consent authorizing the action.

Unitholder Communications

Interested parties can communicate directly with non–management directors by mail in care of EV Energy Partners, L.P., 1001 Fannin Street, Suite 800, Houston, Texas 77002. Such communications should specify the intended recipient or recipients. Commercial solicitations or communications will not be forwarded.

Committees of the Board of Directors

EV Management's board of directors established an audit committee, a compensation committee, a conflicts committee and a strategic advisory committee. The charters for our audit and compensation committees are posted under the "Investor Relations" section of our website at www.evenergypartners.com. Our conflicts committee was created in our partnership agreement and does not have a charter.

Audit Committee

The audit committee is comprised of Messrs. Larson (Chairman), Burk and Lindahl, all of whom meet the independence and experience standards established by the NASDAQ and the Exchange Act. The board of directors has determined that each of Messrs. Larson and Burk is an "audit committee financial expert" as defined under SEC rules.

The audit committee assists the board of directors in its oversight of the integrity of our financial statements and our compliance with legal and regulatory requirements and corporate policies and controls. The audit committee also reviews our reserve estimation processes.

The audit committee has the sole authority and responsibility to retain and terminate our independent registered public accounting firm, resolve disputes with such firm, approve all auditing services and related fees and the terms thereof, and pre–approve any non–audit services to be rendered by our independent registered public accounting firm. The audit committee is also responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm is given unrestricted access to the audit committee and meets with the audit committee on a regularly scheduled basis. During 2017, representatives of our independent registered public accounting firm attended all of our audit committee meetings. The audit committee may also engage the services of advisors and accountants as it deems advisable.

Compensation Committee

Although not required by the listing requirements of the NASDAQ, the board of directors established and maintains a compensation committee comprised of non-employee directors. The compensation committee is comprised of Messrs. Lindahl (Chairman), Burk, Petersen and Churay. The compensation committee reviews the compensation and benefits of our executive officers, establishes and reviews general policies related to our compensation and benefits and administers our long–term incentive plans (the “Plans”).

Conflicts Committee

The conflicts committee is comprised of Messrs. Burk (Chairman), Larson, Lindahl and Churay, all of whom meet the independence standards established by the NASDAQ. The conflicts committee reviews specific matters that our management or board of directors believes may involve conflicts of interest. Any matters approved by the conflicts committee will be conclusively deemed to be fair and reasonable to us, approved by all of our partners, and not a breach by our general partner of any duties it may owe us or our unitholders.

Strategic Advisory Committee

The strategic advisory committee is comprised of Messrs. Churay (Chairman), Burk, Larson and Lindahl, all of whom meet the independence standards established by the NASDAQ. The strategic advisory committee was established to review and advise management on potential strategic transactions to reduce debt leverage at the Partnership.

Meetings and Other Information

During 2017, the board of directors had fifteen regularly scheduled and special meetings, the audit committee had four meetings, the compensation committee had five meetings, the conflicts committee had four meetings and the strategic advisory committee had two meetings. None of our directors attended fewer than 75% of the aggregate number of meetings of the board of directors and committees of the board on which the director served.

Our partnership agreement provides that the general partner manages and operates us and that, unlike holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business or governance. Accordingly, we do not hold annual meetings of unitholders.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires executive officers and directors of EV Management and persons who beneficially own more than 10% of a class of our equity securities registered pursuant to Section 12 of the Exchange Act to file certain reports with the SEC and the NASDAQ concerning their beneficial ownership of such securities.

Based solely on a review of the copies of reports on Forms 3, 4 and 5 and amendments thereto furnished to us and written representations from the executive officers and directors of EV Management, we believe that during 2017, the officers and directors of EV Management and beneficial owners of more than 10% of our equity securities registered pursuant to Section 12 were in compliance with the applicable requirements of Section 16(a).

Code of Business Conduct

The corporate governance of EV Management is, in effect, the corporate governance of our partnership, subject in all cases to any specific unitholder rights contained in our partnership agreement.

EV Management has adopted a code of business conduct that applies to all officers, directors and employees of EV Management and its affiliates. A copy of our code of business conduct is available on our website at www.evenergypartners.com. We will provide a copy of our code of business conduct to any person, without charge, upon request to EV Management, LLC, 1001 Fannin, Suite 800, Houston, Texas 77002, Attn: Corporate Secretary.

Reimbursement of Expenses of our General Partner

Our general partner does not receive any management fee or other compensation for its management of our partnership. Under the terms of the omnibus agreement, we pay EnerVest a fee for general and administrative services undertaken for our benefit and for our allocable portion of the premiums on insurance policies covering our assets. In addition, we reimburse EV Management for the costs of employee, officer and director compensation and benefits properly allocable to us, as well as for other expenses necessary or appropriate to the conduct of our business and properly allocable to us. Our partnership agreement provides that our general partner will determine the expenses that are allocable to us in any reasonable manner determined by our general partner in its sole discretion.

ITEM 11. EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

Because our general partner is a limited partnership, its general partner, EV Management, manages our operations and activities. We do not directly employ any of the persons responsible for managing our business. Mr. Michael E. Mercer and Mr. Nicholas P. Bobrowski are employees of EV Management, and we reimburse EV Management for the costs of their compensation. Messrs. Mercer and Bobrowski do not currently perform services for EnerVest or its affiliates (other than EV Management). Their compensation is approved by the compensation committee of EV Management’s board of directors, which we refer to as our compensation committee.

Mr. John B. Walker is an officer of EV Management and is also an officer and employee of other subsidiaries of EnerVest. In these capacities, he performs services for us as well as for EnerVest and its other affiliates. In order to compensate Mr. Walker for the time he devotes to our business and to provide our compensation committee with oversight of the portion of his annual bonus reflecting his services to us, a portion of his cash bonus was reviewed and approved by our compensation committee, and we reimburse EnerVest for this cash bonus. In addition, Mr. Walker continues to participate in the Plans.

Our compensation committee discusses with EnerVest the philosophy used by EnerVest in setting the salaries and bonus compensation for its employees who perform services for us under the omnibus agreement. However, except for the bonus payment noted in the previous paragraph, the compensation committee has no role in determining the base salary and short–term and long–term incentive compensation paid to EnerVest employees. We pay EnerVest a fee under the omnibus agreement which is based in part on the compensation paid to EnerVest employees who perform work for us, but other than the portion of Mr. Walker’s cash bonus charged to us, we do not directly reimburse EnerVest for the costs of the compensation of Mr. Walker and our compensation committee does not oversee his annual compensation. Awards made to Mr. Walker, Ryan J. Flory and other employees of EnerVest under the Plans are determined by our compensation committee.

Our compensation committee has overall responsibility for the approval, evaluation and oversight of all of our compensation programs. The compensation committee’s primary purpose is to assist the board of directors in the discharge of its fiduciary responsibilities relating to fair and competitive compensation. The compensation committee meets in the fourth quarter of each year to review the compensation program and to determine cash compensation levels for the ensuing fiscal year and long term incentive awards for the then current fiscal year. The compensation committee may meet at other times as required.

Objectives of Our Compensation Program

Our executive compensation program is intended to align the interests of our management team with those of our unitholders by motivating our executive officers to achieve strong financial and operating results for us, which we believe closely correlate to long–term unitholder value. In addition, our program is designed to achieve the following objectives:

- attract and retain talented executive officers by providing reasonable total compensation levels competitive with that of executives holding comparable positions in similarly situated organizations;
- provide total compensation that takes into account individual performance;
- provide performance–based compensation that balances rewards for short–term and long–term results and takes into account both individual and our performance; and
- encourage the long–term commitment of our executive officers to us and our unitholders’ long–term interests.

What Our Compensation Program is Designed to Reward

Our compensation program is designed to reward performance that contributes to the achievement of our business strategy. As a result of our current financial condition and our intent to effectuate a restructuring, we have shifted our performance focus towards retaining employees, optimizing operating cash flow, and deploying capital into higher return drilling opportunities. In addition, we reward qualities that we believe help achieve our strategy such as teamwork; individual performance in light of general economic and industry specific conditions; performance that supports our core values; resourcefulness; the ability to manage our existing assets; the ability to explore new avenues to increase oil, natural gas and natural gas liquids production and reserves; level of job responsibility; and tenure.

Compensation Consultant

Our compensation committee retained an independent compensation consultant for assistance in structuring and determining compensation. Since 2010, EnerVest has retained Longnecker & Associates to provide compensation advice and data to EnerVest regarding its employees, including our executive officers. In general, the role of the outside compensation consultant is to assist EnerVest with the analysis of executive pay packages; however EnerVest is under no obligation to follow the advice or recommendations of any compensation consultant.

EnerVest provided our compensation committee with a summary of Longnecker & Associates’ analysis of the compensation of EnerVest employees who perform services for us, as well as Messrs. Mercer and Bobrowski, which the compensation committee considered in approving the compensation of our executive officers. Like EnerVest, the compensation committee is under no obligation to follow the advice or recommendations on any compensation consultant. In conducting its analysis, Longnecker & Associates took into account factors including: current compensation for the named executives and directors, size of the company compared to the peer group, market talent pool conditions and market trends, commodity market factors, company performance, executive responsibility as compared to similar positions in the market and competitive compensation within our market.

Benchmarking

As part of the proposed compensation plan, our chief executive officer asked Longnecker & Associates to prepare an analysis of the compensation paid (based on survey data and proxy analysis) by a peer group composed of the following companies: Amplify Energy Corp.; Bill Barrett Corp.; Carrizo Oil & Gas, Inc.; Jones Energy, Inc.; Laredo Petroleum Holdings, Inc.; Legacy Reserves LP; Linn Energy, Inc.; Matador Resources Company; Oasis Petroleum; PDC Energy, Inc.; Resolute Energy Corporation; Sanchez Energy Corporation; and Unit Corporation. The compensation committee reviews the composition of the peer group each year. Longnecker & Associates reviewed peer group and survey data and made recommendations to management regarding executive and director compensation.

In connection with setting base salary for 2018 and bonus and long–term equity incentive compensation for 2017, our management and compensation committee used information regarding peer companies to check their base salary and bonus compensation decisions for reasonableness and to benchmark with respect to base salary, bonus and long–term equity incentive compensation. Our compensation committee does not employ a specific target or market percentile for any element of compensation. The compensation committee takes into consideration a number of factors in making compensation decisions.

Performance Metrics

With respect to bonus and long–term incentive awards, our compensation committee did not establish performance metrics for our executive officers for 2017 in order to remain flexible in our compensation practices. The compensation committee makes a subjective determination at the end of the fiscal year as to the appropriate compensation based on a recommendation from our chief executive officer and given their view of our performance for the year.

Elements of Our Compensation Program and Why We Pay Each Element

To accomplish our objectives, we seek to offer a total direct compensation program to our executive officers that, when valued in its entirety, serves to attract, motivate and retain executives with the character, experience and professional accomplishments required to execute our strategy in a demanding environment. Our compensation program is currently comprised of five elements:

- base salary;
- cash bonus;
- key employee incentive;
- retention bonus; and
- benefits.

Base Salary

We pay base salary in order to recognize each executive officer's unique value and historical contributions to our success in light of salary norms in the industry and the general marketplace; to effectively compete with others for executive talent; to provide executives with sufficient, regularly–paid income; and to reflect position and level of responsibility.

To provide stability and appropriate incentive, Mr. Mercer is party to an employment agreement which sets his minimum base salary per annum. In the compensation committee's discretion, however, his base salary may be increased based upon performance and subjective factors.

In February 2015, Mr. Mercer's base salary was increased to $350,000 in conjunction with his promotion to Chief Executive Officer of EV Management with an actual pro-rated base salary of $310,167.

In February 2015, in conjunction with Mr. Bobrowski's appointment as the Chief Financial Officer of EV Management, the compensation committee set the base salary for Mr. Bobrowski at $230,000, with an actual pro-rated base salary of $225,000.

For 2016, in an effort to further reduce costs, our chief executive officer recommended, and the compensation committee approved, reducing the base salaries for Messrs. Mercer and Bobrowski from 2015 amounts ($350,000 and $230,000, respectively) by 10%, effective March 1, 2016. Accordingly, the actual pro-rated base salaries for 2016 were $320,833 for Mr. Mercer and $210,833 for Mr. Bobrowski.

In December 2016, our chief executive officer recommended, and the compensation committee approved, reinstating 50% of the 10% reduction taken in March 2016, effective January 1, 2017. Effective April 1, 2017, Messrs. Mercer and Bobrowski both received a 3% base salary increase. In November 2017, our chief executive officer recommended, and the committee approved, increasing the base salaries for both Messrs. Mercer and Bobrowski. On November 17, 2017, an employment agreement was signed for both Messrs. Mercer and Bobrowski, changing their salary to $400,000 and $300,000, respectively. Thus, the actual base salaries for 2018 will be $400,000 for Mr. Mercer and $300,000 for Mr. Bobrowski and the actual pro-rated base salaries for 2017 were $347,172 for Mr. Mercer and $232,784 for Mr. Bobrowski. This results in total direct compensation (base salary, bonus and long–term incentive) for Messrs. Mercer and Bobrowski below the 25th percentile of the peer group. The committee believes the increase in salary provides stability and incentive for our executive officers during a time of transition for the Partnership.

Cash Bonus

We include an annual cash bonus as part of our compensation program because we believe this element of compensation helps to motivate management to achieve key operational objectives by rewarding the achievement of these objectives. The annual cash bonus also allows us to be competitive from a total remuneration standpoint. Our compensation committee also reviewed and approved a portion of the cash bonus paid to Mr. Walker.

Mr. Mercer's employment agreement provides that the cash bonus element of compensation will be equal to a percentage of the executive's total base salary paid during each such annual period, such percentage to be established by the compensation committee in its sole discretion. Generally, for Mr. Mercer, our compensation committee targets between 40% and 80% of total base salary for performance deemed by our compensation committee to be good and exceptional, respectively, with the possibility of no bonus for poor performance and higher for exceptional corporate or individual performance.

Our chief executive officer recommended the cash bonus to be paid to Messrs. Mercer and Bobrowski. Based on this recommendation, the compensation committee, in determining the cash bonus amounts, took into account its belief that the efforts of Messrs. Mercer and Bobrowski directly affected the achievement of the following key operational objectives in 2017:

- we successfully resumed our drilling program in core areas with promising initial results;
- we improved our base business through operating and G&A cost cutting measures; and
- we ended the year with over $66 million of liquidity between borrowing base capacity and cash on hand.

In 2017, Mr. Mercer received a performance bonus of $309,957, of which $109,957 was contributed to the Retirement Plan and $200,000 was delivered in cash. The total bonus represents 89% of his total base salary, which amount placed Mr. Mercer below the 25th percentile of cash bonus compensation of our peer group. In 2017, Mr. Bobrowski received a performance bonus of $157,952, of which $7,952 was the amount contributed to the Retirement Plan and $150,000 was delivered in cash. The performance bonus represents 68% of his total base salary, which amount placed Mr. Bobrowski below the 25th percentile of cash bonus compensation of our peer group. The bonuses for Messrs. Mercer and Bobrowski also reflected the compensation committee's determination that their performances in accomplishing the 2017 objectives described above were very strong.

In addition, Mr. Walker was awarded a cash bonus of $100,000, representing a portion of his total annual compensation paid by us and EnerVest. The amount of his bonus was recommended to our compensation committee by Mr. Walker based on his subjective view as to appropriate compensation levels taking into account the performance objectives discussed above and, in the case of Mr. Walker, the amount of time he spent on our business activities. The compensation committee then determined to accept this recommendation.

In addition to performance bonuses, Mr. Mercer and Mr. Bobrowski were awarded retention bonuses as described below.

Long–term Equity–based Compensation

Long–term equity–based compensation has traditionally been an element of our compensation policy because we believe it aligns executives' interests with the interests of our unitholders; rewards long–term performance; is required in order for us to be competitive from a total remuneration standpoint; encourages executive retention; and gives executives the opportunity to share in our long–term performance. We have generally sought to allocate a large portion of total compensation to long–term equity compensation, generally targeting between the 50th and 75th percentiles of our peer group for such compensation, with higher amounts for performance our compensation committee views as exceptional.

On August 30, 2016, the common unitholders approved the EV Energy Partners, L.P. 2016 Long-Term Incentive Plan (the "2016 Plan"), which provides for the issuance of up to 5,000,000 units. The 2016 Plan became effective by its terms on the date of approval by the unitholders and replaces the 2006 Long-Term Incentive Plan (the "2006 Plan" and together, the "Plans") as to future issuances.

The compensation committee acts as the administrator of the Plans and performs functions that include selecting award recipients (or the manner in which such recipients will be chosen), determining the timing of grants and assigning the number of units subject to each award (or the manner in which such assignments will be made), fixing the time and manner in which awards are exercisable, setting exercise prices and vesting and expiration dates, and from time to time adopting rules and regulations for carrying out the purposes of our Plans. For compensation decisions regarding the grant of equity compensation to executive officers, our compensation committee will consider recommendations from our chief executive officer. Typically, awards vest over multiple years, but the compensation committee maintains the discretionary authority to vest the equity grant immediately if the individual situation merits.

For grants under the 2006 Plan, the compensation committee, in its discretion, can provide that in the event of a termination of employment upon a change of control, all outstanding equity-based awards will immediately vest. In the event of termination of a grantee's employment upon the death, disability, or involuntary termination of a grantee's employment without good reason, the compensation committee, in its discretion, can provide that all outstanding equity-based awards will vest effective upon the normal vesting date that coincides with, or immediately follows, the termination.

For grants under the 2016 Plan, the compensation committee, in its discretion, can provide that in the event of a termination of employment upon a change of control or the grantee's death or disability, all outstanding equity-based awards will immediately vest. In the event of involuntary termination of a grantee's employment without good reason, the compensation committee, in its discretion, can provide that equity-based awards scheduled to vest on the vesting date that coincides with, or immediately follows, the termination will vest effective upon the normal vesting date, and all other outstanding equity-based awards will be forfeited as of the date of termination.

The compensation committee has discretion with respect to full acceleration provisions in the equity award agreements under our Plans upon a change in control because we believe that it is important to provide the named executive officers with a sense of stability in the middle of transactions that may create uncertainty regarding their future employment as well as maximize unitholder value by encouraging the named executive officers to review objectively any proposed transaction in determining whether such proposal is in the best interest of our unitholders, whether or not the executive will continue to be employed.

The Plans permit the compensation committee to delegate its authority to grant awards, except for awards to executive officers and directors, to one or more of our executive officers.

We have no set formula for granting awards to our executives or employees. In determining whether to grant awards and the amount of any awards, our compensation committee takes into consideration discretionary factors such as the individual's current and expected future performance, level of responsibility, retention considerations and the total compensation package.

Awards under the Plans may be unit options, phantom units, performance units, restricted units and deferred equity rights, or DERs. There are 1.3 million common units awarded and outstanding under the 2006 Plan, and the aggregate amount of our common units that may be awarded under the 2016 Plan is 5.0 million units. As of December 31, 2017, there are 4.2 million units available for issuance. Unless earlier terminated by us or unless all units available under the 2016 Plan have been paid to participants, the 2016 Plan will terminate as of the close of business on August 30, 2026.

Although the 2016 Plan generally provides for the grant of unit options, Internal Revenue Code Section 409A and authoritative guidance thereunder provides that options can generally only be granted to employees of the entity granting the option and certain affiliates without being required to comply with Internal Revenue Code Section 409A as nonqualified deferred compensation. Until further guidance is issued by the Treasury Department and Internal Revenue Service under Internal Revenue Code Section 409A, we do not intend to grant unit options.

In addition, because we are a partnership, tax and accounting conventions make it more costly for us to issue additional common units or options as incentive compensation. Consequently, we have no outstanding options or restricted units and have no plans to issue options or restricted units in the future. Instead, we have issued phantom units and performance units to our executive officers. A phantom unit is the right to receive, upon satisfaction of the vesting criteria specified in the grant, a common unit or, at the discretion of our compensation committee, cash based on the average closing price of our common units on the date of vesting, or if there is no trading on that date, the next preceding trading date. The phantom units typically vest in equal annual installments over a four year period beginning January 15th of the year following the first full year after the date of grant. Unlike "vesting" of an option, vesting of a phantom unit results in the delivery of a common unit or cash equivalent value as opposed to a right to exercise. These phantom and performance unit awards entitle the recipients of the unit awards to receive, with respect to each unit subject to such award that has not either vested or been forfeited, a cash payment equal to each cash distribution per units made by us on our units promptly following each such distribution by us to our unitholders.

As the compensation committee has recently refocused the objectives of our compensation program in order to encourage executive retention for the periods prior to and during the Chapter 11 Cases, the compensation committee determined that it was in the best interests of the Partnership not to grant phantom units or other long-term unit-based awards during 2017.

Key Employee Incentive Plan

In 2017, the board of directors of EV Management adopted the EV Management 2017-2018 Key Employee Incentive Plan (the "Incentive Plan") for key employees whose continued employment and performance is critical to the success of the Partnership. The Incentive Plan is designed to motivate EV Management's officers to achieve the Partnership's performance objectives and reward officers when those objectives are met or exceeded. The Incentive Plan features pre-established target levels related to three key performance measures for EV Management: quarterly production, lease operating expenses ("LOE") and Adjusted EBITDAX of EV Management. The Incentive Plan was adopted as of November 17, 2017 and is in effect for the four consecutive calendar quarters beginning October 1, 2017 through September 30, 2018.

Actual cash bonuses that may be payable under the Incentive Plan will be determined and earned based on the achievement of quarterly threshold, target and maximum performance metrics and goals as of the end of each calendar quarter during the term of the plan. Each such quarterly period is referred to as a "performance period" under the Incentive Plan. In addition to cash bonuses being determined on a quarterly basis, each performance metric shall also be measured cumulatively as of the end of each performance period, and to the extent the Partnership' performance equals or exceeds the cumulative performance goals/metrics, a "catch-up payment" will also be made to the participants.

For Mr. Mercer, his quarterly threshold amount is $50,000, his quarterly target amount is $100,000 and his quarterly maximum amount is $150,000. For Mr. Bobrowski, his quarterly threshold amount is $26,250, his quarterly target amount is $52,500 and his quarterly maximum amount is $78,750. For Mr. Walker, his quarterly threshold amount is $31,250, his quarterly target amount is $62,500 and his quarterly maximum amount is $93,750. Each of the performance metrics ¾ production, LOE and Adjusted EBITDAX — is weighted equally (33.33% for each performance metric) in determining the total amount eligible for the participant to earn. For the term of the Incentive Plan, the aggregate of all four quarterly and all cumulative amounts that may be paid to Mr. Mercer, to Mr. Bobrowski and to Mr. Walker are:

- For Mr. Mercer, $200,000 (threshold amount), $400,000 (target amount) and $600,000 (maximum amount);
- For Mr. Bobrowski, $105,000 (threshold amount), $210,000 (target amount) and $315,000 (maximum amount); and
- For Mr. Walker, $125,000 (threshold amount), $250,000 (target amount) and $375,000 (maximum amount).

These amounts assume that all quarterly payments and cumulative payments are made under the applicable category (threshold, target or maximum).

The foregoing description of the Incentive Plan does not purport to be complete and is qualified in its entirety by the full text of such Incentive Plan.

Retention Bonus

Messrs. Mercer and Bobrowski have each entered into a Retention Bonus Agreement (each a "Retention Agreement") with EV Management dated as of November 17, 2017. Each Retention Agreement provides that EV Management will pay each such officer a cash lump sum payment within 15 days of the date that such officer executed and returned a copy of his Retention Agreement to EV Management.

In the event that the officer's employment with EV Management terminates for any reason other than a "Qualifying Termination" before December 31, 2018 (the "Completion Date"), that officer will be required to repay to EV Management within 15 days of such termination, the total amount of the retention bonus previously paid to him, net of any taxes that the officer is required to pay in respect of the retention bonus and determined by taking into account any tax benefit that may be available in respect of such repayment. However, if the officer's employment terminates because of a Qualifying Termination before the Completion Date, and that officer executes and does not revoke a customary release of claims in a form reasonably satisfactory to EV Management, then such officer will not be required to repay any portion of his retention bonus previously paid.

Under each Retention Agreement, the term “Qualifying Termination” means the termination of the officer’s employment (i) by EV Management for a reason other than “cause,” (ii) by the officer for “good reason,” or (iii) due to such officer’s death or disability. The definitions of the terms “cause” and “good reason” are similar to, but not identical to, the definitions of those terms contained in the Employment Agreements for Messrs. Mercer and Bobrowski.

Under their respective Retention Agreements, the amount of Mr. Mercer’s retention bonus is $550,000 and the amount of Mr. Bobrowski’s retention bonus is $290,000.

The foregoing description of the Retention Agreements does not purport to be complete and is qualified in its entirety by the full text of the Retention Agreements.

Benefits

We believe in a simple, straight–forward compensation program and, as such, Messrs. Mercer and Bobrowski are not provided unique perquisites or other personal benefits. Consistent with this strategy, no perquisites or other personal benefits have or are expected to exceed $10,000 for Messrs. Mercer and Bobrowski.

Through EnerVest, we provide company benefits that we believe are standard in the industry. These benefits consist of a group medical, dental and vision insurance program for employees and their qualified dependents, group life insurance for employees, accidental death and dismemberment coverage for employees, a 401(k) employee savings and investment plan, and a defined benefit plan.

In 2011, EnerVest established the EnerVest Ltd. Retirement Plan (the “Retirement Plan”), a defined benefit plan under ERISA, for certain officers and other highly compensated employees of EnerVest and its subsidiaries. The purpose of the Retirement Plan is to provide a company funded tax–qualified plan for retirement benefits on a tax advantaged basis. The participants accrue a benefit based on their age, designated “allocation group,” the investment yield on the Retirement Plan’s assets and other factors, subject to the limits on benefits prescribed under the Internal Revenue Code. The benefit is payable in various annuity forms or as a lump sum. All benefit election forms are actuarially equivalent, and there are no subsidies to any election.

Employees who are eligible to participate in the Retirement Plan receive their cash compensation in two forms: (i) base salary and annual bonus, subject to applicable taxes and withholdings and (ii) a fully vested annual company contribution to the Retirement Plan. Therefore, the overall level of compensation is not enhanced for the Retirement Plan participants because a portion of compensation is contributed to the Retirement Plan by us in lieu of current cash compensation. In 2017, 2016 and 2015, the total bonus paid to both Messrs. Mercer and Bobrowski were inclusive of the amount delivered in cash and in company contributions under the Retirement Plan.

At the time of the adoption of the Retirement Plan, EnerVest amended its 401(k) Plan with regard to EnerVest’s contributions. Under the 401(k) Plan, all employees who are eligible to participate receive a 3% "safe harbor" contribution from EnerVest. In addition, under the 401(k) plan, EnerVest may make a discretionary profit sharing contribution that is allocated to participant accounts based on their designated "allocation group." The allocation groups are structured so that certain officers and other highly paid employees receive a profit sharing contribution that is a greater percentage of compensation than the percentage applicable to other participants.

Messrs. Mercer and Bobrowski participate in the Retirement Plan and received discretionary profit sharing 401(k) contributions in an allocation group which paid a higher percent of their compensation than allocated to other participants.

We reimburse EnerVest for any amounts contributed to the Retirement Plan and the 401(k) plan attributable to Messrs. Mercer and Bobrowski. In the Summary Compensation Table, the present values of benefits under the Retirement Plan are reflected under the column “Change in Pension Value and Nonqualified Deferred Compensation Earnings” and the contributions to the 401(k) plan are included under “All Other Compensation.” Additional information about the Retirement Plan is set forth under “–Retirement Plan,” below.

How Elements of Our Compensation Program are Related to Each Other

We view the various components of compensation as related but distinct and emphasize “pay for performance” with a significant portion of total compensation tied to short–term financial and strategic goals. We determine the appropriate level for each compensation component based in part, but not exclusively, on our view of internal equity and consistency, and other considerations we deem relevant, such as rewarding extraordinary performance. For the reasons described above, we did not grant long-term equity-based incentives in 2017.

Our compensation committee, however, has not adopted any formal or informal policies or guidelines for allocating compensation between long–term and currently paid out compensation, between cash and non–cash compensation, or among different forms of non–cash compensation.

Assessment of Risk

The compensation committee is aware of the need to take risk into account when making compensation decisions and periodically conducts a compensation risk analysis. Our policy is to conduct our commercial activities within pre-defined risk parameters that are closely monitored and are structured in a manner intended to control and minimize the potential for unwarranted risk taking.

Based on the foregoing, our compensation committee does not believe that risks arising from our compensation policies and practices are reasonably likely to have a material adverse effect on us.

Other Compensation Related Matters

Although we encourage our named executive officers to acquire and retain ownership in us, we do not have a policy requiring maintenance of a specified equity ownership level. As of February 15, 2018, our named executive officers beneficially owned in the aggregate approximately 6.1% of our common units (excluding any unvested equity awards). In addition, through their ownership of EnerVest and EV Investors, our executive officers also have a substantial indirect ownership interest in our general partner.

Accounting and Tax Considerations

If an executive is entitled to nonqualified deferred compensation benefits that are subject to Internal Revenue Code Section 409A, and such benefits do not comply with Internal Revenue Code Section 409A, then the benefits are taxable in the first year they are not subject to a substantial risk of forfeiture. In such case, the service provider is subject to regular federal income tax, interest and an additional federal penalty tax of 20% of the benefit includible in income.

When the compensation committee makes awards under the 2016 Plan, they also review the effect the awards will have on our consolidated financial statements.

Compensation Committee Report

We have reviewed and discussed with management the compensation discussion and analysis required by Item 402(b) of Regulation S–K. Based on the review and discussion referred to above, we recommend to the board of directors that the compensation discussion and analysis be included in this Form 10–K.

Compensation Committee:
George Lindahl III (Chairman)
Victor Burk
Gary R. Petersen
Daniel J. Churay

Pay Ratio Disclosure

As required by Section 953(b) of the Dodd-Frank Wall Street Reform and Consumer Protection Act, and Item 402(u) of Regulation S-K, we are providing the following information about the relationship of the total annual compensation of our employees and the annual total compensation of our president and chief executive officer:

For 2017, our last completed fiscal year:

- The median of the total annual compensation of all employees of our Company (excluding our CEO) was $115,419; and
- The total annual compensation of our chief executive officer, as reported in the Summary Compensation Table below, was $1,369,491.

Based on this information, for 2017 the ratio of the annual total compensation of Mr. Mercer, our president and chief executive officer, to the median of the annual total compensation of all employees was 11.9.

To identify the median of the annual total compensation of all our employees, as well as to determine the annual total compensation of our median employee and our CEO, we took the following steps:

- We determined that, as of December 31, 2017, our employee population consisted of approximately six full-time employees, with all of these individuals located in the United States. This population did not include employees who were on leaves of absence as of December 31, 2017, or any part-time or temporary employees;
- To identify the "median employee" from our employee population, we used cash compensation consisting of total compensation (base salary, bonus, long-term incentive plan, and employer contribution to both the defined benefit and defined contribution plan). In making this determination, we annualized the base pay or monthly wages and annual bonus amounts paid in respect of 2017 for those full-time employees who did not work for the entire 12-month period;
- Once we identified our median employee, we combined all of the elements of such employee's compensation for 2017 in accordance with the requirements of Item 402(c)(2)(x) of Regulation S-K, resulting in annual total compensation of $115,419;
- With respect to the total annual compensation of our CEO, we used the amount reported in the "Total" column of the Summary Compensation Table.

Because the SEC rules for identifying the median compensated employee and calculating the pay ratio based on that employee's annual total compensation allow companies to adopt a variety of methodologies, to apply certain exclusions, and to make reasonable estimates and assumptions that reflect their compensation practices, the pay ratio reported by other companies may not be comparable to the pay ratio reported above, as other companies may have different employment and compensation practices and may utilize different methodologies, exclusions, estimates and assumptions in calculating their own pay ratios.

Summary Compensation Table

The following table sets forth certain information with respect to compensation of our named executive officers. We reimburse EV Management for the costs of salaries and bonuses for Messrs. Mercer and Bobrowski. Our compensation committee approved, and we reimbursed EnerVest for, cash bonuses paid to Mr. Walker in 2017, 2016 and 2015 as listed in the table below. Mr. Walker is, and Mr. Houser was, compensated by EnerVest. We pay EnerVest a fee under the omnibus agreement, but, other than the cash bonuses listed in the table below, we do not directly reimburse EnerVest for the costs of their salaries and bonuses. Compensation for Mr. Flory is not included in the table as it was less than $100,000.

There was no compensation awarded to, earned by or paid to any of the named executive officers related to option awards or non–equity incentive compensation plans.

Name and Principal Position	Year	Salary	Bonus (1)	Unit Awards (2)	Change in Pension Value and Nonqualified Deferred Compensation Earnings (3)	All Other Compensation (4)	Total
John B. Walker	2017	$ -	$ 179,033	$ -	$ -	$ -	$ 179,033
Executive Chairman	2016	-	75,000	236,695	-	11,156	322,851
	2015	-	83,000	281,250	-	124,500	488,750
Michael E. Mercer	2017	347,172	876,452	-	109,957	35,910	1,369,491
President, Chief Executive Officer	2016	320,833	36,124	210,828	104,224	44,206	716,215
	2015	310,167	30,829	228,125	94,171	140,745	804,037
Nicholas P. Bobrowski	2017	232,784	506,387	-	7,952	35,910	783,033
Vice President, Chief Financial Officer	2016	210,833	72,463	105,198	7,537	38,613	434,644
	2015	225,000	94,041	241,850	5,959	56,532	623,382

(1) Includes retention bonuses paid in November 2017 of $550,000 and $290,000 for Messrs. Mercer and Bobrowski, respectively. In the event that the officer's employment with EV Management terminates for any reason other than a "Qualifying Termination" before December 31, 2018, that officer will be required to repay to EV Management total amount of the retention bonus, net of any taxes that the officer is required to pay. Also includes bonuses of $79,033, $126,452 and $66,387 for Messrs. Walker, Mercer and Bobrowski, respectively, paid in 2018 under the Key Employee Incentive Plan for the quarter ended December 31, 2017. The remaining bonus included in this amount represents amounts paid in December 2017, 2016 and 2015 as bonuses for services in 2017, 2016 and 2015, respectively.

(2) Reflects the aggregate grant date fair value of the phantom units granted computed in accordance with ASC Topic 718. See "Item 8. Financial Statements and Supplementary Data" for the assumptions used in estimating the grant date fair value of the phantom units granted in 2016 and 2015. No phantom units were granted in 2017.

(3) Amounts in this column reflect the aggregate change during 2017, 2016 and 2015 in the actuarial present value of the executive's accumulated benefit under the Retirement Plan. We do not provide above market rates of return (defined by SEC rules as a rate that exceeds 120% of the federal long–term rate) under the Retirement Plan.

(4) Represents cash distributions received on unvested phantom and performance units and, for Messrs. Mercer and Bobrowski, the amounts contributed by us to their 401(k) plans. In 2017, we contributed $35,910 and $35,910 to the 401(k) plans of Messrs. Mercer and Bobrowski, respectively. In 2016, we contributed $35,000 and $35,000 to the 401(k) plans of Messrs. Mercer and Bobrowski, respectively. In 2015, we contributed $35,245 and $32,648 to the 401(k) plans of Messrs. Mercer and Bobrowski, respectively. Any perquisites or other personal benefits received were less than $10,000.

Grants of Plan–Based Awards

There were no grants of phantom units, non-equity incentives or option awards to our named executive officers in 2017.

Outstanding Equity Awards at Fiscal Year End

The following table sets forth certain information with respect to outstanding equity awards at December 31, 2017. There were no option awards outstanding.

Name	Number of Units That Have Not Yet Vested	Market Value of Units That Have Not Yet Vested (1)
John B. Walker	5,250(2)	$ 110,969
	12,500(3)	
	84,375(4)	
	115,461(5)	
Michael E. Mercer	5,000(2)	95,513
	11,000(3)	
	68,437(4)	
	102,843(5)	
Nicholas P. Bobrowski	625(2)	44,038
	6,283(3)	
	28,125(4)	
	51,316(5)	

(1) Based on the closing price of our common units on December 29, 2017 of $0.51.

(2) These phantom units vested in January 2018.

(3) One–half of these phantom units vested in January 2018, with the remaining one–half vesting in January 2019.

(4) One–third of these phantom units vested in January 2018, with one–third each vesting in January 2019 and January 2020.

(5) These phantom units vested 25% in January 2018, with 25% each vesting in January 2019, January 2020 and January 2021.

Option Exercises and Units Vested

The following table sets forth certain information with respect to phantom units and performance units vested during 2017. There were no option awards that vested.

Name	Number of Units Acquired on Vesting	Value Realized on Vesting (1)
John B. Walker	46,625	$ 94,183
Michael E. Mercer	38,313	77,391
Nicholas P. Bobrowski	13,142	26,546

(1) Represents the aggregate dollar amount realized on the date of vesting based on the market price of our common units on the NASDAQ Global Market on January 13, 2017.

Pension Benefits

The following table sets forth certain information with respect to the Retirement Plan:

Name	Number of Years Credited Service	Present Value of Accumulated Benefit (1)	Contribution During 2017
Michael E. Mercer	7	$ 815,351	$ 109,957
Nicholas P. Bobrowski	5	27,416	7,952

(1) The present value of the accumulated benefit as of December 31, 2017 is based on the RP 2014 IRS Combined Static Mortality Table, the applicable interest rates under IRC Section 430(h)(2)(D) and age 62 normal retirement age. These assumptions are prescribed under ERISA and could be considered reasonable under accounting standards generally accepted in the United States.

Retirement benefits are provided through the Retirement Plan, which is a defined benefit retirement plan. The Retirement Plan provides that the ultimate lump sum value of the benefit a participant will be eligible to receive is equal to the contributions made to the Retirement Plan on the participant's behalf, adjusted by investment returns experienced during participation in the Retirement Plan. Payment of the benefit may begin on or after the participant has either terminated employment or attained age 62. Participants are always 100% vested in their benefit.

The Retirement Plan is a tax–qualified plan subject to Internal Revenue Code provisions that, as of December 31, 2017, limit the benefits under a defined benefit plan to $210,000.

Nonqualified Deferred Compensation

We do not have a nonqualified deferred compensation plan.

Termination of Employment and Change–in–Control Provisions

Mr. Mercer and Mr. Bobrowski are both party to an employment agreement with EV Management, which provides each of them with post–termination benefits in a variety of circumstances. The amount of compensation payable in some cases may vary depending on the nature of the termination, whether as a result of retirement/voluntary termination, involuntary not–for–cause termination, termination following a change of control and in the event of disability or death of the executive. The discussion below describes the varying amounts payable in each of these situations. It assumes, in each case, that Messrs. Mercer and Bobrowski's terminations were effective as of December 31, 2017. In presenting this disclosure, we describe amounts earned through December 31, 2017 and, in those cases where the actual amounts to be paid out can only be determined at the time of separation from EV Management, our estimates of the amounts which would be paid out upon termination.

Provisions Under the Employment Agreement

Under Mr. Mercer's or Mr. Bobrowski's employment agreement, if his employment with EV Management and its affiliates terminates, he is entitled to unpaid salary for the full month in which the termination date occurred. However, if he is terminated for cause, he is only entitled to receive accrued but unpaid salary through the termination date. In addition, if his employment terminates, he is entitled to unpaid vacation days for that year which have accrued through the termination date, reimbursement of reasonable business expenses that were incurred but unpaid as of the termination date, and COBRA coverage as required by law. Salary and accrued vacation days are payable in cash lump sum less applicable withholdings. Business expenses are reimbursable in accordance with normal procedures.

If Mr. Mercer's employment is involuntarily terminated by EV Management (except for cause or due to the death of the executive) or if his employment is terminated due to disability or retirement, EV Management is obligated to pay as additional compensation an amount in cash equal to 104 weeks of his base salary in effect as of the termination date. Assuming he was terminated as of December 31, 2017, this amount would have been $800,000. In addition, he is entitled to continued group health plan coverage following the termination date for him and his eligible spouse and dependents for the maximum period for which such qualified beneficiaries are eligible to receive COBRA coverage. He shall not be required to pay more for COBRA coverage than officers who are then in active service for EV Management and receiving coverage under the plan. Assuming he was terminated as of December 31, 2017, this amount would have been $38,198.

In the event Mr. Mercer's employment terminates within the 12–month period immediately following the effective date of a change in control other than by reason of death, disability or for cause, he will be entitled to receive payment of the compensation and benefits as set forth above and to become 100% fully vested in all unvested shares or units of equity compensation granted as of the effective date of the change in control. Assuming a change in control as of December 31, 2017, this amount would have been $800,000, representing 104 weeks of base salary, $95,513, representing vesting of unvested units, $400,000, representing the target bonus under the Key Employee Incentive Plan, and $38,198, representing COBRA coverage.

If Mr. Bobrowski's employment is involuntarily terminated by EV Management (except for cause or due to the death of the executive) or if his employment is terminated due to disability or retirement, EV Management is obligated to pay as additional compensation an amount in cash equal to 104 weeks of his base salary in effect as of the termination date. Assuming he was terminated as of December 31, 2017, this amount would have been $600,000. In addition, he is entitled to continued group health plan coverage following the termination date for him and his eligible spouse and dependents for the maximum period for which such qualified beneficiaries are eligible to receive COBRA coverage. He shall not be required to pay more for COBRA coverage than officers who are then in active service for EV Management and receiving coverage under the plan. Assuming he was terminated as of December 31, 2017, this amount would have been $38,198.

In the event Mr. Bobrowski's employment terminates within the 12–month period immediately following the effective date of a change in control other than by reason of death, disability or for cause, he will be entitled to receive payment of the compensation and benefits as set forth above and to become 100% fully vested in all unvested shares or units of equity compensation granted as of the effective date of the change in control. Assuming a change in control as of December 31, 2017, this amount would have been $600,000, representing 104 weeks of base salary, $44,038, representing vesting of unvested units, $210,000, representing the target bonus under the Key Employee Incentive Plan, and $38,198, representing COBRA coverage.

If the compensation is paid or benefits are provided under the employment agreement by reason of a change in control, no additional compensation will be payable or benefits provided by reason of a subsequent change in control during the term of the agreement.

"Cause" generally means:

- his conviction by a court of competent jurisdiction as to which no further appeal can be taken of a felony or entering the plea of nolo contendere to such crime by the executive;

- the commission by him of a demonstrable act of fraud, or a misappropriation of funds or property, of or upon the Partnership or any affiliate;

- the engagement by him without approval of the board of directors or compensation committee in any material activity which directly competes with the business of the Partnership or any affiliate or which would directly result in a material injury to the business or reputation of the Partnership or any affiliate; or

- the material breach by him of the employment agreement, or the repeated nonperformance of his duties to the Partnership or any affiliate (other than by reason of illness or incapacity).

In some cases, he has the opportunity to cure the breach or nonperformance before being terminated for cause.

A "change in control" generally means the occurrence of any of following events:

- a corporation, person, or group acquires, directly or indirectly, beneficial ownership of more than 50% of the equity interests in EV Management and is then entitled to vote generally in the election of the board of directors;

- the withdrawal, removal or resignation of EV Management as the general partner of our general partner or the withdrawal, removal or resignation of our general partner as the general partner of the partnership;

- the effective date of a merger, consolidation, or reorganization plan that is adopted by the board of directors of EV Management involving EV Management in which EV Management is not the surviving entity, or a sale of all or substantially all of our assets; or

- any other transactions or series of related transactions which have substantially the same effect as the foregoing.

"Retirement" means the termination of employment for normal retirement at or after attaining age sixty-five provided that the employee has been with the Partnership for at least five years.

Provisions Under Phantom Unit and Performance Unit Award Agreements

Both the phantom unit award agreements and performance unit award agreements provide that any unvested units will vest upon Mr. Mercer or Mr. Bobrowski's death, disability, termination of employment other than for cause and upon a change of control. Assuming termination of employment or change of control as of December 31, 2017, the value of the awards would have been $95,513 for Mr. Mercer or $44,038 for Mr. Bobrowski. If he resigns or his employment or is terminated for cause, all unvested units are forfeited. Upon vesting, the units may be paid in cash equal to the fair market value of the units on the date immediately preceding the vesting date, at the option of our general partner. The definitions of the terms such as "cause" and "change in control" in the award agreements are substantially similar to the definitions in the employment agreements.

Compensation of Directors

We use a combination of cash and unit–based incentive compensation to attract and retain qualified candidates to serve on EV Management's board. In setting director compensation, we consider the significant amount of time that directors expend in fulfilling their duties to us as well as the skill level we require of members of the board. In addition, our compensation committee reviews director compensation at our peer group companies.

In an effort to further reduce costs, our chief executive officer recommended, and the compensation committee approved, reducing the annual retainers and fees for 2016 for directors by 10%. In December 2016, our chief executive officer recommended, and the compensation committee approved, reinstating 50% of the 10% reduction taken in March 2016. Thus, in 2017, directors who are not officers or employees of EV Management, EnCap or their respective affiliates received an annual retainer of $38,000 with the chairmen of the audit committee, conflicts committee and strategic advisory committee receiving an additional annual fee of $9,500 and the chairman of the compensation committee receiving an additional annual fee of $4,750. In addition, each non-employee director received $950 per committee meeting attended ($475 if by phone) and was reimbursed for his out-of-pocket expenses in connection with attending meetings. We indemnify each director for his actions associated with being a director to the fullest extent permitted under Delaware law.

There were no changes to director compensation during 2017. Thus, in 2018, directors who are not officers or employees of EV Management, EnCap or their respective affiliates will receive an annual retainer of $38,000 with the chairmen of the audit committee, conflicts committee and strategic advisory committee receiving an additional annual fee of $9,500 and the chairman of the compensation committee receiving an additional annual fee of $4,750. In addition, each non-employee director will receive

$2,000 per strategic advisory committee meeting attended ($1,000 if by phone) and $950 per other committee meetings attended ($475 if by phone) and will be reimbursed for his out-of-pocket expenses in connection with attending meetings.

The following table discloses the cash unit awards and other compensation earned, paid or awarded to each of EV Management's directors during year ended December 31, 2017:

Name [1]	Fees Earned or Paid in Cash	Unit Awards [2]	All Other Compensation [3]	Total
Victor Burk [4]	$ 61,375	$ -	$ -	$ 61,375
James R. Larson [4]	57,050	-	-	57,050
George Lindahl III [4]	55,625	-	-	55,625
Mark A. Houser [4]	38,000	-	-	38,000
Gary R. Petersen [4]	-	-	-	-
Ken Mariani [4]	-	-	-	-
Daniel J. Churay [4]	14,853	-	-	14,853

(1) Mr. Walker is not included in this table as he is an employee of EnerVest and receives no compensation for his services as director. Mr. Mariani did not receive any compensation for his services as director during the year ended December 31, 2017, as he was an employee of EnerVest during 2017. Mr. Petersen is not an independent director because of his affiliations with EnCap and does not receive a cash director's fee.

(2) Reflects the aggregate grant date fair value of the phantom units granted computed in accordance with ASC Topic 718. However, there were no phantom units awarded during 2017.

(3) Reflects the dollar amount of compensation recognized for financial statement reporting purposes for 2017 for distributions paid on the unvested phantom units. However, there were no distributions paid during 2017.

(4) As of December 31, 2017, Messrs. Burk, Larson and Lindahl each have 24,625 equity awards outstanding, Mr. Houser has 22,625 equity awards outstanding, Mr. Petersen has 24,550 equity awards outstanding and both Mr. Mariani and Mr. Churay did not have any equity awards outstanding.

Compensation Committee Interlocks and Insider Participation

None of our executive officers serves as a member of the board of directors or compensation committee of any entity that has one or more of its executive officers serving as a member of EV Management's board of directors or compensation committee.

None of the members of the compensation committee have served as an officer or employee of us, our general partner or its general partner. Furthermore, except for compensation arrangements discussed in this Form 10–K and as set forth in the next sentences, we have not participated in any contracts, loans, fees, awards or financial interests, direct or indirect, with any committee member, nor are we aware of any means, directly or indirectly, by which a committee member could receive a material benefit from us.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED UNITHOLDER MATTERS

Security Ownership of Certain Beneficial Owners and Management

Based solely on a review of the copies of reports on Schedules 13D and 13G and amendments thereto furnished to us, we believe that there were no beneficial owners of more than 5% of our common units as of February 15, 2018 other than as set forth below.

The following table sets forth the beneficial ownership of our units as of March 27, 2018 held by:

- each person who is known to us to beneficially own 5% or more of our outstanding common units;
- each member of the Board of Directors of EV Management;
- each named executive officer of EV Management; and
- all directors and executive officers of EV Management as a group.

Name of Beneficial Owner (1)	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned
5% Beneficial Owner:		
Jerry R. Kent (2) 4965 Preston Park Blvd., Suite 170 East Plano, Texas 75093-5180	2,507,100	5.1%
Officers and Directors:		
John B. Walker (3)	2,798,765	5.7%
Michael E. Mercer	187,977	*
Nicholas P. Bobrowski	28,341	*
Ryan J. Flory	6,808	*
Victor Burk	25,625	*
James R. Larson	23,791	*
George Lindahl III (4)	79,325	*
Gary R. Petersen (5)	937,946	1.9%
Mark A. Houser (6)	991,106	2.0%
Kenneth Mariani (7)	190,803	*
Daniel J. Churay	-	*
All directors and executive officers as a group (11 persons)	5,270,487	10.7%

* Less than 1%

(1) Unless otherwise indicated, the address for all beneficial owners in this table is 1001 Fannin Street, Suite 800, Houston, TX 77002.

(2) All information in this table is based solely on a Schedule 13G filed on January 10, 2018 by the following person ("Filing Party"): Jerry R. Kent. The Filing Party reports beneficial ownership over all or a portion of 2,507,100 common units. In addition, Jerry R. Kent reported the sole power to vote or to direct the voting of and the sole dispositive power over 1,704,100 of our common units set forth in the table above. Each reporting person expressly disclaims (a) the existence of any group and (b) beneficial ownership with respect to any common units other than the common units owned of record by such reporting person.

(3) Includes 2,008,098 common units owned by John B. and Lisa A. Walker, L.P. and 13,400 common units owned by Mr. Walker's spouse. Mr. Walker disclaims beneficial ownership of these common units. Also includes 155,600 common units owned by EnerVest. Mr. Walker, by virtue of his direct and indirect ownership of the limited liability company that acts as EnerVest's general partner, may be deemed to beneficially own the common units owned by EnerVest.

(4) Includes 20,000 common units owned by a trust for Mr. Lindahl's daughters. Mr. Lindahl disclaims beneficial ownership of these common units.

(5) Includes 523,666 common units owned by EnCap Energy Capital Fund V, L.P. and 414,280 common units owned by EnCap V–B Acquisitions, L.P. EnCap V–B Acquisitions GP, LLC, as the general partner of EnCap V–B Acquisitions, L.P., EnCap Energy Capital Fund V–B, L.P., as the general partner of EnCap V–B Acquisitions GP, LLC, EnCap Equity Fund V GP, L.P., as the general partner of each of EnCap Energy Capital Fund V, L.P. and EnCap Energy Capital Fund V–B, L.P., EnCap Investments L.P., as the general partner of EnCap Equity Fund V GP, L.P., EnCap Investments GP, L.L.C., as the general partner of EnCap Investments L.P., RNBD GP LLC, as the sole member of EnCap Investments GP, L.L.C., may be deemed to share voting and dispositive control over the common units owned by EnCap Energy Capital Fund V, L.P. and EnCap V–B Acquisitions, L.P. Each of EnCap V–B Acquisitions GP, LLC, EnCap Energy Capital Fund V-B, L.P., EnCap Equity Fund V GP, L.P., EnCap Investments L.P., EnCap Investments GP, L.L.C., RNBD GP LLC, disclaim beneficial ownership of the securities in excess of such entity's respective pecuniary interest in the securities. Gary R. Petersen is a member of RNBD GP LLC, and disclaims beneficial ownership of the securities owned by EnCap Energy Capital Fund V, L.P. and EnCap V-B Acquisitions, L.P.

(6) Includes 320,488 common units owned by DSEA II, LP, a limited partnership of which Mr. Houser and his spouse manage the general partner and 190,800 common units owned by trusts for Mr. Houser's children. Mr. Houser disclaims beneficial ownership of these common units.

(7) Includes 160,803 common units owned by KS Mariani, LP, a limited partnership of which Mr. Mariani and his spouse are the general partner and 30,000 common units owned equally by trusts for Mr. Mariani's children. Mr. Mariani disclaims beneficial ownership of these common units.

Beneficial Ownership of Our General Partner

EV Management, the general partner of our general partner, is a limited liability company wholly owned by EnerVest, a limited partnership. Jones EnerVest Ltd., a limited partnership managed by its general partner, Jones–Tucker Corporation, whose directors are Jon Rex Jones, A.V. Jones, Jr. and Jean Jones Tucker, and members of EnerVest's executive management team, including Messrs. Walker and Mariani, own substantially all of the partnership interests in EnerVest. The address for Jones EnerVest Ltd. and the members of EnerVest's executive management team which own interests in EnerVest, is 1001 Fannin Street, Suite 800, Houston, Texas 77002.

Securities Authorized for Issuance under Equity Compensation Plans

The number of common units which we could have issued under the 2006 Plan prior to its expiration in September 2016 was 4.5 million. The number of common units we may issue under the 2016 Plan is 5.0 million. The following table summarizes information about our equity compensation plans as of December 31, 2017:

	Number of securities to be issues upon exercise of outstanding options, warrants and rights (a)	Weighted average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	2,225,877	-	4,048,506
Equity compensation plans not approved by security holders	-	-	-
Total	2,225,877	-	4,048,506

For a description of our equity compensation plan, please see the discussion under Item 11 above.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Our partnership agreement provides that whenever a potential conflict exists or arises between our general partner or its affiliates, on the one hand, and us, on the other hand, any resolution or course of action by the general partner shall be permitted and deemed approved by all of the partners, and shall not constitute a breach of the partnership agreement or any duty stated or implied by law or equity if the resolution or the course of action taken in respect of such conflict of interest is approved by a vote of a majority of the members of our conflicts committee. Our partnership agreement does not require that we submit potential conflicts to our conflicts committee, but as a matter of course, our general partner submits to our conflicts committee for review any transaction that involves or may involve a conflict of interest. Other than the provision of our partnership agreement, we have no written policies or procedures for the conflicts committee to follow in making these determinations.

Ownership in Our General Partner by the Management of EV Management and EnCap

Our general partner, EV Energy GP, is owned 71.25% by EnerVest, 23.75% by EnCap and 5% by EV Investors. Our general partner has a 2% interest in us and owns all of the incentive distribution rights, which entitle our general partner to a portion of the distributions we make. The distributions we will make to our general partner are described under Item 5. While EnerVest and EV Investors are under common control with us, EnCap may be deemed our affiliate because EnCap has designated a director to the board of directors of EV Management.

Contracts with EnerVest and Its Affiliates

EnerVest owns all of the membership interests in EV Management, the general partner of our general partner. Messrs. John B. Walker and Kenneth Mariani own partnership interests in EnerVest. In addition, some of the employees of EnerVest who perform services for us under the administrative services agreement and operating agreement described below are owners of EnerVest.

We have entered into agreements with EnerVest. The following is a description of these agreements.

Omnibus Agreement

In connection with our initial public offering, we entered into an omnibus agreement with EnerVest, our general partner and others that addressed the following matters:

- our obligation to pay EnerVest a monthly fee for providing us general and administrative and all other services with respect to our existing business and operations;
- our obligation to reimburse EnerVest for any insurance coverage expenses it incurs with respect to our business and operations; and
- EnerVest’s obligation to indemnify us for certain liabilities and our obligation to indemnify EnerVest for certain liabilities.

Pursuant to the omnibus agreement, EnerVest performs certain centralized corporate functions for us, such as accounting, treasury, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes and engineering and senior management oversight.

Any or all of the provisions of the omnibus agreement, other than the indemnification provisions described below, will be terminable by EnerVest at its option if our general partner is removed without cause and units held by our general partner and its affiliates are not voted in favor of that removal. The omnibus agreement will also terminate in the event of a change of control of us, our general partner or the general partner of our general partner.

Under the omnibus agreement, EnerVest indemnified us for losses attributable to title defects, retained assets and liabilities (including any preclosing litigation relating to assets contributed to us) and income taxes attributable to preclosing operations. EnerVest’s maximum liability for these indemnification obligations will not exceed $1.5 million and EnerVest will not have any obligation under this indemnification until our aggregate losses exceed $200,000. We also will indemnify EnerVest for all losses attributable to the operations of the assets contributed to us after September 29, 2006, to the extent not subject to EnerVest’s indemnification obligations.

During 2017, we paid EnerVest $14.1 million in administrative fees under the omnibus agreement. These fees are based on an allocation of charges between EnerVest and us based on the estimated use of such services by each party, and include a deduction for the value of the awards we issue to EnerVest employees (including Messrs. Walker and Mariani) who perform services for us. We believe that the allocation method employed by EnerVest is reasonable and reflective of the estimated level of costs we would have incurred on a standalone basis. In March 2018, EV Management and EnerVest extended the term of the omnibus agreement through December 2018.

Operating Agreements

We are party to operating agreements under which a subsidiary of EnerVest acts as contract operator of all wells in which we own an interest and are entitled to appoint the operator. As contract operator, EnerVest designs and manages the drilling and completion of our wells and the day–to–day operating and maintenance activities of our wells and facilities.

Under the operating agreements, EnerVest establishes a joint account for each well in which we have an interest. The joint account is charged with all direct expenses incurred in the operation of our wells and related gathering systems and production facilities, and we are required to pay our working interest share of amounts charged to the joint account. 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 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 well, gathering and other equipment used on our properties. In addition, direct expenses will include the allocable share of the cost of the EnerVest employees who perform services on our properties. The allocation of the cost of EnerVest employees who perform services on our properties are based on time sheets maintained by EnerVest's employees. Direct expenses charged to the joint account will 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.

During 2017, we reimbursed EnerVest approximately $20.1 million for direct expenses incurred in the operation of our wells and related gathering systems and production facilities and for the allocable share of the costs of EnerVest employees who performed services on our properties. As the vast majority of such expenses are charged to us on an actual basis (i.e., no mark–up or subsidy is charged or received by EnerVest), we believe that the aforementioned services were provided to us at fair and reasonable rates relative to the prevailing market and are representative of what the amounts would have been on a standalone basis.

Acquisitions from Institutional Partnerships Managed by EnerVest

EnerVest is the general partner of institutional partnerships formed to acquire, develop and produce oil and natural gas properties. EnerVest generally has a 1% to 1.5% interest in the institutional partnerships that they manage, which increases to 20% following return of invested capital and a stated rate of return.

In October 2015, we acquired oil and natural gas properties in the Appalachian Basin, the San Juan Basin, Michigan and the Austin Chalk from certain institutional partnerships managed by EnerVest for a combined cash consideration of $259.0 million.

Overriding Royalty Interest Partnership

In 2011, we and certain institutional partnerships managed by EnerVest carved out a 7.5% ORRI from certain acres in Ohio (the "Underlying Properties"), which we believe 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. We own a 48% limited partner interest in the partnership. In 2017, we recognized $0.5 million of income from unconsolidated affiliates, and we received $0.3 million of distributions.

Development of the Knox Acreage

We and certain institutional partnerships managed by EnerVest own acreage in the Knox formation in the Appalachian Basin. In December 2009, we entered into an area of mutual interest ("AMI") agreement with these institutional partnerships to jointly explore and develop these properties. Under the AMI agreement, we and the institutional partnerships contributed approximately 7,760 net acres and approximately 1,740 net acres, respectively, to the AMI. We and the institutional partnerships will share 3–D seismic, development, acquisition and other costs associated with developing these properties. The revenues and costs will be shared based on the net acres contributed to the AMI, and any additional properties acquired in the area will be acquired based on such interest.

Long–Term Incentive Awards

We award phantom units under our long-term incentive plans to employees of EnerVest who provide services to us. These units are awarded to particular employees based on the recommendation of EnerVest's senior management. During 2017, we did not award any phantom units to such employees under the 2016 Plan.

Director Independence

During 2017, all members of the board of directors of EV Management, other than Messrs. Walker, Mariani, Mercer, Houser, and Petersen, are independent as defined under the independence standards established by the NASDAQ. The NASDAQ does not require a listed limited partnership like us to have a majority of independent directors on the board of directors of our general partner.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The audit committee of EV Management selected Deloitte & Touche LLP, an independent registered public accounting firm, to audit our consolidated financial statements for the year ended December 31, 2017. The audit committee's charter requires the audit committee to approve in advance all audit and non–audit services to be provided by our independent registered public accounting firm. All services reported in the audit, audit–related, tax and all other fees categories below with respect to this Annual Report on Form 10–K for the year ended December 31, 2017 were approved by the audit committee.

Fees approved to be paid to Deloitte & Touche LLP are as follows:

	2017	2016
Audit fees [(1)]	$ 1,466,400	$ 1,537,000
Audit–related fees	-	15,000
All other fees	20,500	27,414
Total	$ 1,486,900	$ 1,579,414

(1) Represents fees for professional services provided in connection with the audit of our annual financial statements and review of our quarterly financial statements.

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:

3.1	First Amended and Restated Partnership Agreement EV Energy Partners, L.P. (incorporated by reference from Exhibit 3.1 to EV Energy Partners, L.P.'s current report on Form 8–K filed with the SEC on October 5, 2006).
3.2	First Amended and Restated Partnership Agreement of EV Energy GP, L.P. (incorporated by reference from Exhibit 3.2 to EV Energy Partners, L.P.'s current report on Form 8–K filed with the SEC on October 5, 2006).
3.3	Amended and Restated Limited Liability Company Agreement of EV Management, LLC. (incorporated by reference from Exhibit 3.3 to EV Energy Partners, L.P.'s current report on Form 8–K filed with the SEC on October 5, 2006).
3.4	First Amendment dated April 15, 2008 to First Amended and Restated Partnership Agreement of EV Energy Partners, L.P., effective as of January 1, 2007 (incorporated by reference from Exhibit 3.1 to EV Energy Partners, L.P.'s current report on Form 8–K filed with the SEC on April 18, 2008).
4.1	Indenture, dated as of March 22, 2011, by and among EV Energy Partners, L.P., EV Energy Finance Corp., the Guarantors named therein and U.S. National Bank Association, as trustee (incorporated by reference from Exhibit 4.1 to EV Energy Partners L.P.'s current report on Form 8–K filed with the SEC on March 22, 2011).
10.1	Omnibus Agreement, dated September 29, 2006, by and among EnerVest Management Partners, Ltd., EV Management, LLC, EV Energy GP, L.P., EV Energy Partners, L.P., and EV Properties, L.P. (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 October 5, 2006).
10.2	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).
10.3	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).
*10.4	EV Energy Partners, L.P. Long–Term Incentive Plan (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 October 5, 2006).
10.5	Omnibus Agreement Extension, dated March 8, 2018, by and between EnerVest, Ltd. and EV Energy GP, 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 March 14, 2018).

*10.6	Form of EV Energy Partners, L.P. Incentive Unit Agreements (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 18, 2009).
10.7	Second Amended and Restated Credit Agreement, dated as of April 26, 2011 by and among EV Energy Partners, L.P., EV Properties, L.P., and JPMorgan Chase Bank, N.A. as Administrative Agent for the lenders named therein (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 April 29, 2011).
10.8	First Amendment dated December 21, 2011 to Second Amended and Restated Credit Agreement (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 December 27, 2011).
10.9	Second Amendment dated March 29, 2012 to Second Amended and Restated Credit Agreement (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 April 4, 2012).
10.10	Third Amendment dated September 27, 2012 to Second Amended and Restated Credit Agreement (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 October 3, 2012).
10.11	Amended and Restated Assignment Agreement dated October 1, 2012, between M3 Ohio Gathering LLC, Utica Gas Services, L.L.C., CGAS Properties, L.P. and Utica East Ohio Midstream L.L.C. (incorporated by reference from Exhibit 10.17 to EV Energy Partners L.P.'s annual report on Form 10–K filed with the SEC on March 1, 2013).
10.12	Fourth Amendment dated February 26, 2013 to Second Amended and Restated Credit Agreement (incorporated by reference from Exhibit 10.18 to EV Energy Partners L.P.'s annual report on Form 10–K filed with the SEC on March 1, 2013).
10.13	Fifth Amendment dated August 7, 2013 to Second Amended and Restated Credit Agreement (incorporated by reference from Exhibit 10.1 to EV Energy Partners, L.P.'s quarterly report on Form 10–Q filed with the SEC on August 9, 2013).
10.14	Sixth Amendment dated September 19, 2014 to Second Amended and Restated Credit Agreement (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 September 25, 2014).
10.15	Seventh Amendment dated February 26, 2015 to Second Amended and Restated Credit Agreement (incorporated by reference from Exhibit 10.17 to EV Energy Partners, L.P.'s annual report on Form 10–K filed with the SEC on March 2, 2015).
10.16	Guarantee, dated as of April 2, 2015, by and among Williams Partners L.P. and CGAS Properties, L.P. (incorporated by reference from Exhibit 10.1 to EV Energy Partners, L.P.'s quarterly report on Form 10–Q filed with the SEC on August 10, 2015).
10.17	Guarantee, dated as of April 2, 2015, by and among CGAS Properties, L.P. and Utica Gas Services, L.L.C. (incorporated by reference from Exhibit 10.2 to EV Energy Partners, L.P.'s quarterly report on Form 10–Q filed with the SEC on August 10, 2015).
10.18	Membership Interest Purchase Agreement, dated as of April 2, 2015, by and among CGAS Properties, L.P. and Utica Gas Services, L.L.C. (incorporated by reference from Exhibit 10.3 to EV Energy Partners, L.P.'s quarterly report on Form 10–Q filed with the SEC on August 10, 2015).
10.19	Amendment No. 1 to Membership Interest Purchase Agreement, dated as of May 26, 2015, by and among CGAS Properties, L.P. and Utica Gas Services, L.L.C. (incorporated by reference from Exhibit 10.4 to EV Energy Partners, L.P.'s quarterly report on Form 10–Q filed with the SEC on August 10, 2015).

10.20 Membership Interest Purchase Agreement, dated as of May 26, 2015, by and among CGAS Properties, L.P. and M3 Ohio Gathering L.L.C. (incorporated by reference from Exhibit 10.5 to EV Energy Partners, L.P.'s quarterly report on Form 10–Q filed with the SEC on August 10, 2015).

10.21 Eighth Amendment dated October 8, 2015 to Second Amended and Restated Credit Agreement (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 October 15, 2015).

10.22 Stock Purchase Agreement, dated as of September 2, 2015, among Capital C Energy Operations, LP, CGAS Properties, L.P. and Belden & Blake Corporation (incorporated by reference from Exhibit 10.1 to EV Energy Partners, L.P.'s quarterly report on Form 10–Q filed with the SEC on November 9, 2015).

10.23 Membership Interest Purchase Agreement, dated as of September 2, 2015, among EnerVest Energy Institutional Fund XI–A, L.P., Enervest Energy Institutional Fund XI–WI, L.P., EV Properties, L.P. and EnerVest Mesa, LLC (incorporated by reference from Exhibit 10.2 to EV Energy Partners, L.P.'s quarterly report on Form 10–Q filed with the SEC on November 9, 2015).

10.24 Purchase and Sale Agreement, dated as of September 2, 2015, among EnerVest Energy Institutional Fund X–A, L.P., EnerVest Energy Institutional Fund X–WI, L.P. and EV Properties, L.P. (incorporated by reference from Exhibit 10.3 to EV Energy Partners, L.P.'s quarterly report on Form 10–Q filed with the SEC on November 9, 2015).

10.25 Purchase and Sale Agreement, dated as of September 2, 2015, among EnerVest Energy Institutional Fund XI–A, L.P., EnerVest Energy Institutional Fund XI–WI, L.P. and CGAS Properties, L.P. (incorporated by reference from Exhibit 10.4 to EV Energy Partners, L.P.'s quarterly report on Form 10–Q filed with the SEC on November 9, 2015).

10.26 Ninth Amendment dated April 1, 2016 to Second Amended and Restated Credit Agreement (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 April 4, 2016).

*10.27 2016 Long-Term Incentive Plan (incorporated by reference to Exhibit A of the Partnership's Definitive Proxy Statement on Form DEF 14A filed with SEC on July 20, 2016).

*10.28 Form of Phantom Units Award Agreement (incorporated by reference to Exhibit 10.1 of the Partnership's Registration Statement on Form S-8 filed with SEC on October 31, 2016).

*10.29 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).

*10.30 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).

*10.31 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).

*10.32 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).

*10.33 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).

10.34	Tenth Amendment dated October 23, 2017 to Second Amended and Restated Credit Agreement (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 October 25, 2017).
10.35	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 EV Energy Partners, L.P.
+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.

* Management contract or compensatory plan or arrangement

\+ Filed herewith

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

EV Energy Partners, L.P.
(Registrant)

Date: April 2, 2018

By: /s/ NICHOLAS BOBROWSKI
Nicholas Bobrowski
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/JOHN B. WALKER John B. Walker	Executive Chairman and Director (principal executive officer)	April 2, 2018
/s/MICHAEL E. MERCER Michael E. Mercer	President, Chief Executive Officer and Director	April 2, 2018
/s/NICHOLAS BOBROWSKI Nicholas Bobrowski	Vice President and Chief Financial Officer (principal financial officer)	April 2, 2018
/s/RYAN J. FLORY Ryan J. Flory	Controller (principal accounting officer)	April 2, 2018
/s/VICTOR BURK Victor Burk	Director	April 2, 2018
/s/JAMES R. LARSON James R. Larson	Director	April 2, 2018
/s/GEORGE LINDAHL III George Lindahl, III	Director	April 2, 2018
/s/GARY R. PETERSEN Gary R. Petersen	Director	April 2, 2018
/s/MARK A. HOUSER Mark A. Houser	Director	April 2, 2018
/s/KENNETH MARIANI Kenneth Mariani	Director	April 2, 2018
/s/DANIEL J. CHURAY Daniel J. Churay	Director	April 2, 2018