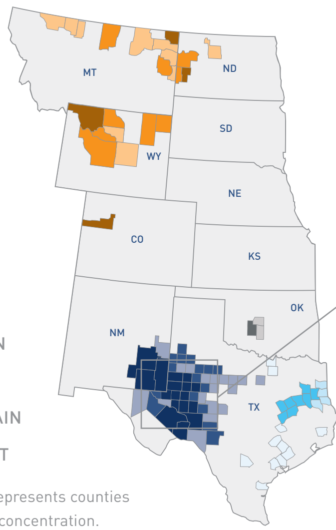
LEGACY RESERVES

2017 ANNUAL REPORT

2017 KEY ACCOMPLISHMENTS & OUTLOOK

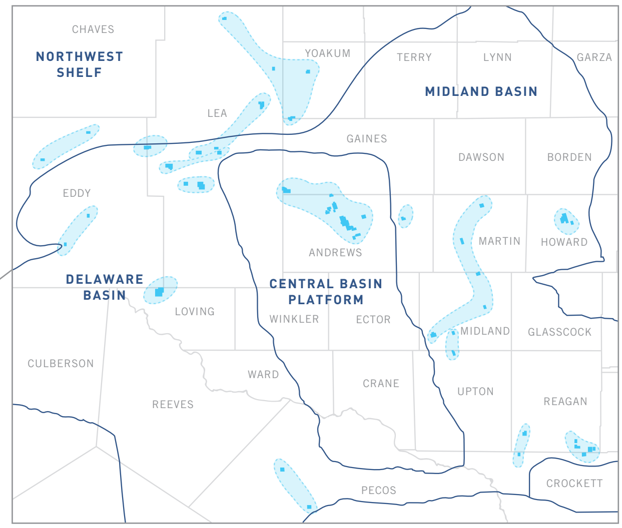
We are extremely proud of our cornerstone 2017 achievements. Significant strides remain for us to fully realize our goal of becoming a growth-oriented development company. We therefore continue to evaluate and opportunistically pursue alternatives that will promote our long-term success.

Our shallow-decline PDP will generate tremendous free cash flow to fund the development of our significant horizontal Permian inventory.



- PERMIAN BASIN
- EAST TEXAS
- ROCKY MOUNTAIN
- MID-CONTINENT

Note: Darker shading represents counties with increased reserve concentration.



HORIZONTAL PERMIAN STATISTICS [1]

40,600	31,500	$203	588	408
GROSS OPERATED HZ ACRES	NET OPERATED HZ ACRES	MILLION 2018E CAPITAL (91% OF TOTAL)	GROSS OPERATED HZ LOCATIONS	NET OPERATED HZ LOCATIONS

We generated record annual production of 44,967 Boe/d, up 3% from 2016, and record annual oil production of 13,786 Bbls/d, up 26% from 2016.

We achieved record-low LOE per Boe of $10.58, finishing 2H '17 at under $10.00.

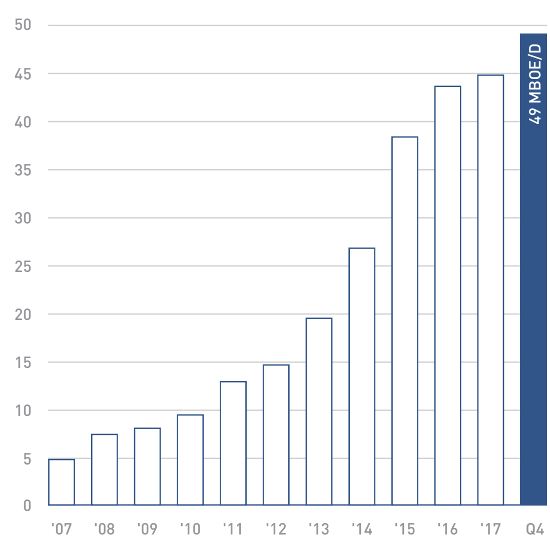
We made a $141 million Acceleration Payment to TPG Sixth Street Partners, dramatically increasing our exposure to this high-return drilling program in the Permian Basin.

We repurchased $187MM of our 6.625% Senior Notes at $0.70, gaining meaningful voting power in our Senior Notes and capturing discount.

We significantly improved our Debt / pro forma EBITDA by 2.1x in 2017.

We brought online 30 horizontal Permian wells (47 total since commencement of our drilling program).

AVERAGE DAILY PRODUCTION (MBOE/D)



(1) Please see our press releases, investor presentations and SEC filings for important information and disclaimers regarding non-GAAP financial measures and operational metrics, all of which can be found on our website.

FORM 10-K

2017 ANNUAL REPORT

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

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

For the fiscal year ended December 31, 2017

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

For the transition period from to

Commission file number 1-33249

Legacy Reserves LP

(Exact name of registrant as specified in its charter)

Delaware *(State or other jurisdiction of incorporation or organization)*	**16-1751069** *(I.R.S. Employer Identification No.)*
303 W. Wall Street, Suite 1800 **Midland, Texas** *(Address of principal executive offices)*	**79701** *(Zip Code)*

Registrant's telephone number, including area code:
(432) 689-5200

Securities registered pursuant to Section 12(b) of the Act:
Units representing limited partner interests listed on the NASDAQ Stock Market LLC.
8% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units representing preferred limited partner interests on the NASDAQ Stock Market LLC.
8.00% Series B Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units representing preferred limited partner interests on the NASDAQ Stock Market LLC.
Securities registered pursuant to 12(g) of the Act:

None.

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

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

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

Indicate by check mark whether the registrant has submitted electronically 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 ☑ No ☐

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. ☐

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 ☐ Smaller reporting company ☐ Emerging growth company ☐
(Do not check if a smaller reporting 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 ☑

The aggregate market value of units held by non-affiliates of the registrant was approximately $90.2 million on June 30, 2017, based on $1.46 per unit, the last reported sales price of the units on the NASDAQ Global Select Market on such date.

76,894,049 units representing limited partner interests in the registrant were outstanding as of February 21, 2018.

DOCUMENTS INCORPORATED BY REFERENCE

Parts of the definitive proxy statement for the registrant's 2018 annual meeting of unitholders are incorporated by reference into Part III of this annual report on Form 10-K.

LEGACY RESERVES LP

Table of Contents

GLOSSARY OF TERMS

Bbl. One stock tank barrel or 42 U.S. gallons liquid volume.

Bcf. Billion cubic feet.

Boe. One barrel of oil equivalent determined using a ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Boe/d. Barrels of oil equivalent per day.

Btu. British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

Developed acreage. The number of acres that are allocated or assignable to productive wells or wells capable of production.

Development project. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

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. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production would exceed production expenses and taxes.

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

Hydrocarbons. Oil, NGLs and natural gas are all collectively considered hydrocarbons.

Liquids. Oil and NGLs.

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

MBoe. One thousand barrels of crude oil equivalent, using a ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Mcf. One thousand cubic feet.

MGal. One thousand gallons of natural gas liquids or other liquid hydrocarbons.

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

MMBoe. One million barrels of crude oil equivalent, using a ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

MMBtu. One million British thermal units.

MMcf. One million cubic feet.

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

NGLs. The combination of ethane, propane, butane and natural gasolines that when removed from natural gas become liquid under various levels of higher pressure and lower temperature.

NYMEX. New York Mercantile Exchange.

Oil. Crude oil and condensate.

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Proved developed reserves. Reserves that can be expected to be recovered through: (i) 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; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Proved developed non-producing or PDNPs. Proved oil and natural gas reserves that are developed behind pipe or shut-in or that can be recovered through improved recovery only after the necessary equipment has been installed, or when the costs to do so are relatively minor. Shut-in reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not started producing, (2) wells that were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe reserves are expected to be recovered from zones in existing wells that will require additional completion work or future recompletion prior to the start of production.

Proved reserves. Proved oil and natural 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.

Proved undeveloped drilling location. A site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.

Proved undeveloped reserves or PUDs. Proved undeveloped oil and gas 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.

(i) Proved reserves on undrilled acreage shall be 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.

(ii) Proved undrilled locations can be classified as having undeveloped reserves 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.

(iii) Under no circumstances shall estimates for proved undeveloped reserves be attributable 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.

Reserve acquisition cost. The total consideration paid for an oil and natural gas property or set of properties, which includes the cash purchase price and any value ascribed to units issued to a seller adjusted for any post-closing items.

R/P ratio (reserve life). The reserves as of the end of a period divided by the production volumes for the same period.

Reserve replacement. The replacement of oil and natural gas produced with reserve additions from acquisitions, reserve additions and reserve revisions.

Reserve replacement cost. An amount per Boe equal to the sum of costs incurred relating to oil and natural gas property acquisition, exploitation, development and exploration activities (as reflected in our year-end financial statements for the relevant year) divided by the sum of all additions and revisions to estimated proved reserves, including reserve purchases. The calculation of reserve additions for each year is based upon the reserve report of our independent engineers. Management uses reserve replacement cost to compare our company to others in terms of our historical ability to increase our reserve base in an economic manner. However, past performance does not necessarily reflect future reserve replacement cost performance. For example, increases in oil and natural gas prices in past years have increased the economic life of reserves, adding additional reserves with no required capital expenditures. On the other hand, increases in oil and natural gas prices have increased the cost of reserve purchases and reserves added through development projects. The reserve replacement cost may not be indicative of the economic value of the reserves added due to differing lease operating expenses per barrel, differing timing of production, and other qualitative factors.

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

Standardized measure. The present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with assumptions required by the Financial Accounting Standards Board and the Securities and Exchange Commission (using current costs and the average annual prices based on the unweighted arithmetic average of the first-day-of-the-month price for each month) without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expenses or to depreciation, depletion and amortization, and discounted using an annual discount rate of 10%. Federal income taxes have not been deducted from future production revenues in the calculation of standardized measure as each partner is separately taxed on its share of Legacy's taxable income. In addition, Texas margin taxes and the federal income taxes associated with a corporate subsidiary have not been deducted from future production revenues in the calculation of the standardized measure as the impact of these taxes would not have a significant effect on the calculated standardized measure. Standardized measure does not give effect to commodity derivative transactions.

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

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

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

CAUTIONARY STATEMENT
REGARDING FORWARD-LOOKING INFORMATION

This document contains forward-looking statements that are subject to a number of risks and uncertainties, many of which are beyond our control, which may include statements about:

- our business strategy;
- the amount of oil and natural gas we produce;
- the price at which we are able to sell our oil and natural gas production;
- our ability to identify, acquire, exploit and appropriately finance additional oil and natural gas properties at economically attractive prices;
- our ability to replace reserves and increase reserve value;
- our drilling locations and our ability to continue our development activities at economically attractive costs;
- the level of our lease operating expenses, general and administrative costs and finding and development costs, including payments to our general partner;
- the level of our capital expenditures;
- our ability to comply with, renegotiate or receive waivers of debt covenants under our Revolving Credit Agreement and our Term Loan Credit Agreement (as those terms are defined herein);
- our ability to engage in lending and capital markets activity which may include debt refinancing or extensions, exchanges or repurchases or debt or equity issuances;
- our ability to divest non-core assets at economically attractive prices;
- our ability to resume cash distributions to our limited partners;
- our future operating results; and
- our plans, objectives, expectations and intentions.

All of these types of statements, other than statements of historical fact included in this document, are forward-looking statements. In some cases, you can identify forward-looking statements by terminology such as "may," "could," "should," "expect," "plan," "project," "intend," "anticipate," "believe," "estimate," "predict," "potential," "pursue," "target," "continue," the negative of such terms or other comparable terminology.

The forward-looking statements contained in this document are largely based on our expectations, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management's assumptions about future events may prove to be inaccurate. All readers are cautioned that the forward-looking statements contained in this document are not guarantees of future performance, and our expectations may not be realized or the forward-looking events and circumstances may not occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to factors described in "Item 1A. Risk Factors." The forward-looking statements in this document speak only as of the date of this document; we disclaim any obligation to update these statements unless required by securities law, and we caution you not to unduly rely on them.

PART I

ITEM 1. *BUSINESS*

References in this annual report on Form 10-K to "Legacy Reserves," "Legacy," "we," "our," "us," or like terms refer to Legacy Reserves LP and its subsidiaries. References to "units" refers to our units representing limited partner interests in the Partnership and not to the Series A Preferred Units (as defined herein), the Series B Preferred Units (as defined herein) or the Incentive Distribution Units (as defined herein), and "unitholders" refers to the holders of units. As used herein, unless the context requires otherwise, the term "limited partner interests" refers to the units, the Series A Preferred Units, the Series B Preferred Units and the Incentive Distribution Units, collectively, and "limited partners" refers to the holders of limited partner interests. References to "Preferred Units" refer to the Series A Preferred Units and the Series B Preferred Units, collectively, and "Preferred Unitholders" refers to holders of the Preferred Units.

Legacy Reserves LP

We are a master limited partnership headquartered in Midland, Texas, focused on the development of oil and natural gas properties primarily located in the Permian Basin, East Texas, Rocky Mountain and Mid-Continent regions of the United States.

Our oil and natural gas production and reserve data as of December 31, 2017 are as follows:

- we had proved reserves of approximately 180.0 MMBoe, of which 66% were natural gas, 34% were oil and natural gas liquids ("NGLs") and 94% were classified as proved developed producing; and
- our proved reserves to production ratio was approximately 10.0 years based on the annualized production volumes for the three months ended December 31, 2017.

We have built a diverse portfolio of oil and natural gas reserves primarily through the acquisition of producing oil and natural gas properties and the development of properties in established producing trends. These acquisitions, along with our ongoing development activities and operational improvements, have allowed us to achieve significant production and reserve growth over the last decade.

2017 Highlights

- Deployed $176.8 million of development capital expenditures, primarily focused on the drilling and completion of our Permian Basin horizontal assets;
- Paid $141 million for the acceleration payment (the "Acceleration Payment") under our joint development agreement with certain investment funds of TPG Sixth Street Partners to gain additional exposure to certain of our Permian Basin horizontal assets and improve our credit metrics;
- Increased revenue 39%, relative to 2016, to $436 million;
- Increased oil production 26%, relative to 2016, to 13,786 Bbls/d;
- Entered into an agreement to repurchase $187 million of our 6.625% senior unsecured notes due 2021 (the "2021 Senior Notes") at $0.70 per $1.00 of principal amount; and
- Entered into an agreement to amend our second lien term loan credit agreement (our "Term Loan Credit Agreement") to increase the amount of aggregate commitments from $300 million to $400 million.

Business Strategy

The key elements of our business strategy are to:

- Prudently deploy capital in developing drilling opportunities that maximize return on investment, production, reserves and cash flow;
- Identify, acquire and exploit additional opportunities to broaden our operational footprint and enrich our future growth potential;

- Maintain efficient operations to minimize production declines, improve lifting costs and well economics; and
- Rationalize our asset base by regularly reviewing our asset portfolio and divesting non-core assets.

2018 Operating Focus

In 2018, we plan to focus on the development of our Permian Basin horizontal drilling inventory. Our development capital expenditures are expected to be approximately $225 million, compared to approximately $176.8 million in 2017 and $29.5 million in 2016. We expect to fund our 2018 investments from cash flow from operations. Should projected commodity prices deviate from our current outlook, we may elect to make adjustments to our level of capital expenditures. We are evaluating and intend to opportunistically pursue alternatives to change our legal structure and tax status as a partnership, materially reduce our outstanding indebtedness and extend our near term maturity indebtedness. In the event that cash flows from operations are greater than we currently anticipate, whether as a result of increased commodity prices, reduced interest expense or otherwise, or additional external financing sources become available to us, we intend to accelerate our development plan and increase capital expenditures.

Operating Regions

Permian Basin. The Permian Basin, one of the largest and most prolific oil and natural gas producing basins in the United States, was discovered in 1921 and extends over 100,000 square miles in West Texas and southeast New Mexico. It is characterized by oil and natural gas fields with long production histories and multiple producing formations. These stacked formations have been further drilled and produced following the advent and refinement of horizontal drilling. Currently, the majority of the rigs running in the Permian Basin are drilling horizontal wells. The Permian Basin has historically been our largest operating region and still contains the majority of our drilling locations and development projects. Our producing wells in the Permian Basin are generally characterized as oil wells that also produce high-Btu casinghead gas with significant NGL content.

East Texas. We entered the East Texas region through our July 2015 acquisitions in Anderson, Freestone, Houston, Leon, Limestone and Robertson counties. The properties in East Texas consist of mature, low-decline natural gas wells. The East Texas properties are supported by a 601 mile natural gas gathering system and plant we acquired as part of those acquisitions.

Rocky Mountain. Our Rocky Mountain region was originally comprised by acquisitions in the Big Horn, Wind River and Powder River Basins in Wyoming largely consisting of mature oil wells with a natural water drive producing primarily from the Dinwoody-Phosphoria, Tensleep and Minnelusa formations. We expanded our footprint with our acquisition of oil properties in North Dakota and Montana in 2012 and our acquisition of non-operated natural gas properties in Colorado in 2014. The North Dakota properties produce primarily from the Madison and Bakken formations, while the Montana properties produce mostly from the Sawtooth and Bowes formations. The Colorado properties produce primarily from the Williams Fork formation.

Mid-Continent. Our properties in the Mid-Continent region are located in Oklahoma. These properties were acquired in 2007.

Our proved reserves by operating region as of December 31, 2017 are as follows:

Proved Reserves by Operating Region as of December 31, 2017

Operating Regions	Oil (MBbls)	Natural Gas (MMcf)	NGLs (MBbls)	Total (MBoe)	% Liquids	% PDP	% Total
Permian Basin	43,023	125,810	1,433	65,424	68%	87%	36%
East Texas	79	343,720	216	57,582	1%	98%	32%
Rocky Mountain	5,987	234,176	5,338	50,354	22%	99%	28%
Mid-Continent	2,057	12,428	2,465	6,593	69%	96%	4%
Total	**51,146**	**716,134**	**9,452**	**179,953**	**34%**	**94%**	**100%**

Development Activities

Our development projects are primarily focused on drilling and completing new wells, but also include accessing additional productive or improving existing formations in existing well-bores, and artificial lift equipment enhancement, as well as secondary (waterflood) and tertiary recovery projects.

The table below details the activity in our PUD locations from December 31, 2016 to December 31, 2017:

	Gross Locations	Net Locations	Net Volume (MBoe)
Balance, December 31, 2016	47	16.9	5,643
PUDs converted to PDP by drilling	(17)	(4.1)	(3,384)
PUDs removed due to performance (a)	(1)	(0.6)	(13)
PUDs removed from future drilling schedule (b)	(8)	(6.1)	(684)
PUDs removed due to sale	(2)	(2.0)	(212)
Additions due to performance (a)	21	11.3	4,402
Other	—	4.7	2,211
Balance, December 31, 2017	40	20.1	7,963

(a) PUDs removed or added due to performance are those PUDs removed or added, as applicable, due to new or revised engineering, geologic and economic evaluations such as offset well production data, the drilling of offset wells, new geologic data or changes in projected capital costs or product prices. PUDs are removed or added depending on whether the technical criteria for the proved undeveloped reserve classification is satisfied and, in the case of additions due to performance, whether the well is scheduled to be drilled within five years after initial recognition as proved reserves.

The increases in PUDs due to performance were driven by offset drilling in connection with our drilling program in the Permian Basin, which includes the horizontal Spraberry, horizontal Wolfcamp and horizontal Bone Spring wells.

The reduction in PUDs due to performance was due to the removal of a PUD as it became uneconomic as of December 31, 2017 based on offset well performance.

(b) These PUD locations were removed from our PUD inventory because we determined, based upon review of our current inventory and as indicated in our future drilling plans, that these PUD locations are not scheduled to be drilled within five years after initial recognition as proved reserves.

As of December 31, 2017, we identified 57 gross (32.4 net) recompletion and fracture stimulation projects.

Excluding any potential acquisitions, we expect to make capital expenditures of approximately $225 million during the year ending December 31, 2018.

A significant portion of our horizontal operated development activity in the Permian Basin is pursued through our development agreement (as amended, the "Development Agreement") entered into in 2015 with Jupiter JV, LP ("Investor"), which was formed by certain of TPG Sixth Street Partners' investment funds. Our capital resources and liquidity benefit from our interest in the development activity under the Development Agreement as described below.

On August 1, 2017, we, along with Investor, entered into the First Amended and Restated Development Agreement (the "Restated Agreement"), which amended and restated the Development Agreement pursuant to which we and Investor agreed to participate in the funding, exploration, development and operation of certain of our undeveloped oil and gas properties in the Permian Basin. Under the Restated Agreement and through subsequent elections, the parties have now committed to develop a tranche of 26 wells plus 9 wells in the Restated Agreement's area of mutual interest (the "Second Tranche"). Investor's share of its development costs is limited to $80 million.

In connection with the Restated Agreement, we made a payment of $141 million (the "Acceleration Payment") to cause the reversion of Investor's working interest from 80% to 15% of the parties' combined interests in the 48 wells contained in the first tranche such that our working interest reverted from 20% to 85% of the parties' combined working interests in all such wells, and all undeveloped assets subject to the terms of the Restated Agreement reverted back to us. The reversion of interests as a result of the Acceleration Payment was accounted for as an asset acquisition. See "—Footnote 4—Acquisitions" in the Notes to Consolidated Financial Statements for discussion of the impact ASU 2017-01 had on our current period consolidated financial statements. Pursuant to the Restated Agreement, Investor shall fund 40% of the costs to the parties' combined interests to develop the wells in the Second Tranche in exchange for an undivided 33.7% working interest of our original working interest in the wells, subject to a reversionary interest of 6.3% of our original working interest in the wells upon the occurrence of Investor achieving a 15% internal rate of return in the aggregate with respect to such tranche of wells. The Restated Agreement provides that Investor can suspend its obligation to fund wells in a tranche upon the occurrence of certain events, but that we can continue to drill and fund on our own any such wells in which Investor elects to not participate (subject to Investor's later right to participate in such wells in accordance with the Restated Agreement).

The Acceleration Payment was funded by a $145 million draw under our Term Loan Credit Agreement.

During 2017, we completed several individually immaterial divestitures totaling $11.1 million net of costs subject to customary post-closing obligations. These divestitures consisted of dispositions of unproved leasehold acreage and low-volume, high-cost producing properties and resulted in a loss on disposal of assets of $1.6 million for the year ended December 31, 2017.

Oil and Natural Gas Derivative Activities

Our business strategy includes entering into oil and natural gas derivative contracts which are designed to mitigate price risk for a portion of our oil, NGL and natural gas production from time to time. At December 31, 2017, we had in place oil and natural gas derivatives covering portions of our estimated future oil and natural gas production. Our derivative contracts are in the form of fixed price swaps, enhanced swaps and costless collars for NYMEX WTI oil; fixed price swaps for NYMEX Henry Hub; and fixed price swaps for the Midland-to-Cushing oil differential.

Marketing and Major Purchasers

For the year ended December 31, 2017, Legacy sold oil, NGL and natural gas production representing 10% or more of total revenues to the purchaser as detailed in the table below. For the years ended December 31, 2016 and 2015, Legacy did not sell oil, NGL or natural gas production representing 10% or more of total revenue to any one customer.

	2017	2016	2015
Plains Marketing, LP	10%	6%	7%

Our oil sales prices are based on formula pricing and calculated either using a discount to NYMEX WTI oil or using the appropriate buyer's posted price less a regional differential and transportation fee.

Although we believe we could identify a substitute purchaser if we were to lose any of our oil or natural gas purchasers, the loss could temporarily cause a loss or deferral of production and sale of our oil and natural gas in that particular purchaser's service area. However, if one or more of our larger purchasers ceased purchasing oil or natural gas altogether, the loss of any such purchaser could have a detrimental impact on our short-term production volumes and our ability to find substitute purchasers for our production volumes in a timely manner, though we do not believe this would have a long-term material adverse effect on our operations.

Competition

We operate in a highly competitive environment for acquiring leases and properties, securing and retaining trained personnel and service providers and marketing oil and natural gas. Our competitors may be able to pay more for leases, productive oil and natural gas properties and development projects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our ability to acquire additional properties and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment.

Seasonal Nature of Business

The demand for oil and natural gas can be seasonal based on motor vehicle driving patterns and heating and cooling demands related to weather. Our Rockies' oil prices suffer relative to WTI in the winter due to reduced demand for asphaltic crude. Refinery turnarounds in the Permian typically occur in the first quarter, and, historically, we have experienced wider oil differentials during this time.

Environmental Matters and Regulation

General. Our operations are subject to stringent and complex federal, state and local laws and regulations governing environmental protection 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;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with oil and natural gas drilling and production activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and
- require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells.

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 and state agencies frequently revise environmental laws and regulations, and any changes that result in more stringent and costly waste handling, disposal and cleanup requirements for the oil and natural gas industry could have a significant impact on our operating costs.

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

Waste Handling. The Resource Conservation and Recovery Act, or RCRA, and comparable state statutes, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the United States Environmental Protection Agency, or the EPA, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development, and production of crude oil or natural gas are currently regulated under RCRA's non-hazardous waste provisions. However, it is possible that certain oil and natural gas drilling and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change could result in an increase in our costs to manage and dispose of wastes, 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, or CERCLA, also known as the Superfund law, may impose joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third-parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

We currently own, lease, or operate numerous properties that have been used for oil and natural gas development and production for many years. Although we believe that 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 off-site locations, where such substances have been taken for disposal. In addition, most of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or hydrocarbons were not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA, and analogous state laws. Under such laws, we could be required to remove previously disposed of substances and wastes, remediate contaminated property, or perform remedial plugging or pit closure operations to prevent future contamination.

Water Discharges. The Federal Water Pollution Control Act, or the Clean Water Act, and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into 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. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

The Oil Pollution Act of 1990, as amended or OPA, which amends the Clean Water Act, establishes strict liability for owners and operators of facilities that cause a release of oil into waters of the United States. In addition, owners and operators of facilities that store oil above threshold amounts must develop and implement spill response plans.

Safe Drinking Water Act. Our injection well facilities may be regulated under the Underground Injection Control, or UIC, program established under the Safe Drinking Water Act, or SDWA. The state and federal regulations implementing that program require mechanical integrity testing and financial assurance for wells covered under the program. The federal Energy Policy Act of 2005 amended the UIC provisions of the federal SDWA to exclude hydraulic fracturing from the definition of underground injection. From time to time, Congress has considered bills to repeal this exemption. The EPA conducted a study of hydraulic fracturing and issued a final report in December 2016. This study and other studies that may be undertaken by EPA or other federal agencies could spur initiatives to further regulate hydraulic fracturing under the SDWA or other statutory and/or regulatory mechanisms.

Endangered Species Act. Additionally, environmental laws such as the Endangered Species Act, or ESA, may impact exploration, development and production activities on public or private lands. The ESA provides broad protection for species of fish, wildlife and plants that are listed as threatened or endangered in the United States, and prohibits taking of endangered species. Federal agencies are required to ensure that any action authorized, funded or carried out by them is not likely to jeopardize the continued existence of listed species or modify their critical habitat. Some of our facilities may be located in areas that are designated as habitat for endangered or threatened species. Though the rule listing the Lesser Prairie Chicken was vacated, portions of our properties in New Mexico and west Texas are enrolled in Habitat Conservation Plans and as a result we are subject to certain practices and restrictions designed to protect the habitat of the Lesser Prairie Chicken. We believe that we are in substantial compliance with the ESA and the practices and restrictions related to the Lesser Prairie Chicken should not result in material costs or constraints to our operations. However, the designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

Air Emissions. The Federal Clean Air Act, and comparable state laws, regulates emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources including pursuing the energy extraction sector under a National Enforcement Initiative. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the Federal Clean Air Act and associated state laws and regulations. In addition, more stringent federal, state and local regulations, such as the EPA rules issued in May 2016 regarding the aggregation of exploration and production equipment as a single source could result in increased costs and the need for operational changes. Finally, the EPA issued rules in May 2016 covering methane emissions from new oil and natural gas industry operations which could result in additional costs and restrictions on our operations. In July 2017, the EPA proposed a two-year stay of certain requirements of this rule pending reconsideration of the rule.

National Environmental Policy Act. Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act, or NEPA. NEPA requires federal agencies, including the Department of the Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency may 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. 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 the development of oil and natural gas projects.

OSHA and Other Laws and Regulation. We are subject to the requirements of the federal Occupational Safety and Health Act (OSHA) and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under 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. We believe that we are in compliance with these applicable requirements and with other OSHA and comparable requirements.

In 2009, the EPA began to adopt regulations that would require a reduction in emissions of greenhouse gases from certain stationary sources and has required monitoring and reporting for other stationary sources, including the oil and natural gas production industry. In May 2016, the EPA finalized regulations that establish new controls for emissions of methane and volatile organic compounds from oil and natural gas operations. In July 2017, the EPA proposed a two-year stay of certain requirements of this rule pending reconsideration of the rule. Additional regional, federal or state requirements may be imposed in the future. New legislation or regulatory programs that restrict emissions of greenhouse gases in areas in which we conduct business could have an adverse affect on our operations and demand for our products. Currently, our operations are not adversely impacted by existing state and local climate change initiatives and, at this time, it is not possible to accurately estimate how potential future laws or regulations addressing greenhouse gas emissions would impact our business. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our exploration and production operations.

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. For instance, we did not incur any material capital expenditures for remediation or pollution control activities for the year ended December 31, 2017. Additionally, as of the date of this document, we are not aware of any environmental issues or claims that require material capital expenditures during 2018. However, we cannot assure investors that the passage of more stringent laws or regulations in the future will not have a negative impact on our financial position or results of operations.

Activities on Federal Lands. Oil and natural gas exploitation and production activities on federal lands are subject to NEPA. NEPA 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 typically prepare an Environmental Assessment to assess 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. Our current production activities, as well as proposed development plans, on federal lands require governmental permits or similar authorizations that are subject to the requirements of NEPA. This process has the potential to delay, limit or increase the cost of developing oil and natural gas projects. Authorizations under NEPA are also subject to protest, appeal or litigation, any or all of which may delay or halt projects.

Federal, State or Native American Leases. Our operations on federal, state, or Native American oil and natural gas leases are subject to numerous restrictions, including nondiscrimination statutes. Such operations must be conducted pursuant to certain on-site security regulations and other permits and authorizations issued by the Bureau of Land Management, or BLM, and other agencies. For example, in November 2016, the BLM finalized regulations which update standards to reduce venting and flaring from oil and gas production on public lands. In December 2017, the BLM suspended or delayed certain requirements of the rule until January 17, 2019.

Other Regulation of the Oil and Natural Gas Industry

The oil and natural gas industry is extensively regulated by numerous federal, state and local authorities. Legislation affecting the oil and natural gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations binding on the oil and 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 oil and natural gas industry with similar types, quantities and locations of production.

Legislation continues to be introduced in Congress and development of regulations continues in the Department of Homeland Security and other agencies concerning the security of industrial facilities, including oil and natural gas facilities. Our operations may be subject to such laws and regulations. Presently, it is not possible to accurately estimate the costs we could incur to comply with any such facility security laws or regulations, but such expenditures could be substantial.

Drilling and Production. Our operations are subject to various types of regulation at 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 and casing wells;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells; and
- notice to surface owners and other third parties.

State laws regulate the size and shape of drilling and spacing units or pro-ration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally regulate and seek to restrict the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and natural gas we can produce from our wells or limit the number of wells or the locations at which we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction.

Natural gas regulation. The availability, terms and cost of transportation significantly affect sales of natural gas. The interstate transportation and sale or resale of natural gas is 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, or the FERC. Federal and state regulations govern the price and terms for access to natural gas pipeline transportation. The FERC's regulations for interstate natural gas transmission in some circumstances may also affect the intrastate transportation of natural gas.

Although natural gas 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 condensate and natural gas liquids are not currently regulated and are made at market prices.

State regulation. The various states regulate the drilling for, and the production, gathering and sale of, oil and natural gas, including imposing severance taxes and requirements for obtaining drilling permits. For example, Texas currently imposes a 4.6% severance tax on oil production and a 7.5% severance tax on natural gas production. New Mexico currently imposes a 3.75% severance tax on both oil and natural gas production. States also regulate the method of developing new fields, the spacing and operation of wells and the prevention of waste of natural gas resources. States may regulate rates of production and may establish maximum daily production allowable from natural gas wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulation, but there can be no assurance that they will not do so in the future. The effect of these regulations may be to limit the amounts of natural gas that may be produced from our wells, and to limit the number of wells or locations we can drill.

The petroleum industry is also subject to compliance with various other federal, state and local regulations and laws. Some of those laws relate to resource conservation and equal employment opportunity. We do not believe that compliance with these laws will have a material adverse effect on us.

Employees

As of December 31, 2017, we had 331 full-time employees, none of whom are subject to collective bargaining agreements. We also contract for the services of independent consultants involved in land, engineering, regulatory, accounting, financial and other disciplines as needed. We believe that we have a favorable relationship with our employees.

Offices

Our principal offices are located in Midland, Texas at 303 W. Wall Street. In addition to our principal offices, we have regional offices located in Cody, Wyoming for engineering, land and accounting staff and in The Woodlands, Texas for engineering, geology and land staff.

Available Information

We make available free of charge on our website, www.legacylp.com, 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 the Securities Exchange Act of 1934, as amended, as soon as reasonably practicable after we electronically file such information with, or furnish it to, the Securities and Exchange Commission ("SEC").

The information on our website is not, and shall not be deemed to be, a part of this annual report on Form 10-K or incorporated into any of our other filings with the SEC.

ITEM 1A. *RISK FACTORS*

Risks Related to our Business

We may not have sufficient available cash to resume distributions to limited partners, following establishment of cash reserves and payment of fees and expenses.

We have suspended cash distributions to the holders of our units and Preferred Units. Our $1.5 billion secured revolving credit facility with Wells Fargo Bank, National Association, as administrative agent, Compass Bank, as syndication agent, UBS Securities LLC and U.S. Bank National Association, as co-documentation agents and the lenders party thereto as amended most recently by the Eight Amendment thereto (as amended, the "Revolving Credit Agreement") and our Term Loan Credit Agreement provide that any such cash distributions can be made only out of our available cash, provided that distributions do not exceed 90% of available cash, and both before and after giving effect to any such distribution (i) no default or event of default has occurred and is continuing or would result therefrom, (ii) we have unused lender commitments of not less than 15% of the total lender commitments then in effect under our Revolving Credit Agreement, and (iii) our ratio of total debt at such time to our EBITDA for the four fiscal quarters ending on the last day of the fiscal quarter immediately preceding the date of determination for which financial statements are available is equal to or less than 4.00 to 1.00. Absent the elimination or conversion to equity of a larger portion of our debt or our ability to pay down a significant portion of indebtedness under our Revolving Credit Agreement, we do not anticipate achieving these metrics or paying any distributions.

Although we have suspended distributions to the holders of our Preferred Units, such distributions continue to accrue in arrears. Pursuant to the terms of our partnership agreement, we are required to pay or set aside for payment all accrued but unpaid distributions with respect to the Preferred Units prior to or contemporaneously with making any distribution with respect to our units.

If oil and natural gas prices decline, our cash flow from operations will decline.

Lower oil and natural gas prices may decrease our revenues and thus cash flow from operations. Prices for oil and natural gas may fluctuate widely in response to relatively minor changes in the supply of and demand for oil and natural gas, 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 and natural gas;
- market expectations about future prices of oil and natural gas;
- the price and quantity of imports of crude oil and natural gas;
- overall domestic and global economic conditions;
- political and economic conditions in other oil and natural gas producing countries, including embargoes and continued hostilities in the Middle East and other sustained military campaigns, and acts of terrorism or sabotage;
- the willingness and ability of members of the Organization of Petroleum Exporting Countries and other petroleum producing countries to agree to and maintain oil price and production controls;
- trading in oil and natural gas derivative contracts;
- the level of consumer product demand;
- weather conditions and natural disasters;
- technological advances affecting energy production and consumption;
- domestic and foreign governmental regulations and taxes;
- the proximity, cost, availability and capacity of oil and natural gas pipelines and other transportation facilities;
- the impact of the U.S. dollar exchange rates on oil and natural gas prices; and
- the price and availability of alternative fuels.

Historically, oil and natural gas prices have been extremely volatile. For example, for the five years ended December 31, 2017, the NYMEX-WTI oil price ranged from a high of $110.62 per Bbl to a low of $26.19 per Bbl, while the NYMEX-Henry Hub natural gas price ranged from a high of $8.15 per MMBtu to a low of $1.49 per MMBtu. As of February 12, 2018, the NYMEX WTI oil spot price was $59.41 per Bbl and the NYMEX-Henry Hub natural gas spot price was $2.60 per MMBtu. If oil and natural gas prices decline from current levels, it may have a material adverse effect on our operations and financial condition.

Our business requires significant capital expenditures and we may be unable to obtain needed capital or financing on satisfactory terms or at all.

Our development and acquisition activities require substantial capital expenditures. We expect to fund our capital expenditures through cash flows from operations. Future cash flows are subject to a number of variables, including the level of production from existing wells, prices of oil and natural gas and our success in developing and producing new reserves. If our cash flow from operations is not sufficient to fund our capital expenditure budget, we may have limited ability to obtain the additional capital necessary to sustain our operations at current levels. We may not be able to obtain debt or equity financing on terms favorable to us or at all. The failure to obtain additional financing could result in a curtailment of our operations relating to development of our oil and natural gas properties, which in turn could lead to a decline in our oil and natural gas production or reserves, and in some areas a loss of properties.

Failure to replace reserves may negatively affect our business, results of operation and financial condition.

The growth of our business depends upon our ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable. Our proved reserves generally decline when reserves are produced, unless we conduct successful exploration or development activities or acquire properties containing proved reserves, or both. Further, the rate of estimated decline of our oil and natural gas reserves may increase if our wells do not produce as expected. We may not be able to find, develop or acquire additional reserves to replace our current and future production at acceptable costs. If oil and natural gas prices increase, our costs for additional reserves would also increase; conversely if natural gas or oil prices decrease, it could make it more difficult to fund the replacement of our reserves.

Increases in the cost of or failure of costs to adjust downward for drilling rigs, service rigs, pumping services and other costs in drilling and completing wells could reduce the viability of certain of our development projects.

The costs of rigs and oil field services necessary to implement our development projects decreased when oil and natural gas prices decreased in 2015. As oil and natural gas prices have increased, we are seeing service costs rise and availability diminish. Increased capital requirements for our projects will result in higher reserve replacement costs and could cause certain of our projects to become uneconomic even with increased commodity prices and therefore not to be implemented, reducing our production and cash flow. Decreased availability of drilling equipment and services could significantly impact the planned execution of our development program.

Our substantial indebtedness and liquidity issues may impact our business, financial condition and operations.

Due to our substantial indebtedness and liquidity issues, there is risk that, among other things:

- third parties' confidence in our ability to develop oil and natural gas properties could erode, which could impact our ability to execute on our business strategy;
- it may become more difficult to retain, attract or replace key employees;
- employees could be distracted from performance of their duties or more easily attracted to other career opportunities; and
- our suppliers, vendors and service providers could renegotiate the terms of our arrangements, terminate their relationship with us or require financial assurances from us.

The occurrence of certain of these events may increase our operating costs and may have a material adverse effect on our business, results of operations and financial condition.

The interests of the holders of our Senior Notes may not be aligned with our interests.

Pursuant to repurchases we have made in the past, we own a face amount of $67.0 million of our 8% senior unsecured notes due 2020 (the "2020 Senior Notes" and together with the 2021 Senior Notes, the "Senior Notes") and $304.0 million of our 2021 Senior Notes, representing approximately 22% and 55% of the amounts outstanding, respectively. While we have treated these repurchases as extinguishments of debt for accounting purposes, we have not retired any of the Senior Notes that we have repurchased to date and, subject to certain restrictions, we retain voting rights under the corresponding indentures that govern the Senior Notes. In the future we may seek to exercise the voting rights we hold by virtue of our ownership of the Senior Notes pursuant to the indentures in order to vote in such a manner that is contrary to the interests of other holders of our Senior Notes.

Our debt levels may limit our flexibility to obtain additional financing and pursue other business opportunities.

As of February 21, 2018, we had total long-term debt of approximately $1.3 billion. Our existing and future indebtedness could have important consequences to us, including:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on terms acceptable to us;
- covenants in our existing and future credit and debt arrangements will require us to meet financial tests that may affect our flexibility in planning for and reacting to changes in our business, including possible acquisition opportunities;
- our access to the capital markets may be limited;
- our borrowing costs may increase;
- we will need a substantial portion of our cash flow to make principal and interest payments on our indebtedness, reducing the funds that would otherwise be available for operations and future business opportunities; and
- our debt level will make us more vulnerable than our competitors with less debt to competitive pressures or a downturn in our business or the economy generally.

Our ability to service our indebtedness will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond our control. If our operating results and cash flows are not sufficient to service our current or future indebtedness, in addition to the suspension of distributions, we will be forced to take actions such as further reducing or delaying business activities, acquisitions, investments and/or capital expenditures, selling assets, restructuring or refinancing our indebtedness, or seeking additional equity capital or bankruptcy protection. We may not be able to effect any of these remedies on satisfactory terms or at all.

Our Revolving Credit Agreement matures on April 1, 2019, our Term Loan Credit Agreement matures on August 31, 2021 (or August 31, 2020 if we have $15 million or more of outstanding Senior Notes), our 2020 Senior Notes mature on December 1, 2020 and our 2021 Senior Notes mature on December 1, 2021; if we are unable to refinance or otherwise repay such indebtedness there would be a material and adverse effect on our business continuity and our financial condition.

As maturity dates for our outstanding indebtedness approach, particularly that of our Revolving Credit Agreement, we are evaluating, and will continue to evaluate and will opportunistically pursue, our options to refinance or repay such indebtedness, including alternatives in the debt and equity capital markets or discussions with lenders under our Revolving Credit Agreement and Term Loan Credit Agreement.

If we do not have the capital necessary to repay our outstanding indebtedness when it matures, it will be necessary for us to take significant actions, such as revising or delaying our strategic plans, reducing or delaying planned capital expenditures, selling assets, restructuring or refinancing our debt or seeking additional equity capital. We may be unable to effect any of these remedial steps on a satisfactory basis, or at all. If we are unable to refinance or otherwise repay our debt upon the maturity of our indebtedness, we would be in default, which would result in material adverse consequences for us.

In addition, if we are unable to refinance indebtedness before that debt's maturity becomes current, there could be substantial doubt about our ability to continue as a going concern. If we are unable, or there is substantial doubt about our ability, to continue as a going concern, it would have a material adverse effect on the value of an investment in us.

We are a master limited partnership ("MLP"). Volatile market conditions and widespread suspension of distributions have changed investor appetite and resulted in a decrease in demand for debt and equity securities issued by MLPs engaged in the widespread distribution suspensions of upstream oil and gas business ("Upstream MLPs"). This may affect our ability to access the equity and debt capital markets.

The volatility in energy prices and widespread suspension of distributions, among other factors, has contributed to a dislocation in the pricing of debt and equity securities issued by Upstream MLPs, as a number of Upstream MLPs have been adversely affected by this environment. The elimination of distributions to limited partners has caused many investors to discontinue their interest in investing in debt and equity securities issued by Upstream MLPs. While we intend to finance our future capital expenditures with cash flow from operations and, subject to availability, borrowings under our Revolving Credit Agreement and our Term Loan Credit Agreement, we may need to rely on our ability to raise capital in the equity and debt markets to add reserves and to refinance our debt. Continued volatility and lack of investor demand may affect our ability to access capital markets to finance our growth or refinance our debt in our current legal structure and tax status.

Our development projects 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 oil and natural gas reserves.

We make and expect to continue to make substantial capital expenditures in our business for the development, production and acquisition of oil and natural gas reserves. We intend to finance our future capital expenditures with cash flow from operations and, subject to availability, borrowings under our Revolving Credit Agreement and our Term Loan Credit Agreement. Our cash flow from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the level of oil and natural gas we are able to produce from existing wells;
- capital and lending market conditions;
- the prices at which our oil and natural gas are sold; and
- our ability to identify, acquire and exploit new reserves.

If our revenues or the borrowing base under our Revolving Credit Agreement decrease as a result of lower oil and/or natural gas 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 Revolving Credit Agreement and our Term Loan Credit Agreement restrict our ability to obtain new financing. If additional capital is needed, we may not be able to obtain debt or equity financing due to such restrictions, market conditions or otherwise. If cash generated by operations or available under our Revolving Credit Agreement and our Term Loan Credit Agreement 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 decline in our oil and natural gas production and reserves, and could adversely affect our business, results of operations and financial condition.

Drilling for and producing oil and natural gas are high risk activities with many uncertainties that could adversely affect our business, results of operations and financial condition.

Our drilling activities are subject to many risks, including the risk that we will not encounter commercially productive reservoirs. Drilling for oil and natural gas can be uneconomic, not only from dry holes, but also from productive wells that do not produce sufficient revenues to be commercially viable.

In addition, our drilling and producing operations may be curtailed, delayed or canceled as a result of other factors, including:

- the high cost, shortages or delivery delays of equipment and services;
- unexpected operational events;
- adverse weather conditions or events;
- facility or equipment malfunctions;
- title disputes;
- pipeline ruptures or spills;
- collapses of wellbore, casing or other tubulars;
- unusual or unexpected geological formations;
- loss of drilling fluid circulation;
- formations with abnormal pressures;
- fires;
- blowouts, craterings and explosions; and
- uncontrollable flows of oil, natural gas or well fluids.

Any of these events can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination, loss of wells and regulatory penalties.

We ordinarily maintain insurance against various losses and liabilities arising from our operations; however, insurance against all operational risks is not available to us. 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, results of operations and financial condition.

If commodity prices decline, a significant portion of our development projects may become uneconomic and cause write downs of the value of our oil and natural gas properties, which may adversely affect our financial condition.

Lower oil and natural gas prices may not only decrease our revenues, but also may render many of our development and production projects uneconomic and result in a downward adjustment of our reserve estimates, which would negatively impact our borrowing base under our Revolving Credit Agreement and ability to fund operations.

A reduction in commodity prices may be caused by many factors, including substantial increases in U.S. production and reserves from unconventional (shale) reservoirs, without a corresponding increase in demand. The International Energy Agency forecasts continued U.S. oil production growth in 2018. This environment could cause the prices for oil to fall to lower levels.

Furthermore, a decrease in oil and natural gas prices may render a significant portion of our development projects uneconomic. In addition, if oil and natural gas prices decline, 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. For example, in the year ended December 31, 2017, we incurred impairment charges of $37.3 million, a portion of which was driven by commodity price changes. We may incur further impairment charges in the future related to depressed commodity prices, which could have a material adverse effect on our results of operations in the period taken.

Our identified drilling location inventories are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Our management team has specifically identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our acreage. These identified drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of factors, including the availability of capital, seasonal conditions, regulatory approvals, oil and natural gas prices, costs and drilling results. Our final determination on whether to drill any of these drilling locations will be dependent upon the factors described above as well as, to some degree, the results of our drilling activities with respect to our proved drilling locations. Because of these uncertainties, we do not know if the numerous drilling locations we have identified will be drilled within our expected time frame or 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 be materially different from those presently identified, which could adversely affect our business, results of operations and financial condition.

Fluctuations in price and demand for our production may force us to shut in a significant number of our producing wells, which may adversely impact our revenues.

We are subject to great fluctuations in the prices we are paid for our production due to a number of factors. Drilling in shale resources has developed large amounts of new oil and natural gas supplies, both from natural gas wells and associated natural gas from oil wells, that have depressed the prices paid for our production, and we expect the shale resources to continue to be drilled and developed by our competitors. We also face the potential risk of shut-in production due to high levels of oil, natural gas and NGL inventory in storage, weak demand due to mild weather and the effects of any economic downturns on industrial demand. Lack of NGL storage in Mont Belvieu where our West Texas and New Mexico NGLs are shipped for processing could cause the processors of our natural gas to curtail or shut-in our natural gas wells and potentially force us to shut-in oil wells that produce associated natural gas, which may adversely impact our revenues. For example, following past hurricanes, certain Permian Basin natural gas processors were forced to shut down their plants due to the shutdown of the Texas Gulf Coast NGL fractionators, requiring us to vent or flare the associated natural gas from our oil wells. There is no certainty we will be able to vent or flare natural gas again due to potential changes in regulations. Furthermore, we may encounter problems in restarting production of previously shut-in wells.

An increase in the differential between the West Texas Intermediate ("WTI") or other benchmark prices of oil and the wellhead price we receive for our production could adversely affect our operating results and financial condition.

The prices that we receive for our oil production sometimes reflect a discount to the relevant benchmark prices, such as WTI, that are used for calculating derivative positions. The difference between the benchmark price and the price we receive is called a differential. Increases in the differential between the benchmark prices for oil and the wellhead price we receive could adversely affect our operating results and financial condition. While this differential remained largely unchanged from 2015 through 2017, we have been adversely impacted by widening differentials in prior periods and a recurrence of such wider differentials could adversely affect our operating results and financial condition.

Due to regional fluctuations in the actual prices received for our natural gas production, the derivative contracts we enter into may not provide us with sufficient protection against price volatility since they are based on indexes related to different and remote regional markets.

We sell our natural gas into local markets, the majority of which is produced in East Texas, Colorado, West Texas, Southeast New Mexico, Central Oklahoma and Wyoming and shipped to the Midwest, West Coast and Texas Gulf Coast. These regions account for over 90% of our natural gas sales. In the past, we have used swaps on Northwest Pipeline, California SoCal NGI and San Juan Basin natural gas prices and we may do so again in the future. While we are paid a local price indexed to or closely related to these indexes, these indexes are heavily influenced by prices received in remote regional consumer markets less transportation costs and thus may not be effective in protecting us against local price volatility.

The substantial restrictions and financial covenants of both our Revolving Credit Agreement and our Term Loan Credit Agreement, any negative redetermination of our borrowing base under our Revolving Credit Agreement by our lenders and any potential disruptions of the financial markets could adversely affect our business, results of operations and financial condition.

We depend on our Revolving Credit Agreement and our Term Loan Credit Agreement for future capital needs. Our Revolving Credit Agreement, which matures on April 1, 2019, limits the amounts we can borrow to a borrowing base amount, determined by the lenders in their sole discretion. As of February 21, 2018, our borrowing base was $575.0 million and we had approximately $72.2 million available for borrowing. Our Term Loan Credit Agreement for second lien term loans maturing on August 31, 2020 provides for up to an aggregate principal amount of $400.0 million, of which we have used $338.6 million.

Our Revolving Credit Agreement and our Term Loan Credit Agreement restrict, among other things, our ability to incur debt and requires us to comply with certain financial covenants and ratios. We may not be able to comply with these restrictions and covenants in the future and will be affected by the levels of cash flow from our operations and events or circumstances beyond our control, such as any potential disruptions in the financial markets. Our failure to comply with any of the restrictions and covenants under our Revolving Credit Agreement or our Term Loan Credit Agreement could result in a default under our Revolving Credit Agreement or our Term Loan Credit Agreement. A default under our Revolving Credit Agreement or our Term Loan Credit Agreement could cause all of our existing indebtedness, including our second lien term loans and our Senior Notes, to be immediately due and payable.

Outstanding borrowings under our Revolving Credit Agreement in excess of the borrowing base must be repaid within four months, and, if mortgaged properties represent less than 95% of total value of oil and natural gas properties used to determine the borrowing base, we must pledge other oil and natural gas properties as additional collateral. We may not have the financial resources in the future to make any mandatory principal prepayments required under our Revolving Credit Agreement.

The occurrence of an event of default or a negative redetermination of our borrowing base, such as a result of lower commodity prices or a deterioration in the condition of the financial markets, could adversely affect our business, results of operations and financial condition.

Please read "Management's Discussion and Analysis of Financial Condition and Results of Operation — Financing Activities."

Low commodity prices may impact our ability to comply with debt covenants.

Should oil and natural gas prices decline dramatically in 2018, we could breach certain financial covenants under our Revolving Credit Agreement or our Term Loan Credit Agreement, which would constitute a default under our Revolving Credit Agreement or our Term Loan Credit Agreement. Such default would require a waiver from our lenders in order for us to avoid an event of default and subsequent acceleration of all amounts outstanding under our Revolving Credit Agreement or our Term Loan Credit Agreement or foreclosure on our oil and natural gas properties. If the lenders under our Revolving Credit Agreement were to accelerate the indebtedness under our Revolving Credit Agreement as a result of such defaults, such acceleration could cause a cross-default of all of our other outstanding indebtedness and permit the holders of such indebtedness to accelerate the maturities of such indebtedness. Such a cross-default or cross-acceleration could have a wider impact on our liquidity than might otherwise arise from a default or acceleration of a single debt instrument. If an event of default occurs, or if other debt agreements cross-default, and the lenders under the affected debt agreements accelerate the maturity of any loans or other debt outstanding, the saleable value of our assets may not be sufficient to repay all of our outstanding indebtedness.

Any acquisitions we complete are subject to substantial risks that could adversely affect our financial condition and results of operations.

We may not achieve the expected results of any acquisition we complete, and any adverse conditions or developments related to any such acquisition may have a negative impact on our operations and financial condition.

Further, even if we complete any acquisitions, which we would expect to increase our cash flow, actual results may differ from our expectations and the impact of these acquisitions may actually result in a decrease in cash flow. Any acquisition involves potential risks, including, among other things:

- the validity of our assumptions about recoverable reserves, development potential, future production, revenues, capital expenditures, future oil and natural gas prices, operating costs and potential environmental and other liabilities;
- an inability to successfully integrate the assets and businesses we acquire;
- a decrease in our liquidity by using a portion of our available cash or borrowing capacity under our Revolving Credit Agreement and our Term Loan Credit Agreement to finance acquisitions;
- a significant increase in our interest expense or financial leverage if we incur additional debt to finance acquisitions;
- the assumption of unknown environmental and other liabilities, losses or costs for which we are not indemnified or for which our indemnity is inadequate;
- the diversion of management's attention from other business concerns;
- the incurrence of other significant charges, such as impairment of oil and natural gas properties, goodwill or other intangible assets, asset devaluation or restructuring charges; and
- the loss of key purchasers.

Our decision to acquire a property depends in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses, seismic data and other information, the results of which are often inconclusive and subject to various interpretations. Our estimates of future reserves and estimates of future development and production for our acquisitions and related forecasts of anticipated cash flow therefrom are initially based on detailed information furnished by the sellers and are subject to review, analysis and adjustment by our internal staff, typically without consulting with outside petroleum engineers. Such assessments are inexact and their accuracy is inherently uncertain and our proved reserves estimates and cash flow forecasts therefrom may exceed actual acquired proved reserves or the estimates of future cash flows therefrom. In connection with our assessments, we perform a review of the acquired properties included in our acquisitions that we believe is generally consistent with industry practices. However, such a review will not reveal all existing or potential problems.

Also, our reviews of newly acquired properties are inherently incomplete because it is generally not feasible to perform an in-depth review of the individual properties involved in each acquisition given time constraints imposed by sellers. 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 fully assess their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken. Even when we inspect a well, we do not always discover structural, subsurface and environmental problems that may exist or arise.

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 oil and natural gas exploration and production operations are subject to complex and stringent laws and regulations. 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 including the Bureau of Land Management. We may incur substantial costs in order to maintain compliance with these existing laws and regulations and could experience substantial disruptions to our operations if we do not timely receive permits required to drill new wells, especially on federal lands. In addition, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. All such costs or disruptions may have a negative effect on our business, results of operations and financial condition.

Our business is subject to federal, state and local laws and regulations as interpreted and enforced by governmental authorities possessing jurisdiction over various aspects of the exploration for, and the production of, oil and natural gas. Failure to comply with such laws and regulations, as interpreted and enforced, could have a material adverse effect on our business, results of operations and financial condition.

Our operations expose us to significant costs and liabilities with respect to environmental and operational safety matters.

We may incur significant costs and liabilities as a result of environmental and safety requirements applicable to our oil and natural gas exploration and production activities. These costs and liabilities could arise under a wide range of federal, state and local environmental and safety laws and regulations, including regulations and enforcement policies, which have tended to become increasingly strict over time. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, and to a lesser extent, issuance of injunctions to limit or cease operations. In addition, claims for damages to persons or property may result from environmental and other impacts of our operations.

Strict, joint and several liability may be imposed under certain environmental laws, which could cause us to become liable for the conduct of others or for consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. New laws, regulations or enforcement policies could be more stringent and impose unforeseen liabilities or significantly increase compliance costs. If we were not able to recover the resulting costs through insurance or increased revenues, our financial condition could be adversely affected.

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

From time to time, Congress has considered legislation to amend the federal Safe Drinking Water Act to require the disclosure of chemicals used by the oil and natural gas industry in the hydraulic fracturing process. Hydraulic fracturing is an important and commonly used process in the completion of unconventional wells in shale formations, as well as tight conventional formations including many of those that Legacy completes and produces. This process involves the injection of water, sand and chemicals under pressure into rock formations to stimulate hydrocarbon production. Sponsors of these bills have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. In addition, some states have adopted and others are considering legislation to restrict hydraulic fracturing. Several states including Texas and Wyoming have adopted or are considering legislation requiring the disclosure of hydraulic fracturing chemicals. Public disclosure of chemicals used in the hydraulic fracturing process could make it easier for third parties opposed to the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect the environment, including groundwater, soil or surface water. In addition, state and federal agencies recently have focused on a possible connection between the operation of injection wells used for oil and natural gas waste disposal and seismic activity. Similar concerns have been raised that hydraulic fracturing may also contribute to seismic activity. In light of these concerns, some state regulatory agencies have modified their regulations or issued order to address seismic activity. For example, the Railroad Commission of Texas has adopted regulations which place additional restrictions on the permitting of disposal well operations in areas of historical or future seismic activity. Any additional level of regulation could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

Final rules regulating air emissions from natural gas production operations could cause us to incur increased capital expenditures and operating costs, which may be significant.

On April 17, 2012, the EPA approved final regulations under the Clean Air Act that, among other things, require additional emissions controls for natural gas and natural gas liquids production, including New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds ("VOCs") and a separate set of emission standards to address hazardous air pollutants frequently associated with such production activities. The final regulations require the reduction of VOC emissions from natural gas wells through the use of reduced emission completions or "green completions" on all hydraulically fractured wells constructed or refractured after January 1, 2015. For well completion operations occurring at such well sites before January 1, 2015, the final regulations allow operators to capture and direct flowback emissions to completion combustion devices, such as flares, in lieu of performing green completions. These regulations also establish specific new requirements regarding emissions from dehydrators, storage tanks and other production equipment. In addition, in May 2016, the EPA issued rules covering methane emissions from new oil and natural gas industry operations. In July 2017, the EPA proposed a two-year stay of certain requirements of this rule pending reconsideration of the rule. Compliance with these requirements could increase our costs of development and production, which costs may be significant.

We may not be able to maintain our listing on the NASDAQ Global Select Market.

NASDAQ has established certain standards for the continued listing of a security on the NASDAQ Global Select Market. The standards for continued listing include, among other things, that the minimum bid price for the listed securities not fall below $1.00 per share for a period of 30 consecutive trading days. Although we are currently in compliance with the minimum bid price requirement, in the future we may not satisfy the NASDAQ's continued listing standards. If we do not satisfy any of the NASDAQ's continued listing standards, our units and Preferred Units could be delisted. Any such delisting could adversely affect the market liquidity of our units and Preferred Units and the market price of our units and Preferred Units could decrease. A delisting could adversely affect our ability to obtain financing for our operations or result in a loss of confidence by investors, customers, suppliers or employees.

Restrictive covenants under the indentures governing our Senior Notes may adversely affect our operations.

The indentures governing the Senior Notes contains, and any future indebtedness we incur may contain, a number of restrictive covenants that impose significant operating and financial restrictions on us, including restrictions on our ability to, among other things:

- sell assets, including equity interests in our restricted subsidiaries;
- pay distributions on, redeem or purchase our units or redeem or purchase our subordinated debt;
- make investments;
- incur or guarantee additional indebtedness or issue preferred units;
- create or incur certain liens;
- enter into agreements that restrict distributions or other payments from our restricted subsidiaries to us;
- consolidate, merge or transfer all or substantially all of our assets;
- engage in transactions with affiliates;
- create unrestricted subsidiaries; and
- engage in certain business activities.

As a result of these covenants, we are limited in the manner in which we conduct our business, and we may be unable to engage in favorable business activities or finance future operations or capital needs.

A failure to comply with the covenants in the indentures governing the Senior Notes or any future indebtedness could result in an event of default under the indentures governing the Senior Notes, our Revolving Credit Agreement, our Term Loan Credit Agreement, or any future indebtedness, which, if not cured or waived, could have a material adverse effect on our business, financial condition and results of operations. In addition, complying with these covenants may make it more difficult for us to successfully execute our business strategy and compete against companies that are not subject to such restrictions.

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

No one can measure underground accumulations of oil and natural gas in an exact way. Oil and natural gas reserve engineering requires subjective estimates of underground accumulations of oil and natural gas and assumptions concerning future oil and natural gas 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. Any material inaccuracies in these 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.

Further, the present value of future net cash flows from our proved reserves may not be the current market value of our estimated natural gas and oil reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on the 12-month average oil and gas index prices, calculated as the unweighted arithmetic average for the first-day-of-the-month price for each month and costs in effect on the date of the estimate, holding the prices and costs constant throughout the life of the properties. Actual future prices and costs may differ materially from those used in the net present value estimate, and future net present value estimates using then current prices and costs may be significantly less than the current estimate. To illustrate the price impact of commodity prices on our proved reserves subsequent to December 31, 2017, we recalculated the value of our proved reserves as of December 31, 2017 using the five-year average forward price as of February 14, 2018 for both WTI oil and NYMEX natural gas. While this 5-year NYMEX forward strip price is not necessarily indicative of our overall outlook on future commodity prices, this commonly used methodology may help provide investors with an understanding of the impact of a volatile commodity price environment. Under such assumptions, we estimate the cumulative projected production from our year-end proved reserves would decrease by approximately 3% to 175.4 MMBoe from our previously reported 180.0 MMBoe, which is calculated as required by the SEC. In addition, the 10% discount factor we use when calculating discounted future net cash flows for reporting requirements in compliance with Financial Accounting Standards Board ("FASB") Accounting Standards Codification 932 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 natural gas and oil industry in general.

Our business depends on gathering and transportation facilities owned by others. Any limitation in the availability of those facilities would interfere with our ability to market the oil and natural gas we produce.

The marketability of our oil and natural gas production depends in part on the availability, proximity and capacity of gathering and pipeline systems owned by third parties. 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, oversupply of oil due to nearby refinery outages, excessive pressure, physical damage to the gathering 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. Any significant curtailment in gathering system or pipeline capacity, or significant delay in the construction of necessary gathering and transportation facilities, could adversely affect our business, results of operations and financial condition.

We do not control all of our operations and development projects and failure of an operator of wells in which we own partial interests to adequately perform could adversely affect our business, results of operations and financial condition.

Many of our business activities are conducted through joint operating agreements under which we own partial interests in oil and natural gas wells.

If we do not operate wells in which we own an interest, we do not have control over normal operating procedures, expenditures or future development of underlying properties. The success and timing of our development projects on properties operated by others is outside of our control.

The failure of an operator of wells in which we own partial interests to adequately perform operations, or an operator's breach of the applicable agreements, could reduce our production and revenues and could adversely affect our business, results of operations and financial condition.

Increases in interest rates could adversely affect our business, results of operations, cash flows from operations and financial condition, and cause a decline in the demand for yield-based equity investments such as our units and Preferred Units.

Since all of the indebtedness outstanding under our Revolving Credit Agreement is at variable interest rates, we have significant exposure to increases in interest rates. As a result, our business, results of operations and cash flows may be adversely affected by significant increases in interest rates. Further, an increase in interest rates may cause a corresponding decline in demand for equity investments, in particular for yield-based equity investments such as our units or Preferred Units. Any reduction in demand for our units resulting from other more attractive investment opportunities may cause the trading price of our units or Preferred Units to decline.

The inability of one or more of our customers to meet their obligations may adversely affect our financial condition and results of operations.

Substantially all of our accounts receivable result from oil and natural gas sales or joint interest billings to third parties in the energy industry who are also subject to the effects of the current oil and natural gas commodity price environment. This concentration of customers and joint interest owners may impact our overall credit risk in that these entities may be similarly affected by changes in economic, industry and other conditions. In addition, our oil, natural gas and interest rate derivative transactions expose us to credit risk in the event of nonperformance by counterparties.

We depend on a limited number of key personnel who would be difficult to replace.

Our operations are dependent on the continued efforts of our executive officers, senior management and key employees. The loss of any executive officer, member of our senior management or other key employees could negatively impact our ability to execute our strategy.

Our business may be affected by shortages of skilled employees and labor cost inflation.

Competition for skilled employees in the oil and gas industry in Midland, Texas is strong, and labor costs have increased moderately since 2015. We expect that the demand and, hence, costs for skilled employees will increase as prices for oil and natural gas rise. Continual high demand for skilled employees and continued increases in labor costs could have a material adverse effect on our business, financial condition, results of operations and prospects.

We may be unable to compete effectively, which could have an adverse effect on our business, results of operations and financial condition.

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 competitors not only explore for and produce oil and natural gas, 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 productive oil and natural gas properties and exploratory prospects or define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may have a greater ability to continue exploration and development activities during periods of low oil and natural gas market prices and to absorb the burden of present and future federal, state, local and other laws and regulations. Our inability to compete effectively with these companies could have an adverse effect on our business, results of operations and financial condition.

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 investors could lose confidence in our financial reporting, which would harm our business and the trading price of our securities.

Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. 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. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results could 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 certain reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which could have a negative effect on the trading price of our securities.

A failure in our operational systems or cyber security attacks on any of our facilities or those of third parties may have a material adverse effect on our business, results of operations and financial condition.

Our business is dependent upon our operational systems to process a large amount of data and complex transactions. If any of our financial, operational or other data processing systems fail or have other significant shortcomings, our financial results could be adversely affected. Our financial results could also be adversely affected if an employee causes our operational systems to fail, either as a result of inadvertent error or by deliberately tampering with or manipulating our operational systems. In addition, dependence upon automated systems may further increase the risk that operational system flaws, employee tampering or manipulation of those systems will result in losses that are difficult to detect.

Our operations are also subject to the risk of cyber security attacks. Any cyber security attacks that affect our facilities, our customers or our financial data could have a material adverse effect on our business. In addition, cyber security attacks on our customer and employee data may result in financial loss or potential liability and may negatively impact our reputation. Third-party systems on which we rely could also suffer system failures, which could negatively impact our business, results of operations and financial condition.

Our sales of oil, natural gas, NGLs and other energy commodities, and related hedging activities, expose us to potential regulatory risks.

The Federal Trade Commission, the Federal Energy Regulatory Commission and the Commodity Futures Trading Commission (the "CFTC") hold statutory authority to monitor certain segments of the physical and futures energy commodities markets. These agencies have imposed broad regulations prohibiting fraud and manipulation of such markets. With regard to our physical sales of oil, natural gas, NGLs or other energy commodities, and any related hedging activities that we undertake, we are required to observe the market-related regulations enforced by these agencies, which hold substantial enforcement authority. Our sales and trading may also be subject to certain reporting and other requirements. Failure to comply with such regulations, as interpreted and enforced, could have a material adverse effect on our business, results of operations and financial condition.

The swaps-related provisions of the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Act") and the rules the CFTC has adopted regulate the markets in certain derivative transactions, broadly referred to as "swaps" and which include hedging and non-hedging oil and gas and interest rate transactions, and market participants. Swaps falling within classes designated or to be designated by the CFTC are or will be subject to clearing on a derivatives clearing organization, and, if accepted for clearing, are subject to execution on an exchange or a swap execution facility if made available for trading on such facility. To date, the CFTC has designated only certain classes of interest rate and index credit default swaps for mandatory clearing. The Act provides an exception from application of the Act's clearing and trade execution requirements that qualifying commercial end-users may elect for swaps they use to hedge or mitigate commercial risks ("End-User Exception"). Although we believe we will be able to qualify for, and have elected, the End-User Exception with respect to most, if not all, of the swaps we enter that otherwise would have to be cleared, if we cannot do so with respect to many of the swaps we enter into, our ability to execute our hedging program efficiently will be adversely affected. In addition, the CFTC and federal banking regulators have adopted rules (which are being phased in) requiring certain regulated persons to collect margin as to any uncleared swap from their counterparty to such swap if that counterparty is not a non-financial end user (as defined in such rules) Although we believe we qualify as a non-financial end user under such rules, if we do not do so and must provide margin regarding uncleared swaps to which we are a party, our results of operations and financial condition could be adversely affected.

The European Market Infrastructure Regulation ("EMIR") includes regulations related to the trading, reporting and clearing of derivatives subject to EMIR. We have counterparties that are located in a jurisdiction subject to EMIR. Such counterparties are required to comply with EMIR and accordingly will require us to transact with them in a manner that will ensure their compliance with EMIR. In broad terms, EMIR's effect on the derivatives markets and their participants, creates similar risks and could have similar adverse impacts as those under the swap regulatory provisions of the Act and the CFTC's swap rules. Finally, the Act included provisions, including related to position limits and reporting, that reflect that volatility in oil and natural gas prices is attributed by some legislators and regulators to speculative trading in derivatives and commodity instruments related to oil and natural gas. The CFTC and Congress periodically focus on such concerns, particularly at times of price rises in the market. Our revenues could be adversely affected if a consequence of that focus is legislative or regulatory actions that lead to lower commodity prices.

Current and proposed derivatives legislation and rulemaking as well as restrictions on hedging activities in our revolving credit agreement could have a material adverse effect on our business.

If we or our derivatives counterparties are subject to additional requirements imposed as a result of the Act or any new (or newly implemented) regulations or international legislation, such changes may increase our transaction costs or make it more difficult for us to enter into hedging transactions on favorable terms. Any such regulations could also subject our hedge counterparties to limits on commodity positions and thereby have an adverse effect on our ability to hedge risks associated with our business or on the cost of our hedging activity. Further, our revolving credit agreement restricts the types of counterparties that we can enter into hedging transactions with and the security that we are able to provide counterparties that are not lenders under our revolving credit facility. Our inability to enter into hedging transactions on favorable terms, or at all, could increase our operating expenses and put us at increased exposure to risks of adverse changes in oil and natural gas prices. Any of these consequences could have a material adverse effect on us, our financial condition, and our results of operations and cash flows.

Units eligible for future sale may have adverse effects on our unit price and the liquidity of the market for our units.

We cannot predict the effect of future sales of our units, or the availability of units for future sales, on the market price of or the liquidity of the market for our units. Sales of substantial amounts of units, or the perception that such sales could occur, could adversely affect the prevailing market price of our units. Such sales, or the possibility of such sales, could also make it difficult for us to sell equity securities in the future at a time and at a price that we deem appropriate. The founding investors (the "Founding Investors") and their affiliates, including members of our management, own approximately 14% of our outstanding units. We granted the Founding Investors certain registration rights to have their units registered under the Securities Act. Upon registration, these units will be eligible for sale into the market without volume limitations. Because of the substantial size of the Founding Investors' holdings, the sale of a significant portion of these units, or a perception in the market that such a sale is likely, could have a significant impact on the market price of our units.

Risks Related to our Preferred Units

Our Series A Preferred Units and Series B Preferred Units rank senior in right of payment to our units, and we are unable to make any distribution to our unitholders unless full cumulative distributions are made on our Series A Preferred Units and Series B Preferred Units.

We have issued 2,300,000 of our 8% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the "Series A Preferred Units"). We have also issued 7,200,000 of our 8.00% Series B Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the "Series B Preferred Units"). The Series A Preferred Units and Series B Preferred Units (collectively, the "Preferred Units") represent perpetual equity interests in us and rank senior in right of payment to our units. Distributions on the Preferred Units are cumulative from the date of original issue and are payable monthly on the 15th day of each month. No distribution may be declared or paid or set apart for payment on the units, or any other junior securities, unless full cumulative distributions have been or contemporaneously are being paid or provided for on all outstanding Preferred Units and any parity securities through the most recent respective distribution payment dates.

The Preferred Units are subordinated to our existing and future debt obligations, and could be diluted by the issuance of additional partnership securities, including additional preferred units, and by other transactions.

The Preferred Units are subordinated to all of our existing and future indebtedness (including indebtedness outstanding under our Revolving Credit Agreement, our Term Loan Credit Agreement and our Senior Notes). We may incur additional debt under our Revolving Credit Agreement, our Term Loan Credit Agreement or future credit facilities or by issuing additional senior or subordinated debt securities. The payment of principal and interest on our debt reduces cash available for distribution to limited partners, including the holders of Preferred Units.

The issuance of additional partnership securities pari passu with or senior to the Preferred Units would dilute the interests of the holders of the Preferred Units, and any issuance of senior securities or parity securities or additional indebtedness could affect our ability to pay distributions on, redeem or pay the liquidation preference on the Preferred Units. Only the change of control provision relating to the Preferred Units protects the holders of the Preferred Units in the event of a highly leveraged or other transaction, including a merger or the sale, lease or conveyance of all or substantially all our assets or business, which might adversely affect the holders of the Preferred Units.

Unitholders will be allocated taxable income irrespective of cash distributions received.

Although Legacy has suspended distributions to holders of the Preferred Units, such distributions continue to accrue in arrears. Pursuant to the terms of Legacy's partnership agreement, Legacy is required to pay or set aside for payment all accrued but unpaid distributions with respect to the Preferred Units prior to or contemporaneously with making any distribution with respect to Legacy's units. Accruals of distributions on the Preferred Units are treated for tax purposes as guaranteed payments for the use of capital that will generally be taxable to the holders of such Preferred Units as ordinary income even in the absence of contemporaneous distributions.

For more information regarding the effects of allocated taxable income on our unitholders and holders of our Preferred Units, please read "Tax Risks to Unitholders and Preferred Unitholders—Our unitholders may be required to pay taxes on their share of our income even if they do not receive any cash distributions from us."

Risks Related to Our Limited Partnership Structure

Our Founding Investors, including members of our management, own an approximately 14% limited partner interest in us and control our general partner, which has sole responsibility for conducting our business and managing our operations. Our general partner has conflicts of interest and limited fiduciary duties, which may permit it to favor its own interests to the detriment of our limited partners.

Our Founding Investors, including members of our management, own an approximately 14% limited partner interest in us through the ownership of units and therefore have the ability to influence the election of the members of the board of directors of our general partner. Although our general partner has a fiduciary duty to manage us in a manner beneficial to us and our limited partners, the directors and officers of our general partner have a fiduciary duty to manage our general partner in a manner beneficial to its owners, our Founding Investors and their affiliates. Conflicts of interest may arise between our Founding Investors and their affiliates, including our general partner, on the one hand, and us and our limited partners, on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of its affiliates over the interests of our limited partners. These conflicts include, among others, the following situations:

- neither our partnership agreement nor any other agreement requires our Founding Investors or their controlled affiliates, other than our executive officers, to pursue a business strategy that favors us;
- our general partner is allowed to take into account the interests of parties other than us, such as our Founding Investors, in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to our limited partners;
- our Founding Investors and their controlled affiliates (other than our executive officers and their controlled affiliates) may engage in competition with us;
- our general partner has limited its liability and reduced its fiduciary duties under our partnership agreement and has also restricted the remedies available to our limited partners for actions that, without the limitations, might constitute breaches of fiduciary duty. As a result of purchasing limited partner interests, limited partners consent to some actions and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable state law;
- our general partner determines the amount and timing of asset purchases and sales, capital expenditures, borrowings, issuance of additional partnership securities, and reserves, each of which can affect the amount of cash that is distributed to our limited partners;
- our general partner determines the amount and timing of any capital expenditures. Such determination can affect the amount of cash that is available to be distributed to our limited partners;
- our general partner determines which costs incurred by it and its affiliates are reimbursable by us;
- 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 intends to limit its liability regarding our contractual and other obligations;
- our general partner controls the enforcement of obligations owed to us by it and its affiliates; and
- our general partner decides whether to retain separate counsel, accountants, or others to perform services for us.

Our partnership agreement restricts the voting rights of those limited partners owning 20% or more of any class of limited partner interests.

Limited partners' voting rights are further restricted by the partnership agreement provision providing that any limited partner interests held by a person that owns 20% or more of any class of limited partner interest then outstanding, other than our general partner, its affiliates, their transferees, and persons who acquired such limited partner interest with the prior approval of the board of directors of our general partner, cannot vote on any matter. Our partnership agreement also contains provisions limiting the ability of limited partners to call meetings or to acquire information about our operations, as well as other provisions limiting the limited partners' ability to influence the manner or direction of management.

Our Founding Investors and their controlled affiliates (other than our general partner and executive officers and their controlled affiliates) may compete directly with us.

Our Founding Investors and their controlled affiliates, other than our general partner and our executive officers and their controlled affiliates, are not prohibited from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, our Founding Investors or their controlled affiliates, other than our general partner and our executive officers and their controlled affiliates, may acquire, develop and operate oil and natural gas properties or other assets in the future, without any obligation to offer us the opportunity to acquire, develop or operate those assets.

Our partnership agreement limits our general partner's fiduciary duties to our limited partners and restricts the remedies available to limited partners for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that reduce the standards to which our general partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement:

- permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner;
- provides that our general partner will not have any liability to us or our limited partners 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;
- provides that our general partner is entitled to make other decisions in "good faith" if it believes that the decision is in our best interest;
- provides generally that affiliated transactions and resolutions of conflicts of interest not approved by the conflicts committee of the board of directors of our general partner and not involving a vote of limited partners must be on terms no less favorable to us than those generally being provided to or available from unrelated third parties or 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.

Our partnership agreement permits our general partner to redeem any partnership interests held by a limited partner who is a non-citizen assignee.

If we are or become subject to federal, state or local laws or regulations that, in the reasonable determination of our general partner, create a substantial risk of cancellation or forfeiture of any property that we have an interest in because of the nationality, citizenship or other related status of any limited partner, our general partner may redeem the partnership interest held by the limited partner at their current market price. In order to avoid any cancellation or forfeiture, our general partner may require each limited partner to furnish information about his nationality, citizenship or related status. If a limited partner fails to furnish information about his nationality, citizenship or other related status within 30 days after a request for the information or our general partner determines after receipt of the information that the limited partner is not an eligible citizen, our general partner may elect to treat the limited partner as a non-citizen assignee. A non-citizen assignee is entitled to an interest equivalent to that of a limited partner for the right to share in allocations and distributions from us, including liquidating distributions. A non-citizen assignee does not have the right to direct the voting of his partnership interests and may not receive distributions in kind upon our liquidation.

We may issue an unlimited number of additional units or other equity securities without the approval of our unitholders, which would dilute their existing ownership interest in us.

Our general partner, without the approval of our unitholders, may cause us to issue an unlimited number of additional units or other equity securities. The issuance by us of additional units or other equity securities of equal or senior rank will have the following effects:

- our limited partners' proportionate ownership interests in us will decrease;
- the amount of cash available for distribution on each unit may decrease;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the units may decline.

The liability of our limited partners may not be limited if a court finds that limited partner 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. In some states, including Delaware, a limited partner is only liable if he participates in the "control" of the business of the partnership. These statutes generally do not define control, but do permit limited partners to engage in certain activities, including, among other actions, taking any action with respect to the dissolution of the partnership, the sale, exchange, lease or mortgage of any asset of the partnership, the admission or removal of the general partner and the amendment of the partnership agreement. Our limited partners could, however, be liable for any and all of our obligations as if our limited partners 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
- our limited partners' right to act with other limited partners to take other actions under our partnership agreement constitutes "control" of our business.

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

Under certain circumstances, limited partners 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 our limited partners 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 distribution, limited partners who received an impermissible 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 transferring limited partner to make contributions to the partnership that are known to such substitute 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.

We have reported negative limited partners' equity on a GAAP basis, which may have an impact on investors' perceptions of the value of Legacy and our units and preferred units.

As of December 31, 2017, we reported on a GAAP basis a deficit in limited partners' equity. Since we have historically distributed all of our available cash to our limited partners, we have not retained earnings on our balance sheet. Volatility in our asset values and impairment of our long-lived assets have caused our limited partners' equity to be negative on a GAAP basis and may cause our limited partners' equity to remain negative in future periods, which may adversely impact investors' perceptions of the value of our units and preferred units.

Tax Risks to Unitholders and Preferred Unitholders

Our unitholders may be required to pay taxes on their share of our income even if they do not receive any cash distributions from us.

As partners in a partnership, unitholders are allocated a share of taxable income irrespective of the amount of cash, if any, distributed by us to the unitholders. Taxable income in a given period to a unitholder may include of ordinary income from cancellation of our debt and capital gain upon our disposition of properties and the tax allocation of our taxable income may require the payment of U.S. federal income taxes and, in some cases, state and local income taxes by our unitholders. As of January 21, 2016, we have suspended all cash distributions to unitholders and monthly cash distributions to holders of our preferred units. We may engage in transactions to de-lever the Partnership and manage our liquidity that may result in income and gain to our unitholders. For example, if we sell assets and use the proceeds to repay existing debt or fund capital or operating expenditures, our unitholders may be allocated taxable income and gain resulting from the sale without receiving a cash distribution. Further, if we engage in debt exchanges, debt repurchases, or modifications of our existing debt, these or similar transactions could result in "cancellation of indebtedness" or COD income being allocated to our unitholders as taxable income. For tax purposes, we repurchased $187 million of our 6.625% Senior Notes at $0.70 per $1.00 principal amount on December 31, 2017. Unitholders may be allocated gain and income from asset sales and COD income and may owe income tax as a result of such allocations notwithstanding the fact that we have currently suspended cash distributions to our unitholders. The ultimate effect of any such allocations will depend on the unitholder's individual tax position with respect to its units. Unitholders are encouraged to consult their tax advisors with respect to the consequences of potential transactions that may result in income and gain to unitholders.

Our tax treatment depends on our status as a partnership for U.S. federal income tax purposes, as well as our not being subject to a material amount of additional entity-level taxation by states and localities. If the Internal Revenue Service ("IRS") were to treat us as a corporation or if we were to become subject to a material amount of additional entity-level taxation for state or local tax purposes, then our cash available for distribution to our limited partners, if any, would be substantially reduced.

The anticipated after-tax economic benefit of an investment in us depends largely on our being treated as a partnership for U.S. federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this or any other tax matter affecting us.

Despite the fact that we are a limited partnership under Delaware law, we would be treated as a corporation for U.S. federal income tax purposes unless we satisfy a "qualifying income" requirement. Based upon our current operations, we believe we satisfy the qualifying income requirement. Failing to meet the qualifying income requirement or a change in our business or a change in current law could cause us to be treated as a corporation for U.S. federal income tax purposes or otherwise subject us to taxation as an entity. If we were treated as a corporation for U.S. federal income tax purposes, we would pay U.S. federal income tax on our taxable income at the corporate tax rate, and would likely pay state and local income tax at varying rates. Distributions to our limited partners who are treated as holders of corporate stock would generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits would flow through to our limited partners. Because a tax would be imposed upon us as a corporation, our cash available to pay distributions to our limited partners would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to our limited partners likely causing a substantial reduction in the value of our limited partner interests.

In addition, changes in current state law may subject us to entity-level taxation by individual states. Because of widespread state budget deficits and other reasons, several states have been evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. For example, we are and have been subject to an entity-level state tax on the portion of our gross income that is apportioned to Texas, and imposition of any similar taxes by any other state may further reduce the cash available for distribution, if any, to our limited partners.

Our partnership agreement provides that if a law is enacted or an existing law is modified or interpreted in a manner that subjects us to additional amounts of entity-level taxation for U.S. federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.

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

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. For example, from time to time, members of Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships or an investment in our limited partner interests. Further, final Treasury regulations under Section 7704(d)(1)(E) of the Internal Revenue Code recently published in the Federal Register interpret the scope of the qualifying income requirements for publicly traded partnerships by providing industry-specific guidance. We do not believe the final regulations affect our ability to be treated as a partnership for U.S. federal income tax purposes.

In addition, the Tax Cuts and Jobs Act (the “TCJA”) enacted December 22, 2017, makes significant changes to the federal income tax rules applicable to both individuals and entities, including changes to the tax rate on an individual or other non-corporate unitholder’s allocable share of certain income from a publicly traded partnership. The TCJA is complex and lacks administrative guidance, thus, the impact of certain aspects of its provisions on us or an investment in our common units is currently unclear. Unitholders should consult their tax advisor regarding the TCJA and its effect on an investment in our common units.

Any modification to the federal income tax laws and interpretations thereof (including administrative guidance relating to the TCJA) 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 federal income tax purposes or otherwise adversely affect us. We are unable to predict whether any changes or other proposals will ultimately be enacted, including as a result of fundamental tax reform. Any such changes could negatively impact the value of an investment in our units.

Certain federal income tax deductions currently available with respect to oil and natural gas drilling and development may be eliminated as a result of future legislation.

From time to time, members of Congress propose changes that would, if enacted into law, make significant changes to United States tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. The passage of any legislation with changing U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such change could increase the taxable income allocable to our unitholders and negatively impact the value of an investment in our limited partner interests.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. Although final Treasury regulations allow publicly traded partnerships to use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders, such tax items must be prorated on a daily basis and these regulations do not specifically authorize all aspects of the proration method we have adopted. Accordingly, our counsel is unable to opine as to the validity of this method. If the IRS were to successfully challenge this method or new Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A successful IRS contest of the U.S. federal income tax positions we take may adversely affect the market for our units and preferred units and the costs of any contest will reduce our cash available for distribution to our limited partners.

We have not requested any ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from our counsel's conclusions or the positions we take. 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 disagree with some or all of our counsel's conclusions or the positions we take. Any contest with the IRS may materially and adversely impact the market for our limited partner interests and the price at which they trade. In addition, the costs of any contest with the IRS will result in a reduction in cash available to pay distributions to our limited partners and thus will be borne indirectly by our limited partners.

If the IRS makes audit adjustments to our income tax returns for tax years beginning after December 31, 2017, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us, in which case we may either pay the taxes directly to the IRS or elect to have our unitholders and former unitholders take such audit adjustment into account and pay any resulting taxes. If we bear such payment our cash available for distribution to our unitholders might be substantially reduced.

Pursuant to the Bipartisan Budget Act of 2015, for tax years beginning after December 31, 2017, if the IRS makes audit adjustments to our income tax returns, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us. To the extent possible under the new rules, our general partner may either pay the taxes (including any applicable penalties and interest) directly to the IRS or, if we are eligible, elect to issue a revised Schedule K-1 to each unitholder with respect to an audited and adjusted return. Although our general partner may elect to have our unitholders and former unitholders take such audit adjustment into account and pay any resulting taxes (including applicable penalties or interest) in accordance with their interests in us during the tax year under audit, there can be no assurance that such election will be practical, permissible or effective in all circumstances. As a result, our current unitholders may bear some or all of the tax liability resulting from such audit adjustment, even if such unitholders did not own common units in us during the tax year under audit. If, as a result of any such audit adjustment, we are required to make payments of taxes, penalties and interest, our cash available for distribution to our unitholders might be substantially reduced.

Unitholders may be subject to limitations on their ability to deduct interest expense incurred by us.

In general, we are entitled to a deduction for interest paid or accrued on indebtedness properly allocable to our trade or business during our taxable year. However, under the TCJA, for taxable years beginning after December 31, 2017, our deduction for "business interest" is limited to the sum of our business interest income plus 30% of our "adjusted taxable income." For the purposes of this limitation, our adjusted taxable income is computed without regard to any business interest expense or business interest income, and in the case of taxable years beginning before January 1, 2022, any deduction allowable for depreciation, amortization, or depletion. Any interest disallowed may be carried forward and deducted in future years by the unitholder from his share of our "excess taxable income," which is generally equal to the excess of 30% of our adjusted taxable income over the amount of our deduction for business interest for such future taxable year, subject to certain restrictions.

Tax-exempt entities face unique tax issues from owning units that may result in adverse tax consequences to them.

Investment in our units by tax-exempt entities, including employee benefit plans and individual retirement accounts (known as IRAs), and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations exempt from U.S. federal income tax, including individual retirement accounts and other retirement plans, will be unrelated business taxable income and will be taxable to such a unitholder. Further, with respect to taxable years beginning after December 31, 2017, a tax-exempt entity with more than one unrelated trade or business (including by attribution from investment in a partnership such as ours that is engaged in one or more unrelated trade or business) is required to compute the unrelated business taxable income of such tax-exempt entity separately with respect to each such trade or business (including for purposes of determining any net operating loss deduction). As a result, for years beginning after December 31, 2017, it may not be possible for tax-exempt entities to utilize losses from an investment in our partnership to offset unrelated business taxable income from another unrelated trade or business and vice versa. Tax-exempt entities should consult a tax advisor before investing in our common units.

Non-U.S. unitholders will be subject to U.S. taxes and withholding with respect to their income and gain from owning our common units.

Non-U.S. unitholders are generally taxed and subject to income tax filing requirements by the United States on income effectively connected with a U.S. trade or business ("effectively connected income"). A unitholder's share of our income, gain, loss and deduction, and any gain from the sale or disposition of our common units will generally be considered to be "effectively connected" with a U.S. trade or business and subject to U.S. federal income tax. Additionally, distributions to a Non-U.S. unitholder will be subject to withholding at the highest applicable effective tax rate.

The TCJA imposes a withholding obligation of 10% of the amount realized upon a Non-U.S. unitholder's sale or disposition of common units. The IRS has temporarily suspended the application of the withholding requirements on sales of publicly traded interests, including our common units, pending promulgation of regulations or other guidance. It is not clear if or when such regulations or other guidance will be issued. Non-U.S. unitholders should consult a tax advisor before investing in our common units.

Tax gain or loss on the disposition of our common units could be more or less than expected because prior distributions in excess of allocations of income will decrease our unitholders tax basis in their common units.

If our unitholders sell any of their common units, they will recognize gain or loss equal to the difference between the amount realized and their tax basis in those units. Prior distributions to our unitholders in excess of the total net taxable income they were allocated for a unit, which decreased their tax basis in that unit, will, in effect, become taxable income to our unitholders if the unit is sold at a price greater than their tax basis in that unit, even if the price our unitholders receive is less than their original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income to our unitholders due to the potential recapture items, including depreciation, depletion and intangible drilling cost recapture. In addition, because the amount realized may include a unitholder's share of our nonrecourse liabilities, if they sell their units, they may incur a tax liability in excess of the amount of cash they receive from the sale.

We will treat each purchaser of our common units as having the same tax benefits without regard to the 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, we will adopt depletion, depreciation and amortization positions that may not conform with all aspects of existing Treasury regulations. Our counsel is unable to opine as to the validity of such filing positions. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain on the sale of units and could have a negative impact on the value of our units or result in audits of and adjustments to our unitholders' tax returns.

A limited partner whose limited partner interests are the subject of a securities loan (e.g. a loan to a "short seller" to cover a short sale of limited partner interests) may be considered as having disposed of those limited partner interests. If so, the limited partner would no longer be treated for tax purposes as a partner with respect to those limited partner interests during the period of the loan and may recognize gain or loss from the disposition.

Because there are no specific rules governing the U.S. federal income tax consequence of loaning a partnership interest, a limited partner whose limited partner interests are the subject of a securities loan may be considered as having disposed of the loaned limited partner interests, he may no longer be treated for tax purposes as a partner with respect to those limited partner interests during the period of the loan and the limited partner may recognize gain or loss from such disposition. Moreover, during the period of the loan, any of our income, gain, loss or deduction with respect to those limited partner interests may not be reportable by the limited partner and any cash distributions received by the limited partner as to those limited partner interests could be fully taxable as ordinary income. Our counsel has not rendered an opinion regarding the treatment of a limited partner whose limited partner interests are the subject of a securities loan; therefore, limited partners desiring to assure their status as partners and avoid the risk of gain recognition from a securities loan are urged to consult with their tax advisor about whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from borrowing and loaning their limited partner interests.

Our limited partners may be subject to state and local taxes and return filing requirements in states where they do not live as a result of investing in our limited partner interests.

In addition to U.S. federal income taxes, our limited partners will likely be subject to other taxes, including state and local income 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 now or in the future, even if they do not reside in any of those jurisdictions. Our limited partners 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 various jurisdictions. Further, our limited partners may be subject to penalties for failure to comply with those requirements. As we make acquisitions or expand our business, we may do business or own assets in additional states or foreign countries that impose a personal income tax or an entity level tax. It is the responsibility of each limited partner to file all United States federal, foreign, state and local tax returns that may be required of such limited partner. Our counsel has not rendered an opinion on the foreign, state or local tax consequences of an investment in our limited partner interests.

We have adopted certain valuation methodologies in determining a unitholder's allocations of income, gain, loss and deduction. The IRS may challenge these methodologies or the resulting allocations, and such a challenge could adversely affect the value of our units.

In determining the items of income, gain, loss and deduction allocable to our unitholders, we must routinely determine the fair market value of our assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we make many fair market value estimates ourselves using a methodology based on the market value of our units as a means to determine the fair market value of our assets. The IRS may challenge these valuation methods and the resulting allocations of income, gain, loss and deduction.

A successful IRS challenge to these methods or allocations could adversely affect the timing or amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders' sale of units and could have a negative impact on the value of the units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

Treatment of distributions on our preferred units as guaranteed payments for the use of capital creates a different tax treatment for the holders of our preferred units than the holders of our units and such distributions may not be eligible for the 20% deduction for qualified publicly traded partnership income.

The tax treatment of distributions on our preferred units is uncertain. We treat the holders of our preferred units as partners for tax purposes and treat distributions on the preferred units as guaranteed payments for the use of capital that are generally taxable to the holders of our preferred units as ordinary income. A holder of our preferred units will recognize taxable income in the amount of the accrual of such a guaranteed payment even in the absence of a contemporaneous distribution. As of January 21, 2016, we have suspended all monthly cash distributions to holders of our preferred units. Otherwise, the holders of our preferred units are generally not anticipated to share in our items of income, gain, loss or deduction. Nor will we allocate any share of our nonrecourse liabilities to the holders of our preferred units. If the preferred units were treated as indebtedness for tax purposes, rather than as guaranteed payments for the use of capital, distributions likely would be treated as payments of interest by us to the holders of the preferred units.

The Tax Cuts and Jobs Act allows individuals and other non-corporate owners of interests in a publicly traded partnership to take a deduction equal to 20% of their allocable share of qualified publicly traded partnership income. Although we expect that much of the income we earn is generally eligible for the 20% deduction for qualified publicly traded partnership income, it is uncertain whether a guaranteed payment for the use of capital may constitute an allocable or distributive share of such income. As a result the guaranteed payment for use of capital received by the holders of our preferred units may not be eligible for the 20% deduction for qualified publicly traded partnership income. A holder of our preferred units will be required to recognize gain or loss on a sale of units equal to the difference between such holder's amount realized and tax basis in the preferred units sold. The amount realized generally will equal the sum of the cash and the fair market value of other property such holder receives in exchange for such preferred units. Subject, in certain circumstances, to rules requiring a blended basis among multiple partnership interests, the tax basis of a preferred unit will generally be equal to the sum of the cash and the fair market value of other property paid by the holder of the preferred unit to acquire such preferred unit. Gain or loss recognized by a holder of our preferred units on the sale or exchange of a preferred unit held for more than one year generally will be taxable as long-term capital gain or loss. Because holders of our preferred units will not be allocated a share of our items of depreciation, depletion or amortization, it is not anticipated that such holders would be required to recharacterize any portion of their gain as ordinary income as a result of the recapture rules.

Investment in our preferred units by tax-exempt investors, such as employee benefit plans and individual retirement accounts, and non-U.S. persons raises issues unique to them. A non-U.S. holder's income from guaranteed payments and any gain from the sale or disposition of our preferred units will generally be considered to be effectively connected income and subject to U.S. federal income tax. Distributions to non-U.S. holders of our preferred units will be subject to withholding taxes imposed at the highest effective tax rate applicable to such non-U.S. holders. If the amount of withholding exceeds the amount of U.S. federal income tax actually due, non-U.S. holders may be required to file U.S. federal income tax returns in order to seek a refund of such excess. The Tax Cuts and Jobs Act imposes a withholding obligation of 10% of the amount realized upon a non-U.S. unitholder's sale or disposition of preferred units. The IRS has temporarily suspended the application of the withholding requirements on sales of publicly traded interests in partnerships pending promulgation of Treasury regulations or other guidance. It is not clear if or when such Treasury regulations or other guidance will be issued.

Additionally, the treatment of guaranteed payments for the use of capital to tax-exempt investors is not certain. Holders of our preferred units should consult their tax advisor with respect to the tax consequences of owning our preferred units.

ITEM 1B. *UNRESOLVED STAFF COMMENTS*

None.

ITEM 2. *PROPERTIES*

As of December 31, 2017, we owned interests in producing oil and natural gas properties in 606 fields in the Permian Basin, East Texas, Piceance Basin of Colorado, Texas Panhandle, Wyoming, North Dakota, Montana, Oklahoma and several other states, from 10,492 gross productive wells of which 3,497 are operated and 6,995 are non-operated. The following table sets forth information about our proved oil and natural gas reserves as of December 31, 2017. The standardized measure amounts shown in the table are not intended to represent the current market value of our estimated oil and natural gas reserves. For a definition of "standardized measure," please see the glossary of terms at the beginning of this annual report on Form 10-K.

	As of December 31, 2017				
	Proved Reserves			Standardized Measure	
Field or Region	MMBoe	R/P (a)	% Oil and NGLs	Amount (b)	% of Total
				($ in Millions)	
Spraberry Field	19.2	7.1	76%	$ 289.9	25%
East Texas (c)	57.0	12.9	—	195.2	17
Lea Field	10.6	6.9	78	166.4	14
Piceance Basin (d)	44.6	10.7	13	133.4	11
Total — Top 4	131.4	10.2	22%	$ 784.9	67%
All others	48.6	9.5	66	387.2	33
Total	180.0	10.0	34%	$1,172.1	100%

(a) Reserves as of December 31, 2017 divided by annualized fourth quarter production volumes.

(b) Texas margin taxes and the federal income taxes associated with a corporate subsidiary have not been deducted from future production revenues in the calculation of the standardized measure as the impact of these taxes would not have a significant effect on the calculated standardized measure.

(c) As East Texas contains 57.0 MMBoe, or 31.7% of total proved reserves of 180.0 MMBoe, the following table presents the production, by product, for East Texas for 2017, 2016 and 2015.

	Year Ended December 31,		
	2017	2016	2015
	(In thousands, except daily production)		
Oil (MBbls)	15	17	4
Natural gas liquids (Mgal)	1,139	1,117	13
Natural gas (MMcf)	27,737	30,315	12,548
Total (Mboe)	4,665	5,097	2,096
Average daily production (Boe per day)*	12,781	13,926	13,610

* Calculated using 154 days for the year ended December 31, 2015, the number of days between the closing date of the assets acquired from Anadarko E&P Onshore LLC and December 31, 2015.

(d) As the Piceance Basin contains 44.6 MMBoe, or 24.8% of total proved reserves of 180.0 MMBoe, the following table presents the production, by product, for the Piceance Basin for 2017, 2016 and 2015.

	Year Ended December 31,		
	2017	2016	2015
	(In thousands, except daily production)		
Oil (MBbls)	48	52	46
Natural gas liquids (Mgal)	22,110	22,288	24,448
Natural gas (MMcf)	22,065	24,206	23,639
Total (Mboe)	4,252	4,617	4,568
Average daily production (Boe per day)	11,649	12,615	12,515

Summary of Oil and Natural Gas Properties and Projects

Our most significant fields and regions are Spraberry, East Texas, Lea and Piceance Basin. As of December 31, 2017, these four areas accounted for approximately 67% of our standardized measure and 73% of our total estimated proved reserves.

Spraberry Field. The Spraberry field is located in Andrews, Howard, Midland, Martin, Reagan and Upton Counties, Texas. This Spraberry field summary includes wells in the War San field which produce from the same formations and in the same area as our Spraberry field wells. This field produces from Spraberry and Wolfcamp age formations from 5,000 to 11,000 feet. We operate 193 active wells (187 producing, 6 injecting) in this field with working interests ranging from 12.9% to 100% and net revenue interests ranging from 9.6% to 90.8%. We also own another 169 non-operated wells (165 producing, 4 injecting). As of December 31, 2017, our properties in the Spraberry field contained 19.2 MMBoe (76% liquids) of net proved reserves with a standardized measure of $289.9 million. The average net daily production from this field was 7,365 Boe/d for the fourth quarter of 2017. The estimated reserve life (R/P) for this field is 7.1 years based on the annualized fourth quarter production rate.

20 wells were drilled on our properties in the Spraberry field in 2017. We have identified six more proved undeveloped projects, four of which are horizontal Wolfcamp or horizontal Spraberry locations and the remainder are primarily 40-acre infill drilling locations, and three behind-pipe or proved developed non-producing recompletion projects in this field. We have also identified numerous unproved drilling locations in this field.

East Texas. Legacy's wells in the East Texas basin are primarily located in Freestone, Leon and Robertson Counties, Texas. The wells in our East Texas fields are produced from multiple fields and formations which primarily include the Bossier and Cotton Valley formations at depths of approximately 12,000 to 14,000 feet. Legacy operates 911 active wells (905 producing, 6 injecting) in East Texas with working interests ranging from 19.2% to 100% and net revenue interests ranging from 3.2% to 87.5%. We also own another 545 non-operated wells (527 producing, 18 injecting). As of December 31, 2017, our properties in East Texas contained 57.0 MMBoe of net proved reserves with a standardized measure of $195.2 million. The average net daily production from this field was 12,128 Boe/d for the fourth quarter of 2017. The estimated reserve life (R/P) for this field is 12.9 years based on the annualized fourth quarter production rate.

Lea Field. The Lea field is located in Lea County, New Mexico. Our Lea field properties consist primarily of interests in the Lea Unit. The majority of the production from these properties is from the Bone Spring formation at depths of 9,500 feet to 11,500 feet. These properties also produce from the Morrow, Devonian, Delaware and Pennsylvania formations at depths ranging from 6,500 feet to 14,500 feet. We operate 36 wells (35 producing, 1 injecting) in the Lea Field with working interests ranging from 2.4% to 91.3% and net revenue interests ranging from 4.1% to 75.9%. As of December 31, 2017, our properties in the Lea Field contained 10.6 MMBoe (78% liquids) of net proved reserves with a standardized measure of $166.4 million. The average net daily production from this field was 4,205 Boe/d for the fourth quarter of 2017. The estimated reserve life (R/P) of the field is 6.9 years based on the annualized fourth quarter production rate.

10 wells were drilled on our properties in the Lea field in 2017. Our engineers have identified nine additional proved undeveloped horizontal Bone Spring drilling locations and two behind-pipe or proved developed non-producing recompletion projects in this field. We have also identified numerous unproved horizontal drilling locations in this field.

Piceance Basin. Legacy's wells in the Piceance Basin are located in Garfield County, Colorado in the Grand Valley, Parachute and Rulison fields. Most of the wells in these fields produce from the Williams Fork formation at depths of approximately 7,000 to 9,000 feet and some wells produce from the Wasatch formation at depths of 1,600 to 4,000 feet. Legacy's ownership in this basin is comprised of non-operated interests in 2,676 active wells acquired in 2014 (the "Piceance Acquisition"). As of December 31, 2017, our properties in the Piceance Basin contained 44.6 MMBoe (13% liquids) of net proved reserves with a standardized measure of $133.4 million. The average net daily production from this field was 11,464 Boe/d for the fourth quarter of 2017. The estimated reserve life (R/P) for this field is 10.7 years based on the annualized fourth quarter production rate.

Proved Reserves

The following table sets forth a summary of information related to our estimated net proved reserves as of the dates indicated based on reserve reports prepared by LaRoche Petroleum Consultants, Ltd. (“LaRoche”). The estimates of net proved reserves have not been filed with or included in reports to any federal authority or agency. Standardized measure amounts shown in the table are not intended to represent the current market value of our estimated oil and natural gas reserves.

The following information represents estimates of our proved reserves as of December 31, 2017, 2016 and 2015. These reserve estimates have been prepared in compliance with the SEC rules and accounting standards using current costs and the average annual prices based on the unweighted arithmetic average of the first-day-of-the-month price for each month in the years ended December 31, 2017, 2016 and 2015. As a result of this methodology, we used an average WTI posted price of $47.79 per Bbl for oil and an average Platts’ Henry Hub natural gas price of $2.98 per MMBtu to calculate our estimate of proved reserves as of December 31, 2017. Please see the table below.

	As of December 31,		
	2017	2016	2015
Reserve Data:			
Estimated net proved reserves:			
Oil (MMBbls)	51.1	32.5	36.1
Natural Gas Liquids (MMBbls)	9.5	7.8	7.8
Natural Gas (Bcf)	716.1	627.0	721.6
Total (MMBoe)	180.0	144.8	164.2
Proved developed reserves (MMBoe)	172.0	139.2	161.7
Proved undeveloped reserves (MMBoe)	8.0	5.6	2.5
Proved developed reserves as a percentage of total proved reserves	96%	96%	98%
Standardized measure (in millions)(a)	$1,172.1	$ 575.6	$ 694.9
Oil and Natural Gas Prices(b)			
Oil - WTI per Bbl	$ 47.79	$ 39.25	$ 46.79
Natural gas - Henry Hub per MMBtu	$ 2.98	$ 2.48	$ 2.59

(a) Standardized measure is the present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with assumptions required by the FASB and the SEC (using current costs and the average annual prices based on the unweighted arithmetic average of the first-day-of-the-month price) without giving effect to non-property related expenses such as general administrative expenses and debt service or to depletion, depreciation and amortization and discounted using an annual discount rate of 10%. For the purpose of calculating the standardized measure, the costs and prices are unescalated. Federal income taxes have not been deducted from future production revenues in the calculation of standardized measure as each partner is separately taxed on its share of Legacy’s taxable income. In addition, Texas margin taxes and the federal income taxes associated with a corporate subsidiary have not been deducted from future production revenues in the calculation of the standardized measure as the impact of these taxes would not have a significant effect on the calculated standardized measure. Standardized measure does not give effect to derivative transactions. For a description of our derivative transactions, please read “Management’s Discussion and Analysis of Financial Condition and Results of Operation—Investing Activities.” Oil and natural gas prices as of each date are based on the unweighted arithmetic average of the first-day-of-the-month price for each month as posted by Plains Marketing L.P. and Platts Gas Daily for oil and natural gas, respectively, with these representative prices adjusted by property to arrive at the appropriate net sales price, which is held constant over the economic life of the property.

(b) Oil and natural gas prices as of each date are based on the unweighted arithmetic average of the first day of the month price for each month as posted by Plains Marketing L.P. and Platts Gas Daily for oil and natural gas, respectively, with these representative prices adjusted by property to arrive at the appropriate net sales price, which is held constant over the economic life of the property.

Proved developed reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are reserves that are expected to be recovered from new wells on undrilled acreage for which the existence and recoverability of such reserves can be estimated with reasonable certainty, or from existing wells on which a relatively major expenditure is required for recompletion.

The data in the above table represents estimates only. Oil and natural gas reserve engineering is inherently a subjective process of estimating underground accumulations of oil and natural gas 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 and natural gas that are ultimately recovered. Please read "Risk Factors—Risks Related to our Business—Our estimated reserves are based on many assumptions that may prove inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves." Future prices received for production and costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. Standardized measure amounts shown above should not be construed as the current market value of our estimated oil and natural gas reserves. The 10% discount factor used to calculate standardized measure, which is required by FASB 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.

From time to time, we engage LaRoche to prepare a reserve and economic evaluation of properties that we are considering purchasing. Neither LaRoche nor any of its employees have any interest in those properties, and the compensation for these engagements is not contingent on their estimates of reserves and future net revenues for the subject properties. During 2017, 2016 and 2015, we paid LaRoche approximately $314,186, $395,740 and $621,822, respectively, for such reserve and economic evaluations as well as its annual reserve report.

Internal Control Over Reserve Estimations

Legacy's proved reserves are estimated at the well or unit level and compiled for reporting purposes by Legacy's reservoir engineering staff, none of whom are members of Legacy's operating teams nor are they managed by members of Legacy's operating teams. Legacy maintains internal evaluations of its reserves in a secure engineering database. Legacy's reservoir engineering staff meets with LaRoche periodically throughout the year to discuss assumptions and methods used in the reserve estimation process. Legacy provides LaRoche information on all properties acquired during the year for addition to Legacy's reserve report. LaRoche updates production data from public sources and then modifies production forecasts for all properties as necessary. Legacy provides to LaRoche lease operating statement data at the property level from Legacy's accounting system for estimation of each property's operating expenses, price differentials, gas shrinkage and NGL yield. Legacy's reserve engineering staff provides all changes to Legacy's ownership interests in the properties to LaRoche for input into the reserve report. Legacy provides information on all capital projects completed during the year as well as changes in the expected timing of future capital projects. Legacy provides updated capital project cost estimates and abandonment cost and salvage value estimates. Legacy's internal engineering staff coordinates with Legacy's accounting and other departments and works closely with LaRoche to ensure the integrity, accuracy and timeliness of data that is furnished to LaRoche for its reserve estimation process. All of the reserve information in Legacy's secure reserve engineering data base is provided to LaRoche. After evaluating and inputting all information provided by Legacy, LaRoche, as independent third-party petroleum engineers, provides Legacy with a preliminary reserve report which Legacy's engineering staff and its Chief Financial Officer review for accuracy and completeness with an emphasis on ownership interest, capital spending and timing, expense estimates and production curves. After considering comments provided by Legacy, LaRoche completes and publishes the final reserve report. Legacy's engineering staff, in coordination with Legacy's accounting department and its Chief Financial Officer, ensure that the information derived from LaRoche's reports is properly disclosed in our filings.

Legacy's Corporate Planning Manager is the reservoir engineer primarily responsible for overseeing the preparation of reserve estimates by the third-party engineering firm, LaRoche. He has held a wide variety of technical and supervisory positions during a 40-year career with four publicly traded oil and natural gas producing companies, including Legacy. He has over 30 years of SEC reserve report preparation experience in addition to continuing education courses on reserve estimation and reporting, including one in 2009 covering the effect of the SEC's Final Rule, *Modernization of Oil and Gas Reporting*. For the professional qualifications of the primary person responsible for the third-party reserve evaluation, please see the last paragraph of Exhibit 99.1 - Summary Reserve Report from LaRoche Petroleum Consultants, Ltd.

Production and Price History

The following table sets forth a summary of unaudited information with respect to our production and sales of oil and natural gas for the years ended December 31, 2017, 2016 and 2015:

	Year Ended December 31,		
	2017(a)	2016	2015(b)
Production:			
Oil (MBbls)	5,032	4,019	4,608
Natural gas liquids (MGal)	38,159	36,757	42,210
Gas (MMcf)	62,833	66,824	50,687
Total (MBoe)	16,413	16,032	14,061
Average daily production (Boe per day)	44,967	43,803	38,523
Average sales price per unit (excluding commodity derivative cash settlements):			
Oil (per Bbl)	$ 47.59	$ 37.95	$ 43.37
NGL (per Gal)	$ 0.65	$ 0.42	$ 0.39
Gas (per Mcf)	$ 2.74	$ 2.19	$ 2.41
Combined (per Boe)	$ 26.58	$ 19.61	$ 24.09
Average sales price per unit (including commodity derivative cash settlements):			
Oil (per Bbl)	$ 49.94	$ 47.27	$ 63.32
NGL (per Gal)	$ 0.65	$ 0.42	$ 0.39
Gas (per Mcf)	$ 2.93	$ 2.60	$ 3.22
Combined (per Boe)	$ 28.05	$ 23.63	$ 33.55
Average unit costs per Boe:			
Production costs, excluding production and other taxes	$ 10.58	$ 10.59	$ 13.03
Ad valorem taxes	$ 0.59	$ 0.60	$ 0.81
Production and other taxes	$ 1.21	$ 0.89	$ 1.17
General and administrative, excluding transaction costs and LTIP	$ 2.07	$ 1.95	$ 2.20
Total general and administrative	$ 3.01	$ 2.72	$ 3.31
Depletion, depreciation and amortization	$ 7.73	$ 9.38	$ 12.61

(a) Includes the production and operating results of the properties acquired as a part of our asset acquisition in conjunction with the Acceleration Payment from the closing date on August 1, 2017 through December 31, 2017.

(b) Includes the production and operating results of the properties acquired as a part of our acquisition of both 100% of the issued and outstanding limited liability company membership interests in Dew Gathering LLC from WGR Operating LP and various oil and natural gas properties and associated exploration and production assets from Anadarko E&P Onshore LLC (collectively, the "Anadarko Acquisitions") from the closing date on July 31, 2015 through December 31, 2015.

Productive Wells

The following table sets forth information at December 31, 2017 relating to the productive wells in which we owned a working interest as of that date. 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 producing wells in which we own an interest, and net wells are the product of our fractional working interests owned in gross wells.

	Oil		Natural Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
Operated	2,205	1,678	1,292	1,134	3,497	2,812
Non-operated	2,819	264	4,176	1,230	6,995	1,494
Total	5,024	1,942	5,468	2,364	10,492	4,306

Developed and Undeveloped Acreage

The following table sets forth information as of December 31, 2017 relating to our leasehold acreage.

	Developed Acreage(a)		Undeveloped Acreage(b)		Total Acreage	
	Gross(c)	Net(d)	Gross(c)	Net(d)	Gross(c)	Net(d)
Total	1,004,500	483,497	190,251	54,119	1,194,751	537,616

(a) Developed acres are acres spaced or assigned to productive wells or wells capable of production.

(b) Undeveloped acres include acres held by production but not currently allocated or assigned to producing wells or wells capable of production and acres not held by production and subject to the primary term of the leases, regardless of whether such acreage contains proved reserves. The majority of our proved undeveloped locations are located on acreage currently held by production. As the economic viability of any potential oil and natural gas development related to the acres not held by production is remote, we have assigned minimal value to our acreage not held by production and thus the minimum remaining term of those leases is immaterial to us.

(c) A gross acre is an acre in which we own a working interest. The number of gross acres is the total number of acres in which we own a working interest.

(d) A net acre is deemed to exist when the sum of the fractional ownership working interests in gross acres equals one. The number of net acres is the product of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

Drilling Activity

The following table sets forth information with respect to wells completed by Legacy during the years ended December 31, 2017, 2016 and 2015. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the numbers of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that produce commercial quantities of oil and natural gas, regardless of whether they produce a reasonable rate of return.

	Year Ended December 31,		
	2017	2016	2015
Gross:			
Development			
Productive	42	12	14
Dry	—	—	—
Total	42	12	14
Exploratory			
Productive	—	—	—
Dry	—	—	—
Total	—	—	—
Net:			
Development			
Productive	27.4	2.2	3.8
Dry	—	—	—
Total	27.4	2.2	3.8
Exploratory			
Productive	—	—	—
Dry	—	—	—
Total	—	—	—

Summary of Development Projects

For the year ended December 31, 2017, we invested approximately $176.8 million in implementing our development strategy, including $101.0 million related to the drilling and completion of 42 gross (27.4 net) development wells. The remaining $75.8 million was comprised of the development of proved undeveloped reserves still in process, recompletions, fracture stimulation projects and various infrastructure capital. We estimate that our capital expenditures for the year ending December 31, 2018 will be approximately $225 million for development drilling, recompletions and fracture stimulation and other development-related projects to implement this strategy. Over 90% of this capital is expected to be deployed in the Permian Basin while the balance is expected to be spread across East Texas, Wyoming, North Dakota and the East Binger field in Oklahoma. We will consider adjustments to this capital program based on our assessment of additional development opportunities that are identified during the year and the cash available to invest in our development projects.

Present Activities

As of December 31, 2017, we were in the process of drilling or completing 22 gross (14.1 net) wells, all of which were development wells. Further, 4 were classified as PUD within our year-end reserve report while 18 were classified as unproved and therefore not included in our year-end reserve report.

Operations

General

We operate approximately 62% of our total net daily production of oil and natural gas. Excluding our assets in the Piceance Basin, we operate approximately 84% of our net daily production of oil and natural gas. We design and manage the development, recompletion or workover for all of the wells we operate and supervise operation and maintenance activities. We do not own drilling rigs or any material oil field services equipment used for drilling or maintaining wells on properties we operate. Independent contractors engaged by us provide all the equipment and personnel associated with these activities. We employ drilling, production and reservoir engineers, geologists and other specialists who have worked and will work to improve production rates, increase reserves, and lower the cost of operating our oil and natural gas properties. We also employ field operating personnel including production superintendents, production foremen, production technicians and lease operators. We charge the non-operating partners an operating fee for operating the wells, typically on a fee per well-operated basis proportionate to each owner's working interest. Our non-operated wells are managed by third-party operators who are typically independent oil and natural gas companies.

Oil and Natural Gas Leases

The typical oil and natural gas lease agreement covering our properties provides for the payment of royalties to the mineral owner for all oil and natural gas produced from any well drilled on the lease premises. In our areas of operation, this amount generally ranges from 12.5% to 33.7%, resulting in an 87.5% to 66.3% net revenue interest to the working interest owners, including us. Most of our leases are held by production and do not require lease rental payments.

Derivative Activity

We enter into derivative transactions with unaffiliated third parties with respect to oil and natural gas prices to achieve more predictable cash flows and to reduce our exposure to short-term fluctuations in oil and natural gas prices. We have entered into derivative contracts in the form of fixed price swaps for NYMEX WTI oil, NYMEX Henry Hub natural gas as well as Midland-to-Cushing crude oil basis differentials. We have also entered into multiple NYMEX WTI oil derivative three-way collar contracts and enhanced swap contracts, as well as NYMEX Henry Hub natural gas three-way collar contracts. We also enter into derivative transactions with respect to London Interbank Offered Rate ("LIBOR") interest rates to achieve more predictable cash flows and to reduce our exposure to short-term fluctuations in LIBOR interest rates. All of our interest rate derivative transactions are LIBOR interest rate swaps. Our derivatives swap floating LIBOR rates for fixed rates. All of these commodity and interest rate contracts were executed in a costless manner, requiring no payment of premiums. Furthermore, none of our current derivative counterparties require us to post collateral. For a more detailed discussion of our derivative activities, please read “Business—Oil and Natural Gas Derivative Activities,” “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Cash Flow from Operations” and “—Quantitative and Qualitative Disclosures About Market Risk.”

Title to Properties

Prior to completing an acquisition of producing oil and natural gas leases, we perform title reviews on significant leases and, depending on the materiality of properties, we may obtain a title opinion or review previously obtained title opinions. As a result, title opinions have been obtained on a portion of our 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.

We believe that we have satisfactory title to all of our material assets. Although title to these properties is subject to encumbrances in some cases, such as customary interests generally retained in connection with the acquisition of real property, customary royalty interests and contract terms and restrictions, liens under operating agreements, liens related to environmental liabilities associated with historical operations, liens for current taxes and other burdens, easements, restrictions and minor encumbrances customary in the oil and natural gas industry, we believe that none of these liens, restrictions, easements, burdens and encumbrances will materially detract from the value of these properties or from our interest in these properties or will materially interfere with our use in the operation of our business. In addition, we believe that we have obtained sufficient rights-of-way grants and permits from public authorities and private parties for us to operate our business in all material respects as described in this document.

ITEM 3. *LEGAL PROCEEDINGS*

Although we may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business, we are not currently a party to any material legal proceedings. In addition, we are not aware of any legal or governmental proceedings against us, or contemplated to be brought against us, under the various environmental protection statutes to which we are subject.

ITEM 4. *MINE SAFETY DISCLOSURES*

Not applicable.

PART II

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

Our units, which were first offered and sold to the public on January 12, 2007, are listed on the NASDAQ Global Select Market under the symbol "LGCY." As of February 21, 2018, there were 76,894,049 units outstanding, held by approximately 131 holders of record, including units held by our Founding Investors. This number reflects only the holders of record, and does not reflect all beneficial owners of units, such as those who hold their units through a broker.

The following table presents the high and low sales prices for our units during the periods indicated (as reported on the NASDAQ Global Select Market) and the amount of the quarterly cash distributions we paid on each of our units with respect to such periods.

	Price Ranges		Cash Distribution	Cash Distribution
2017	**High**	**Low**	**per Unit**	**to General Partner**
First Quarter	$ 2.77	$1.76	$ —	$ —
Second Quarter	$ 2.42	$1.26	$ —	$ —
Third Quarter	$ 1.55	$1.08	$ —	$ —
Fourth Quarter	$ 1.82	$1.07	$ —	$ —

	Price Ranges		Cash Distribution	Cash Distribution
2016	**High**	**Low**	**per Unit**	**to General Partner**
First Quarter	$ 1.96	$0.61	$ —	$ —
Second Quarter	$ 3.89	$0.78	$ —	$ —
Third Quarter	$ 2.01	$1.25	$ —	$ —
Fourth Quarter	$ 2.74	$1.13	$ —	$ —

As of January 21, 2016, we have suspended all cash distributions to unitholders and monthly cash distributions to holders of our Preferred Units. Please read "Management's Discussion and Analysis of Financial Condition and Results of Operations—Restrictions on Paying Distributions" for a description of our restrictions on paying distributions.

ITEM 6. *SELECTED FINANCIAL DATA*

You should read the following selected financial data in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Legacy's financial statements and related notes included elsewhere in this annual report on Form 10-K. The operating results of the properties acquired have been included from their respective acquisition dates as discussed below.

	Years Ended December 31,				
	2017(a)	2016	2015(b)	2014(c)	2013
	(In thousands, except per unit data)				
Statement of Operations Data:					
Revenues:					
Oil sales	$239,448	$ 152,507	$ 199,841	$ 396,774	$ 405,536
Natural gas liquids sales	24,796	15,406	16,645	27,483	14,095
Natural gas sales	172,057	146,444	122,293	108,042	65,858
Total revenues	436,301	314,357	338,779	532,299	485,489
Expenses:					
Oil and natural gas production	183,219	179,333	194,491	198,801	154,679
Production and other taxes	19,825	14,267	16,383	31,534	29,508
General and administrative	49,372	43,639	46,511	38,980	28,907
Depletion, depreciation, amortization and accretion	126,938	150,414	177,258	173,686	158,415
Impairment of long-lived assets	37,283	61,796	633,805	448,714	85,757
(Gain) loss on disposal of assets	1,606	(50,095)	(3,972)	(2,479)	579
Total expenses	418,243	399,354	1,064,476	889,236	457,845
Operating income (loss)	18,058	(84,997)	(725,697)	(356,937)	27,644
Other income (expense):					
Interest income	64	67	329	873	776
Interest expense	(89,206)	(79,060)	(76,891)	(67,218)	(50,089)
Gain on extinguishment of debt	—	150,802	—	—	—
Equity in income of equity method investees	17	—	126	428	559
Net gains (losses) on commodity derivatives	17,776	(41,224)	98,253	138,092	(13,531)
Other	792	(179)	841	258	18
Loss before income taxes	(52,499)	(54,591)	(703,039)	(284,504)	(34,623)
Income tax (expense) benefit	(1,398)	(1,229)	1,498	859	(649)
Net loss	(53,897)	(55,820)	(701,541)	(283,645)	(35,272)
Distributions to preferred unitholders	(19,000)	(19,000)	(19,000)	(11,694)	—
Net loss attributable to unitholders	$ (72,897)	$ (74,820)	$(720,541)	$(295,339)	$ (35,272)

	Years Ended December 31,				
	2017(a)	2016	2015(b)	2014(c)	2013
	(In thousands, except per unit data)				
Loss per unit					
Basic and diluted	$ (1.01)	$ (1.06)	$ (10.45)	$ (4.92)	$ (0.62)
Distributions paid per unit	$ —	$ —	$ 1.46	$ 2.41	$ 2.31
Cash Flow Data:					
Net cash provided by (used in) operating activities	$100,209	$ (310)	$ 2,046	$ 207,216	$ 241,134
Net cash provided by (used in) investing activities	$(279,236)	$ 119,989	$(377,420)	$(632,414)	$(209,401)
Net cash provided by (used in) financing activities	$177,718	$ (119,130)	$ 376,655	$ 423,339	$ (32,658)
Capital expenditures	$314,491	$ 41,932	$ 579,463	$ 640,414	$ 204,911

	Historical As of December 31,				
	2017(a)	2016	2015(b)	2014(c)	2013
	(In thousands)				
Balance Sheet Data					
Cash and cash equivalents	$ 1,246	$ 2,555	$ 2,006	$ 725	$ 2,584
Other current assets	111,358	80,217	127,453	191,529	72,115
Oil and natural gas properties, net of accumulated depletion, depreciation, amortization and impairment	1,353,356	1,181,909	1,408,956	1,639,974	1,535,429
Other assets	27,122	35,145	74,705	66,378	49,705
Total assets	$1,493,082	$1,299,826	$1,613,120	$1,898,606	$ 1,659,833
Current liabilities	$ 144,810	$ 86,609	$ 81,093	$ 97,576	$ 93,890
Long-term debt	1,346,769	1,161,394	1,427,614	938,876	878,693
Other long-term liabilities	273,190	273,902	284,090	224,949	176,854
Partners' equity (deficit)	(271,687)	(222,079)	(179,677)	637,205	510,396
Total liabilities and partners' equity (deficit)	$1,493,082	$1,299,826	$1,613,120	$1,898,606	$ 1,659,833

(a) Includes the production and operating results of the properties acquired as a part of our assets acquired in conjunction with Acceleration Payment from the closing date on August 1, 2017 through December 31, 2017.

(b) Includes Legacy's purchase of the oil and natural gas properties acquired in the Anadarko Acquisitions as of the closing date of the acquisition on July 31, 2015. Consequently, the operations of these acquired properties are only included for the period from the closing date of the acquisition through December 31, 2015 and thereafter.

(c) Includes Legacy's purchase of the oil and natural gas properties acquired in the Piceance Acquisition as of the closing date of the acquisition on June 4, 2014. Consequently, the operations of these acquired properties are only included for the period from the closing date of the acquisition through December 31, 2014 and thereafter.

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

The following discussion and analysis should be read in conjunction with the "Selected Historical Consolidated Financial Data" and the accompanying financial statements and related notes included elsewhere in this annual report on Form 10-K. The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, market prices for oil and natural gas, production volumes, estimates of proved reserves, capital expenditures, economic and competitive conditions, regulatory changes and other uncertainties, as well as those factors discussed below and elsewhere in this report, particularly in "Risk Factors" and "Cautionary Statement Regarding Forward-Looking Information," all of which are difficult to predict. In light of these risks, uncertainties and assumptions, actual results may differ materially from those anticipated or implied in the forward-looking statements.

Overview

Because of our historical growth through acquisitions and development of properties as well as large fluctuations in commodity prices, historical results of operations and period-to-period comparisons of these results and certain financial data may not be meaningful or indicative of future results. The operating results of the properties acquired as a part of our asset acquisition in conjunction with acceleration payment (the "Acceleration Payment") under our joint development agreement with TPG Sixth Street Partners (the "JDA") have been included since August 1, 2017. The operating results of the acquisition of (1) 100% of the issued and outstanding limited liability company membership interests in Dew Gathering LLC, which owns directly and indirectly natural gas gathering and processing assets in Anderson, Freestone, Houston, Leon, Limestone and Robertson Counties, Texas (the "WGR Acquisition") from WGR Operating LP ("WGR"), and (2) various oil and natural gas properties and associated exploration and production assets (the "Anadarko E&P Acquisition," together with the WGR Acquisition, the "Anadarko Acquisitions") from Anadarko E&P Onshore LLC ("Anadarko") have been included since July 31, 2015.

Trends Affecting Our Business and Operations

Sustained periods of low prices for oil or natural gas have and could materially and adversely affect our financial position, our results of operations, the quantities of oil and natural gas reserves that we can economically produce and our access to capital.

We face the challenge of natural production declines. As initial reservoir pressures are depleted, oil and natural gas production from a given well or formation decreases. We attempt to overcome this natural decline by drilling to find additional reserves, acquiring more reserves than we produce, utilizing multiple types of recovery techniques such as secondary (waterflood) and tertiary recovery methods to re-pressure the reservoir and recover additional oil, recompleting or adding pay in existing wellbores and improving artificial lift.

Outlook. The oil and natural gas industry is in a challenging environment, especially over the past four years, as evidenced by volatility in the crude oil prices that ranged from over $100 per barrel in early 2014 to less than $30 per barrel in 2016 with 2017 bringing a recovery off the lows experienced in 2016 but below levels seen in 2014. Our development capital expenditures are expected to be approximately $225 million in 2018 and will be focused on the development of our Permian Basin horizontal assets. We will continue to prudently manage our historical low-decline proved developed producing oil and gas properties to support the development of our high return prospects as we pursue additional cash flow and increase oil and natural gas reserves. To illustrate the sensitivity our proved reserves to fluctuations in commodity prices, we recalculated our proved reserves as of December 31, 2017, using the five-year average forward price as of February 14, 2018 for both WTI oil and NYMEX natural gas. While this 5-year NYMEX forward strip price is not necessarily indicative of our overall outlook on future commodity prices, this commonly used methodology may help provide investors with an understanding of the impact of a volatile commodity price environment. Under such assumptions, we estimate the cumulative projected production from our year-end proved reserves would decrease by approximately 3% to 175.4 MMBoe from the reported 180.0 MMBoe, which is calculated as required by the SEC.

Should we experience a decline in oil and natural gas prices in 2018, we could breach certain financial covenants under our $1.5 billion secured revolving credit facility with Wells Fargo Bank, National Association, as administrative agent, Compass Bank, as syndication agent, UBS Securities LLC and U.S. Bank National Association, as co-documentation agents and the lenders party thereto as amended most recently by the Eight Amendment thereto (as amended, the "Revolving Credit Agreement") and our second lien term loan credit agreement (as amended, our "Term Loan Credit Agreement"), which would constitute a default under our Revolving Credit Agreement or our Term Loan Credit Agreement. Such default, if not remedied, would require a waiver from our lenders in order for us to avoid an event of default and subsequent acceleration of all amounts outstanding under our Revolving Credit Agreement or our Term Loan Credit Agreement or foreclosure on our oil and natural gas properties. Certain payment defaults or acceleration under our Revolving Credit Agreement or our Term Loan Credit Agreement could cause a cross-default or cross-acceleration of all of our indebtedness. While no assurances can be made that, in the event of a covenant breach, such a waiver will be granted, we believe the long-term global outlook for commodity prices and our efforts to date will be viewed positively by our lenders. For further discussion on the consequences of a breach of such covenants, including a potential cross-default of all our existing indebtedness, please read "Risk Factors—Risks Related to Our Business—Continued low commodity prices may impact our ability to comply with debt covenants."

Considering the current environment for the oil and natural gas industry, our goals in 2018 are to:

- efficiently develop our horizontal inventory in the Permian Basin to meaningfully grow oil production and total company cash flow and reserve value;
- minimize production declines and operating costs through efficient operations; and
- reposition our balance sheet by (i) remaining free cash flow positive for the year and (ii) evaluating and opportunistically pursuing alternatives to change our legal structure and tax status as a partnership, materially reduce our outstanding indebtedness and restructure our near term maturity indebtedness.

In the event that cash flows from operations are greater than we currently anticipate, whether as a result of increased commodity prices, reduced interest expense or otherwise, or additional external financing sources become available to us, we intend to accelerate our development plan and increase development capital expenditures.

Our future growth will depend on our ability to continue to add reserves in excess of production. We will maintain our focus on adding reserves through organic development projects and acquisitions. Our ability to add reserves through organic development projects and acquisitions is dependent upon many factors including our ability to raise capital, obtain regulatory approvals and contract drilling rigs and completions equipment and personnel.

Our revenues are highly sensitive to changes in oil and natural gas prices and to levels of production. As set forth under "Investing Activities," we have entered into oil and natural gas derivatives designed to mitigate the effects of price fluctuations covering a portion of our expected production, which allows us to mitigate, but not eliminate, oil and natural gas price risk. By removing a portion of our price volatility on our future oil and natural gas production through 2019, we have mitigated, but not eliminated, the potential effects of changing oil and natural gas prices on our cash flows from operations for those periods. Commodity prices may decrease, which could alter our acquisition and development plans, and adversely affect our growth strategy and ability to access additional capital in the capital markets and through our Revolving Credit Agreement. We continuously conduct financial sensitivity analyses to assess the effect of changes in pricing and production. These analyses allow us to determine how changes in oil and natural gas prices will affect our ability to execute our development plans and to meet future financial obligations. Further, the financial analyses allow us to monitor any impact such changes in oil and natural gas prices may have on the value of our proved reserves and their impact on any redetermination to our borrowing base under our Revolving Credit Agreement.

Restrictions on Paying Distributions

As of January 21, 2016, we have suspended all cash distributions to unitholders and monthly cash distributions to holders of our Preferred Units. Our Revolving Credit Agreement and our Term Loan Credit Agreement provide that cash distributions can be made only out of our available cash, provided that distributions do not exceed 90% of available cash, and both before and after giving effect to any such distribution (i) no default or event of default has occurred and is continuing or would result therefrom, (ii) we have unused lender commitments of not less than 15% of the total lender commitments under our Revolving Credit Agreement then in effect, and (iii) our ratio of total debt at such time to our EBITDA for the four fiscal quarters ending on the last day of the fiscal quarter immediately preceding the date of determination for which financial statements are available is equal to or less than 4.00 to 1.00. Our Revolving Credit Agreement currently prohibits distributions to unitholders given our leverage ratios and limited availability under our Revolving Credit Agreement. Additionally, our partnership agreement requires us to pay or set aside for payment all accrued but unpaid distributions with respect to the Preferred Units prior to or contemporaneously with making any distribution with respect to our units.

Operating Data

The following table sets forth our selected financial and operating data for the periods indicated.

	Year Ended December 31,		
	2017(b)	2016	2015(c)
	(In thousands, except per unit data and production)		
Revenues			
Oil sales	$239,448	$152,507	$199,841
Natural gas liquids sales	24,796	15,406	16,645
Natural gas sales	172,057	146,444	122,293
Total revenues	$436,301	$314,357	$338,779
Expenses:			
Oil and natural gas production	$173,599	$169,755	$183,163
Ad valorem taxes	9,620	9,578	11,328
Total	$183,219	$179,333	$194,491
Production and other taxes	$ 19,825	$ 14,267	$ 16,383
General and administrative, excluding transaction costs and LTIP	$ 34,006	$ 31,196	$ 30,919
Transaction costs	8,769	5,245	8,919
LTIP expense	6,597	7,198	6,673
Total general and administrative	$ 49,372	$ 43,639	$ 46,511
Depletion, depreciation, amortization and accretion	$126,938	$150,414	$177,258
Commodity derivative cash settlements:			
Oil derivative cash settlements received	11,840	37,464	91,953
Natural gas derivative cash settlements received	12,316	27,041	40,972
Total commodity derivative cash settlements	24,156	64,505	132,925
Production:			
Oil (MBbls)	5,032	4,019	4,608
Natural gas liquids (MGal)	38,159	36,757	42,210
Natural gas (MMcf)	62,833	66,824	50,687
Total (MBoe)	16,413	16,032	14,061
Average daily production (Boe/d)	44,967	43,803	38,523
Average sales price per unit (excluding commodity derivative cash settlements):			
Oil price (per Bbl)	$ 47.59	$ 37.95	$ 43.37
Natural gas liquids price (per Gal)	$ 0.65	$ 0.42	$ 0.39
Natural gas price (per Mcf)(a)	$ 2.74	$ 2.19	$ 2.41
Combined (per Boe)	$ 26.58	$ 19.61	$ 24.09
Average sales price per unit (including commodity derivative cash settlements):			
Oil price (per Bbl)	$ 49.94	$ 47.27	$ 63.32
Natural gas liquids price (per Gal)	$ 0.65	$ 0.42	$ 0.39
Natural gas price (per Mcf)(a)	$ 2.93	$ 2.60	$ 3.22
Combined (per Boe)	$ 28.05	$ 23.63	$ 33.55
Average WTI oil spot price (per Bbl)	$ 50.80	$ 43.29	$ 48.66
Average Henry Hub natural gas spot price (per MMBtu)	$ 2.99	$ 2.52	$ 2.62
Average unit costs per Boe:			
Production costs, excluding production and other taxes	$ 10.58	$ 10.59	$ 13.03
Ad valorem taxes	$ 0.59	$ 0.60	$ 0.81
Production and other taxes	$ 1.21	$ 0.89	$ 1.17
General and administrative, excluding transaction costs and LTIP	$ 2.07	$ 1.95	$ 2.20
Total general and administrative	$ 3.01	$ 2.72	$ 3.31
Depletion, depreciation, amortization and accretion	$ 7.73	$ 9.38	$ 12.61

(a) We primarily report and account for our Permian Basin natural gas volumes inclusive of the NGL content contained within those natural gas volumes. Given the price disparity between an equivalent amount of NGLs compared to natural gas, our realized natural gas prices in the Permian Basin and for Legacy as a whole are higher than Henry Hub natural gas index prices due to this NGL content.

(b) Includes the production and operating results of the properties acquired as a part of our asset acquisition in conjunction with the Acceleration Payment from the closing date on August 1, 2017 through December 31, 2017.

(c) Includes the production and operating results of the oil and natural gas properties acquired in the Anadarko Acquisitions from the closing date of the acquisition on July 31, 2015 through December 31, 2015.

Results of Operations

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

Legacy's revenues from the sale of oil were $239.4 million and $152.5 million for the years ended December 31, 2017 and 2016, respectively. Legacy's revenues from the sale of NGLs were $24.8 million and $15.4 million for the years ended December 31, 2017 and 2016, respectively. Legacy's revenues from the sale of natural gas were $172.1 million and $146.4 million for the years ended December 31, 2017 and 2016, respectively. The $86.9 million increase in oil revenue reflects an increase in oil production of 1,013 MBbls (25%) and an increase in average realized price of $9.64 per Bbl (25%) to $47.59 for the year ended December 31, 2017 from $37.95 for the year ended December 31, 2016. The increase in realized oil price was primarily caused by an increase in the average WTI crude oil price of $7.51 and improved realized regional differentials. The increase in production is due to an increase in net well count under our JDA following the Acceleration Payment and continued development of our Permian Basin horizontal assets. The increase was partially offset by individually immaterial divestitures and natural declines. The $9.4 million increase in NGL revenues reflects an increase in realized NGL price of $0.23 per Gal (55%) to $0.65 per Gal for the year ended December 31, 2017 from $0.42 per Gal for the year ended December 31, 2016 and an increase in NGL production of 1,402 MGals (4%) during 2017. The $25.6 million increase in natural gas revenues reflects an increase our realized natural gas prices partially offset by a decrease in our natural gas production volumes. Average realized gas prices increased by $0.55 per Mcf (25%) to $2.74 per Mcf for the year ended December 31, 2017 from $2.19 per Mcf for the year ended December 31, 2016, primarily due to an increase in the average NYMEX Henry Hub natural gas price of $0.47 per Mcf over the same time period and increased natural gas volumes produced from assets in the Permian Basin which are accounted for inclusive of the NGL content contained within the natural gas volumes, resulting in a realized gas price for those assets that is higher than the NYMEX Henry Hub index price. Our natural gas production decreased by approximately 3,991 MMcf (6%), primarily due to natural production declines in our East Texas and Piceance Basin properties partially offset by increased production from the assets developed by our Permian Basin horizontal development program.

For the year ended December 31, 2017, Legacy recorded $17.8 million of net gains on oil and natural gas derivatives. Commodity derivative gains and losses represent the changes in fair value of our commodity derivative contracts during the period and are primarily based on oil and natural gas futures prices. The net gain recognized during 2017 was primarily due to cash receipts and the decrease in natural gas futures prices for periods beyond 2017, which increased the fair value of our derivatives in such periods. For the year ended December 31, 2016, Legacy recorded $41.2 million of net losses on oil and natural gas derivatives. The net loss recognized during 2016 was primarily due to the increase in futures prices for periods beyond 2016, which reduced the fair value of our derivatives in such periods. Settlements of such contracts resulted in cash receipts of $24.2 million and $64.5 million during 2017 and 2016, respectively.

Legacy's oil and natural gas production expenses, excluding ad valorem taxes, increased to $173.6 million ($10.58 per Boe) for the year ended December 31, 2017 from $169.8 million ($10.59 per Boe) for the year ended December 31, 2016. This increase is primarily attributable to increased workover and repair activity across all operating regions, increased well count due to our Permian horizontal drilling program and increased working interests under our JDA following the Acceleration Payment partially offset by general cost reduction efforts. These reduction efforts, as well as the increase in oil and NGL production, resulted in decreased production expenses per Boe during 2017 compared to 2016. Legacy's ad valorem tax expense remained consistent period over period due to increased oil and natural gas property valuations offset by immaterial divestitures.

Legacy's production and other taxes were $19.8 million and $14.3 million for the years ended December 31, 2017 and 2016, respectively. Production and other taxes increased due to higher total revenues in 2017. On a per Boe basis, production and other taxes increased to $1.21 for the year ended December 31, 2017 from $0.89 for the year ended December 31, 2016 due to higher realized prices.

Legacy's general and administrative expenses were $49.4 million and $43.6 million for the years ended December 31, 2017 and 2016, respectively. General and administrative expenses increased approximately $5.7 million between periods primarily due to a $3.5 million increase in transaction-related expenses and other general cost increases.

Legacy's depletion, depreciation, amortization and accretion expense, or DD&A, was $126.9 million and $150.4 million for the years ended December 31, 2017 and 2016, respectively. DD&A decreased primarily due to lower depletion rates across our historical properties primarily related to impairment charges incurred in 2016 and 2017, which reduced our depletable cost basis. This decrease was partially offset by additional well count from our Permian Basin horizontal development program. Our depletion rate per Boe for the year ended December 31, 2017 was $7.73 compared to $9.38 for the year ended December 31, 2016. This decrease is primarily driven by a lower net cost basis on our historical assets due to previously recognized depletion and impairment.

Impairment expense was $37.3 million and $61.8 million for the years ended December 31, 2017 and 2016, respectively. In 2017, Legacy recognized $37.3 million of impairment expense in 47 separate producing fields, due primarily to the further decline in oil and natural gas futures prices in early 2017 as well as increased expenses and well performance during the year ended December 31, 2017, which decreased the expected future cash flows below the carrying value of the assets. In 2016, Legacy recognized impairment expense of $61.8 million in 43 separate producing fields, due primarily to well performance and the further decline in commodity prices during the year ended December 31, 2016, which decreased the expected future cash flows below the carrying value of the assets.

Interest expense was $89.2 million and $79.1 million for the years ended December 31, 2017 and 2016, respectively. The increase in interest expense is primarily due to interest expense on our Second Lien Term Loans issued in October 2016 partially offset by a reduction in bond interest expense due to repurchases and exchanges of our 8% senior unsecured notes maturing on December 1, 2020 (the "2020 Senior Notes") and our 6.625% senior unsecured notes maturing on December 1, 2021 (the "2021 Senior Notes", together with the 2020 Senior Notes, the "Senior Notes") completed during 2016. Additionally, interest expenses related to the gains (losses) on our interest rate swaps decreased by $3.3 million to $1.2 million in 2017 from $(2.1) million in 2016. Cash payments on our interest rate swaps were $0.8 million and $2.7 million in 2017 and 2016, respectively.

As a result of the items described above, Legacy recorded net losses of $53.9 million and $55.8 million for the years ended December 31, 2017 and 2016, respectively. The decrease in net loss was primarily due to a decrease in impairment expense to $37.3 million during the year ended December 31, 2017 from $61.8 million for the year ended December 31, 2016 as well as increased revenue from our oil, natural gas and NGL production. These factors were partially offset by a decrease in the gain on extinguishment of debt in 2017 as compared to 2016.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

Legacy's revenues from the sale of oil were $152.5 million and $199.8 million for the years ended December 31, 2016 and 2015, respectively. Legacy's revenues from the sale of NGLs were $15.4 million and $16.6 million for the years ended December 31, 2016 and 2015, respectively. Legacy's revenues from the sale of natural gas were $146.4 million and $122.3 million for the years ended December 31, 2016 and 2015, respectively. The $47.3 million decrease in oil revenue reflects a decrease in average realized price of $5.42 per Bbl (12%) to $37.95 for the year ended December 31, 2016 from $43.37 for the year ended December 31, 2015, and a decrease in oil production of 589 MBbls (13%). The decrease in realized oil price was primarily caused by a decrease in the average WTI crude oil price of $5.37. The decrease in production is due to individually immaterial divestitures and natural declines related to reduced capital spending. The $1.2 million decrease in NGL revenues reflects a decrease in NGL production of 5,453 MGals (13%) during 2016 partially offset by an increase in realized NGL price of $0.03 per Gal (8%) to $0.42 per Gal for the year ended December 31, 2016 from $0.39 per Gal for the year ended December 31, 2015. The decrease in NGL production is due primarily to ethane rejection in our Piceance Basin properties, individually immaterial divestitures and natural production declines. The $24.2 million increase in natural gas revenues reflects an increase in our natural gas production volumes partially offset by a decrease in our realized natural gas prices. Our natural gas production increased by approximately 16,137 MMcf (32%), primarily due to a full year of inclusion of production from our 2015 acquisitions, most notably the acquisitions of East Texas properties (17,767 MMcf), partially offset by natural production declines. Average realized gas prices decreased by $0.22 per Mcf (9%) to $2.19 per Mcf for the year ended December 31, 2016 from $2.41 per Mcf for the year ended December 31, 2015, primarily due to a decrease in the average NYMEX Henry Hub natural gas price of $0.10 per Mcf over the same time period and an increase in realized regional differentials.

For the year ended December 31, 2016, Legacy recorded $41.2 million of net losses on oil and natural gas derivatives. Commodity derivative gains and losses represent the changes in fair value of our commodity derivative contracts during the period and are primarily based on oil and natural gas futures prices. The net loss recognized during 2016 was primarily due to the increase in futures prices for periods beyond 2016, which reduced the fair value of our derivatives in such periods. For the year ended December 31, 2015, Legacy recorded $98.3 million of net gains on oil and natural gas derivatives. The net gain recognized during 2015 was due to the significant decrease in oil futures prices during 2015 as well as the addition of natural gas derivatives during 2015 and subsequent decline in natural gas prices. Settlements of such contracts resulted in cash receipts of $64.5 million and $132.9 million during 2016 and 2015, respectively.

Legacy's oil and natural gas production expenses, excluding ad valorem taxes, decreased to $169.8 million ($10.59 per Boe) for the year ended December 31, 2016 from $183.2 million ($13.03 per Boe) for the year ended December 31, 2015. Production expenses decreased primarily due cost reductions realized on our historical properties, partially offset by increased production expenses associated with the acquisition of East Texas properties ($25.2 million). These reduction efforts, as well as the large volume of natural gas production related to the properties acquired in East Texas, resulted in decreased production expenses per Boe 2016 compared to 2015. Legacy's ad valorem tax expense decreased to $9.6 million ($0.60 per Boe) for the year ended December 31, 2016 from $11.3 million ($0.81 per Boe) for the year ended December 31, 2015 due to lower valuations of our oil and natural gas properties due to lower commodity prices partially offset by a full year of increased well counts from our acquisition of additional oil and natural gas properties.

Legacy's production and other taxes were $14.3 million and $16.4 million for the years ended December 31, 2016 and 2015, respectively. Production and other taxes decreased due to lower total revenues in 2016. On a per Boe basis, production and other taxes decreased to $0.89 for the year ended December 31, 2016 from $1.17 for the year ended December 31, 2015 due to lower total revenues.

Legacy's general and administrative expenses were $43.6 million and $46.5 million for the years ended December 31, 2016 and 2015, respectively. General and administrative expenses decreased approximately $2.9 million between periods primarily due to $3.7 million of decreased acquisition-related expenses partially offset by increased expenses commensurate with a larger asset base.

Legacy's depletion, depreciation, amortization and accretion expense, or DD&A, was $150.4 million and $177.3 million for the years ended December 31, 2016 and 2015, respectively. DD&A decreased primarily due to lower depletion rates across our historical properties primarily related to impairment charges incurred in 2015 and 2016, which reduced our depletable cost basis. This decrease was partially offset by a full year of inclusion of depletion expense related to acquisitions completed in 2015, most notable the East Texas acquisitions. Our depletion rate per Boe for the year ended December 31, 2016 was $9.38 compared to $12.61 for the year ended December 31, 2015. This decrease is primarily driven by a lower net cost basis on our historical assets due to previously recognized depletion and impairment.

Impairment expense was $61.8 million and $633.8 million for the years ended December 31, 2016 and 2015, respectively. In 2016, Legacy recognized $61.8 million of impairment expense in 43 separate producing fields, due primarily to well performance and the further decline in commodity prices during the year ended December 31, 2016, which decreased the expected future cash flows below the carrying value of the assets. In 2015, Legacy recognized impairment expense of $598.1 million in 218 separate producing fields due to the significant decrease in commodity prices during the year ended December 31, 2015, which decreased the expected future cash flows below the carrying value of the assets. Additionally, we recorded impairment of $35.7 million related to unproved properties acquired since 2010 that, in the current and expected future commodity price environment, are no longer economically viable.

Interest expense was $79.1 million and $76.9 million for the years ended December 31, 2016 and 2015, respectively. The increase in interest expense is primarily due to an increase of $10.1 million of interest expense on our Revolving Credit Agreement and $1.4 million of interest expense on our second lien term loans issued in October 2016 partially offset by a $10.8 million reduction in bond interest expense due to repurchases and exchanges of our 8% senior unsecured notes maturing on December 1, 2020 (the "2020 Senior Notes") and our 6.625% senior unsecured notes maturing on December 1, 2021 (the "2021 Senior Notes", together with the 2020

Senior Notes, the "Senior Notes") completed during 2016. Additionally, interest expenses related to our interest rate swaps increased by $0.6 million to $2.1 million in 2016 from $1.5 million in 2015. Cash payments on our interest rate swaps were $2.7 million and $3.3 million in 2016 and 2015, respectively.

As a result of the items described above, Legacy recorded a net loss of $55.8 million and $701.5 million for the years ended December 31, 2016 and 2015, respectively. The decrease in net loss was primarily due to a decrease in impairment expense from $633.8 million during the year ended December 31, 2015 to $61.8 million for the year ended December 31, 2016.

Non-GAAP Financial Measure

Legacy's management uses Adjusted EBITDA as a tool to provide additional information and a metric relative to the performance of Legacy's business. Legacy's management believes that Adjusted EBITDA is useful to investors because this measure is used by many companies in the industry as a measure of operating and financial performance and is commonly employed by financial analysts and others to evaluate the operating and financial performance of the Partnership from period to period and to compare it with the performance of our peers. Adjusted EBITDA may not be comparable to a similarly titled measure of such peers because all entities may not calculate Adjusted EBITDA in the same manner.

The following presents a reconciliation of "Adjusted EBITDA," which is a non-GAAP measure, to its nearest comparable GAAP measure. Adjusted EBITDA should not be considered as an alternative to GAAP measures, such as net income, operating income, cash flow from operating activities, or any other GAAP measure of financial performance.

Adjusted EBITDA is defined as net income (loss) plus:

- Interest expense;
- (Gain) loss on extinguishment of debt;
- Income tax expense (benefit);
- Depletion, depreciation, amortization and accretion;
- Impairment of long-lived assets;
- (Gain) loss on sale of partnership investment;
- Loss (gain) on disposal of assets;
- Equity in (income) loss of equity method investees;
- Unit-based compensation expense (benefit) related to LTIP unit awards accounted for under the equity or liability methods;
- Minimum payments received in excess of overriding royalty interest earned;
- Equity in EBITDA of equity method investee;
- Net (gains) losses on commodity derivatives;
- Net cash settlements received (paid) on commodity derivatives; and
- Transaction costs.

The following table presents a reconciliation of Legacy's consolidated net income (loss) to Adjusted EBITDA for the years ended December 31, 2017, 2016 and 2015, respectively.

	Year Ended December 31,		
	2017	2016	2015
		(In thousands)	
Net loss	$ (53,897)	$ (55,820)	$(701,541)
Plus:			
Interest expense	89,206	79,060	76,891
Gain on extinguishment of debt	—	(150,802)	—
Income tax expense (benefit)	1,398	1,229	(1,498)
Depletion, depreciation, amortization and accretion	126,938	150,414	177,258
Impairment of long-lived assets	37,283	61,796	633,805
Loss (gain) on disposal of assets	1,606	(50,095)	(3,972)
Equity in income of equity method investees	(17)	—	(126)
Unit-based compensation expense	6,597	7,198	6,673
Minimum payments received in excess of overriding royalty interest earned(a)	1,936	1,659	1,130
Equity in EBITDA of equity method investee(b)	—	—	169
Net (gains) losses on commodity derivatives	(17,776)	41,224	(98,253)
Net cash settlements received on commodity derivatives	24,156	64,505	132,925
Transaction costs	8,769	5,245	8,919
Adjusted EBITDA	$ 226,199	$ 155,613	$ 232,380

(a) A portion of minimum payments received in excess of overriding royalties earned under a contractual agreement expiring December 31, 2019. The remaining amount of the minimum payments are recognized in net income.

(b) EBITDA applicable to equity method investee is defined as the equity method investee's net income plus interest expense and depreciation. We divested our interest in this investee in May of 2015.

For the year ended December 31, 2017, Adjusted EBITDA increased 45% to $226.2 million from $155.6 million for the year ended December 31, 2016. This increase is due primarily to increased oil and natural gas production as well as increased realized commodity prices partially offset by lower commodity derivative realizations and increased production costs. For the year ended December 31, 2016, Adjusted EBITDA decreased 33% to $155.6 million from $232.4 million for the year ended December 31, 2015. This decrease is due primarily to significant declines in commodity prices and lower commodity derivative realizations partially offset by lower production costs.

Capital Resources and Liquidity

Legacy's primary sources of capital and liquidity have been cash flow from operations, the issuance of the Senior Notes, the issuance of additional units and Preferred Units, our second lien term loans and bank borrowings, or a combination thereof. To date, Legacy's primary use of capital has been for the acquisition and development of oil and natural gas properties, the repayment of bank borrowings and repurchases of Senior Notes.

Based upon current oil and natural gas price expectations and our commodity derivatives positions, we anticipate that our cash on hand and cash flow from operations will provide us sufficient liquidity to fund our operations in 2018 including our planned capital expenditures of approximately $225 million. Should oil and natural gas prices decline dramatically in 2018, we could breach certain financial covenants under our Revolving Credit Agreement or our Term Loan Credit Agreement, which would constitute a default under our Revolving Credit Agreement or our Term Loan Credit Agreement. Such a default, if not remedied, would require a waiver from our lenders in order for us to avoid an event of default and potential subsequent acceleration of all amounts outstanding under our Revolving Credit Agreement or our Term Loan Credit Agreement or foreclosure on our oil and natural gas properties. Certain payment defaults or acceleration under our Revolving Credit Agreement could cause a cross-default or cross-acceleration of all of our other indebtedness. If an event of default occurs, or if other debt agreements cross-default, and the lenders under the affected debt agreements accelerate the maturity of any loans or other debt outstanding, we will not have sufficient liquidity to repay all of our outstanding indebtedness. In light of this, we elected to suspend distributions to unitholders in January 2016. Future cash flows are subject to a number of variables, including the level of oil and natural gas production and prices. There can be no assurance that operations and other capital resources will provide cash in sufficient amounts to operate or to maintain planned levels of capital expenditures. Please read "—Financing Activities—Our Revolving Credit Facility."

The amounts available for borrowing under our Revolving Credit Agreement are re-determined at least semi-annually in April and October of each year. On October 5, 2017, our borrowing base was reduced to $575 million, leaving $72.2 million available for borrowing as of February 21, 2018. Our next such redetermination event will occur in April 2018.

Our commodity derivatives position, which we use to mitigate commodity price volatility and (if positive) support our borrowing capacity, resulted in $24.2 million of cash receipts in the year ended December 31, 2017.

As market conditions warrant, we may, subject to certain restrictions, repurchase, exchange or otherwise pay down our outstanding debt, including our Senior Notes, in open market transactions, privately negotiated transactions, by tender offer or otherwise which may impact the trading liquidity of such securities. The amounts involved in any such transactions, individually or in the aggregate, may be material. In January 2018, we repurchased approximately $187.1 million of original principal amount of our 2021 Senior Notes from certain holders in a single transaction. During 2016, we repurchased approximately $52.0 million of original principal amount of our 2020 Senior Notes and $117.3 million of original principal amount of our 2021 Senior Notes on the open market, and we exchanged 2,719,124 units for $15.0 million of face amount of our 2020 Senior Notes.

A significant portion of our horizontal operated development activity in the Permian Basin is pursued through our development agreement (as amended, the "Development Agreement") entered into in 2015 with Jupiter JV, LP ("Investor"), which was formed by certain of TPG Sixth Street Partners' investment funds. Our capital resources and liquidity benefit from our interest in the development activity under the Development Agreement as described below.

On August 1, 2017, we, along with Investor, entered into the First Amended and Restated Development Agreement (the "Restated Agreement"), which amended and restated the Development Agreement pursuant to which we and Investor agreed to participate in the funding, exploration, development and operation of certain of our undeveloped oil and gas properties in the Permian Basin. Under the Restated Agreement and through subsequent elections, the parties have now committed to develop a tranche of 26 wells plus 9 wells in the Restated Agreement's area of mutual interest (the "Second Tranche"). Investor's share of its development costs is limited to $80 million.

In connection with the Restated Agreement, we made the Acceleration Payment to cause the reversion of Investor's working interest from 80% to 15% of the parties' combined interests in all wells contained in the first tranche such that our working interest reverted from 20% to 85% of the parties' combined working interests in all wells contained in the tranche, and all undeveloped assets subject to the terms of the Restated Agreement reverted back to us. The reversion of interests as a result of the Acceleration Payment was accounted for as an asset acquisition. See "—Footnote 4—Acquisitions" in the Notes to Consolidated Financial Statements for discussion of the impact ASU 2017-01 had on our current period consolidated financial statements. Pursuant to the Restated Agreement, Investor shall fund 40% of the costs to the parties' combined interests to develop the wells in the Second Tranche in exchange for an undivided 33.7% working interest of our original working interest in the wells, subject to a reversionary interest of 6.3% of our original working interest in the wells upon the occurrence of Investor achieving a 15% internal rate of return in the aggregate with respect to such tranche of wells. The Restated Agreement provides that Investor can suspend its obligation to fund wells in a tranche upon the occurrence of certain events, but that we can continue to drill and fund on our own any such wells in which Investor elects to not participate (subject to Investor's later right to participate in such wells in accordance with the Restated Agreement).

Cash Flow from Operations

Our net cash provided by (used in) operating activities was $100.2 million and $(0.3) million for the years ended December 31, 2017 and 2016, respectively, with the 2017 period being favorably impacted by higher realized commodity prices, partially offset by higher production expenses.

Our net cash (used in) provided by operating activities was $(0.3) million and $2.0 million for the years ended December 31, 2016 and 2015, respectively, with the 2016 period being unfavorably impacted by lower realized commodity prices, partially offset by lower production expenses and higher production volumes primarily related to a full year of inclusion of 2015 acquisitions, most notably the Anadarko Acquisitions.

Our cash flow from operations is subject to many variables, the most significant of which is the volatility of oil, NGL and natural gas prices. Oil, NGL and natural gas prices are determined primarily by prevailing market conditions, which are dependent on regional and worldwide economic activity, weather and other factors beyond our control. Our future cash flow from operations will depend on our ability to maintain and increase production through acquisitions and development projects, as well as the prices of oil, NGLs and natural gas.

Investing Activities

Our cash capital expenditures were $313.9 million for the year ended December 31, 2017. The total includes $163.4 million related to the Acceleration Payment and 6 individually immaterial acquisitions and $150.6 million of development projects.

Our cash capital expenditures were $41.5 million for the year ended December 31, 2016. The total includes $12.0 million related to 3 individually immaterial acquisitions and $29.5 million of development projects.

We currently anticipate that our development capital budget, which predominantly consists of drilling, recompletion and well stimulation projects related to our horizontal Permian Basin inventory will be approximately $225 million for the year ending December 31, 2018. Our available borrowing capacity under our Revolving Credit Agreement is $72.2 million as of February 21, 2018. The amount and timing of our capital expenditures is largely discretionary and within our control, with the exception of certain projects managed by other operators. Accordingly, we routinely monitor and adjust our capital expenditures in response to changes in oil and natural gas prices, drilling and acquisition costs, industry conditions, non-operated capital requirements and internally generated cash flow. Matters outside our control that could affect the timing of our capital expenditures include obtaining required permits and approvals in a timely manner as well as other regulatory matters.

We enter into oil and natural gas derivatives to reduce the impact of oil and natural gas price volatility on our operations. At February 21, 2018, we had in place oil, natural gas and price differential derivatives covering portions of our estimated 2018 through 2019 oil and natural gas production.

By reducing the cash flow effects of price volatility from a portion of our oil and natural gas production, we have mitigated, but not eliminated, the potential effects of changing prices on our cash flow from operations for those periods. While mitigating negative effects of falling commodity prices, these derivative contracts also limit the benefits we would receive from increases in commodity prices. It is our policy to enter into derivative contracts only with counterparties that are major, creditworthy institutions deemed by management as competent and competitive market makers. In addition, none of our current counterparties require us to post margin. However, we cannot be assured that all of our counterparties will meet their obligations under our derivative contracts. Due to this uncertainty, we routinely monitor the creditworthiness of our counterparties.

The following tables summarize, for the periods indicated, our oil and natural gas derivatives in place as of February 21, 2018 covering the period from January 1, 2018 through December 31, 2019. We use derivatives, including swaps, enhanced swaps and three-way collars, as our mechanism for offsetting the cash flow effects of changes in commodity prices whereby we pay the counterparty floating prices and receive fixed prices from the counterparty, which serves to reduce the effects on cash flow of the floating prices we are paid by purchasers of our oil and natural gas. These transactions are mostly settled based upon the monthly average closing price of front-month NYMEX WTI oil and the price on the last trading day of front-month NYMEX Henry Hub natural gas.

Oil Swaps:

Calendar Year	Volumes (Bbls)	Average Price per Bbl	Price Range per Bbl
2018	2,998,500	$54.67	$51.20 - $63.68

Natural Gas Swaps:

Calendar Year	Volumes (MMBtu)	Average Price per MMBtu	Price Range per MMBtu
2018	36,200,000	$3.23	$3.04 - $3.39
2019	25,800,000	$3.36	$3.29 - $3.39

We have entered into regional crude oil differential swap contracts in which we have swapped the floating WTI-ARGUS (Midland) crude oil price for floating WTI-ARGUS (Cushing) less a fixed-price differential. As noted above, we receive a discount to the NYMEX WTI crude oil price at the point of sale. Due to refinery downtimes and limited takeaway capacity that has impacted the Permian Basin, the difference between the WTI-ARGUS (Midland) price, which is the price we receive on almost all of our Permian crude oil production, and the WTI-ARGUS (Cushing) price reached historic highs in late 2012 and early 2013 and again in late 2014. We entered into these differential swaps to negate a portion of this volatility. The following table summarizes the oil differential swap contracts currently in place as of February 21, 2018, covering the period from January 1, 2018 though December 31, 2019:

Time Period	Volumes (Bbls)	Average Price per Bbl	Price Range per Bbl
2018	4,015,000	$(1.13)	$(1.25) - $(0.80)
2019	730,000	$(1.15)	$(1.15)

We have also entered into multiple NYMEX WTI crude oil costless collar contracts. Each contract combines a long put option or "floor" with a short call option or "ceiling." At an annual WTI market price of $40.00, $50.00 and $65.00, the summary positions below would result in a net price of $47.06, $50.00 and $60.29, respectively for 2018. The following table summarizes the costless oil collar contracts currently in place as of February 21, 2018, covering the period from January 1, 2018 through December 31, 2018:

Time Period	Volumes (Bbls)	Average Long Put Price per Bbl	Average Short Call Price per Bbl
2018	1,551,250	$47.06	$60.29

We have also entered into multiple NYMEX WTI crude oil derivative enhanced swap contracts. The first type of enhanced swap contract combines buying a lower-priced put, selling a higher-priced put, and using the net proceeds from these positions to simultaneously obtain a swap at above market prices ("enhanced swap price"). If the market price is at or above the higher-priced short put, this contract allows us to settle at the enhanced swap price. If the market price is below the higher-priced short put but above the lower-priced long put, this contract allows us to settle for the market price plus the spread between the enhanced swap price and the higher-priced short put. If the market price is at or below the lower-priced long put, this contract allows us to settle for the lower-priced long put plus the spread between the enhanced swap price and the higher-priced short put. For example, at an annual average WTI market price of $40.00, $50.00 and $65.00, the summary positions below would result in a net price of $65.50, $65.50 and $73.50, respectively for 2018. The following table summarizes these type of enhanced swap contracts currently in place as of February 21, 2018, covering the period from January 1, 2018 through December 31, 2018:

Calendar Year	Volumes (Bbls)	Average Long Put Price per Bbl	Average Short Put Price per Bbl	Average Swap Price per Bbl
2018	127,750	$57.00	$82.00	$90.50

Financing Activities

Our net cash provided by financing activities was $177.7 million for the year ended December 31, 2017, compared to $119.1 million used in financing activities for the year ended December 31, 2016. During the year ended December 31, 2017, total net borrowings under our Revolving Credit Agreement were $36.0 million. We raised $142.1 million in proceeds, net of original issue discount, but excluding other offering expenses paid by us, from a draw under our Term Loan Credit Agreement. Legacy's net cash used in financing activities was $119.1 million for the year ended December 31, 2016, compared to $376.7 million provided by financing activities for the year ended December 31, 2015. During the year ended December 31, 2016, total net repayments under our Revolving Credit Agreement were $145.0 million. We raised $58.8 million in proceeds, net of original issue discount, but excluding other offering expenses paid by Legacy, from a draw under our Term Loan Credit Agreement. Our net cash provided by financing activities was $376.7 million for the year ended December 31, 2015. During the year ended December 31, 2015, total net borrowings under our Revolving Credit Agreement were $499.0 million. Finally, we had a cash outflow during the year ended December 31, 2015 in the amount of $120.4 million for distributions to unitholders and our Series A and Series B Preferred unitholders.

On June 4, 2014, we issued 300,000 incentive distribution units representing limited partner interests in us (the "Incentive Distribution Units") to WPX Energy Rocky Mountain, LLC ("WPX"), an affiliate of WPX Energy, Inc. ("WPX Energy"), as part of the Piceance Acquisition. The Incentive Distribution Units issued to WPX include 100,000 Incentive Distribution Units that immediately vested along with the ability to vest in up to an additional 200,000 Incentive Distribution Units (the "Unvested IDUs") in connection with any future asset sales or transactions completed with us pursuant to the terms of the IDR Holders Agreement. Incentive Distribution Units that are not issued to WPX or other parties will remain in our treasury for the benefit of all limited partners until such time as Legacy may make future issuances of Incentive Distribution Units. Effective January 1, 2016, WPX has assigned its vested and unvested IDUs to WPX Energy Holdings, LLC, a controlled affiliate of WPX Energy. As of June 4, 2017, all of the Unvested IDUs had been forfeited.

Our Revolving Credit Facility

On April 1, 2014, we entered into our Revolving Credit Agreement. Borrowings under the Revolving Credit Agreement mature on April 1, 2019. Our obligations under the Revolving Credit Agreement are secured by mortgages on over 95% of the total value of our oil and natural gas properties as well as a pledge of all of our ownership interests in our operating subsidiaries. The amount available for borrowing at any one time is limited to the borrowing base and contains a $2 million sub-limit for letters of credit. The borrowing base is currently set at $575 million, and as of February 21, 2018, we have approximately $502 million drawn under the Revolving Credit Agreement leaving approximately $72.2 million of current availability. The borrowing base is subject to semi-annual redeterminations on or about April 1 and October 1 of each year. Additionally, either we or the lenders may, once during each calendar year, elect to redetermine the borrowing base between scheduled redeterminations. We also have the right, once during each calendar year, to request the redetermination of the borrowing base upon the proposed acquisition of certain oil and natural gas properties where the purchase price is greater than 10% of the borrowing base. Any increase in the borrowing base requires the consent of all the lenders, and any decrease in or maintenance of the borrowing base must be approved by the lenders holding at least 66-2/3% of the outstanding aggregate principal amounts of the loans or participation interests in letters of credit issued under the Revolving Credit Agreement. If the required lenders do not agree on an increase or decrease, then the borrowing base will be the highest borrowing base acceptable to the lenders holding 66-2/3% of the outstanding aggregate principal amounts of the loans or participation interests in letters of credit issued under the Revolving Credit Agreement so long as it does not increase the borrowing base then in effect.

The Revolving Credit Agreement permits us to issue additional senior notes in order to refinance our currently outstanding Senior Notes as well as to issue an additional $300 million in aggregate principal amount of new senior notes, in each case, subject to specified conditions in the Revolving Credit Agreement (including pro forma compliance with the first lien debt to EBITDA ratio and interest coverage ratio described below), which include that the borrowing base shall be reduced by an amount equal to (i) (A) in the case of new senior notes, 25% of the stated principal amount of such senior notes and (B) in the case of refinancing our currently outstanding Senior Notes, 100% of the portion of the new debt that exceeds the original principal amount of the senior notes being refinanced or (ii) in the sole discretion of the lenders holding at least 66-2/3% of the outstanding aggregate principal amounts of the loans or participation interests in letters of credit issued under the Revolving Credit Agreement prior to the issuance of the senior notes or new debt, an amount less than the amount specified in clause (A). In addition, we must prepay any amount outstanding under the Revolving Credit Agreement in excess of the redetermined borrowing base upon such a reduction.

We may elect that borrowings be comprised entirely of alternate base rate ("ABR") loans or Eurodollar loans. Interest on the loans is determined as follows:

- with respect to ABR loans, the alternate base rate equals the highest of the prime rate, the Federal funds effective rate plus 0.50%, or the one-month London Interbank Offered Rate ("LIBOR") plus 1.00%, plus an applicable margin ranging from and including 1.00% to 2.00% per annum, determined by the percentage of the borrowing base then in effect that is utilized, provided, that if the ratio of our first lien debt as of the last day of any fiscal quarter to our EBITDA (as defined in the Revolving Credit Agreement) for the four fiscal quarters ending on such day is greater than 3.00 to 1.00, then the applicable margin shall be increased by 0.50% during the next succeeding fiscal quarter, or
- with respect to any Eurodollar loans, one-, two-, three- or six-month LIBOR plus an applicable margin ranging from and including 2.00% to 3.00% per annum, determined by the percentage of the borrowing base then in effect that is utilized.

We pay a commitment fee ranging from and including 0.375% to 0.50% per annum on the average daily amount of the unused amount of the commitments under the Revolving Credit Agreement, determined by the percentage of the borrowing base then in effect that is utilized, payable quarterly.

Interest is generally payable quarterly for ABR loans and on the last day of the applicable interest period for any Eurodollar loans.

Our Revolving Credit Agreement also contains various covenants that limit our ability to:

- incur indebtedness;
- enter into certain leases;
- grant certain liens;
- enter into certain derivatives;
- make certain loans, acquisitions, capital expenditures and investments;
- make distributions other than from available cash;
- merge, consolidate or allow certain material changes in the character of our business;
- repurchase Senior Notes or repay second lien term loans;
- engage in certain asset dispositions, including a sale of all or substantially all of our assets; or
- maintain a consolidated cash balance in excess of $20 million without prepaying the loans in an amount equal to such excess.

Our Revolving Credit Agreement also contains covenants that, among other things, require us to maintain specified ratios or conditions as follows:

- as of any day, first lien debt to EBITDA for the four fiscal quarters ending on the last day of the fiscal quarter immediately preceding the date of determination for which financial statements are available to not be greater than: 2.50 to 1.00;
- as of the last day of any fiscal quarter secured debt to EBITDA for the four fiscal quarters ending on the last day of the fiscal quarter immediately preceding the date of determination to not be greater than 4.50 to 1.00 beginning with the fiscal quarter ending December 31, 2018;

- as of the last day of any fiscal quarter, total EBITDA over the last four quarters to total interest expense over the last four quarters to be greater than 2.00 to 1.00;
- consolidated current assets, as of the last day of the most recent quarter and including the unused amount of the total commitments, to consolidated current liabilities as of the last day of the most recent quarter of not less than 1.00 to 1.00, excluding current maturities under the Revolving Credit Agreement and non-cash assets and liabilities under ASC 815, which includes the current portion of oil, natural gas and interest rate derivatives;
- as of the last day of any fiscal quarter, the ratio of (a) the sum of (i) the net present value using NYMEX forward pricing, discounted at 10 percent per annum, of our proved developed producing oil and gas properties (“PDP PV-10”), as reflected in the most recent reserve report delivered either July 1 or December 31 of each year, as the case may be, beginning with the reserve report to be delivered on July 1, 2017 (giving pro forma effect to material acquisitions or dispositions since the date of such reports), (ii) the net mark to market value of our swap agreements and (iii) our cash and cash equivalents to (b) Secured Debt to not be equal to or less than 1.00 to 1.00 .

If an event of default exists under our Revolving Credit Agreement, the lenders will be able to accelerate the maturity of the credit agreement and exercise other rights and remedies. Each of the following would be an event of default:

- failure to pay any principal when due or any reimbursement amount, interest, fees or other amount within certain grace periods;
- a representation or warranty is proven to be incorrect when made;
- failure to perform or otherwise comply with the covenants or conditions contained in the Revolving Credit Agreement or other loan documents, subject, in certain instances, to certain grace periods;
- default by us on the payment of any other indebtedness in excess of $15.0 million, or any event occurs that permits or causes the acceleration of the indebtedness;
- bankruptcy or insolvency events involving us or any of our subsidiaries;
- the loan documents cease to be in full force and effect;
- our failing to create a valid lien, except in limited circumstances;
- a change of control, which will occur upon (i) the acquisition by any person or group of persons of beneficial ownership of more than 50% of the aggregate ordinary voting power of our equity securities, (ii) the acquisition by any person or group of persons (excluding us and our subsidiaries) of beneficial ownership of more than 50% of the aggregate voting power or economic interest in our general partner, (iii) the first day on which a majority of the members of the board of directors of our general partner are not continuing directors (which is generally defined to mean members of our board of directors as of April 1, 2014 and persons who are nominated for election or elected to our general partner’s board of directors with the approval of a majority of the continuing directors who were members of such board of directors at the time of such nomination or election), (iv) the direct or indirect sale, transfer or other disposition in one or a series of related transactions of all or greater than 50% of the properties or assets (including equity interests of subsidiaries) of us and our subsidiaries to any person, (v) the adoption of a plan related to our liquidation or dissolution or (vi) Legacy Reserves GP, LLC’s ceasing to be our sole general partner; provided that, under certain circumstances, a conversion from one form of entity to another form of entity or exchange of equity interests in another form entity shall not constitute a change in control;
- the entry of, and failure to pay, one or more adverse judgments in excess of $15.0 million or one or more non-monetary judgments that could reasonably be expected to have a material adverse effect and for which enforcement proceedings are brought or that are not stayed pending appeal;
- specified ERISA events relating to our employee benefit plans that could reasonably be expected to result in liabilities in excess of $2.0 million in any year;

- the Intercreditor Agreement (as defined below) ceases to be in effect, except to the extent permitted by the terms thereof; and
- if an "Event of Default" occurs under the Term Loan Credit Agreement (as defined below).

As of December 31, 2017, we were in compliance with all financial and other covenants of the Revolving Credit Agreement. Should oil and natural gas prices decline in 2018, we could breach certain financial covenants under our Revolving Credit Agreement, which would constitute a default under our Revolving Credit Agreement. Such default, if not remedied, would require a waiver from our lenders in order for us to avoid an event of default and subsequent acceleration of all amounts outstanding under our Revolving Credit Agreement or foreclosure on our oil and natural gas properties. As previously noted, if the lenders under our Revolving Credit Agreement were to accelerate the indebtedness under our Revolving Credit Agreement as a result of a default, such acceleration could cause a cross-default of all of our other outstanding indebtedness, including our second lien term loans and Senior Notes, and permit the holders of such indebtedness to accelerate the maturities of such indebtedness. While no assurances can be made that, in the event of a covenant breach, such a waiver will be granted, we believe the long-term global outlook for commodity prices and our efforts to date, which include the suspension of distributions to our unitholders and Preferred Unitholders, as well as completed asset sales, will be viewed positively by our lenders.

Our Second Lien Term Loans

On October 25, 2016, we entered into our Term Loan Credit Agreement among us, as borrower, Cortland Capital Market Services LLC, as administrative agent and second lien collateral agent, and the lenders party thereto, providing for second lien term loans up to an aggregate principal amount of $300.0 million and subsequently increased to $400.0 million on December 31, 2017 as part of the third amendment to the Term Loan Credit Agreement. GSO Capital Partners L.P. ("GSO") and certain funds and accounts managed, advised or sub-advised, by GSO are the initial lenders thereunder. The second lien term loans are secured on a second lien priority basis by the same collateral that secures the Revolving Credit Agreement and are unconditionally guaranteed on a joint and several basis by the same wholly owned subsidiaries of ours that are guarantors under the Revolving Credit Agreement.

We used the initial $60.0 million of gross loan proceeds from our Term Loan Credit Agreement to repay outstanding indebtedness and pay associated transaction expenses. We used subsequent draws to fund the acceleration payment under our JDA and repurchase a portion of our 2021 Senior Notes. Additional second lien term loans up to an aggregate amount of $61.4 million are available until October 25, 2019. The second lien term loans under the Term Loan Credit Agreement will be issued with an upfront fee of 2% and bear interest at a rate of 12.00% per annum payable quarterly in cash or, prior to the 18 month anniversary of the Term Loan Credit Agreement, we may elect to pay in kind up to 50% of the interest payable. The second lien term loans may be used for general corporate purposes and for the repayment of outstanding indebtedness, in any case as may be approved by us and GSO. For the first 24 months following the effective date of the Term Loan Credit Agreement, GSO may not assign more than 49% of the second lien term loans without our consent. The Term Loan Credit Agreement matures on August 31, 2021; provided that, if on July 1, 2020, we have greater than or equal to a face amount of $15.0 million of Senior Notes that were outstanding on the date the Term Loan Credit Agreement was entered into or any other senior notes with a maturity date that is earlier than August 31, 2021, the Term Loan Credit Agreement will mature on August 1, 2020. The Term Loan Credit Agreement contains customary prepayment provisions and make-whole premiums.

The Term Loan Credit Agreement also contains covenants that, among other things, require us to maintain specified ratios or conditions as follows:

- not permit, as of the last day of the fiscal quarter, the ratio of the sum of (i) PDP PV-10, (ii) the net mark to market value of our swap agreements and (iii) our cash and cash equivalents to Secured Debt to be less than (i) 0.85 to 1.00 through and including the fiscal quarter ended December 31, 2018 and (ii) 1.00 to 1.00 thereafter;
- not permit, as of the last day of any fiscal quarter beginning with the fiscal quarter ending December 31, 2018, our ratio of Secured Debt as of such day to EBITDA for the four fiscal quarters then ending to be greater than 4.50 to 1.00;
- within a certain period of time after the date of the Term Loan Credit Agreement, enter into hedging transactions covering at least 75% of the projected oil and natural gas production from Proved Developed Producing Properties for each month until the two year anniversary of the Term Loan Credit Agreement;
- We are required to mortgage 95% of the total value of all of its Oil and Gas Properties set forth in the most recently evaluated Reserve Report and grant a mortgage on certain identified undeveloped acreage in the Permian Basin; and
- require us to grant a perfected security interest in its cash and securities accounts, subject to certain customary exceptions.

All capitalized terms used but not defined in the foregoing description have the meaning assigned to them in the Term Loan Credit Agreement.

As of December 31, 2017, we were in compliance with all financial and other covenants of the Term Loan Credit Agreement.

A customary intercreditor agreement was entered into by Wells Fargo Bank, National Association, as priority lien agent, and Cortland Capital Markets Services LLC, as junior lien agent and acknowledged and accepted by Legacy and the subsidiary guarantors (the “Intercreditor Agreement”). If an event of default exists under the Term Loan Credit Agreement, subject to the terms of the Intercreditor Agreement, the lenders will be able to accelerate the maturity of the Term Loan Credit Agreement and exercise other rights and remedies.

8% Senior Notes Due 2020

On December 4, 2012, we and our 100% owned subsidiary Legacy Reserves Finance Corporation completed a private placement offering to eligible purchasers of an aggregate principal amount of $300.0 million of our 2020 Senior Notes, which were subsequently registered through a public exchange offer that closed on January 8, 2014. The 2020 Senior Notes were issued at 97.848% of par. We received net proceeds of approximately $286.7 million, after deducting the discount to initial purchasers and offering expense paid by us.

We have the option to redeem the 2020 Senior Notes, in whole or in part, at any time on or after December 1, 2016, at the specified redemption prices set forth below together with any accrued and unpaid interest to the date of redemption, if redeemed during the twelve-month period beginning on December 1 of the years indicated below.

Year	Percentage
2017	102.000%
2018	100.000%

We may be required to offer to repurchase the 2020 Senior Notes at a purchase price of 101% of the principal amount, plus accrued and unpaid interest, if any, to the redemption date, in the event of a change of control as defined by the indenture. Our and Legacy Reserves Finance Corporation’s obligations under the 2020 Senior Notes are guaranteed by our 100% owned subsidiaries Legacy Reserves Operating GP LLC, Legacy Reserves Operating LP, Legacy Reserves Services, Inc., Legacy Reserves Energy Services LLC, Dew Gathering LLC and Pinnacle Gas Treating LLC, which constitute all of Legacy’s wholly-owned subsidiaries other than Legacy

Reserves Finance Corporation. In the future, the guarantees may be released or terminated under the following circumstances: (i) in connection with any sale or other disposition of all or substantially all of the properties of the guarantor; (ii) in connection with any sale or other disposition of sufficient capital stock of the guarantor so that it no longer qualifies as our Restricted Subsidiary (as defined in the indenture); (iii) if designated to be an unrestricted subsidiary; (iv) upon legal defeasance, covenant defeasance or satisfaction and discharge of the indenture; (v) upon the liquidation or dissolution of the guarantor provided no default or event of default has occurred or is occurring; (vi) at such time the guarantor does not have outstanding guarantees of our, or any other guarantor's, other debt; or (vii) upon merging into, or transferring all of its properties to us or another guarantor and ceasing to exist. Refer to Note 14 - Subsidiary Guarantors in the Notes to the Consolidated Financial Statements for further details on our guarantors.

The indenture governing the 2020 Senior Notes limits our ability and the ability of certain of our subsidiaries to (i) sell assets; (ii) pay distributions on, repurchase or redeem equity interests or purchase or redeem our subordinated debt, provided that such subsidiaries may pay dividends to the holders of their equity interests (including us) and we may pay distributions to the holders of our equity interests subject to the absence of certain defaults, the satisfaction of a fixed charge coverage ratio test and so long as the amount of such distributions does not exceed the sum of available cash (as defined in our partnership agreement) at Legacy, net proceeds from the sales of certain securities and return of or reductions to capital from restricted investments; (iii) make certain investments; (iv) incur or guarantee additional indebtedness or issue preferred units; (v) create or incur certain liens; (vi) enter into agreements that restrict distributions or other payments from certain of our subsidiaries to us; (vii) consolidate, merge or transfer all or substantially all of our assets; (viii) engage in certain transactions with affiliates; (ix) create unrestricted subsidiaries; and (x) engage in certain business activities. These covenants are subject to a number of important exceptions and qualifications. If at any time when the 2020 Senior Notes are rated investment grade by each of Moody's Investors Service, Inc. and Standard & Poor's Ratings Services and no Default (as defined in the indenture) has occurred and is continuing, many of such covenants will terminate and we and our subsidiaries will cease to be subject to such covenants. The indenture also includes customary events of default. We are in compliance with all financial and other covenants of the 2020 Senior Notes. As previously noted, if the lenders under our Revolving Credit Agreement were to accelerate the indebtedness under our Revolving Credit Agreement as a result of a default, such acceleration could cause a cross-default of all of our other outstanding indebtedness and permit the holders of such indebtedness to accelerate the maturities of such indebtedness.

During the year ended December 31, 2016, we repurchased a face amount of $52.0 million of our 2020 Senior Notes on the open market. We treated these repurchases as an extinguishment of debt. Accordingly, we recognized a gain for the difference between (1) the face amount of the 2020 Senior Notes repurchased net of the unamortized portion of both the original issuer's discount and issuance costs and (2) the repurchase price.

On June 1, 2016, we exchanged 2,719,124 units for $15.0 million of face amount of its outstanding 2020 Senior Notes. We treated this exchange as an extinguishment of debt. Accordingly, we recognized a gain for the difference between (1) the face amount of the 2020 Senior Notes repurchased net of the unamortized portion of both the original issuer's discount and issuance costs and (2) the fair value of the units issued in the exchange based on the closing price on June 1, 2016. We previously repurchased and exchanged, and have not retired, $67.0 million of our 2020 Senior Notes. Subject to certain restrictions, we retain our voting rights under the indenture governing the 2020 Senior Notes.

6.625% Senior Notes Due 2021

On May 28, 2013, we and our 100% owned subsidiary Legacy Reserves Finance Corporation completed a private placement offering to eligible purchasers of an aggregate principal amount of $250 million of our 2021 Senior Notes. The 2021 Senior Notes were issued at 98.405% of par. We received approximately $240.7 million of net cash proceeds, after deducting the discount to initial purchasers and offering expenses paid by us.

On May 13, 2014, Legacy and its 100% owned subsidiary Legacy Reserves Finance Corporation completed a private placement offering to eligible purchasers of an aggregate principal amount of an additional $300 million of our 6.625% 2021 Senior Notes. This issuance of our 2021 Senior Notes was at 99.0% of par. We received approximately $291.8 million of net cash proceeds, after deducting the discount to initial purchasers and offering expenses payable by us.

The terms of the 2021 Senior Notes, including details related to our guarantors, are substantially identical to the terms of the 2020 Senior Notes with the exception of the interest rate and redemption provisions noted below. We will have the option to redeem the 2021 Senior Notes, in whole or in part, at any time on or after June 1, 2017, at the specified redemption prices set forth below together with any accrued and unpaid interest, if any, to the date of redemption if redeemed during the twelve-month period beginning on June 1 of the years indicated below.

Year	Percentage
2017	103.313%
2018	101.656%
2019 and thereafter	100.000%

Legacy may be required to offer to repurchase the 2021 Senior Notes at a purchase price of 101% of the principal amount, plus accrued and unpaid interest, if any, to the redemption date, in the event of a change of control as defined by the indenture. We are in compliance with all financial and other covenants of the 2021 Senior Notes. Our and Legacy Reserves Finance Corporation's obligations under the 2021 Senior Notes are guaranteed by the same parties and on the same terms as our 2020 Senior Notes discussed above. Further, if the lenders under Legacy's Credit Agreement were to accelerate the indebtedness under Legacy's Credit Agreement as a result of a default, such acceleration could cause a cross-default of all of the 2021 Senior Notes and permit the holders of such notes to accelerate the maturities of such indebtedness.

On December 31, 2017, we entered into an agreement to repurchase a face amount of $187.1 million of our 2021 Senior Notes from certain holders in a single transaction. The transaction was settled on January 5, 2018 and will therefore be recognized in 2018. We will treat these repurchases as an extinguishment of debt. Accordingly, we will recognize a gain for the difference between (1) the face amount of the 2021 Senior Notes repurchased net of the unamortized portion of both the original issuer's discount and issuance costs and (2) the repurchase price.

During the year ended December 31, 2016, we repurchased a face amount of $117.3 million of our 2021 Senior Notes on the open market. We treated these repurchases as an extinguishment of debt. Accordingly, we recognized a gain for the difference between (1) the face amount of the 2021 Senior Notes repurchased net of the unamortized portion of both the original issuer's discount and issuance costs and (2) the repurchase price. We previously repurchased, and have not retired, $304.4 million of our 2021 Senior Notes. Subject to certain restrictions, we retain our voting rights under the indenture governing the 2021 Senior Notes.

Off-Balance Sheet Arrangements

None.

Contractual Obligations

A summary of our contractual obligations as of December 31, 2017 is provided in the following table.

Contractual Cash Obligations	Obligations Due in Period				
	2018	2019-2020	2021-2022	Thereafter	Total
			(In thousands)		
Long-term debt					
Revolving credit facility(a)	$ —	$ 499,000	$ —	$ —	$ 499,000
Interest on revolving credit facility(b)	21,806	5,452	—	—	27,258
Second Lien Term Loans	—	205,000	—	—	205,000
Interest on Second Lien Term Loans	24,600	38,950	—	—	63,550
Senior Notes(c)	—	232,989	432,656	—	665,645
Interest on Senior Notes	47,302	93,051	11,943	—	152,296
Management compensation(d)	2,430	4,860	4,860	—	12,150
Employee compensation(e)	3,101	823	—	—	3,924
Office lease	1,341	2,361	—	—	3,702
Total contractual cash obligations	$100,580	$1,082,486	$449,459	$ —	$1,632,525

(a) Represents amounts outstanding under our revolving credit facility as of December 31, 2017.

(b) Based upon our weighted average interest rate of 4.37% under our revolving credit facility as of December 31, 2017.

(c) Includes $187.1 million of 2021 Senior Notes repurchased on January 5, 2018.

(d) The related employment agreements do not contain termination provisions; therefore, the ultimate payment obligation is not known. For purposes of this table, management has not reflected payments subsequent to 2022.

(e) Legacy has bonus agreements with certain of its non-executive employees. The bonus agreements provide for fixed bonus amounts to be paid to employees contingent upon various criteria including their continuous employment or a change in control.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations is based upon the consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our consolidated financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is a reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. Estimates and assumptions are evaluated on a regular basis. We based our estimates on historical experience and various other 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. Actual results may differ from these estimates and assumptions used in preparation of the financial statements. Changes in these estimates and assumptions could materially affect our financial position, results of operations or cash flows. Management considers an accounting estimate to be critical if:

- it requires assumptions to be made that were uncertain at the time the estimate was made, and
- changes in the estimate or different estimates that could have been selected could have a material impact on our consolidated results of operations or financial condition.

Please read Note 1 of the Notes to Consolidated Financial Statements for a detailed discussion of all significant accounting policies that we employ and related estimates made by management.

Nature of Critical Estimate Item: Oil and Natural Gas Reserves — Our estimate of proved reserves is based on the quantities of oil and gas which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under existing economic and operating conditions. LaRoche prepares a reserve and economic evaluation of all our properties in accordance with Securities and Exchange Commission, or "SEC," guidelines on a lease, unit or well-by-well basis, depending on the availability of well-level production data. The accuracy of our reserve estimates is a function of many factors including the following: the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions, and the judgments of the individuals preparing the estimates. In addition, we must estimate the amount and timing of future operating costs, severance taxes, development costs, and workover costs, all of which may in fact vary considerably from actual results. In addition, as prices and cost levels change from year to year, the economics of producing the reserves may change and therefore the estimate of proved reserves also may change. Any significant variance in these assumptions could materially affect the estimated quantity and value of our reserves. Despite the inherent imprecision in these engineering estimates, our reserves are used throughout our financial statements. Reserves and their relation to estimated future net cash flows impact our depletion and impairment calculations. As a result, adjustments to depletion rates are made concurrently with changes to reserve estimates.

Assumptions/Approach Used: Units-of-production method to deplete our oil and natural gas properties — The quantity of reserves could significantly impact our depletion expense. Any reduction in proved reserves without a corresponding reduction in capitalized costs will increase the depletion rate.

Effect if Different Assumptions Used: Units-of-production method to deplete our oil and natural gas properties — A 10% increase or decrease in reserves would have decreased or increased, respectively, our depletion expense for the year ended December 31, 2017 by approximately 10%.

Nature of Critical Estimate Item: Asset Retirement Obligations — We have certain obligations to remove tangible equipment and restore land at the end of oil and gas production operations. Our removal and restoration obligations are primarily associated with plugging and abandoning wells. GAAP requires us to estimate asset retirement costs for all of our assets, adjust those costs for inflation to the forecast abandonment date, discount that amount using a credit-adjusted-risk-free rate back to the date we acquired the asset or obligation to retire the asset and record an asset retirement obligation ("ARO") liability in that amount with a corresponding addition to our asset value. When new obligations are incurred, i.e. a new well is drilled or acquired, we add a layer to the ARO liability. We then accrete the liability layers quarterly using the applicable effective credit-adjusted-risk-free rate for each layer. Should either the estimated life or the estimated abandonment costs of a property change materially upon our periodic review, a new calculation is performed using the same methodology of taking the abandonment cost and inflating it forward to its abandonment date and then discounting it back to the present using our credit-adjusted-risk-free rate. The carrying value of the ARO is adjusted to the newly calculated value, with a corresponding offsetting adjustment to the asset retirement cost. When well obligations are relieved by sale of the property or plugging and abandoning the well, the related liability and asset costs are removed from our balance sheet. Any difference in the cost to plug and the related liability is recorded as a gain or loss on our income statement in the disposal of assets line item.

Assumptions/Approach Used: Estimating the future asset 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. Inherent in the estimate of the present value calculation of our AROs are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit-adjusted-risk-free rates, timing of settlement, and changes in the legal, regulatory, environmental and political environments.

Effect if Different Assumptions Used: Since there are so many variables in estimating AROs, we attempt to limit the impact of management's judgment on certain of these variables by developing a standard cost estimate based on historical costs and industry quotes updated annually. Unless we expect a well's plugging to be significantly different than a normal abandonment, we use this estimate. The resulting estimate, after application of a discount factor and present value calculation, could differ from actual results, despite our efforts to make an accurate estimate. We engage independent engineering firms to evaluate our properties annually. We consider the remaining estimated useful life from the year-end reserve report prepared by our independent reserve engineers in estimating when abandonment could be expected for each property. On an annual basis we evaluate our latest estimates against actual abandonment costs incurred.

Nature of Critical Estimate Item: Derivative Instruments and Hedging Activities — We use derivative financial instruments to achieve a more predictable cash flow from our oil and natural gas production and interest expense by reducing our exposure to price fluctuations and interest rate changes. Currently, these transactions are swaps, enhanced swaps and collars whereby we exchange our floating price for our oil and natural gas for a fixed price and floating interest rates for fixed rates with qualified and creditworthy counterparties. The contracts with our counterparties enable us to avoid margin calls for out-of-the-money positions.

We do not specifically designate derivative instruments as cash flow hedges, even though they reduce our exposure to changes in oil and natural gas prices and interest rate changes. Therefore, the mark-to-market of these instruments is recorded in current earnings. We estimate market values utilizing software provided by a third party firm, which specializes in valuing derivatives, and validate these estimates by comparison to counterparty estimates as the basis for these end-of-period mark-to-market adjustments. In order to estimate market values, we use forward commodity price curves, if available, or estimates of forward curves provided by third party pricing experts. For our interest rate swaps, we use a yield curve based on money market rates and interest swap rates to estimate market value. When we record a mark-to-market adjustment resulting in a gain or loss in a current period, this change in fair value represents a current period mark-to-market adjustment for commodity derivatives which will be settled in future periods. As shown in the previous tables, we have hedged a portion of our future production through 2019. Taking into account the mark-to-market liabilities and assets recorded as of December 31, 2017, the future cash obligations table presented above shows the amounts which we would expect to pay the counterparties over the time periods shown. As oil and gas prices rise and fall, our future cash obligations related to these derivatives will rise and fall.

Nature of Critical Estimate Item: Oil and Natural Gas Property Impairments — Oil and natural gas properties are reviewed for impairment when facts and circumstances indicate that their carrying value may not be recoverable. Legacy compares net capitalized costs of proved oil and natural gas properties to estimated undiscounted future net cash flows using management's expectations of future oil and natural gas prices. These future price scenarios reflect Legacy's estimation of future price volatility. If net capitalized costs exceed estimated undiscounted future net cash flows, the measurement of impairment is based on estimated fair value, using estimated discounted future net cash flows. Significant inputs used to determine the fair values of proved properties include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices and (iv) a market-based weighted average cost of capital rate. The underlying commodity prices embedded in Legacy's estimated cash flows are the product of a process that begins with NYMEX forward curve pricing, adjusted for estimated location and quality differentials, as well as other factors that Legacy's management believes will impact realizable prices.

As of December 31, 2017, a 10% decrease in net cash flows attributable to our production caused by any one or a combination of variables, including commodity prices, development costs, changes in production levels or other factors, would increase our recognized oil and natural gas property impairments by $6.0 million.

Recently Issued Accounting Pronouncements

In February 2016, the FASB issued ASU No. 2016-02, Leases ("ASU 2016-02"). ASU 2016-02 establishes a right-of-use (ROU) model that requires a lessee to record a ROU asset and a lease liability on the balance sheet for all leases with terms longer than 12 months. Leases will be classified as either finance or operating, with classification affecting the pattern of expense recognition in the income statement. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. A modified retrospective transition approach is required for lessees for capital and operating leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements, with certain practical expedients available. We are currently evaluating the impact of our pending adoption of ASU 2016-02 on our consolidated financial statements.

In May 2014, the FASB issued ASU No. 2014-09, "Revenue from Contracts with Customers" ("ASU 2014-09"), which supersedes nearly all existing revenue recognition guidance under U.S. GAAP. The core principle of ASU 2014-09 is to recognize revenues when promised goods or services are transferred to customers in an amount that reflects the consideration to which an entity expects to be entitled for those goods or services. ASU 2014-09 defines a five step process to achieve this core principle and, in doing so, more judgment and estimates may be required within the revenue recognition process than are required under existing U.S. GAAP. In August 2015, the FASB issued ASU No. 2015-14, "Revenue from Contracts with Customers" ("ASU 2015-14"), which approved a one-year delay of the standard's effective date. In accordance with ASU 2015-14, the standard is now effective for annual periods beginning after December 15, 2017, and interim periods therein, using either of the following transition methods: (i) a full retrospective approach reflecting the application of the standard in each prior reporting period with the option to elect certain practical expedients, or (ii) a retrospective approach with the cumulative effect of initially adopting ASU 2014-09 recognized at the date of adoption (which includes additional footnote disclosures). We will adopt ASU 2014-09 utilizing the modified retrospective approach as of January 1, 2018.

We have completed our scoping and impact assessment of ASU 2014-09. Our assessment included involvement from a consultant to assist with our implementation methodology and development of conclusions related to the impact that ASU 2014-09 is expected to have on our financial statements.

In performing our impact assessment, we evaluated a representative population of revenue contracts related to our three material revenue streams: oil, natural gas and natural gas liquids. Through our contract review process, we identified all material contract types and contractual features that represent our revenue. For those contracts evaluated during its implementation, we reviewed key contract provisions under ASU 2014-09 to assess the impact on the amount and timing of revenue recognition, as well as the presentation of revenues upon adoption of the new standard. As a part of this assessment, we compared our historical accounting policies and practices to that required by ASU 2014-09.

Based upon work completed to date, the adoption of ASU 2014-09 will not have a material impact on net profit. However, certain reclassifications between revenue and expenses will be required based upon our assessment of (i) where control of our product passes to our customer for certain natural gas and NGL contracts and (ii) whether we represent the principal or the agent in certain arrangements. In addition, our disclosures surrounding revenue recognition will be more robust upon adoption of ASU 2014-09. We are continuing to perform other implementation activities, including the development of new controls and policies and draft disclosures.

ITEM 7A. *QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK*

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in oil and natural gas prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

Commodity Price Risk

Our major market risk exposure is in the pricing applicable to our oil and natural gas production. Realized pricing is primarily driven by the spot market prices applicable to our natural gas production and the prevailing price for crude oil. Pricing for oil, natural gas and NGLs has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside of our control, such as the strength of the global economy and the supply of oil outside of the United States.

We periodically enter into and anticipate entering into derivative arrangements with respect to a portion of our projected oil and natural gas production through various transactions that offset changes in the future prices received. These transactions may include swaps, enhanced swaps and three-way collars. These derivative activities are intended to support oil and natural gas prices at targeted levels and to manage our exposure to oil and natural gas price fluctuations. We do not hold or issue derivative instruments for speculative trading purposes.

As of December 31, 2017, the fair market value of Legacy's commodity derivative positions was a net asset of $6.3 million. As of December 31, 2016, the fair market value of Legacy's commodity derivative positions was a net asset of $12.7 million. We routinely monitor the credit default risk of our counterparties via risk monitoring services. For more discussion about our derivative transactions and to see a table listing the oil and natural gas derivatives for 2018 through December 31, 2019, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations—Investing Activities."

If oil prices decline by $1.00 per Bbl, then the standardized measure of our combined proved reserves as of December 31, 2017 would decline from $1,172.1 million to $1,145.3 million, or 2.3%. If natural gas prices decline by $0.10 per Mcf, then the standardized measure of our combined proved reserves as of December 31, 2017 would decline from $1,172.1 million to $1,143.5 million, or 2.4%. However, larger decreases in oil and natural gas prices may have a disproportionate impact on our standardized measure.

Interest Rate Risks

At December 31, 2017, Legacy had debt outstanding under the Revolving Credit Agreement of $499 million, which incurred interest at floating rates in accordance with its Revolving Credit Agreement. The average annual interest rate incurred by Legacy for the year ended December 31, 2017 on its floating rate borrowings was 4.18%. A 1% increase in LIBOR on Legacy's outstanding floating rate debt as of December 31, 2017 would result in an estimated $2.6 million increase in annual interest expense as Legacy has entered into interest rate swaps to mitigate the volatility of interest rates. The interest rate swaps expire on September 1, 2019 and cover $235 million of floating rate debt with a weighted-average fixed rate of 1.36%. It is never management's intention to hold or issue derivative instruments for speculative trading purposes. Conditions sometimes arise where actual borrowings are less than notional amounts hedged which has and could result in overhedged amounts.

ITEM 8. *FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA*

Our Consolidated Financial Statements and supplementary financial data are included in this annual report on Form 10-K beginning on page F-3.

ITEM 9. *CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE*

None.

ITEM 9A. *CONTROLS AND PROCEDURES*

We maintain disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended, or the "Exchange Act") that are designed to ensure that information required to be disclosed in Exchange Act reports is recorded, processed, summarized, and reported within the time periods specified in the rules and forms of the SEC and that such information is accumulated and communicated to our management, including our general partner's Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. Any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives.

Our management, with the participation of our general partner's Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the design and operation of our disclosure controls and procedures as of December 31, 2017. Based upon that evaluation and subject to the foregoing, our general partner's Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures provide reasonable assurance that such controls and procedures were effective to accomplish their objectives.

Our general partner's Chief Executive Officer and Chief Financial Officer do not expect that our disclosure controls or our internal controls will prevent all error and all fraud. The design of a control system must reflect the fact that there are resource constraints and the benefit of controls must be considered relative to their cost. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that we have detected all of our control issues and all instances of fraud, if any. The design of any system of controls also is based partly on certain assumptions about the likelihood of future events and there can be no assurance that any design will succeed in achieving our stated goals under all potential future conditions.

There have been no changes in our internal control over financial reporting that occurred during our fiscal quarter ended December 31, 2017, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Annual Report on Internal Control over Financial Reporting

Legacy's management is responsible for establishing and maintaining adequate control over financial reporting. Our internal control over financial reporting is a process designed by, or under the supervision of, our general partner's Chief Executive Officer and Chief Financial Officer, and effected by the board of directors of our general partner, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Our internal control over financial reporting includes those policies and procedures that:

- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of management and the board of directors of our general partner; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisitions, use or disposition of our assets that could have a material effect on our financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. 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 and procedures may deteriorate.

As of December 31, 2017, management assessed the effectiveness of Legacy's internal control over financial reporting based on the criteria for effective internal control over financial reporting established in "Internal Control — Integrated Framework (2013)," issued by the Committee of Sponsoring Organizations of the Treadway Commission. This assessment included design effectiveness and operating effectiveness of internal controls over financial reporting as well as the safeguarding of assets. Based on that assessment, management determined that Legacy maintained effective internal control over financial reporting as of December 31, 2017, based on those criteria.

BDO USA, LLP, the independent registered public accounting firm who also audited our Consolidated Financial Statements included in this Annual Report on Form 10-K, has issued an attestation report on our internal control over financial reporting as of December 31, 2017, which is set forth below under "Attestation Report."

Report of Independent Registered Public Accounting Firm

Board of Directors and Unitholders
Legacy Reserves LP
Midland, Texas

Opinion on Internal Control over Financial Reporting

We have audited Legacy Reserves LP's (the "Partnership") internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the "COSO criteria"). In our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated balance sheets of the Partnership and subsidiaries as of December 31, 2017 and 2016, the related consolidated statements of operations, unitholders' equity, and cash flows for each of the three years in the period ended December 31, 2017, and the related notes, and our report dated February 23, 2018 expressed an unqualified opinion thereon.

Basis for Opinion

The Partnership's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Item 9A, Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Partnership's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Partnership in accordance with U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit of internal control over financial reporting in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the 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.

/s/ BDO USA, LLP
Houston, Texas
February 23, 2018

ITEM 9B. *OTHER INFORMATION*

None.

PART III

ITEM 10. *DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE*

We intend to include the information required by this Item 10 in Legacy's definitive proxy statement for its 2018 annual meeting of unitholders under the headings "Election of Directors," "Corporate Governance" and "Section 16(a) Beneficial Ownership Reporting Compliance," which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2017.

ITEM 11. *EXECUTIVE COMPENSATION*

We intend to include information with respect to executive compensation in Legacy's definitive proxy statement for its 2018 annual meeting of unitholders under the heading "Executive Compensation," which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2017.

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

We intend to include information regarding Legacy's securities authorized for issuance under equity compensation plans and ownership of Legacy's outstanding securities in Legacy's definitive proxy statement for its 2018 annual meeting of unitholders under the headings "Equity Compensation Plan Information" and "Security Ownership of Certain Beneficial Owners and Management," respectively, which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2017.

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

We intend to include the information regarding related party transactions in Legacy's definitive proxy statement for its 2018 annual meeting of unitholders under the headings "Corporate Governance" and "Certain Relationships and Related Transactions," which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2017.

ITEM 14. *PRINCIPAL ACCOUNTING FEES AND SERVICES*

We intend to include information regarding principal accountant fees and services in Legacy's definitive proxy statement for its 2018 annual meeting of unitholders under the heading "Independent Registered Public Accounting Firm," which information will be incorporated herein by reference; such proxy statement will be filed with the SEC not later than 120 days after December 31, 2017.

PART IV

ITEM 15. *EXHIBITS, FINANCIAL STATEMENT SCHEDULES*

(a)(1) and (2) Financial Statements

The consolidated financial statements of Legacy Reserves LP are listed on the Index to Financial Statements to this annual report on Form 10-K beginning on page F-1.

(a)(3) Exhibits

The following documents are filed as a part of this annual report on Form 10-K or incorporated by reference:

Exhibit Number		Description
2.1	—	Membership Interest Purchase and Sale Agreement, dated July 3, 2015, by and between Legacy Reserves Operating LP and WGR Operating LP (Incorporated by reference to Legacy Reserves LP’s current report on Form 8-K (File No. 001-33249) filed on July 9, 2015, Exhibit 2.1)
2.2	—	Purchase and Sale Agreement, dated July 3, 2015, by and between Legacy Reserves Operating LP and Anadarko E&P Onshore LLC (Incorporated by reference to Legacy Reserves LP’s current report on Form 8-K (File No. 001-33249) filed on July 9, 2015, Exhibit 2.2)
3.1	—	Certificate of Limited Partnership of Legacy Reserves LP (Incorporated by reference to Legacy Reserves LP’s Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 3.1)
3.2	—	Fifth Amended and Restated Agreement of Limited Partnership of Legacy Reserves LP dated April 10, 2017 (Incorporated by reference to Legacy Reserves LP's quarterly report on Form 8-K filed on April 10, 2017, Exhibit 3.1)
3.3	—	Certificate of Formation of Legacy Reserves GP, LLC (Incorporated by reference to Legacy Reserves LP’s Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 3.3)
3.4	—	Amended and Restated Limited Liability Company Agreement of Legacy Reserves GP, LLC (Incorporated by reference to Legacy Reserves LP’s Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 3.4)
3.5	—	First Amendment to Amended and Restated Limited Liability Company Agreement of Legacy Reserves GP, LLC (Incorporated by reference to Legacy Reserves LP's quarterly report on Form 10-Q (File No. 001-33249) filed on May 4, 2012, Exhibit 3.6)
3.6	—	Second Amendment to Amended and Restated Limited Liability Company Agreement of Legacy Reserves GP, LLC. (Incorporated by reference to Legacy Reserves LP's quarterly report on Form 10-Q (File No. 001-33249) filed on May 4, 2012, Exhibit 3.7)
4.1	—	Registration Rights Agreement dated June 29, 2006, between Henry Holdings LP and Legacy Reserves LP and Legacy Reserves GP, LLC (the “Henry Registration Rights Agreement”) (Incorporated by reference to Legacy Reserves LP’s Registration Statement on Form S-1 (File No. 333-134056) filed September 5, 2006, Exhibit 4.2)
4.2	—	Registration Rights Agreement dated March 15, 2006, by and among Legacy Reserves LP, Legacy Reserves GP, LLC and the other parties thereto (the “Founders Registration Rights Agreement”) (Incorporated by reference to Legacy Reserves LP’s Registration Statement on Form S-1 (File No. 333-134056) filed September 5, 2006, Exhibit 4.3)
4.3	—	Indenture, dated as of December 4, 2012, among Legacy Reserves LP, Legacy Reserves Finance Corporation, the Guarantors named therein and Wells Fargo Bank, National Association, as trustee (including form of the 8% senior notes due 2020) (Incorporated by reference to Legacy Reserves LP's current report on Form 8-K (File No. 001-33249) filed December 10, 2012, Exhibit 4.1)
4.4	—	Indenture, dated as of May 28, 2013, among Legacy Reserves LP, Legacy Reserves Finance Corporation, the Guarantors named therein and Wells Fargo Bank, National Association, as trustee (including form of 6.625% senior notes due 2021) (Incorporated by reference to Legacy Reserves LP’s current report on Form 8-K (File No. 001-33249) filed May 31, 2013, Exhibit 4.1)
4.5	—	First Supplemental Indenture, dated as of August 25, 2015, among Legacy Reserves LP, Legacy Reserves Finance Corporation, the Guarantors named therein and Wells Fargo Bank, National Association, as trustee (related to 8% Senior Notes due 2020) (Incorporated by reference to Legacy Reserves LP’s quarterly report on Form 10-Q (File No. 001-33249) filed November 6, 2015, Exhibit 10.2)
4.6	—	First Supplemental Indenture, dated as of August 25, 2015, among Legacy Reserves LP, Legacy Reserves Finance Corporation, the Guarantors named therein and Wells Fargo Bank, National Association, as trustee (related to 6.625% Senior Notes due 2021) (Incorporated by reference to Legacy Reserves LP’s quarterly report on Form 10-Q (File No. 001-33249) filed November 6, 2015, Exhibit 10.3)

Exhibit Number		Description
10.1	—	Third Amended and Restated Credit Agreement, among Legacy Reserves LP, as Borrower, Wells Fargo Bank, National Association, as Administrative Agent, Compass Bank, as Syndication Agent, UBS Securities LLC and U.S. Bank National Association, as Co-Documentation Agents and the Lenders Party thereto, dated as of April 1, 2014 (Incorporated by reference to Legacy Reserves LP’s current report on Form 8-K (File No. 001-33249) filed April 2, 2014, Exhibit 10.1)
10.2	—	First Amendment to Third Amended and Restated Credit Agreement, dated April 17, 2014, by and between Legacy Reserves LP, Wells Fargo Bank, National Association, as administrative agent and certain other financial institutions party thereto as lenders (Incorporated by reference to Legacy Reserves LP’s quarterly report on Form 10-Q (File No. 001-33249) filed October 31, 2014, Exhibit 10.1)
10.3	—	Second Amendment to Third Amended and Restated Credit Agreement, dated May 22, 2014, among Legacy Reserves LP, as borrower, the guarantors named therein, Wells Fargo Bank, National Association as administrative agent, and the lenders signatory thereto (Incorporated by reference to Legacy Reserves LP’s current report on Form 8-K (File No. 001-33249) filed May 28, 2014, Exhibit 10.1)
10.4	—	Third Amendment to Third Amended and Restated Credit Agreement, dated December 29, 2014, among Legacy Reserves LP, as borrower, the guarantors named therein, Wells Fargo Bank, National Association, as administrative agent, and the lenders signatory thereto (Incorporated by reference to Legacy Reserves LP's annual report on Form 10-K (File No. 001-33249) filed on February 27, 2015, Exhibit 10.11)
10.5	—	Fourth Amendment to Third Amended and Restated Credit Agreement, dated February 23, 2015, among Legacy Reserves LP, as borrower, the guarantors named therein, Wells Fargo Bank, National Association, as administrative agent, and the lenders signatory thereto (Incorporated by reference to Legacy Reserves LP's annual report on Form 10-K (File No. 001-33249) filed on February 27, 2015, Exhibit 10.12)
10.6	—	Fifth Amendment to Third Amended and Restated Credit Agreement, dated August 5, 2015, among Legacy Reserves LP, as borrower, the guarantors named therein, Wells Fargo Bank, National Association, as administrative agent, and the lenders signatory thereto (Incorporated by reference to Legacy Reserves LP’s quarterly report on Form 10-Q (File No. 001-33249) filed August 7, 2015, Exhibit 10.2)
10.7	—	Sixth Amendment to Third Amended and Restated Credit Agreement, dated November 13, 2015, among Legacy Reserves LP, as borrower, the guarantors named therein, Wells Fargo Bank, National Association, as administrative agent, and the lenders signatory thereto (Incorporated by reference to Legacy Reserves LP's annual report on Form 10-K (File No. 001-33249) filed on February 26, 2016, Exhibit 10.14)
10.8	—	Seventh Amendment to Third Amended and Restated Credit Agreement, dated February 19, 2016, among Legacy Reserves LP, as borrower, the guarantors named therein, Wells Fargo Bank, National Association, as administrative agent, and the lenders signatory thereto (Incorporated by reference to Legacy Reserves LP’s current report on Form 8-K (File No. 001-33249) filed on February 24, 2016, Exhibit 10.1)
10.9	—	Eighth Amendment to Third Amended and Restated Credit Agreement, dated October 25, 2016, among Legacy Reserves LP, as borrower, the guarantors named therein, Wells Fargo Bank, National Association, as administrative agent, and the lenders signatory thereto (Incorporated by reference to Legacy Reserves LP’s current report on Form 8-K (File No. 001-33249) filed October 28, 2016, Exhibit 10.2)
10.10	—	Term Loan Credit Agreement, among Legacy Reserves LP, as Borrower, Cortland Capital Market Services LLC, as Administrative Agent and the lenders party thereto, dated as of October 25, 2016 (Incorporated by reference to Legacy Reserves LP’s current report on Form 8-K (File No. 001-33249) filed October 28, 2016, Exhibit 10.1)

Exhibit Number		Description
10.11	—	First Amendment and Waiver to Term Loan Credit Agreement, among Legacy Reserves LP, as Borrower, Cortland Capital Market Services LLC, as Administrative Agent, and the lenders party thereto, dated as of July 31, 2017 (Incorporated by reference to Legacy Reserves LP's quarterly report on Form 10-Q (File No. 001-33249) filed on August 4, 2017, Exhibit 10.1)
10.12	—	Second Amendment to Term Loan Credit Agreement, among Legacy Reserves LP, as Borrower, Cortland Capital Market Services LLC, as Administrative Agent, and the lenders party thereto, dated as of October 30, 2017 (Incorporated by reference to Legacy Reserves LP’s quarterly report on Form 10-Q (File No. 001-33249) filed on November 1, 2017, Exhibit 10.1)
10.13	—	Third Amendment to Term Loan Credit Agreement, among Legacy Reserves LP, as Borrower, Cortland Capital Market Services LLC, as Administrative Agent, and the lenders party thereto, dated as of December 31, 2017 (Incorporated by reference to Legacy Reserves LP’s current report on Form 8-K (File No. 001-33249) filed on January 5, 2018, Exhibit 10.1)
10.14	—	Note Purchase Agreement, among Legacy Reserves LP, Fir Tree Value Master Fund, L.P., Fir Tree Capital Opportunity Master Fund, L.P., Fir Tree Capital Opportunity Master Fund III, L.P., FT SOF IV Holdings, LLC, FT SOF V Holdings, LLC and FT SOF VII Holdings, LLC, dated as of December 31, 2017 (Incorporated by reference to Legacy Reserves LP’s current report on Form 8-K (File No. 001-33249) filed on January 5, 2018, Exhibit 10.2)
10.15*		Standstill and Voting Agreement, among Legacy Reserves GP, Legacy Reserves LP, Fir Tree Capital Management LP, Fir Tree Value Master Fund, L.P., Fir Tree Capital Opportunity Master Fund, L.P., Fir Tree Capital Opportunity Master Fund III, L.P., FT SOF IV Holdings, LLC, FT SOF V Holdings, LLC, FT SOF VII Holdings, LLC and Fir Tree E&P Holdings XI, LLC, dated as of December 31, 2017
10.16†	—	Amendment No. 1 to the Amended and Restated Legacy Reserves LP Long-Term Incentive Plan, dated as of June 12, 2015. (Incorporated by reference to Legacy Reserves LP’s current report on Form 8-K (File No. 001-33249) filed on June 12, 2015, Exhibit 10.1)
10.17†	—	Amended and Restated Legacy Reserves LP Long-Term Incentive Plan effective as of August 17, 2007 (Incorporated by reference to Legacy Reserves LP’s current report on Form 8-K (File No. 001-33249) filed August 23, 2007, Exhibit 10.1)
10.18†	—	Form of Legacy Reserves LP Long-Term Incentive Plan Restricted Unit Grant Agreement (Incorporated by reference to Legacy Reserves LP’s Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 10.6)
10.19†	—	Form of Legacy Reserves LP Long-Term Incentive Plan Unit Option Grant Agreement (Incorporated by reference to Legacy Reserves LP’s Registration Statement on Form S-1 (File No. 333-134056) filed September 5, 2006, Exhibit 10.7)
10.20†	—	Form of Legacy Reserves LP Long-Term Incentive Plan Unit Grant Agreement (Incorporated by reference to Legacy Reserves LP’s Registration Statement on Form S-1 (File No. 333-134056) filed September 5, 2006, Exhibit 10.8)
10.21†	—	Employment Agreement dated as of March 15, 2006, between Kyle A. McGraw and Legacy Reserves Services, Inc. (Incorporated by reference to Legacy Reserves LP’s Registration Statement on Form S-1 (File No. 333-134056) filed May 12, 2006, Exhibit 10.11)
10.22†	—	Section 409A Compliance Amendment to Employment Agreement dated December 31, 2008, between Kyle A. McGraw and Legacy Reserves Services, Inc. (Incorporated by reference to Legacy Reserves LP’s current report on Form 8-K (File No. 001-33249) filed December 31, 2008, Exhibit 10.3)
10.23†	—	Employment Agreement dated as of March 15, 2006, between Paul T. Horne and Legacy Reserves Services, Inc. (Incorporated by reference to Legacy Reserves LP’s Registration Statement on Form S-1 (File No. 333- 134056) filed May 12, 2006, Exhibit 10.12)
10.24†	—	Section 409A Compliance Amendment to Employment Agreement dated December 31, 2008, between Paul T. Horne and Legacy Reserves Services, Inc. (Incorporated by reference to Legacy Reserves LP’s current report on Form 8-K (File No. 001-33249) filed December 31, 2008, Exhibit 10.4)

Exhibit Number		Description
10.25†	—	Employment Agreement effective April 1, 2012 between Micah C. Foster and Legacy Reserves Services, Inc. (Incorporated by reference to Legacy Reserves LP's current report on Form 8-K (File No. 001-33249) filed April 25, 2012, Exhibit 10.1)
10.26†	—	Employment Agreement effective May 1, 2012 between Dan G. LeRoy and Legacy Reserves Services, Inc. (Incorporated by reference to Legacy Reserves LP's quarterly report on Form 10-Q (File No. 001-33249) filed August 3, 2012, Exhibit 10.3)
10.27†	—	Employment Agreement effective September 24, 2012 between James Daniel Westcott and Legacy Reserves Services, Inc. (Incorporated by reference to Legacy Reserves LP’s quarterly report on Form 10-Q (File No. 001-33249) filed October 31, 2012, Exhibit 10.1)
10.28†	—	Employment Agreement effective as of March 1, 2015, between Kyle M. Hammond and Legacy Reserves Services, Inc. (Incorporated by reference to Legacy Reserves LP’s current report on Form 8-K (File No. 001-33249) filed on February 27, 2015, Exhibit 10.1)
10.29†	—	Second Amendment to Employment Agreement effective as of March 1, 2015, between Legacy Reserves Services, Inc., Paul T. Horne and Legacy Reserves GP, LLC. (Incorporated by reference to Legacy Reserves LP’s current report on Form 8-K (File No. 001-33249) filed on February 27, 2015, Exhibit 10.2)
10.30†	—	Second Amendment to Employment Agreement effective as of March 1, 2015, between Legacy Reserves Services, Inc., Kyle A. McGraw and Legacy Reserves GP, LLC. (Incorporated by reference to Legacy Reserves LP’s current report on Form 8-K (File No. 001-33249) filed on February 27, 2015, Exhibit 10.3)
10.31†	—	Form of Legacy Reserves LP Long-Term Incentive Plan Grant of Phantom Units (Objective) (Incorporated by reference to Legacy Reserves LP's annual report on Form 10-K (File No. 001-33249) filed on February 21, 2014, Exhibit 10.25)
10.32†	—	Form of Legacy Reserves LP Long-Term Incentive Plan Grant of Phantom Units (Subjective) (Incorporated by reference to Legacy Reserves LP’s annual report on Form 10-K (File No. 001-33249) filed on February 21, 2014, Exhibit 10.26)
10.33†	—	Form of Grant of Phantom Units Under Objective Component of Long-Term Equity Incentive Compensation (Incorporated by reference to Legacy Reserves LP’s current report on Form 8-K (File No. 001-33249) filed on June 17, 2016, Exhibit 10.1)
10.34†	—	Form of Grant of Phantom Units (Cash) Under Subjective Component of Long-Term Equity Incentive Compensation (Incorporated by reference to Legacy Reserves LP’s current report on Form 8-K (File No. 001-33249) filed on June 17, 2016, Exhibit 10.2)
10.35†	—	Form of Grant of Phantom Units (Units) Under Subjective Component of Long-Term Equity Incentive Compensation (Incorporated by reference to Legacy Reserves LP’s current report on Form 8-K (File No. 001-33249) filed on June 17, 2016, Exhibit 10.3)
10.36†	—	Form of Retention Bonus Agreement (Incorporated by reference to Legacy Reserves LP’s current report on Form 8-K (File No. 001-33249) filed on June 17, 2016, Exhibit 10.4)
10.37†	—	Purchase and Sale Agreement, by and between WPX Energy Rocky Mountain, LLC, Legacy Reserves Operating LP, Legacy Reserves GP, LLC and Legacy Reserves LP (schedules omitted pursuant to Item 601(b)(2) of Regulation S-K), dated May 2, 2014 (Incorporated by reference to Legacy Reserves LP’s current report on Form 8-K (File No. 001-33249) filed May 6, 2014, Exhibit 2.1)
10.38†	—	IDR Holders Agreement, dated June 4, 2014, by and between Legacy Reserves LP and WPX Rocky Mountain, LLC (Incorporated by reference to Legacy Reserves LP’s current report on Form 8-K (File No. 001-33249) filed June 4, 2014, Exhibit 10.1)
10.39†	—	Form of Legacy Reserves LP Long-Term Incentive Plan Grant of Phantom Units (Units) Under Subjective Component of Long-Term Equity Incentive Compensation (Incorporated by reference to Legacy Reserves LP's current report on Form 8-K (File No. 001-33249) filed on February 22, 2017, Exhibit 10.1)

Exhibit Number		Description
10.40†	—	Form of Legacy Reserves LP Long-Term Incentive Plan Grant of Phantom Units (Cash) Under Subjective Component of Long-Term Equity Incentive Compensation (Incorporated by reference to Legacy Reserves LP's current report on Form 8-K (File No. 001-33249) filed on February 22, 2017, Exhibit 10.2)
10.41†	—	Form of Legacy Reserves LP Long-Term Incentive Plan Grant of Phantom Units Under Objective Component of Long-Term Equity Incentive Compensation (Incorporated by reference to Legacy Reserves LP's current report on Form 8-K (File No. 001-33249) filed on February 22, 2017, Exhibit 10.3)
10.42†	—	Form of Retention Bonus Agreement (Incorporated by reference to Legacy Reserves LP's current report on Form 8-K (File No. 001-33249) filed on February 22, 2017, Exhibit 10.4)
21.1*	—	List of subsidiaries of Legacy Reserves LP
23.1*	—	Consent of BDO USA, LLP
23.2*	—	Consent of LaRoche Petroleum Consultants, Ltd.
31.1*	—	Rule 13a-14(a) Certification of CEO (under Section 302 of the Sarbanes-Oxley Act of 2002)
31.2*	—	Rule 13a-14(a) Certification of CFO (under Section 302 of the Sarbanes-Oxley Act of 2002)
32.1*	—	Section 1350 Certifications (under Section 906 of the Sarbanes-Oxley Act of 2002)
99.1*	—	Summary Reserve Report from LaRoche Petroleum Consultants, Ltd.
101.INS*	—	XBRL Instance Document
101.SCH*	—	XBRL Taxonomy Extension Schema Document
101.DEF*	—	XBRL Taxonomy Extension Definition Linkbase Document
101.PRE*	—	XBRL Taxonomy Extension Presentation Linkbase Document
101.CAL*	—	XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB*	—	XBRL Taxonomy Extension Label Linkbase Document

* Filed herewith

† Management contract or compensatory plan or arrangement

ITEM 16. *FORM 10-K SUMMARY*

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this annual report on Form 10-K to be signed on its behalf by the undersigned, thereunto duly authorized, on the 23rd day of February, 2018.

LEGACY RESERVES LP

By: LEGACY RESERVES GP, LLC,
its general partner

By: /s/ JAMES DANIEL WESTCOTT

Name: James Daniel Westcott
Title: Executive Vice President and Chief Financial Officer (Principal Financial Officer)

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that each person whose signature appears below hereby constitutes and appoints Paul T. Horne and James Daniel Westcott, or either of them, each with power to act without the other, his true and lawful attorney-in-fact and agent, with full power of substitution and resubstitution, for him and in his name, place and stead, in any and all capacities, to sign any or all subsequent amendments and supplements to this Annual Report on Form 10-K, and to file the same, or cause to be filed the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto each said attorney-in-fact and agent full power to do and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as he might or could do in person, hereby qualifying and confirming all that said attorney-in-fact and agent or his substitute or substitutes may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this annual report on Form 10-K 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/ PAUL T. HORNE Paul T. Horne	Chairman of the Board, President and Chief Executive Officer (Principal Executive Officer)	February 23, 2018
/s/ JAMES DANIEL WESTCOTT James Daniel Westcott	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 23, 2018
/s/ MICAH C. FOSTER Micah C. Foster	Chief Accounting Officer and Controller (Principal Accounting Officer)	February 23, 2018
/s/ KYLE A. MCGRAW Kyle A. McGraw	Executive Vice President, Chief Development Officer and Director	February 23, 2018
/s/ CARY D. BROWN Cary D. Brown	Director	February 23, 2018
/s/ DALE A. BROWN Dale A. Brown	Director	February 23, 2018
/s/ WILLIAM R. GRANBERRY William R. Granberry	Director	February 23, 2018
/s/ G. LARRY LAWRENCE G. Larry Lawrence	Director	February 23, 2018
/s/ WILLIAM D. SULLIVAN William D. Sullivan	Director	February 23, 2018
/s/ KYLE D. VANN Kyle D. Vann	Director	February 23, 2018
/s/ D. DWIGHT SCOTT D. Dwight Scott	Director	February 23, 2018

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INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

Board of Directors and Unitholders
Legacy Reserves LP
Midland, Texas

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Legacy Reserves LP (the “Partnership”) and subsidiaries as of December 31, 2017 and 2016, the related consolidated statements of operations, unitholders’ equity, and cash flows for each of the three years in the period ended December 31, 2017, and the related notes (collectively referred to as the “consolidated financial statements”). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Partnership and subsidiaries at December 31, 2017 and 2016, and the results of their operations and their 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.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (“PCAOB”), the Partnership’s internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”) and our report dated February 23, 2018 expressed an unqualified opinion thereon.

Basis for Opinion

These consolidated financial statements are the responsibility of the Partnership’s management. Our responsibility is to express an opinion on the Partnership’s consolidated financial statements based on our audits. We are a public accounting firm registered with the 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 consolidated financial statements are free of material misstatement, whether due to error or fraud.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated 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 consolidated 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 consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ BDO USA, LLP

We have served as the Partnership’s auditor since 2005.

Houston, Texas
February 23, 2018

LEGACY RESERVES LP

CONSOLIDATED BALANCE SHEETS
AS OF DECEMBER 31, 2017 AND 2016

	2017	2016
	(In thousands)	
ASSETS		
Current assets:		
Cash	$ 1,246	$ 2,555
Accounts receivable, net:		
Oil and natural gas	62,755	43,192
Joint interest owners	27,420	23,414
Other	2	2
Fair value of derivatives (Notes 8 and 9)	13,424	6,162
Prepaid expenses and other current assets	7,757	7,447
Total current assets	112,604	82,772
Oil and natural gas properties, at cost:		
Proved oil and natural gas properties using the successful efforts method of accounting	3,529,971	3,305,856
Unproved properties	28,023	13,448
Accumulated depletion, depreciation, amortization and impairment	(2,204,638)	(2,137,395)
Total oil and natural gas properties, net	1,353,356	1,181,909
Other property and equipment, net of accumulated depreciation and amortization of $11,467 and $10,412, respectively	2,961	3,423
Operating rights, net of amortization of $5,765 and $5,369, respectively	1,251	1,648
Fair value of derivatives (Notes 8 and 9)	14,099	20,553
Other assets	8,811	9,521
Total assets	$ 1,493,082	$ 1,299,826
LIABILITIES AND PARTNERS' DEFICIT		
Current liabilities:		
Accounts payable	$ 13,093	$ 9,092
Accrued oil and natural gas liabilities (Note 1)	81,318	53,248
Fair value of derivatives (Notes 8 and 9)	18,013	9,743
Asset retirement obligation (Note 11)	3,214	2,980
Other (Notes 8 and 13)	29,172	11,546
Total current liabilities	144,810	86,609
Long-term debt (Note 3)	1,346,769	1,161,394
Asset retirement obligation (Note 11)	271,472	269,168
Fair value of derivatives (Notes 8 and 9)	1,075	4,091
Other long-term liabilities	643	643
Total liabilities	1,764,769	1,521,905
Commitments and contingencies (Note 6)		
Partners' equity (deficit):		
Series A Preferred equity - 2,300,000 units issued and outstanding at December 31, 2017 and December 31, 2016	55,192	55,192
Series B Preferred equity - 7,200,000 units issued and outstanding at December 31, 2017 and December 31, 2016	174,261	174,261
Incentive distribution equity - 100,000 units issued and outstanding at December 31, 2017 and December 31, 2016	30,814	30,814
Limited partners' deficit - 72,594,620 and 72,056,097 units issued and outstanding at December 31, 2017 and 2016, respectively	(531,794)	(482,200)
General partner's deficit (approximately 0.03%)	(160)	(146)
Total partners' deficit	(271,687)	(222,079)
Total liabilities and partners' deficit	$ 1,493,082	$ 1,299,826

See accompanying notes to consolidated financial statements.

LEGACY RESERVES LP

CONSOLIDATED STATEMENTS OF OPERATIONS
FOR THE YEARS ENDED DECEMBER 31, 2017, 2016 AND 2015

	2017	2016	2015
	(In thousands, except per unit data)		
Revenues:			
Oil sales	$ 239,448	$ 152,507	$ 199,841
Natural gas liquids (NGL) sales	24,796	15,406	16,645
Natural gas sales	172,057	146,444	122,293
Total revenues	436,301	314,357	338,779
Expenses:			
Oil and natural gas production	183,219	179,333	194,491
Production and other taxes	19,825	14,267	16,383
General and administrative	49,372	43,639	46,511
Depletion, depreciation, amortization and accretion	126,938	150,414	177,258
Impairment of long-lived assets	37,283	61,796	633,805
Loss (gain) on disposal of assets	1,606	(50,095)	(3,972)
Total expenses	418,243	399,354	1,064,476
Operating income (loss)	18,058	(84,997)	(725,697)
Other income (expense):			
Interest income	64	67	329
Interest expense (Notes 3, 8 and 9)	(89,206)	(79,060)	(76,891)
Gain on extinguishment of debt	—	150,802	—
Equity in income of equity method investees	17	—	126
Net gains (losses) on commodity derivatives (Notes 8 and 9)	17,776	(41,224)	98,253
Other	792	(179)	841
Loss before income taxes	(52,499)	(54,591)	(703,039)
Income tax (expense) benefit	(1,398)	(1,229)	1,498
Net loss	$ (53,897)	$ (55,820)	$ (701,541)
Distributions to preferred unitholders	(19,000)	(19,000)	(19,000)
Net loss attributable to unitholders	$ (72,897)	$ (74,820)	$ (720,541)
Loss per unit — basic and diluted (Note 12)	$ (1.01)	$ (1.06)	$ (10.45)
Weighted average number of units used in computing loss per unit — Basic and Diluted	72,405	70,605	68,928

See accompanying notes to consolidated financial statements.

LEGACY RESERVES LP

CONSOLIDATED STATEMENTS OF UNITHOLDERS' EQUITY FOR THE YEARS ENDED DECEMBER 31, 2017, 2016 AND 2015

	Series A Preferred Equity		Series B Preferred Equity		Incentive Distribution Equity		Unitholders' Equity (Deficit)			
	Units	Amount	Units	Amount	Units	Amount	Limited Partner Units	Limited Partner Amount	General Partner Amount	Total Partners' Equity (Deficit)
						(In thousands)				
Balance, December 31, 2014	2,300	$55,192	7,200	$174,261	100	$30,814	68,911	$ 376,885	$ 53	$ 637,205
Units issued to Legacy Board of Directors for services	—	—	—	—	—	—	66	604	—	604
Unit-based compensation	—	—	—	—	—	—	—	5,858	—	5,858
Vesting of restricted and phantom units	—	—	—	—	—	—	78	—	—	—
Issuance of units, net	—	—	—	—	—	—	—	(103)	—	(103)
Incentive Distribution Units issued in exchange for oil and natural gas properties	—	—	—	—	—	—	(105)	(1,349)	—	(1,349)
Distributions to preferred unitholders	—	—	—	—	—	—	—	(19,000)	—	(19,000)
Distributions to unitholders, $1.46 per unit	—	—	—	—	—	—	—	(101,351)	—	(101,351)
Net loss	—	—	—	—	—	—	—	(701,355)	(186)	(701,541)
Balance, December 31, 2015	2,300	$55,192	7,200	$174,261	100	$30,814	68,950	$(439,811)	$ (133)	$(179,677)
Units issued to Legacy Board of Directors for services	—	—	—	—	—	—	237	614	—	614
Unit-based compensation	—	—	—	—	—	—	—	6,252	—	6,252
Vesting of restricted and phantom units	—	—	—	—	—	—	150	—	—	—
Units issued in exchange for retirement of debt	—	—	—	—	—	—	2,719	6,607	—	6,607
Distributions to unitholders	—	—	—	—	—	—	—	(55)	—	(55)
Net loss	—	—	—	—	—	—		(55,807)	(13)	(55,820)
Balance, December 31, 2016	2,300	$55,192	7,200	$174,261	100	$30,814	72,056	$(482,200)	$ (146)	$(222,079)
Units issued to Legacy Board of Directors for services	—	—	—	—	—	—	287	586	—	586
Unit-based compensation	—	—	—	—	—	—	—	3,703	—	3,703
Vesting of restricted and phantom units	—	—	—	—	—	—	252	—	—	—
Net loss	—	—	—	—	—	—	—	(53,883)	(14)	(53,897)
Balance, December 31, 2017	2,300	$55,192	7,200	$174,261	100	$30,814	72,595	$(531,794)	$ (160)	$(271,687)

See accompanying notes to consolidated financial statements.

LEGACY RESERVES LP

CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2017, 2016 AND 2015

	2017	2016	2015
		(In thousands)	
Cash flows from operating activities:			
Net loss	$ (53,897)	$ (55,820)	$ (701,541)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:			
Depletion, depreciation, amortization and accretion	126,938	150,414	177,258
Amortization of debt discount and issuance costs	7,657	10,319	5,532
Gain on extinguishment of debt	—	(150,802)	—
Impairment of long-lived assets	37,283	61,796	633,805
(Gain) loss on derivatives	(19,711)	40,679	(99,971)
Equity in income of equity method investees	(17)	—	(126)
Distribution from equity method investee	—	—	191
Unit-based compensation	6,011	7,035	6,451
Loss (gain) on disposal of assets	1,606	(50,095)	(3,972)
Changes in assets and liabilities:			
(Increase) decrease in accounts receivable, oil and natural gas	(19,563)	(9,248)	15,447
(Increase) decrease in accounts receivable, joint interest owners	(4,006)	1,964	(9,143)
Decrease in accounts receivable, other	—	84	151
(Increase) decrease in other assets	417	(940)	333
Increase (decrease) in accounts payable	4,001	(4,489)	10,794
Increase (decrease) in accrued oil and natural gas liabilities	1,891	2,675	(28,042)
Increase (decrease) in other liabilities	11,599	(3,882)	(5,121)
Total adjustments	154,106	55,510	703,587
Net cash provided by (used in) operating activities	100,209	(310)	2,046
Cash flows from investing activities:			
Investment in oil and natural gas properties	(313,898)	(41,496)	(577,186)
Proceeds from sale of assets	11,099	97,416	69,118
Investment in other equipment	(593)	(436)	(2,277)
Net cash settlements on commodity derivatives	24,156	64,505	132,925
Net cash (used in) provided by investing activities	(279,236)	119,989	(377,420)
Cash flows from financing activities:			
Proceeds from long-term debt	538,000	266,000	840,000
Payments of long-term debt	(357,000)	(376,402)	(341,000)
Payments of debt issuance costs	(3,282)	(8,728)	(1,891)
Proceeds from issuance of limited partner interests, net	—	—	(103)
Distributions to unitholders	—	—	(120,351)
Net cash provided by (used in) financing activities	177,718	(119,130)	376,655
Net (decrease) increase in cash	(1,309)	549	1,281
Cash, beginning of period	2,555	2,006	725
Cash, end of period	$ 1,246	$ 2,555	$ 2,006
Non-Cash Investing and Financing Activities:			
Asset retirement obligation costs and liabilities	$ 39	$ 1	$ 92
Asset retirement obligations associated with property acquisitions	$ 62	$ 24	$ 60,526
Asset retirement obligations associated with properties sold	$ (8,464)	$ (24,605)	$ (9,386)
Units acquired in exchange for investment in equity method investee	$ —	$ —	$ (1,349)
Units issued in exchange for Senior Notes	$ —	$ 6,607	$ —
Change in accrued capital expenditures	$ 26,179	$ —	$ —

See accompanying notes to consolidated financial statements.

(1) Summary of Significant Accounting Policies

(a) Organization, Basis of Presentation and Description of Business

Legacy Reserves LP ("LRLP," "Legacy" or the "Partnership") and its affiliated entities are referred to as Legacy in these financial statements.

LRLP, a Delaware limited partnership, was formed by its general partner, Legacy Reserves GP, LLC ("LRGPLLC"), on October 26, 2005 to own and operate oil and natural gas properties. LRGPLLC is a Delaware limited liability company formed on October 26, 2005, and it currently owns an approximately 0.03% general partner interest in LRLP.

Significant information regarding rights of the unitholders includes the following:

- Right to receive distributions of available cash within 45 days after the end of each quarter.
- No limited partner shall have any management power over our business and affairs; the general partner shall conduct, direct and manage LRLP's activities.
- The general partner may be removed if such removal is approved by the unitholders holding at least 66 2/3 percent of the outstanding units, including units held by LRLP's general partner and its affiliates.
- Right to receive information reasonably required for tax reporting purposes within 90 days after the close of the calendar year.

In the event of a liquidation, after making required payments to Legacy's preferred unitholders, all property and cash in excess of that required to discharge all liabilities will be distributed to the unitholders and LRLP's general partner in proportion to their capital account balances, as adjusted to reflect any gain or loss upon the sale or other disposition of Legacy's assets in liquidation.

Legacy owns and operates oil and natural gas producing properties located primarily in East Texas, the Permian Basin (West Texas and Southeast New Mexico), Rocky Mountain and Mid-Continent regions of the United States. Legacy has acquired oil and natural gas producing properties and drilled and undrilled leasehold.

The accompanying financial statements have been prepared on the accrual basis of accounting whereby revenues are recognized when earned, and expenses are recognized when incurred.

(b) Accounts Receivable

Accounts receivable are recorded at the invoiced amount and do not bear interest. Legacy routinely assesses the financial strength of its customers. Bad debts are recorded based on an account-by-account review. Accounts are written off after all means of collection have been exhausted and potential recovery is considered remote. Legacy does not have any off-balance-sheet credit exposure related to its customers (see Note 10).

(c) Oil and Natural Gas Properties

Legacy accounts for oil and natural gas properties using the successful efforts method. Under this method of accounting, costs relating to the acquisition and development of proved areas are capitalized when incurred. The costs of development wells are capitalized whether productive or non-productive. Leasehold acquisition costs are capitalized when incurred. If proved reserves are found on an unproved property, leasehold cost is transferred to proved properties. Exploration dry holes are charged to expense when it is determined that no commercial reserves exist. Other exploration costs, including personnel costs, geological and geophysical expenses and delay rentals for oil and natural gas leases, are charged to expense when incurred. The costs of acquiring or constructing support equipment and facilities used in oil and gas producing activities are capitalized. Production costs are charged to expense as incurred and are those costs incurred to operate and maintain our wells and related equipment and facilities.

Depreciation and depletion of producing oil and natural gas properties is recorded based on units of production. Acquisition costs of proved properties are amortized on the basis of all proved reserves, developed and undeveloped, and capitalized development costs (wells and related equipment and facilities) are amortized on the basis of proved developed reserves. As more fully described below, proved reserves are estimated annually by Legacy's independent petroleum engineer, LaRoche Petroleum Consultants, Ltd. ("LaRoche"), and are subject to future revisions based on availability of additional information. Legacy's in-house reservoir engineers prepare an updated estimate of reserves each quarter. Depletion is calculated each quarter based upon the latest estimated reserves data available. As discussed in Note 11, asset retirement costs are recognized when the asset is placed in service, and are amortized over proved developed reserves using the units of production method. Asset retirement costs are estimated by Legacy's engineers using existing regulatory requirements and anticipated future inflation rates.

Upon sale or retirement of complete fields of depreciable or depletable property, the book value thereof, less proceeds from sale or salvage value, is charged to income. On sale or retirement of an individual well the proceeds are credited to accumulated depletion and depreciation.

Oil and natural gas properties are reviewed for impairment when facts and circumstances indicate that their carrying value may not be recoverable. Legacy compares net capitalized costs of proved oil and natural gas properties to estimated undiscounted future net cash flows using management's expectations of future oil and natural gas prices. These future price scenarios reflect Legacy's estimation of future price volatility. If net capitalized costs exceed estimated undiscounted future net cash flows, the measurement of impairment is based on estimated fair value, using estimated discounted future net cash flows. Significant inputs used to determine the fair values of proved properties include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices and (iv) a market-based weighted average cost of capital rate. The underlying commodity prices embedded in Legacy's estimated cash flows are the product of a process that begins with NYMEX forward curve pricing, adjusted for estimated location and quality differentials, as well as other factors that Legacy's management believes will impact realizable prices. For the year ended December 31, 2017, Legacy recognized $37.3 million of impairment expense in 47 separate producing fields, due primarily to the further decline in oil and natural gas futures prices, increased expenses and well performance during the year ended December 31, 2017, which decreased the expected future cash flows below the carrying value of the assets. For the year ended December 31, 2016, Legacy recognized $61.8 million of impairment expense, in 43 separate producing fields, due primarily to well performance and the further decline in commodity prices during the year ended December 31, 2016, which decreased the expected future cash flows below the carrying value of the assets. For the year ended December 31, 2015, Legacy recognized $633.8 million of impairment expense, $598.1 million of which was in 218 separate producing fields, due to the significant decline in commodity prices during the year ended December 31, 2015, which decreased the expected future cash flows below the carrying value of the assets. The remainder of the impairment related primarily to unproven properties.

Unproven properties that are individually significant are assessed for impairment and if considered impaired are charged to expense when such impairment is deemed to have occurred. Legacy did not recognize impairment expense on unproved properties during the years ended December 31, 2017 and 2016. During the year ended December 31, 2015, Legacy recognized $35.7 million of impairment of unproven properties.

(d) Oil, NGLs and Natural Gas Reserve Quantities

Legacy's estimates of proved reserves are based on the quantities of oil, NGLs and natural gas that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. LaRoche prepares a reserve and economic evaluation of all Legacy's properties on a case-by-case basis utilizing information provided to it by Legacy and information available from state agencies that collect information reported to it by the operators of Legacy's properties. The estimates of Legacy's proved reserves have been prepared and presented in accordance with SEC rules and accounting standards.

Reserves and their relation to estimated future net cash flows impact Legacy's depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. Legacy prepares its reserve estimates, and the projected cash flows derived from these reserve estimates, in accordance with SEC guidelines. The independent engineering firm described above adheres to the same guidelines when preparing the reserve report. The accuracy of Legacy's reserve estimates is a function of many factors including the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions, and the judgments of the individuals preparing the estimates.

Legacy's proved reserve estimates are a function of many assumptions, all of which could deviate significantly from actual results. As such, reserve estimates may materially vary from the ultimate quantities of oil, NGLs and natural gas eventually recovered.

(e) Income Taxes

Legacy is structured as a limited partnership, which is a pass-through entity for United States income tax purposes.

The State of Texas has a margin-based franchise tax law that is commonly referred to as the Texas margin tax and is assessed at a 0.75% rate. Corporations, limited partnerships, limited liability companies, limited liability partnerships and joint ventures are examples of the types of entities that are subject to the tax. The tax is considered an income tax and is determined by applying a tax rate to a base that considers both revenues and expenses.

Legacy recorded income tax (expense) benefit of $(1.4) million, $(1.2) million and $1.5 million for the years ended December 31, 2017, 2016 and 2015, respectively, which consists primarily of the Texas margin tax and federal income tax on a corporate subsidiary which employs full and part-time personnel providing services to the Partnership. The Partnership's total effective tax rate differs from statutory rates for federal and state purposes primarily due to being structured as a limited partnership, which is a pass-through entity for federal income tax purposes.

Net income for financial statement purposes may differ significantly from taxable income reportable to unitholders as a result of differences between the tax bases and financial reporting bases of assets and liabilities and the taxable income allocation requirements under the partnership agreement. In addition, individual unitholders have different investment bases depending upon the timing and price of acquisition of their common units, and each unitholder's tax accounting, which is partially dependent upon the unitholder's tax position, differs from the accounting followed in the consolidated financial statements. As a result, the aggregate difference in the basis of net assets for financial and tax reporting purposes cannot be readily determined as the Partnership does not have access to information about each unitholder's tax attributes in the Partnership. However, with respect to the Partnership, the Partnership's book basis in its net assets exceeds the Partnership's net tax basis by $1.7 billion at December 31, 2017.

(f) Derivative Instruments and Hedging Activities

Legacy uses derivative financial instruments to achieve more predictable cash flows by reducing its exposure to oil and natural gas price fluctuations and interest rate changes. Legacy does not specifically designate derivative instruments as cash flow hedges, even though they reduce its exposure to changes in oil and natural gas prices and interest rates. Therefore, Legacy records the change in the fair market values of oil and natural gas derivatives in current earnings. Changes in the fair values of interest rate derivatives are recorded in interest expense (see Notes 8 and 9).

(g) Use of Estimates

Management of Legacy has made a number of estimates and assumptions relating to the reporting of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities to prepare these consolidated financial statements in conformity with accounting principles generally accepted in the United States of America. Actual results could differ materially from those estimates. Estimates which are particularly significant to the consolidated financial statements include estimates of oil and natural gas reserves, valuation of derivatives, impairment of oil and natural gas properties, depreciation, depletion and amortization, asset retirement obligations and accrued revenues.

(h) Revenue Recognition

Sales of crude oil, NGLs and natural gas are recognized when the delivery to the purchaser has occurred and title has been transferred. This occurs when oil or natural gas has been delivered to a pipeline or a tank lifting has occurred. Crude oil is priced on the delivery date based upon prevailing prices published by purchasers with certain adjustments related to oil quality and physical location. Virtually all of Legacy's natural gas 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 natural gas, and prevailing supply and demand conditions, so that the price of the natural gas fluctuates to remain competitive with other available natural gas supplies. These market indices are determined on a monthly basis. As a result, Legacy's revenues from the sale of oil and natural gas will suffer if market prices decline and benefit if they increase. Legacy believes that the pricing provisions of its oil and natural gas contracts are customary in the industry.

To the extent actual volumes and prices of oil and natural gas are unavailable for a given reporting period because of timing or information not received from third parties, the expected sales volumes and prices for those properties are estimated and recorded as "Accounts receivable - oil and natural gas" in the accompanying consolidated balance sheets.

Natural gas imbalances occur when Legacy sells more or less than its entitled ownership percentage of total natural gas production. Any amount received in excess of its share is treated as a liability. If Legacy receives less than its entitled share, the underproduction is recorded as a receivable. Legacy did not have any significant natural gas imbalance positions as of December 31, 2017, 2016 and 2015.

(i) Investments

Undivided interests in oil and natural gas properties owned through joint ventures are consolidated on a proportionate basis. Investments in entities where Legacy exercises significant influence, but not a controlling interest, are accounted for by the equity method. Under the equity method, Legacy's investments are stated at cost plus the equity in undistributed earnings and losses after acquisition.

(j) Intangible assets

Legacy has capitalized certain operating rights acquired in the acquisition of oil and natural gas properties. The operating rights, which have no residual value, are amortized over their estimated economic life of approximately 15 years beginning July 1, 2006. Amortization expense is included as an element of depletion, depreciation, amortization and accretion expense. Impairment is assessed on a quarterly basis or when there is a material change in the remaining useful life. The expected amortization expenses for 2018, 2019, 2020 and 2021 are $358,000, $349,000, $322,000 and $223,000, respectively.

(k) Environmental

Legacy is subject to extensive federal, state and local environmental laws and regulations. These laws, which are frequently changing, regulate the discharge of materials into the environment and may require Legacy to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Liabilities for expenditures of a non-capital nature are recorded when environmental assessment and/or remediation are probable, and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments is fixed and readily determinable.

(l) Income (Loss) Per Unit

Basic income (loss) per unit amounts are calculated after deducting distributions paid to Legacy's Preferred Units using the weighted average number of units outstanding during each period. Diluted income (loss) per unit also give effect to dilutive unvested restricted units (calculated based upon the treasury stock method) (see Note 12).

(m) Segment Reporting

Legacy's management initially treats each new acquisition of oil and natural gas properties as a separate operating segment. Legacy aggregates these operating segments into a single segment for reporting purposes.

(n) Unit-Based Compensation

Concurrent with its formation on March 15, 2006, a Long-Term Incentive Plan ("LTIP") for Legacy was created. Due to Legacy's history of cash settlements for option exercises and certain phantom unit awards, Legacy accounts for these awards under the liability method, which requires the Partnership to recognize the fair value of each unit option at the end of each period. Expense or benefit is recognized as the fair value of the liability changes from period to period. Legacy accounts for executive phantom unit and restricted unit awards under the equity method. Legacy's issued units, as reflected in the accompanying consolidated balance sheet at December 31, 2017, do not include 241,373 units related to unvested restricted unit awards.

(o) Accrued Oil and Natural Gas Liabilities

Below are the components of accrued oil and natural gas liabilities as of December 31, 2017 and 2016.

	December 31,	
	2017	2016
	(In thousands)	
Accrued capital expenditures	$33,198	$ 7,019
Revenue payable to joint interest owners	18,510	19,576
Accrued lease operating expense	18,179	17,696
Accrued ad valorem tax	5,807	5,300
Other	5,624	3,657
	$81,318	$53,248

(p) Restricted Cash

Restricted cash of $3.2 million and $3.6 million as of December 31, 2017 and 2016, respectively, is recorded in the "Prepaid expenses and other current assets" line. The restricted cash amounts represent various deposits to secure the performance of contracts, surety bonds and other obligations incurred in the ordinary course of business.

(q) Prior Year Financial Statement Presentation

Certain prior year balances have been reclassified to conform to the current year presentation of balances as stated in this annual report on Form 10-K.

(r) Recent Accounting Pronouncements

In February 2016, the FASB issued Accounting Standards Update No. 2016-02, "Leases" ("ASU 2016-02"). ASU 2016-02 establishes a right-of-use (ROU) model that requires a lessee to record a ROU asset and a lease liability on the balance sheet for all leases with terms longer than 12 months. Leases will be classified as either finance or operating, with classification affecting the pattern of expense recognition in the income statement. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. A modified retrospective transition approach is required for lessees for capital and operating leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements, with certain practical expedients available. We are currently evaluating the impact of our pending adoption of ASU 2016-02 on our consolidated financial statements.

In May 2014, the FASB issued ASU No. 2014-09, "Revenue from Contracts with Customers" ("ASU 2014-09"), which supersedes nearly all existing revenue recognition guidance under U.S. GAAP. The core principle of ASU 2014-09 is to recognize revenues when promised goods or services are transferred to customers in an amount that reflects the consideration to which an entity expects to be entitled for those goods or services. ASU 2014-09 defines a five step process to achieve this core principle and, in doing so, more judgment and estimates may be required within the revenue recognition process than are required under existing U.S. GAAP. In August 2015, the FASB issued ASU No. 2015-14, "Revenue from Contracts with Customers" ("ASU 2015-14"), which approved a one-year delay of the standard's effective date. In accordance with ASU 2015-14, the standard is now effective for annual periods beginning after December 15, 2017, and interim periods therein, using either of the following transition methods: (i) a full retrospective approach reflecting the application of the standard in each prior reporting period with the option to elect certain practical expedients, or (ii) a retrospective approach with the cumulative effect of initially adopting ASU 2014-09 recognized at the date of adoption (which includes additional footnote disclosures). Legacy will adopt ASU 2014-09 utilizing the modified retrospective approach as of January 1, 2018.

Legacy has completed its scoping and impact assessment of ASU 2014-09. Legacy's assessment included involvement from a consultant to assist with its implementation methodology and development of conclusions related to the impact that ASU 2014-09 is expected to have on the Partnership's financial statements.

In performing its impact assessment, Legacy evaluated a representative population of revenue contracts related to its three material revenue streams: oil, natural gas and natural gas liquids. Through Legacy's contract review process, the Partnership identified all material contract types and contractual features that represent its revenue. For those contracts evaluated during its implementation, Legacy reviewed key contract provisions under ASU 2014-09 to assess the impact on the amount and timing of revenue recognition, as well as the presentation of revenues upon adoption of the new standard. As a part of this assessment, Legacy compared its historical accounting policies and practices to that required by ASU 2014-09.

Based upon work completed to date, the adoption of ASU 2014-09 will not have a material impact on net profit. However, Legacy does believe that certain reclassifications between revenue and expenses will be required based upon its assessment of (i) where control of Legacy's product passes to its customer for certain natural gas and NGL contracts and (ii) whether Legacy represents the principal or the agent in certain arrangements. In addition, Legacy's disclosures surrounding revenue recognition will be more robust upon adoption of ASU 2014-09. Legacy is continuing to perform other implementation activities, including the development of new controls and policies and draft disclosures.

(2) Fair Values of Financial Instruments

The estimated fair values of Legacy's financial instruments approximate the carrying amounts except as discussed below:

Debt. The carrying amount of the revolving long-term debt approximates fair value because Legacy's current borrowing rate does not materially differ from market rates for similar bank borrowings. The carrying amount of the second lien term loan debt under Legacy's term loan credit agreement approximates fair value because Legacy's current borrowing rate does not materially differ from market rates for similar borrowings. The fair value of the 8% senior notes due 2020 (the "2020 Senior Notes") and the 6.625% senior notes due 2021 (the "2021 Senior Notes") was $175.9 million and $301.2 million, respectively, as of December 31, 2017. As these valuations are based on unadjusted quoted prices in an active market, the fair values would be classified as Level 1.

Long-term incentive plan obligations. See Note 13 for discussion of process used in estimating the fair value of the long-term incentive plan obligations.

Derivatives. See Note 8 for discussion of process used in estimating the fair value of commodity price and interest rate derivatives.

(3) Long-Term Debt

Long-term debt consists of the following at December 31, 2017 and 2016:

	December 31,	
	2017	2016
	(In thousands)	
Credit Facility due 2019	$ 499,000	$ 463,000
Second Lien Term Loans due 2020	205,000	60,000
8% Senior Notes due 2020	232,989	232,989
6.625% Senior Notes due 2021	432,656	432,656
	1,369,645	1,188,645
Unamortized discount on Second Lien Term Loans and Senior Notes	(13,101)	(12,802)
Unamortized debt issuance costs	(9,775)	(14,449)
Total long term debt	$ 1,346,769	$ 1,161,394

Credit Facility

On April 1, 2014, Legacy entered into a five-year $1.5 billion secured revolving credit facility with Wells Fargo Bank, National Association, as administrative agent, (as amended through the Eighth Amendment, the "Credit Agreement"). Borrowings under the Credit Agreement mature on April 1, 2019. Legacy's obligations under the Credit Agreement are secured by mortgages on over 95% of the total value of its oil and natural gas properties as well as a pledge of all of its ownership interests in its operating subsidiaries. The amount available for borrowing at any one time is limited to the lesser of the borrowing base and the facility amount and contains a $2 million sub-limit for letters of credit. The borrowing base at December 31, 2017 was set at $575 million. The borrowing base is subject to semi-annual redeterminations on April 1 and October 1 of each year. Any borrowings in excess of the redetermined borrowing base must be repaid. Additionally, either Legacy or the lenders may, once during each calendar year, elect to redetermine the borrowing base between scheduled redeterminations. Legacy also has the right, once during each calendar year, to request the redetermination of the borrowing base upon the proposed acquisition of certain oil and natural gas properties where the purchase price is greater than 10% of the borrowing base then in effect. Any increase in the borrowing base requires the consent of all the lenders and any decrease in or maintenance of the borrowing base must be approved by the lenders holding at least 66-2/3% of the outstanding aggregate principal amounts of the loans or participation interests in letters of credit issued under the

Credit Agreement. If the requisite lenders do not agree on an increase or decrease, then the borrowing base will be the highest borrowing base acceptable to the lenders holding 66-2/3% of the outstanding aggregate principal amounts of the loans or participation interests in letters of credit issued under the Credit Agreement so long as it does not increase the borrowing base then in effect. Under the Credit Agreement, interest on debt outstanding is charged based on Legacy's selection of a one-, two-, three- or six-month LIBOR rate plus 1.5% to 2.5%, or the ABR which equals the highest of the prime rate, the Federal funds effective rate plus 0.50% or one-month LIBOR plus 1.00%, plus an applicable margin from 0.5% to 1.5% per annum, determined by the percentage of the borrowing base then in effect that is drawn.

The Credit Agreement contains various covenants that limit Legacy's ability to: (i) incur indebtedness, (ii) enter into certain leases, (iii) grant certain liens, (iv) enter into certain swaps, (v) make certain loans, acquisitions, capital expenditures and investments, (vi) make distributions other than from available cash, (vii) merge, consolidate or allow certain material changes in the character of its business, (viii) repurchase Senior Notes or repay second lien term loans, (ix) engage in certain asset dispositions, including a sale of all or substantially all of its assets or (x) maintain a consolidated cash balance in excess of $20 million without prepaying the loans in an amount equal to such excess. Effective October 25, 2016, Legacy entered into an amendment (the "Eighth Amendment") to the Credit Agreement with the Administrative Agent and certain other financial institutions party thereto as lenders to, among other items: (i) permit the issuance and use of the Second Lien Term Loans pursuant to the Second Lien Term Loan Credit Agreement (as defined below), (ii) increase the percentage of the total value of Legacy's Oil and Gas Properties required to be subject to a mortgage to 95% of the value or the most recently evaluated Reserve Report and grant a mortgage on certain identified undeveloped acreage in the Permian Basin, (iii) require Legacy to grant a perfected security interest in its cash and securities accounts, subject to certain customary exceptions and (iv) allow Legacy to hedge on an unsecured basis with counterparties who (or whose credit support provider) has an issuer rating or whose long term senior unsecured debt rating of BBB-/Baa3. The Credit Agreement, as amended by the Eighth Amendment, also contains covenants that, among other things, require Legacy to maintain specified ratios or conditions. As of December 31, 2017 these covenants were as follows: (i) as of any day, first lien debt to EBITDA for the four fiscal quarters ending on the last day of the fiscal quarter immediately preceding the date of determination for which financial statements are available to not be greater than: 2.50 to 1.00, (ii) as of the last day of any fiscal quarter, beginning the fiscal quarter ended December 31, 2018, secured debt at any time to EBITDA for the four fiscal quarters ending on the last day of the fiscal quarter preceding such day of not more than 4.5 to 1.0, (iii) as of the last day of the most recent quarter, total EBITDA over the last four quarters to total interest expense over the last four quarters to be greater than 2.0 to 1.0, (iv) as of the last day of any fiscal quarter consolidated current assets, as of the last day of the most recent quarter and including the unused amount of the total commitments, to consolidated current liabilities as of the last day of the most recent quarter of not less than 1.0 to 1.0, excluding current maturities under the Credit Agreement and non-cash assets and liabilities under FASB Accounting Standards Codification 815, which includes the current portion of oil, natural gas and interest rate derivatives and (v) as of the last day of any fiscal quarter the ratio of (a) the sum of (i) the net present value using NYMEX forward pricing, discounted at 10 percent per annum, of Legacy's proved developed producing oil and gas properties ("PDP PV-10") as reflected in the most recent reserve report delivered either July 1 or December 31 of each year, as the case may be, beginning with the reserve report to be delivered on July 1, 2017 (giving pro forma effect to material acquisitions or dispositions since the date of such reports), (ii) the net mark to market value of Legacy's swap agreements and (iii) Legacy's cash and cash equivalents, in each case as of such date to (b) Secured Debt as of such day to be equal to or less than 1.00 to 1.00.

All capitalized terms not defined in the foregoing description have the meaning assigned to them in the Credit Agreement, as amended by the Eighth Amendment.

As of December 31, 2017, Legacy had outstanding borrowings of $499 million under the Credit Agreement at a weighted average interest rate of 4.37% and therefore had approximately $75.2 million of borrowing availability remaining. For the year ended December 31, 2017, Legacy paid $20.1 million of interest expense on the Credit Agreement.

At December 31, 2017, Legacy was in compliance with all covenants contained in the Credit Agreement. Should commodity prices dramatically fall in 2018, Legacy could breach certain financial covenants under its revolving credit facility, which would constitute a default under its revolving credit facility. Such default, if not remedied, would require a waiver from Legacy's lenders in order for Legacy to avoid an event of default and subsequent acceleration of all amounts outstanding under Legacy's revolving credit facility or foreclosure on Legacy's oil and natural gas properties. While no assurances can be made that, in the event of a covenant breach, such a waiver will be granted, Legacy believes the long-term global outlook for commodity prices and its efforts to date, which include the suspension of distributions to Legacy's unitholders and Preferred Unitholders, as well as asset sales, will be viewed positively by its lenders. A default under Legacy's revolving credit facility could cause all of Legacy's existing indebtedness, including Legacy's Second Lien Term Loans (as defined below), 2020 Senior Notes and 2021 Senior Notes, to be immediately due and payable.

Second Lien Term Loans

On October 25, 2016, Legacy entered into a Term Loan Credit Agreement (as amended, the "Second Lien Term Loan Credit Agreement") among Legacy, as borrower, Cortland Capital Market Services LLC, as administrative agent and second lien collateral agent, and the lenders party thereto, providing for term loans up to an increased aggregate principal amount of $300.0 million as part of the third amendment to the credit agreement (the "Second Lien Term Loans"). GSO Capital Partners L.P. ("GSO") and certain funds and accounts managed, advised or sub-advised, by GSO are the initial lenders thereunder. The Second Lien Term Loans are secured on a second lien priority basis by the same collateral that secures Legacy's Credit Agreement and are unconditionally guaranteed on a joint and several basis by the same wholly owned subsidiaries of Legacy that are guarantors under the Credit Agreement.

Legacy used the initial $60.0 million of gross loan proceeds from its Second Lien Term Loan to repay outstanding indebtedness and pay associated transaction expenses. Legacy used subsequent draws to fund the Acceleration Payment as defined in Note 4. As of December 31, 2017, there was $205.0 million drawn under the Second Lien Term Loan. The Second Lien Term Loans under the Second Lien Term Loan Credit Agreement will be issued with an upfront fee of 2% and bear interest at a rate of 12.00% per annum payable quarterly in cash or, prior to the 18 month anniversary of the Second Lien Term Loan Credit Agreement, Legacy may elect to pay in kind up to 50% of the interest payable. The Second Lien Term Loans may be used for general corporate purposes and for the repayment of outstanding indebtedness, in any case as may be approved by GSO. For the first 24 months following the effective date of the Term Loan Credit Agreement, GSO may not assign more than 49% of the Second Lien Term Loans without the Partnership's consent. The Second Lien Term Loan Credit Agreement matures on August 31, 2021; provided, however, that, if on July 1, 2020, Legacy has greater than or equal to a face amount of $15.0 million of Senior Notes that were outstanding on the date the Second Lien Term Loan Credit Agreement was entered into or any other senior notes with a maturity date that is earlier than August 31, 2021, the Second Lien Term Loan Credit Agreement will mature on August 1, 2020. The Second Lien Term Loan Credit Agreement contains customary prepayment provisions and make-whole premiums.

The Second Lien Term Loan Credit Agreement was amended on January 5, 2018. See Note 15 for further discussion.

The Second Lien Term Loan Credit Agreement also contains covenants that, among other things, require us to maintain specified ratios or conditions as follows:

- not permit, as of the last day of the fiscal quarter, the ratio of the sum of (i) PDP PV-10, (ii) the net mark to market value of Legacy's swap agreements and (iii) Legacy's cash and cash equivalents to Secured Debt to be less than (i) 0.85 to 1.00 through and including the fiscal quarter ended December 31, 2018 and (ii) 1.00 to 1.00 thereafter;

- not permit, as of the last day of any fiscal quarter beginning with the fiscal quarter ending December 31, 2018, Legacy's ratio of Secured Debt as of such day to EBITDA for the four fiscal quarters then ending to be greater than 4.50 to 1.00;
- within a certain period of time after the date of the Second Lien Term Loan Credit Agreement, enter into hedging transactions covering at least 75% of the projected oil and natural gas production from Proved Developed Producing Properties for each month until the two year anniversary of the Second Lien Term Loan Credit Agreement;
- Legacy is required to mortgage 95% of the total value of all of its Oil and Gas Properties set forth in the most recently evaluated Reserve Report and grant a mortgage on certain identified undeveloped acreage in the Permian Basin; and
- require us to grant a perfected security interest in its cash and securities accounts, subject to certain customary exceptions.

All capitalized terms used but not defined in the foregoing description have the meaning assigned to them in the Second Lien Term Loan Credit Agreement.

At December 31, 2017, Legacy was in compliance with all covenants contained in the Second Lien Term Loan Credit Agreement.

For the year ended December 31, 2017, Legacy incurred interest expense of $15.0 million under the Second Lien Term Loan Credit Agreement.

8% Senior Notes Due 2020

On December 4, 2012, Legacy and its 100% owned subsidiary Legacy Reserves Finance Corporation completed a private placement offering to eligible purchasers of an aggregate principal amount of $300.0 million of Legacy's 8% Senior Notes due 2020 (the "2020 Senior Notes"), which were subsequently registered through a public exchange offer that closed on January 8, 2014. The 2020 Senior Notes were issued at 97.848% of par.

Legacy has the option to redeem the 2020 Senior Notes, in whole or in part, at any time on or after December 1, 2016, at the specified redemption prices set forth below together with any accrued and unpaid interest, if any, to the date of redemption if redeemed during the twelve-month period beginning on December 1 of the years indicated below.

Year	Percentage
2017	102.000%
2018	100.000%

Legacy may be required to offer to repurchase the 2020 Senior Notes at a purchase price of 101% of the principal amount, plus accrued and unpaid interest, if any, to the redemption date, in the event of a change of control as defined by the indenture. Legacy and Legacy Reserves Finance Corporation's obligations under the 2020 Senior Notes are guaranteed by its 100% owned subsidiaries Legacy Reserves Operating GP LLC, Legacy Reserves Operating LP, Legacy Reserves Services, Inc., Legacy Reserves Energy Services LLC, Dew Gathering LLC and Pinnacle Gas Treating LLC, which constitute all of Legacy's wholly-owned subsidiaries other than Legacy Reserves Finance Corporation. In the future, the guarantees may be released or terminated under the following circumstances: (i) in connection with any sale or other disposition of all or substantially all of the properties of the guarantor; (ii) in connection with any sale or other disposition of sufficient capital stock of the guarantor so that it no longer qualifies as Legacy's Restricted Subsidiary (as defined in the indenture); (iii) if designated to be an unrestricted subsidiary; (iv) upon legal defeasance, covenant defeasance or satisfaction and discharge of the indenture; (v) upon the liquidation or dissolution of the guarantor provided no default or event of default has occurred or is occurring; (vi) at such time the guarantor does not have outstanding guarantees of its, or any other guarantor's, other debt; or (vii) upon merging into, or transferring all of its properties to Legacy or another guarantor and ceasing to exist. Refer to Note 14 - Subsidiary Guarantors for further details on Legacy's guarantors.

The indenture governing the 2020 Senior Notes limits Legacy's ability and the ability of certain of its subsidiaries to (i) sell assets; (ii) pay distributions on, repurchase or redeem equity interests or purchase or redeem Legacy's subordinated debt, provided that such subsidiaries may pay dividends to the holders of their equity interests (including Legacy) and Legacy may pay distributions to the holders of its equity interests subject to the absence of certain defaults, the satisfaction of a fixed charge coverage ratio test and so long as the amount of such distributions does not exceed the sum of available cash (as defined in the partnership agreement) at Legacy, net proceeds from the sales of certain securities and return of or reductions to capital from restricted investments; (iii) make certain investments; (iv) incur or guarantee additional indebtedness or issue preferred units; (v) create or incur certain liens; (vi) enter into agreements that restrict distributions or other payments from certain of its subsidiaries to Legacy; (vii) consolidate, merge or transfer all or substantially all of Legacy's assets; (viii) engage in certain transactions with affiliates; (ix) create unrestricted subsidiaries; and (x) engage in certain business activities. These covenants are subject to a number of important exceptions and qualifications. If at any time when the 2020 Senior Notes are rated investment grade by each of Moody's Investors Service, Inc. and Standard & Poor's Ratings Services and no Default (as defined in the indenture) has occurred and is continuing, many of such covenants will terminate and Legacy and its subsidiaries will cease to be subject to such covenants. Further, if the lenders under Legacy's Credit Agreement were to accelerate the indebtedness under Legacy's Credit Agreement as a result of a default, such acceleration could cause a cross-default of all of the 2020 Senior Notes and permit the holders of such notes to accelerate the maturities of such indebtedness.

The indenture also includes customary events of default. As of the December 31, 2017, the Partnership was in compliance with all covenants of the 2020 Senior Notes.

Interest is payable on June 1 and December 1 of each year.

During the year ended December 31, 2016, Legacy repurchased a face amount of $52.0 million of its 2020 Senior Notes on the open market. Legacy treated these repurchases as an extinguishment of debt. Accordingly, Legacy recognized a gain for the difference between (1) the face amount of the 2020 Senior Notes repurchased net of the unamortized portion of both the original issuer's discount and issuance costs and (2) the repurchase price.

On June 1, 2016, Legacy exchanged 2,719,124 units representing limited partner interests in the Partnership for $15.0 million of face amount of its outstanding 2020 Senior Notes. Legacy treated this exchange as an extinguishment of debt. Accordingly, Legacy recognized a gain for the difference between (1) the face amount of the 2020 Senior Notes repurchased net of the unamortized portion of both the original issuer's discount and issuance costs and (2) the fair value of the units issued in the exchange based on the closing price on June 1, 2016.

6.625% Senior Notes Due 2021

On May 28, 2013, Legacy and its 100% owned subsidiary Legacy Reserves Finance Corporation completed a private placement offering to eligible purchasers of an aggregate principal amount of $250 million of Legacy's 6.625% Senior Notes due 2021 (the "2021 Senior Notes"), which were subsequently registered through a public exchange offer that closed on March 18, 2014. The 2021 Senior Notes were issued at 98.405% of par.

On May 13, 2014, Legacy and its 100% owned subsidiary Legacy Reserves Finance Corporation completed a private placement offering to eligible purchasers of an aggregate principal amount of an additional $300 million of the 6.625% 2021 Senior Notes. These 2021 Senior Notes were issued at 99% of par.

The terms of the 2021 Senior Notes, including details related to Legacy's guarantors, are substantially identical to the terms of the 2020 Senior Notes with the exception of the maturity date, interest rate and redemption provisions noted below. Legacy will have the option to redeem the 2021 Senior Notes, in whole or in part, at any time on or after June 1, 2017, at the specified redemption prices set forth below together with any accrued and unpaid interest, if any, to the date of redemption if redeemed during the twelve-month period beginning on June 1 of the years indicated below.

Year	Percentage
2017	103.313%
2018	101.656%
2019 and thereafter	100.000%

Legacy may be required to offer to repurchase the 2021 Senior Notes at a purchase price of 101% of the principal amount, plus accrued and unpaid interest, if any, to the redemption date, in the event of a change of control as defined by the indenture. Legacy and Legacy Reserves Finance Corporation's obligations under the 2021 Senior Notes are guaranteed by the same parties and on the same terms as Legacy's 2020 Senior Notes discussed above. Further, if the lenders under Legacy's Credit Agreement were to accelerate the indebtedness under Legacy's Credit Agreement as a result of a default, such acceleration could cause a cross-default of all of the 2021 Senior Notes and permit the holders of such notes to accelerate the maturities of such indebtedness.

As of December 31, 2017, the Partnership was in compliance with all covenants of the 2021 Senior Notes.

Interest is payable on June 1 and December 1 of each year.

On December 31, 2017, Legacy entered into an agreement to repurchase a face amount of $187.1 million of its 2021 Senior Notes from certain holders in a single transaction. The transaction was funded on January 5, 2018 and will therefore be recognized in 2018. Legacy will treat this repurchase as an extinguishment of debt. Accordingly, Legacy will recognize a gain for the difference between (1) the face amount of the 2021 Senior Notes repurchased net of the unamortized portion of both the original issuer's discount and issuance costs and (2) the repurchase price. See Note 15 for further discussion.

During the year ended December 31, 2016, Legacy repurchased a face amount of $117.3 million of its 2021 Senior Notes on the open market. Legacy treated these repurchases as an extinguishment of debt. Accordingly, Legacy recognized a gain for the difference between (1) the face amount of the 2021 Senior Notes repurchased net of the unamortized portion of both the original issuer's discount and issuance costs and (2) the repurchase price.

For the year ended December 31, 2017, Legacy paid $47.3 million of cash interest expense for the 2020 Senior Notes and 2021 Senior Notes.

(4) Acquisitions

Asset Acquisition

On August 1, 2017, Legacy made a payment in the amount of $141 million (the "Acceleration Payment") in connection with its First Amended and Restated Development Agreement (the "Restated Agreement") with Jupiter JV, LP ("Jupiter"). The Acceleration Payment caused the reversion to Legacy of additional working interests in all wells and associated personal property and infrastructure (collectively, the "Wells") and all undeveloped assets subject to the Restated Agreement. The transaction was accounted for as an asset acquisition in accordance with ASU 2017-01. Therefore, the acquired interests were recorded based upon the cash consideration paid, with all value assigned to proved oil and natural gas properties.

Anadarko Acquisitions

On July 31, 2015, Legacy purchased (1) 100% of the issued and outstanding limited liability company membership interests in Dew Gathering LLC, which owns directly and indirectly natural gas gathering and processing assets in Anderson, Freestone, Houston, Leon, Limestone and Robertson Counties, Texas (the "WGR

Acquisition") from WGR Operating LP ("WGR") for a net purchase price of $96.7 million, and (2) various oil and natural gas properties and associated production assets (the "Anadarko E&P Acquisition," together with the WGR Acquisition, the "Anadarko Acquisitions") from Anadarko E&P Onshore LLC ("Anadarko") for a net purchase price of $337.2 million. The purchase prices were financed with borrowings under Legacy's revolving credit facility. The effective date of these purchases was April 1, 2015. The operating results from the Anadarko Acquisitions have been included from their acquisition on July 31, 2015. During the year ended December 31, 2015, Legacy incurred acquisition costs, recorded in general and administrative expense, of approximately $2.4 million related to the Anadarko Acquisitions and other acquisitions.

The allocation of the purchase price to the fair value of the acquired assets and liabilities assumed was as follows (in thousands):

Proved oil and natural gas properties including related equipment	$461,306
Future abandonment costs	(27,351)
Fair value of net assets acquired	$433,955

Pro Forma Operating Results

The following table reflects the unaudited pro forma results of operations as though the Anadarko Acquisitions had occurred on January 1, 2014. The pro forma amounts are not necessarily indicative of the results that may be reported in the future:

	Year Ended December 31, 2015
	(In thousands)
Revenues	$ 380,619
Net loss attributable to unitholders	$ (713,364)
Loss per unit — basic and diluted	$ (10.35)
Units used in computing loss per unit:	
Basic	68,928
Diluted	68,928

(5) Related Party Transactions

Blue Quail Energy Services, LLC ("Blue Quail"), a company specializing in water transfer services, is an affiliate of Moriah Energy Services LLC, an entity which Cary D. Brown and Dale A. Brown, directors of Legacy, are principals. Legacy has contracted with Blue Quail to provide water transfer services and paid $9,758, $98,297 and $382,629 in 2017, 2016 and 2015, respectively to Blue Quail for such services.

In mid-2015 Legacy performed a technical evaluation of a potential acquisition and, based on such evaluation and Legacy's business model, subsequently decided not to pursue such acquisition. In September 2015, Moriah Powder River LLC, an oil and natural gas exploration and production company which Cary D. Brown and Dale Brown indirectly control, decided to pursue such opportunity and paid Legacy a one-time expense reimbursement of $500,000 to utilize Legacy's prior technical work product.

(6) Commitments and Contingencies

From time to time Legacy is a party to various legal proceedings arising in the ordinary course of business. While the outcome of lawsuits cannot be predicted with certainty, Legacy is not currently a party to any proceeding that it believes could have a potential material adverse effect on its financial condition, results of operations or cash flows.

Legacy is subject to numerous laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes environmental protection requirements that result in increased costs to the oil and natural gas industry in general, the business and prospects of Legacy could be adversely affected.

Legacy has employment agreements and retention bonus agreements with its officers and certain other employees. The employment agreements with its officers specify that if the officer is terminated by Legacy for other than cause or following a change in control, the officer shall receive severance pay ranging from 24 to 36 months salary plus bonus and COBRA benefits, respectively. The retention bonus agreements provide for fixed bonus amounts to be paid to employees contingent upon various criteria including their continuous employment or a change in control.

(7) Business and Credit Concentrations

Cash

Legacy maintains its cash in bank deposit accounts, which, at times, may exceed federally insured amounts. Legacy has not experienced any losses in such accounts. Legacy believes it is not exposed to any significant credit risk on its cash.

Revenue and Accounts Receivable

Substantially all of Legacy's accounts receivable result from oil and natural gas sales or joint interest billings to third parties in the oil and natural gas industry. This concentration of customers and joint interest owners may impact Legacy's overall credit risk in that these entities may be similarly affected by changes in economic and other conditions. Historically, Legacy has not experienced significant credit losses on such receivables. No bad debt expense was recorded in 2017, 2016 or 2015. Legacy cannot ensure that such losses will not be realized in the future. A listing of oil and natural gas purchasers exceeding 10% of Legacy's sales is presented in Note 10.

Commodity Derivatives

Due to the volatility of oil and natural gas prices, Legacy periodically enters into price-risk management transactions (e.g., swaps, enhanced swaps, costless collars or three-way collars) for a portion of its oil and natural gas production to achieve a more predictable cash flow, as well as to reduce exposure from price fluctuations. Legacy values these transactions at fair value on a recurring basis (Note 8). As of December 31, 2017, Legacy's commodity derivative transactions have a fair value favorable to the Partnership of $6.3 million, collectively. Legacy enters into commodity derivative transactions with entities which Legacy's management believes are creditworthy. In addition, Legacy reviews and assesses the creditworthiness of these institutions on a routine basis.

(8) Fair Value Measurements

Fair value is defined as the price that would be received upon the sale of an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Fair value measurements are classified and disclosed in one of the following categories:

Level 1: Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. Legacy considers active markets as those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2: Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability. This category includes those derivative instruments that Legacy values using observable market data. Substantially all of these inputs are observable in the marketplace throughout the term of the derivative instrument, can be derived from observable data, or are supported by observable levels at which transactions are executed in the marketplace. Instruments in this category include non-exchange traded derivatives such as over-the-counter commodity price swaps and collars and interest rate swaps as well as long-term incentive plan liabilities calculated using the Black-Scholes model to estimate the fair value as of the measurement date.

Level 3: Measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources (i.e. supported by little or no market activity). Legacy's valuation models are primarily industry standard models that consider various inputs including: (a) quoted forward prices for commodities, (b) time value, and (c) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Level 3 instruments currently are limited to Midland-Cushing crude oil differential swaps. Although Legacy utilizes third party broker quotes to assess the reasonableness of its prices and valuation techniques, Legacy does not have sufficient corroborating evidence to support classifying these assets and liabilities as Level 2.

Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. Legacy's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

Fair Value on a Recurring Basis

The following table sets forth by level within the fair value hierarchy Legacy's financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2017 and 2016:

	Fair Value Measurements Using			
Description	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Carrying Value as of
		(In thousands)		
LTIP liability(a)	$ —	$ (1,947)	$ —	$ (1,947)
Oil and natural gas derivatives	—	11,406	(5,088)	6,318
Interest rate swaps	—	2,117	—	2,117
Total as of December 31, 2017	$ —	$ 11,576	$ (5,088)	$ 6,488
LTIP liability(a)	$ —	$ (224)	$ —	$ (224)
Oil and natural gas derivatives	—	12,690	8	12,698
Interest rate swaps	—	183	—	183
Total as of December 31, 2016	$ —	$ 12,649	$ 8	$ 12,657

(a) See Note 13 for further discussion on unit-based compensation expenses related to the LTIP liability for certain grants accounted for under the liability method and included in other current liabilities in the accompanying consolidated balance sheet.

Legacy estimates the fair values of its commodity swaps based on published forward commodity price curves for the underlying commodities as of the date of the estimate for those commodities for which published forward pricing is readily available. For those commodity derivatives for which forward commodity price curves are not readily available, Legacy estimates, with the assistance of third-party pricing experts, the forward curves as of the date of the estimate. Legacy validates the data provided by third parties by understanding the pricing models used, obtaining market values from other pricing sources, analyzing pricing data in certain situations and confirming, where applicable, that those securities trade in active markets. Legacy estimates the option value of puts and calls combined into hedges, including costless collars, three-way collars and enhanced swaps using an option pricing model which takes into account market volatility, market prices, contract parameters and discount rates based on published LIBOR rates and interest swap rates. Due to the lack of an active market for periods beyond one-month from the balance sheet date for Legacy's oil price differential swaps, Legacy has reviewed historical differential prices and known economic influences to estimate a reasonable forward curve of future pricing scenarios based upon these factors. In order to estimate the fair value of its interest rate swaps, Legacy uses a yield curve based on money market rates and interest rate swaps, extrapolates a forecast of future interest rates, estimates each future cash flow, derives discount factors to value the fixed and floating rate cash flows of each swap, and then discounts to present value all known (fixed) and forecasted (floating) swap cash flows. Curve building and discounting techniques used to establish the theoretical market value of interest bearing securities are based on readily available money market rates and interest swap market data. The determination of the fair values above incorporates various factors including the impact of Legacy's non-performance risk and the credit standing of the counterparties involved in the Partnership's derivative contracts. The risk of nonperformance by the Partnership's counterparties is mitigated by the fact that enters into derivative transactions with entities which Legacy's management believes are creditworthy. In addition, Legacy routinely monitors the creditworthiness of its counterparties. As the factors described above are based on significant assumptions made by management, these assumptions are the most sensitive to change.

The following table sets forth a reconciliation of changes in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy:

	Significant Unobservable Inputs (Level 3)		
	December 31,		
	2017	2016	2015
	(In thousands)		
Beginning balance	$ 8	$ (4,493)	$ 555
Total gains (losses)	(5,073)	253	(10,029)
Settlements	(23)	4,248	4,981
Ending balance	$ (5,088)	$ 8	$ (4,493)
Gains (losses) included in earnings relating to derivatives still held as of December 31, 2017, 2016 and 2015	$ (5,088)	$ 68	$ (4,493)

During periods of market disruption, including periods of volatile oil and natural gas prices, rapid credit contraction or illiquidity, it may be difficult to value certain of the Partnerships' derivative instruments if trading becomes less frequent and/or market data becomes less observable. There may be certain asset classes that were in active markets with observable data that become illiquid due to changes in the financial environment. In such cases, more derivative instruments may fall to Level 3 and thus require more subjectivity and management judgment. As such, valuations may include inputs and assumptions that are less observable or require greater estimation as well as valuation methods which are more sophisticated or require greater estimation thereby resulting in valuations with less certainty. Further, rapidly changing commodity and unprecedented credit and equity market conditions could materially impact the valuation of derivative instruments as reported within Legacy's consolidated financial statements and the period-to-period changes in value could vary significantly. Decreases in value may have a material adverse effect on Legacy's results of operations or financial condition.

Fair Value on a Non-Recurring Basis

Nonfinancial assets and liabilities measured at fair value on a non-recurring basis include certain nonfinancial assets and liabilities as may be acquired in a business combination, measurements of oil and natural gas property impairments, and the initial recognition of asset retirement obligations, for which fair value is used. These asset retirement obligation ("ARO") estimates are derived from historical costs as well as management's expectation of future cost environments. As there is no corroborating market activity to support the assumptions used, Legacy has designated these measurements as Level 3. A reconciliation of the beginning and ending balances of Legacy's ARO is presented in Note 11.

Nonrecurring fair value measurements of proved oil and natural gas properties during the years ended December 31, 2017 and 2016 consist of:

Description	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
		(In thousands)	
2017			
Impairment(a)	$—	$—	$ 31,850
2016			
Impairment(a)	$—	$—	$ 60,729
Acquisitions(b)	$—	$—	$ 11,998

(a) Legacy periodically reviews oil and natural gas properties for impairment when facts and circumstances indicate that their carrying value may not be recoverable. During the year ended December 31, 2017, Legacy incurred impairment charges of $37.3 million as oil and natural gas properties with a net cost basis of $69.1 million were written down to their fair value of $31.8 million. During the year ended December 31, 2016, Legacy incurred impairment charges of $61.8 million as oil and natural gas properties with a net cost basis of $122.5 million were written down to their fair value of $60.7 million. In order to determine whether the carrying value of an asset is recoverable, Legacy compares net capitalized costs of proved oil and natural gas properties to estimated undiscounted future net cash flows using management's expectations of future oil and natural gas prices. These future price scenarios reflect Legacy's estimation of future price volatility. If the net capitalized cost exceeds the undiscounted future net cash flows, Legacy writes the net cost basis down to the discounted future net cash flows, which is management's estimate of fair value. Significant inputs used to determine the fair value include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; and (iv) a market-based weighted average cost of capital rate. The underlying commodity prices embedded in the Company's estimated cash flows are the product of a process that begins with NYMEX forward curve pricing, adjusted for estimated location and quality differentials, as well as other factors that Legacy's management believes will impact realizable prices. The inputs used by management for the fair value measurements utilized in this review include significant unobservable inputs, and therefore, the fair value measurements employed are classified as Level 3 for these types of assets.

(b) Legacy records the fair value of assets and liabilities acquired in business combinations. During the year ended December 31, 2016, Legacy acquired oil and natural gas properties with a fair value of $12.0 million in 3 immaterial transactions, both individually and in the aggregate. Properties acquired are recorded at fair value, which correlates to the discounted future net cash flow. Significant inputs used to determine the fair value include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; and (iv) a market-based weighted average cost of capital rate. The underlying commodity prices embedded in the Company's estimated cash flows are the product of a process that begins with NYMEX forward curve pricing, adjusted for estimated location and quality differentials, as well as other factors that Legacy's management believes will impact realizable prices. For acquired unproved properties, the market-based weighted average cost of capital rate is subjected to additional project specific risking factors. The inputs used by management for the fair value measurements of these acquired oil and natural gas properties include significant unobservable inputs, and therefore, the fair value measurements employed are classified as Level 3 for these types of assets.

(9) Derivative Financial Instruments

Commodity derivative transactions

Due to the volatility of oil and natural gas prices, Legacy periodically enters into price-risk management transactions (e.g., swaps, enhanced swaps or collars) for a portion of its oil and natural gas production to achieve a more predictable cash flow, as well as to reduce exposure from price fluctuations. While the use of these arrangements limits Legacy's ability to benefit from increases in the prices of oil and natural gas, it also reduces Legacy's potential exposure to adverse price movements. Legacy's arrangements, to the extent it enters into any, apply to only a portion of its production, provide only partial price protection against declines in oil and natural gas prices and limit Legacy's potential gains from future increases in prices. None of these instruments are used for trading or speculative purposes.

These derivative instruments are intended to mitigate a portion of Legacy's price-risk and may be considered hedges for economic purposes, but Legacy has chosen not to designate them as cash flow hedges for accounting purposes. Therefore, all derivative instruments are recorded on the balance sheet at fair value with changes in fair value being recorded in current period earnings.

By using derivative instruments to mitigate exposures to changes in commodity prices, Legacy exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes Legacy, which creates credit risk. Legacy minimizes the credit or repayment risk in derivative instruments by entering into transactions with high-quality counterparties.

The following table sets forth a reconciliation of the changes in fair value of Legacy's commodity derivatives for the years ended December 31, 2017, 2016, and 2015.

	December 31,		
	2017	2016	2015
		(In thousands)	
Beginning fair value of commodity derivatives	$ 12,698	$ 118,427	$ 153,099
Total gain (loss) crude oil derivatives	(15,325)	(9,410)	25,715
Total gain (loss) natural gas derivatives	33,101	(31,814)	72,538
Crude oil derivative cash settlements paid (received)	(11,840)	(37,464)	(91,953)
Natural gas derivative cash settlements received	(12,316)	(27,041)	(40,972)
Ending fair value of commodity derivatives	$ 6,318	$ 12,698	$ 118,427

Certain of our commodity derivatives and interest rate derivatives are presented on a net basis on the Consolidated Balance Sheets. The following table summarizes the gross fair values of our derivative instruments, presenting the impact of offsetting the derivative assets and liabilities on our Consolidated Balance Sheets as of the dates indicated below (in thousands):

	December 31, 2017		
	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts Presented in the Consolidated Balance Sheets
Offsetting Derivative Assets:		(In thousands)	
Commodity derivatives	$ 34,070	$ (8,664)	$ 25,406
Interest rate derivatives	2,118	(1)	2,117
Total derivative assets	$ 36,188	$ (8,665)	$ 27,523
Offsetting Derivative Liabilities:			
Commodity derivatives	$ (27,752)	$ 8,664	$ (19,088)
Interest rate derivatives	(1)	1	—
Total derivative liabilities	$ (27,753)	$ 8,665	$ (19,088)

	December 31, 2016		
	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts Presented in the Consolidated Balance Sheets
Offsetting Derivative Assets:		(In thousands)	
Commodity derivatives	$ 56,103	$(30,648)	$ 25,455
Interest rate derivatives	1,328	(68)	1,260
Total derivative assets	$ 57,431	$(30,716)	$ 26,715
Offsetting Derivative Liabilities:			
Commodity derivatives	$ (43,405)	$ 30,648	$ (12,757)
Interest rate derivatives	(1,145)	68	(1,077)
Total derivative liabilities	$ (44,550)	$ 30,716	$ (13,834)

As of December 31, 2017, Legacy had the following NYMEX WTI crude oil swaps paying floating prices and receiving fixed prices for a portion of its future oil production as indicated below:

Calendar Year	Volumes (Bbls)	Average Price per Bbl	Price Range per Bbl
2018	2,664,500	$53.54	$51.20 - $58.04

As of December 31, 2017, Legacy had the following Midland-to-Cushing crude oil differential swaps paying a floating differential and receiving a fixed differential for a portion of its future oil production as indicated below:

Time Period	Volumes (Bbls)	Average Price per Bbl	Price Range per Bbl
2018	4,015,000	$(1.13)	$(1.25) - $(0.80)
2019	730,000	$(1.15)	$(1.15)

As of December 31, 2017, Legacy had the following NYMEX WTI crude oil costless collars that combine a long put with a short call as indicated below:

Time Period	Volumes (Bbls)	Average Long Put Price per Bbl	Average Short Call Price per Bbl
2018	1,551,250	$47.06	$60.29

As of December 31, 2017, Legacy had the following NYMEX WTI crude oil enhanced swap contracts that combine a short put, a long put and a fixed-price swap as indicated below:

Calendar Year	Volumes (Bbls)	Average Long Put Price per Bbl	Average Short Put Price per Bbl	Average Swap Price per Bbl
2018	127,750	$57.00	$82.00	$90.50

As of December 31, 2017, Legacy had the following NYMEX Henry Hub natural gas swaps paying floating natural gas prices and receiving fixed prices for a portion of its future natural gas production as indicated below:

Calendar Year	Volumes (MMBtu)	Average Price per MMBtu	Price Range per MMBtu
2018	36,200,000	$3.23	$3.04 - $3.39
2019	25,800,000	$3.36	$3.29 - $3.39

Interest rate derivative transactions

Due to the volatility of interest rates, Legacy periodically enters into interest rate risk management transactions in the form of interest rate swaps for a portion of its outstanding debt balance. These transactions allow Legacy to reduce exposure to interest rate fluctuations. While the use of these arrangements limits Legacy's ability to benefit from decreases in interest rates, it also reduces Legacy's potential exposure to increases in interest rates. Legacy's arrangements, to the extent it enters into any, apply to only a portion of its outstanding debt balance, provide only partial protection against interest rate increases and limit Legacy's potential savings from future interest rate declines. It is never management's intention to hold or issue derivative instruments for speculative trading purposes. Conditions sometimes arise where actual borrowings are less than notional amounts hedged which has and could result in overhedged amounts.

Legacy does not designate these derivatives as cash flow hedges, even though they reduce its exposure to changes in interest rates. Therefore, the mark-to-market of these instruments is recorded in current earnings and classified as a component of interest expense. The total impact on interest expense from the mark-to-market and settlements was as follows:

	December 31,		
	2017	2016	2015
	(In thousands)		
Beginning fair value of interest rate swaps	$ 183	$ (362)	$(2,080)
Total gain (loss) loss on interest rate swaps	1,168	(2,108)	(1,548)
Cash settlements paid	766	2,653	3,266
Ending fair value of interest rate swaps	$ 2,117	$ 183	$ (362)

The table below summarizes the interest rate swap assets and liabilities as of December 31, 2017.

Notional Amount	Weighted Average Fixed Rate	Effective Date	Maturity Date	Estimated Fair Market Value at December 31, 2017
		(Dollars in thousands)		
$235,000	1.363%	9/1/2015	9/1/2019	$ 2,117
Total fair value of interest rate derivatives				$ 2,117

(10) Sales to Major Customers

For the year ended December 31, 2017, Legacy sold oil, NGL and natural gas production representing 10% or more of total revenues to the purchaser as detailed in the table below. For the years ended December 31, 2016 and 2015, Legacy did not sell oil, NGL or natural gas production representing 10% or more of total revenue to any one customer.

	2017	2016	2015
Plains Marketing, LP	10%	6%	7%

(11) Asset Retirement Obligation

An asset retirement obligation ("ARO") associated with the retirement of a tangible long-lived asset is recognized as a liability in the period in which it is incurred and becomes determinable. When liabilities for dismantlement and abandonment costs, excluding salvage values, are initially recorded, the carrying amount of the related oil and natural gas properties is increased. The fair value of the additions to the ARO asset and liability is estimated using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation include estimates of: (i) plug and abandon costs per well based on existing regulatory requirements; (ii) remaining life per well; (iii) future inflation factors; and (iv) a credit-adjusted risk-free interest rate. These inputs require significant judgments and estimates by the Partnership's management at the time of the valuation and are the most sensitive and subject to change. Accretion of the liability is recognized each period using the interest method of allocation, and the capitalized cost is depleted using the units of production method. Should either the estimated life or the estimated abandonment costs of a property change materially upon Legacy's periodic review, a new calculation is performed using the same methodology of taking the abandonment cost and inflating it forward to its abandonment date and then discounting it back to the present using Legacy's credit-adjusted-risk-free rate. The carrying value of the ARO is adjusted to the newly calculated value, with a corresponding offsetting adjustment to the asset retirement cost. When obligations are relieved by sale of the property or plugging and abandoning the well, the related liability and asset costs are removed from Legacy's balance sheet. Any difference in the cost to plug and the related liability is recorded as a gain or loss on Legacy's statement of operations in the disposal of assets line item.

The following table reflects the changes in the ARO during the years ended December 31, 2017, 2016 and 2015.

	December 31,		
	2017	2016	2015
		(In thousands)	
Asset retirement obligation — beginning of period	$272,148	$286,405	$226,525
Liabilities incurred with properties acquired	62	24	60,526
Liabilities incurred with properties drilled	39	1	92
Liabilities settled during the period	(1,891)	(2,351)	(2,615)
Liabilities associated with properties sold	(8,464)	(24,605)	(9,386)
Current period accretion	12,792	12,674	11,263
Asset retirement obligation — end of period	$274,686	$272,148	$286,405

Each year the Partnership reviews and, to the extent necessary, revises its ARO estimates. During 2015, 2016 and 2017, no revisions of previous estimates were deemed necessary.

(12) Partners' Equity

As of December 31, 2017, 2,300,000 of Legacy's 8% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the "Series A Preferred Units") were outstanding.

As of December 31, 2017, 7,200,000 of Legacy's 8.00% Series B Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the "Series B Preferred Units") were outstanding.

Distributions on the Series A Preferred Units and Series B Preferred Units (collectively, the "Preferred Units") are cumulative from the date of original issue and will be payable monthly in arrears on the 15th day of each month of each year, when, as and if declared by the board of directors of the Partnership's general partner. Distributions on the Series A Preferred Units will be payable from, and including, the date of the original issuance to, but not including April 15, 2024 at an initial rate of 8.00% per annum of the stated liquidation preference. Distributions on the Series B Preferred Units will be payable from, and including, the date of the original issuance to, but not including June 15, 2024 at an initial rate of 8.00% per annum of the stated liquidation preference. Distributions accruing on and after April 15, 2024 for the Series A Preferred Units and June 15, 2024 for the Series B Preferred Units will accrue at an annual rate equal to the sum of (a) three-month LIBOR as calculated on each applicable date of determination and (b) 5.24% for Series A Preferred Units and 5.26% for Series B Preferred Units, based on the $25.00 liquidation preference per preferred unit.

At any time on or after April 15, 2019 or June 15, 2019, Legacy may redeem the Series A Preferred Units or Series B Preferred Units, respectively, in whole or in part at a redemption price of $25.00 per Preferred Unit plus an amount equal to all accumulated and unpaid distributions thereon through and including the date of redemption, whether or not declared. Legacy may also redeem the Preferred Units in the event of a change of control.

The Series A Preferred Units and the Series B Preferred Units trade on the NASDAQ Global Select Market under the symbols "LGCYP" and "LGCYO," respectively.

On January 21, 2016, Legacy announced that its general partner suspended monthly cash distribution for both its Series A Preferred Units and its Series B Preferred Units. As of December 31, 2017, $3.92 of distributions per unit were in arrears, representing a total cumulative arrearage of approximately $37.2 million.

Incentive Distribution Units

On June 4, 2014, Legacy issued 300,000 Incentive Distribution Units to WPX Energy Rocky Mountain, LLC ("WPX") as part of the Piceance Acquisition. The Incentive Distribution Units issued to WPX include 100,000 Incentive Distribution Units that immediately vested along with the ability to vest in up to an additional 200,000 Incentive Distribution Units (the "Unvested IDUs") in connection with any future asset sales or transactions completed with Legacy pursuant to the terms of the IDR Holders Agreement. Incentive Distribution Units that are not issued to WPX or other parties will remain in Legacy's treasury for the benefit of all limited partners until such time as Legacy may make future issuances of Incentive Distribution Units.

The Incentive Distribution Units represent a right to incremental cash distributions from Legacy after certain target levels of distributions are paid to unitholders, which targets are set above the current levels of Legacy's distributions to unitholders. As of June 4, 2017, all of the Unvested IDUs had been forfeited pursuant to their terms of issuance.

In addition, the vested and outstanding Incentive Distribution Units held by WPX may be converted by Legacy, subject to applicable conversion factors, into units on a one-for-one basis at any time when Legacy has made a distribution in respect of its units for each of the four full fiscal quarters prior to the delivery of its conversion notice, and the amount of the distribution in respect of the units for the full quarter immediately preceding delivery of its conversion notice was equal to at least $0.90 per unit; and the amount of all distributions during each quarter within the four-quarter period immediately preceding delivery of its conversion notice did not exceed the adjusted operating surplus, as defined in Legacy's Partnership Agreement, for such quarter. Further, WPX also has the ability to similarly convert any of its vested Incentive Distribution Units beginning three years after June 4, 2014. WPX may not transfer any of the Incentive Distribution Units it holds to any person that is not a controlled affiliate of WPX.

Loss per unit

The following table sets forth the computation of basic and diluted loss per unit:

	Years Ended December 31,		
	2017	2016	2015
		(In thousands)	
Net loss	$ (53,897)	$ (55,820)	$ (701,541)
Distributions to preferred unitholders	(19,000)	(19,000)	(19,000)
Net loss attributable to unitholders	$ (72,897)	$ (74,820)	$ (720,541)
Weighted average number of units outstanding	72,405	70,605	68,928
Effect of dilutive securities:			
Restricted and phantom units	—	—	—
Weighted average units and potential units outstanding	72,405	70,605	68,928
Basic and diluted loss per unit	$ (1.01)	$ (1.06)	$ (10.45)

As of December 31, 2017, 241,373 restricted units and 1,389,773 phantom units were excluded from the calculation of diluted earnings per unit due to their anti-dilutive effect. Additionally, as the conditions for conversion on the Incentive Distribution Units have not been met, they have been excluded from the calculation. As of December 31, 2016, 484,447 restricted units and 1,212,692 phantom units were excluded from the calculation of diluted earnings per unit due to their anti-dilutive effect. As of December 31, 2015, 550,447 restricted units and 862,064 phantom units were excluded from the calculation of diluted earnings per unit due to their anti-dilutive effect.

On December 31, 2017, Legacy entered into a standstill and voting agreement that included the issuance of 3.8 million units. The units were issued on January 5, 2018. See Note 15 for further discussion.

(13) Unit-Based Compensation

Long Term Incentive Plan

On March 15, 2006, a Long-Term Incentive Plan (as amended, "LTIP") for Legacy was created and Legacy adopted the LTIP for its employees, consultants and directors, its affiliates and its general partner. The awards under the long-term incentive plan may include unit grants, restricted units, phantom units, unit options and unit appreciation rights ("UARs"). The LTIP permits the grant of awards that may be made or settled in units up to an aggregate of 5,000,000 units. As of December 31, 2017 grants of awards net of forfeitures and, in the case of phantom units, historical exercises covering 3,365,716 units have been made, comprised of 266,014 unit option awards, 989,163 restricted unit awards, 1,389,773 phantom unit awards and 720,766 unit awards. The UAR awards granted under the LTIP may only be settled in cash, and therefore are not included in the aggregate number of units granted under the LTIP. The LTIP is administered by the compensation committee of the board of directors ("Compensation Committee") of Legacy's general partner.

The cost of employee services in exchange for an award of equity instruments is measured based on a grant-date fair value of the award (with limited exceptions), and that cost must generally be recognized over the vesting period of the award. However, if an entity that nominally has the choice of settling awards by issuing units predominately settles in cash, or if an entity usually settles in cash whenever an employee asks for cash settlement, the entity is settling a substantive liability rather than repurchasing an equity instrument. Due to Legacy's historical practice of settling options, UARs and certain phantom unit awards in cash, Legacy accounts for unit options, UARS and certain phantom unit awards by utilizing the liability method. The liability method requires companies to measure the cost of the employee services in exchange for a cash award based on the fair value of the underlying security at the end of each reporting period until settlement. Compensation cost is recognized based on the change in the liability between periods.

Unit Appreciation Rights

A UAR is a notional unit that entitles the holder, upon vesting, to receive cash valued at the difference between the closing price of units on the exercise date and the exercise price, as determined on the date of grant. Because these awards are settled in cash, Legacy accounts for the UARs under the liability method.

During the year ended December 31, 2015, Legacy issued (i) 204,500 UARs to employees which vest ratably over a three-year period and (ii) 96,520 UARs to employees which cliff-vest at the end of a three-year period. Legacy did not issue UARs to employees during the years ended December 31, 2016 and 2017. All of the UARs granted in 2015 expire seven years from the grant date and are exercisable when they vest.

For the years ended December 31, 2017, 2016 and 2015, Legacy recorded compensation (benefit) expense of $(37,240), $223,569 and $(10,713), respectively, due to the changes in the compensation liability related to the above awards based on its use of the Black-Scholes model to estimate the December 31, 2017, 2016 and 2015 fair value of these UARs (see Note 8). As of December 31, 2017, there was a total of $32,662 of unrecognized compensation costs related to the unexercised and non-vested portion of the UARs. At December 31, 2017, this cost was expected to be recognized over a weighted-average period of 0.69 years. Compensation expense is based upon the fair value as of the balance sheet date and is recognized as a percentage of the service period satisfied. Based on historical data, Legacy has assumed a volatility factor of approximately 89% and employed the Black-Scholes model to estimate the December 31, 2017 fair value to be realized as compensation cost based on the percentage of the service period satisfied. Based on historical data, Legacy has assumed an estimated forfeiture rate of 5.6%. The Partnership will adjust the estimated forfeiture rate based upon actual experience. Legacy has assumed an annual distribution rate of $0.00 per unit.

A summary of UAR activity for the year ended December 31, 2017, 2016 and 2015 is as follows:

	Units	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1, 2015	671,229	$26.97		
Granted	301,020	$ 6.49		
Forfeited	(36,133)	$21.07		
Outstanding at December 31, 2015	936,116	$20.61	4.91	$ —
UARs exercisable at December 31, 2015	372,049	$26.45	3.28	$ —
Outstanding at January 1, 2016	936,116	$20.61		
Expired	(21,067)	$16.07		
Forfeited	(30,503)	$19.80		
Outstanding at December 31, 2016	884,546	$20.75	3.68	$ —
UARs exercisable at December 31, 2016	570,369	$24.38	2.77	$ —
Outstanding at January 1, 2017	884,546	$20.75		
Expired	(147,024)	$24.50		
Forfeited	(15,501)	$13.91		
Outstanding at December 31, 2017	722,021	$20.13	3.29	$ —
UARs exercisable at December 31, 2017	592,522	$23.23	2.99	$ —

The following table summarizes the status of the Partnership's non-vested UARs since January 1, 2017:

	Non-Vested UARs	
	Number of Units	Weighted-Average Exercise Price
Non-vested at January 1, 2017	312,510	$14.08
Vested	(167,510)	20.37
Forfeited	(15,501)	13.91
Non-vested at December 31, 2017	129,499	$ 5.97

Legacy has used a weighted-average risk free interest rate of 2.0% in its Black-Scholes calculation of fair value, which approximates the U.S. Treasury interest rates at December 31, 2017. Expected life represents the period of time that options and UARs are expected to be outstanding and is based on the Partnership's best estimate. The following table represents the weighted average assumptions used for the Black-Scholes option-pricing model:

	Year Ended December 31,		
	2017	2016	2015
Expected life (years)	3.29	4.02	4.91
Annual interest rate	2.0%	1.6%	1.7%
Annual distribution rate per unit	$0.00	$0.00	$0.60
Volatility	89%	87%	59%

Phantom Units

Legacy has also issued phantom units under the LTIP to executive officers. A phantom unit is a notional unit that entitles the holder, upon vesting, to receive either one Partnership unit for each phantom unit or the cash equivalent of a Partnership unit, as stipulated by the form of the grant. Legacy accounts for the phantom units settled in Partnership units under the equity method. Legacy accounts for the phantom units settled in cash under the liability method.

During March 2015, the Compensation Committee approved the award of 341,251 subjective, or service-based, phantom units and 259,998 objective, or performance-based, phantom units to Legacy's executive officers. During June 2016, the Compensation Committee approved with respect to Paul Horne, and the board of directors of LRGPLLC approved the recommendation of the Compensation Committee with respect to the other executive officers the award of a maximum of 391,674 subjective, or service-based, phantom units that, upon vesting, settle in Partnership units, a maximum of 1,286,930 subjective phantom units that, upon vesting, settle in cash and a maximum of 2,238,138 objective, or performance-based, phantom units to Legacy's executive officers. During February 2017, the Compensation Committee approved the award to Legacy's executive officers of a maximum of 396,850 subjective, or service-based, phantom units that, upon vesting, settle in units, a maximum of 793,701 subjective phantom units that, upon vesting, settle in cash and a maximum of 1,587,402 objective, or performance-based, phantom units that, upon vesting, settle in cash.

Compensation expense related to the phantom units and associated DERs was $4.6 million, $3.7 million and $3.4 million for the years ended December 31, 2017, 2016 and 2015, respectively.

Restricted Units

During the year ended December 31, 2015, Legacy issued an aggregate of 381,860 restricted units to both non-executive employees and an executive employee. The restricted units awarded to non-executive employees vest ratably over a three-year period beginning at the date of grant. The restricted units granted to the executive employee vest ratably over a three-year period for a portion of the restricted units, with the remainder vesting in full at the end of a five-year period. During the year ended December 31, 2016, Legacy issued an aggregate of 137,569 restricted units to non-executive employees. The restricted units vest ratably over a three-year period beginning at the date of grant. During the year ended December 31, 2017, did not issue restricted units to any employees. Compensation expense related to restricted units was $1.5 million, $2.7 million and $2.7 million for the years ended December 31, 2017, 2016 and 2015, respectively. As of December 31, 2017, there was a total of $0.9 million of unrecognized compensation costs related to the non-vested portion of these restricted units. At December 31, 2017, this cost was expected to be recognized over a weighted-average period of 1.6 years.

Pursuant to the provisions of ASC 718, Legacy's issued units as reflected in the accompanying consolidated balance sheet at December 31, 2017, do not include 241,373 units related to unvested restricted unit awards.

Board Units

On June 15, 2015, Legacy granted and issued 11,025 units to each of its five non-employee directors as part of their annual compensation for serving on the board of directors of Legacy's general partner. The value of each unit was $9.13 at the time of issuance. On May 10, 2016, Legacy granted and issued 39,526 units to each of its six non-employee directors as part of their annual compensation for serving on the board of directors of Legacy's general partner. The value of each unit was $2.59 at the time of issuance. On May 16, 2017, Legacy granted and issued 47,847 units to each of its six non-employee directors who receive compensation for their service on Legacy's board of directors as part of their annual compensation for serving on the board of directors of Legacy's general partner. The value of each unit was $2.04 at the time of issuance. None of these units were subject to vesting. Legacy recognized the expense associated with the unit grants on the date of grant.

(14) Subsidiary Guarantors

On October 17, 2014, Legacy filed a registration statement on Form S-3 with the Securities and Exchange Commission ("SEC") to register the issuance and sale of, among other securities, its debt securities, which may be co-issued by Legacy Reserves Finance Corporation. The registration statement also registered guarantees of debt securities by Legacy Reserves Operating GP, LLC, Legacy Reserves Operating LP and Legacy Reserves Services, Inc. The Partnership's 2020 Senior Notes were issued in a private offering on December 4, 2012 and were subsequently registered through a public exchange offer that closed on January 8, 2014. The Partnership's 2021 Senior Notes were issued in two separate private offerings on May 28, 2013 and May 8, 2014. $250 million aggregate principal amount of our 2021 Senior Notes were subsequently registered through a public exchange offer that closed on March 18, 2014. The remaining $300 million of aggregate principal amount of our 2021 Senior Notes were subsequently registered through a public exchange offer that closed on February 10, 2015. The 2020 Senior Notes and the 2021 Senior Notes are guaranteed by Legacy's 100% owned subsidiaries Legacy Reserves Operating GP LLC, Legacy Reserves Operating LP, Legacy Reserves Services, Inc., Legacy Reserves Energy Services LLC, Dew Gathering LLC and Pinnacle Gas Treating LLC, which constitute all of its wholly-owned subsidiaries other than Legacy Reserves Finance Corporation, and certain other future subsidiaries (the "Guarantors", together with any future 100% owned subsidiaries that guarantee the Partnership's 2020 Senior Notes and 2021 Senior Notes, the "Subsidiaries"). The Subsidiaries are 100% owned by the Partnership and the guarantees by the Subsidiaries are full and unconditional, except for customary release provisions described in Note 3 - Long-Term Debt. The Partnership has no assets or operations independent of the Subsidiaries, and there are no significant restrictions upon the ability of the Subsidiaries to distribute funds to the Partnership. The guarantees constitute joint and several obligations of the Guarantors.

(15) Subsequent Events

Note Purchase Agreement

On December 31, 2017, Legacy entered into a definitive agreement with certain funds managed by Fir Tree Partners ("Fir Tree") pursuant to which Legacy acquired $187.0 million of the 6.625% Notes for a price of approximately $132 million with a settlement date of January 5, 2018. Legacy funded the purchase price with borrowings under its Term Loan Credit Agreement, leaving $60.4 million available for borrowing under the Term Loan Credit Agreement as of February 20, 2018. The portion of the purchase price attributable to accrued and unpaid interest was funded with borrowings under Legacy's revolving credit facility. The Third Amendment became effective on January 5, 2018.

Amendment to Term Loan Credit Agreement

On December 31, 2017, Legacy entered into the Third Amendment to the Term Loan Credit Agreement (the "Third Amendment") with GSO. Among other items, the Third Amendment increased the total commitment of terms loans under the Term Loan Credit Agreement to $400.0 million, extended the availability of borrowings under the Term Loan Credit Facility to October 26, 2019 and relaxed the asset coverage ratio to 0.85 to 1.00 until the fiscal quarter ended December 31, 2018.

Standstill and Voting Agreement

On December 31, 2017, Legacy entered into a Standstill and Voting Agreement in which Legacy agreed to pay cash and issue units representing limited partnership interests to certain entities controlled by Fir Tree, in exchange for Fir Tree, among other things, limiting their ability to acquire additional Legacy securities, agreeing to vote the issued units in accordance with the recommendation of the Board of Directors of Legacy's general partner and generally support Legacy's actions. Total consideration to Fir Tree of $8.6 million included $2.5 million in cash and 3.8 million units which were valued for accounting purposes at the December 29, 2017 closing price of $1.61 and is recognized as a general and administrative expense in the year ended December 31, 2017. Legacy settled the transaction with the cash payment and issuance of units on January 5, 2018.

Costs Incurred in Oil and Natural Gas Property Acquisition and Development Activities (Unaudited)

Costs incurred by Legacy in oil and natural gas property acquisition and development are presented below:

	Year Ended December 31,		
	2017	2016	2015
		(In thousands)	
Development costs	$176,827	$ 29,499	$ 36,934
Exploration costs	—	—	—
Acquisition costs:			
Proved properties	148,776	11,998	598,693
Unproved properties	14,575	24	2,180
Total acquisition, development and exploration costs	$340,178	$ 41,521	$637,807

Property acquisition costs include costs incurred to purchase, lease, or otherwise acquire a property. Development costs include costs incurred to gain access to and prepare development well locations for drilling, to drill and equip development wells, and to provide facilities to extract, treat, and gather natural gas. Please see page F-3 for total capitalized costs and associated accumulated depletion.

Net Proved Oil, NGL and Natural Gas Reserves (Unaudited)

The proved oil, NGL and natural gas reserves of Legacy have been estimated by an independent petroleum engineer, LaRoche, as of December 31, 2017, 2016 and 2015. These reserve estimates have been prepared in compliance with the Securities and Exchange Commission rules and accounting standards based on the 12-month unweighted first-day-of-the-month average price for December 31, 2017, 2016 and 2015.

An analysis of the change in estimated quantities of oil and natural gas reserves, all of which are located within the United States, is shown below:

	Oil (MBbls)	NGL (MBbls)(a)	Natural Gas (MMcf)(a)	Total (MBoe)
Total Proved Reserves:				
Balance, December 31, 2014	56,925	12,373	417,975	138,961
Purchases of minerals-in-place	131	4	440,661	73,579
Sales of minerals-in-place	(800)	(149)	(59)	(959)
Extensions and discoveries	(417)	—	(540)	(507)
Revisions from drilling and recompletions	904	2	1,986	1,237
Revisions of previous estimates due to price	(17,321)	(2,796)	(94,588)	(35,882)
Revisions of previous estimates due to performance	1,329	(679)	6,885	1,798
Production	(4,608)	(1,005)	(50,687)	(14,061)
Balance, December 31, 2015	36,143	7,750	721,633	164,166
Purchases of minerals-in-place	13	—	156	39
Sales of minerals-in-place	(1,185)	(40)	(5,573)	(2,154)
Extensions and discoveries	(142)	5	180	(107)
Revisions from drilling and recompletions	1,400	—	2,165	1,761
Revisions of previous estimates due to price	(3,358)	746	(12,987)	(4,777)
Revisions of previous estimates due to performance	3,606	257	(11,730)	1,908
Production	(4,019)	(875)	(66,824)	(16,032)
Balance, December 31, 2016	32,458	7,843	627,020	144,804
Purchases of minerals-in-place	6,363	—	9,971	8,025
Sales of minerals-in-place	(442)	—	(1,121)	(629)
Revisions from ownership changes	998	15	1,751	1,305
Revisions from drilling and recompletions	7,048	302	10,933	9,172
Revisions of previous estimates due to price	5,387	672	51,975	14,722
Revisions of previous estimates due to performance	4,366	1,527	78,436	18,967
Production	(5,032)	(909)	(62,833)	(16,413)
Balance, December 31, 2017	51,146	9,450	716,132	179,953
Proved Developed Reserves:				
December 31, 2014	47,203	12,073	402,802	126,410
December 31, 2015	34,297	7,729	718,094	161,708
December 31, 2016	28,092	7,743	619,959	139,162
December 31, 2017	45,045	9,333	705,679	171,991
Proved Undeveloped Reserves:				
December 31, 2014	9,722	300	15,173	12,551
December 31, 2015	1,846	21	3,539	2,457
December 31, 2016	4,366	100	7,061	5,642
December 31, 2017	6,101	117	10,453	7,963

(a) We primarily report and account for our Permian Basin natural gas volumes inclusive of the NGL content in those natural gas volumes. Given the price disparity between an equivalent amount of NGLs compared to natural gas, Legacy's realized natural gas prices in the Permian Basin are substantially higher than NYMEX Henry Hub natural gas prices due to NGL content.

The primary drivers behind the changes to our proved reserves in each of 2015, 2016 and 2017 are described in more detail below.

2015: The increase in proved reserve quantities for the year ended December 31, 2015 was due primarily to our acquisition of producing properties in 4 separate transactions, including the Anadarko Acquisitions. This increase was partially offset by a net decrease in reserves due to the decline in average NYMEX-WTI oil and Henry Hub natural gas prices during 2015.

2016: The decrease in proved reserve quantities for the year ended December 31, 2016 was due primarily to production of the assets, the decline in average NYMEX-WTI oil and Henry Hub natural gas prices during 2016 which decreased the economic life or our properties and divestitures of low-production, high-cost properties.

2017: The increase in proved reserve quantities for the year ended December 31, 2017 was due primarily to the development of our unproved assets, the increase in average NYMEX-WTI oil and Henry Hub natural gas prices during 2017 which increased the economic life of our properties and the acquisition of producing oil and natural gas properties.

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Reserves (Unaudited)

Summarized in the following table is information for Legacy with respect to the standardized measure of discounted future net cash flows relating to proved reserves. Future cash inflows are computed by applying the 12-month unweighted first-day-of-the-month average price for the years ended December 31, 2017, 2016 and 2015. Future production, development, site restoration, and abandonment costs are derived based on current costs assuming continuation of existing economic conditions. Future net cash flows have not been adjusted for commodity derivative contracts outstanding at the end of each year. Federal income taxes have not been deducted from future production revenues in the calculation of standardized measure as each partner is separately taxed on their share of Legacy's taxable income. In addition, Texas margin taxes and the federal income taxes associated with a corporate subsidiary, as discussed in Note 1(f), have not been deducted from future production revenues in the calculation of the standardized measure as the impact of these taxes would not have a significant effect on the calculated standardized measure.

	December 31,		
	2017	2016	2015
		(In thousands)	
Future production revenues	$ 4,657,406	$ 2,814,259	$ 3,471,519
Future costs:			
Production	(2,347,759)	(1,618,241)	(2,015,514)
Development	(148,936)	(202,304)	(205,213)
Future net cash flows before income taxes	2,160,711	993,714	1,250,792
10% annual discount for estimated timing of cash flows	(988,563)	(418,088)	(555,851)
Standardized measure of discounted net cash flows	$ 1,172,148	$ 575,626	$ 694,941

The standardized measure is based on the following oil and natural gas prices realized over the life of the properties at the wellhead as of the following dates:

	December 31,		
	2017	2016	2015
Oil (per Bbl) (a)	$47.79	$39.25	$46.79
Natural Gas (per MMBtu) (b)	$ 2.98	$ 2.48	$ 2.59

(a) The quoted oil price for all fiscal years is the 12-month unweighted average first-day-of-the-month West Texas Intermediate price, as posted by Plains Marketing, L.P., for each month of 2017, 2016 and 2015.

(b) The quoted gas price for all fiscal years is the 12-month unweighted average first-day-of-the-month Henry Hub price, as posted by Platts Gas Daily, for each month of 2017, 2016 and 2015.

The following table summarizes the principal sources of change in the standardized measure of discounted future estimated net cash flows:

	Year ended December 31, 2017	2016	2015
		(In thousands)	
Increase (decrease):			
Sales, net of production costs	$ (233,257)	$(120,757)	$ (127,905)
Net change in sales prices, net of production costs	310,206	(109,125)	(1,367,523)
Changes in estimated future development costs	(591)	99	9,428
Revisions of previous estimates due to infill drilling, recompletions and stimulations	135,700	15,632	24,694
Revisions of previous quantity estimates due to performance	89,941	57,188	38,083
Previously estimated development costs incurred	16,328	2,097	14,136
Purchases of minerals-in-place	206,038	294	218,463
Sales of minerals-in-place	(2,861)	(14,781)	(19,095)
Ownership interest changes	14,533	(3,886)	(7,341)
Other	5,534	(9,028)	(10,854)
Accretion of discount	54,951	62,952	168,241
Net increase (decrease)	596,522	(119,315)	(1,059,673)
Standardized measure of discounted future net cash flows:			
Beginning of year	575,626	694,941	1,754,614
End of year	$1,172,148	$ 575,626	$ 694,941

The data presented should not be viewed as representing the expected cash flow from or current value of, existing proved reserves since the computations are based on a large number of estimates and arbitrary assumptions. Reserve quantities cannot be measured with precision and their estimation requires many judgmental determinations and frequent revisions. Actual future prices and costs are likely to be substantially different from the current prices and costs utilized in the computation of reported amounts.

Selected Quarterly Financial Data (Unaudited)

For the three-month periods ended:

2017	March 31	June 30	September 30	December 31
	(In thousands, except per unit data)			
Revenues:				
Oil sales	$ 49,142	$ 46,096	$ 59,060	$ 85,150
Natural gas liquids sales	5,050	4,921	6,720	8,105
Natural gas sales	45,355	41,830	41,035	43,837
Total revenues	99,547	92,847	106,815	137,092
Expenses:				
Oil and natural gas production	51,217	44,802	42,079	45,121
Production and other taxes	4,159	4,145	5,475	6,046
General and administrative	10,552	8,581	10,023	20,216
Depletion, depreciation, amortization and accretion	28,796	27,689	33,715	36,738
Impairment of long-lived assets	8,062	1,821	14,665	12,735
(Gain) loss on disposal of assets	(5,524)	11,049	(2,034)	(1,885)
Total expenses	97,262	98,087	103,923	118,971
Operating income (loss)	2,285	(5,240)	2,892	18,121
Interest income	1	8	35	20
Interest expense	(20,133)	(20,614)	(23,621)	(24,838)
Equity in income of equity method investee	11	1	—	5
Net gains (losses) on commodity derivatives	34,669	14,516	(13,309)	(18,100)
Other	(40)	402	403	27
Incomes (loss) before income taxes	16,793	(10,927)	(33,600)	(24,765)
Income taxes	(421)	(150)	(266)	(561)
Net income (loss)	$ 16,372	$ (11,077)	$ (33,866)	$ (25,326)
Distributions to preferred unitholders	(4,750)	(4,750)	(4,750)	(4,750)
Net income (loss) attributable to unitholders	$ 11,622	$ (15,827)	$ (38,616)	$ (30,076)
Net income (loss) per unit — basic and diluted	$ 0.16	$ (0.22)	$ (0.53)	$ (0.41)
Production volumes:				
Oil (MBbl)	1,037	1,044	1,323	1,628
Natural gas liquids (Mgal)	7,653	8,514	11,375	10,617
Natural gas (MMcf)	15,592	15,604	15,771	15,866
Total (MBoe)	3,818	3,847	4,222	4,525

LEGACY RESERVES LP

SUPPLEMENTARY INFORMATION — (Continued)

For the three-month periods ended:

2016	**March 31**	**June 30**	**September 30**	**December 31**
	(In thousands, except per unit data)			
Revenues:				
Oil sales	$ 30,320	$ 41,272	$ 38,751	$ 42,164
Natural gas liquids sales	2,453	3,922	3,457	5,574
Natural gas sales	33,086	28,173	41,332	43,853
Total revenues	65,859	73,367	83,540	91,591
Expenses:				
Oil and natural gas production	50,023	44,561	43,121	41,628
Production and other taxes	2,573	3,390	3,986	4,318
General and administrative	9,434	10,993	9,231	13,981
Depletion, depreciation, amortization and accretion	36,959	37,668	36,068	39,719
Impairment of long-lived assets	15,447	—	4,618	41,731
(Gain) loss on disposal of assets	(31,701)	(9,141)	(8,447)	(806)
Total expenses	82,735	87,471	88,577	140,571
Operating loss	(16,876)	(14,104)	(5,037)	(48,980)
Interest income	38	16	—	13
Interest expense	(25,176)	(20,302)	(17,080)	(16,502)
Gain on extinguishment of debt	130,804	19,998	—	—
Equity in income of equity method investee	(5)	(9)	7	7
Net gains (losses) on commodity derivatives	17,038	(37,675)	18,326	(38,913)
Other	(94)	(98)	(296)	309
Income (loss) before income taxes	$ 105,729	$ (52,174)	$ (4,080)	$ (104,066)
Income taxes	(400)	(87)	(223)	(519)
Net income (loss)	$ 105,329	$ (52,261)	$ (4,303)	$ (104,585)
Distributions to preferred unitholders	$ (3,958)	$ (4,750)	$ (4,750)	$ (5,542)
Net income (loss) attributable to unitholders	$ 101,371	$ (57,011)	$ (9,053)	$ (110,127)
Net income (loss) per unit — basic and diluted	$ 1.47	$ (0.81)	$ (0.13)	$ (1.53)
Production volumes:				
Oil (MBbl)	1,069	1,039	962	949
Natural gas liquids (Mgal)	8,241	9,663	9,742	9,111
Natural gas (MMcf)	17,266	16,743	16,572	16,243
Total (MBoe)	4,143	4,060	3,956	3,873

EXHIBIT 21.1

Legacy Reserves LP
Subsidiaries

Entity	Jurisdiction of Formation
Binger Operations, LLC (50% non-controlling interest)	Oklahoma
Legacy Reserves Operating GP LLC	Delaware
Legacy Reserves Operating LP	Delaware
Legacy Reserves Services Inc.	Texas
Legacy Reserves Finance Corporation	Delaware
Dew Gathering LLC	Texas
Pinnacle Gas Treating LLC	Texas
Legacy Reserves Energy Services LLC	Texas

EXHIBIT 23.1

Consent of Independent Registered Public Accounting Firm

Legacy Reserves LP

Midland, Texas

We hereby consent to the incorporation by reference in the registration statements on Form S-8 (Nos. 333-144586 and 333-204917) of Legacy Reserves LP of our reports dated February 23, 2018, relating to the consolidated financial statements and the effectiveness of Legacy Reserves LP's internal control over financial reporting appearing in the Partnership's annual report on Form 10-K for the year ended December 31, 2017.

/s/ BDO USA, LLP
Houston, Texas

February 23, 2018

EXHIBIT 23.2

Consent of Independent Reserve Engineers and Geologists

As independent reserve engineers, geologists, and geophysicists, we hereby consent to the references to our Firm's name and our Firm's reserve report dated January 18, 2018 on the oil and natural gas reserves of Legacy Reserves LP as of December 31, 2017 in Legacy Reserves LP's annual report for the year ended December 31, 2017 filed on Form 10-K and in Legacy Reserves LP's registration statements on Form S-8 (Nos. 333-144586 and 333-204917) with the Securities and Exchange Commission.

LAROCHE PETROLEUM CONSULTANTS, LTD.

By LPC, Inc. General Partner
By: /s/ Joe A. Young
Name: Joe A. Young
Title: Vice President

February 23, 2018

EXHIBIT 31.1

CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Paul T. Horne, certify that:

1. I have reviewed this annual report on Form 10-K of Legacy Reserves LP (the "registrant") for the year ended December 31, 2017;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 23, 2018

By: /s/ Paul T. Horne
Paul T. Horne
Chairman of the Board,
President and Chief Executive Officer of
Legacy Reserves GP, LLC,
general partner of Legacy Reserves LP
(Principle Executive Officer)

EXHIBIT 31.2

CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, James Daniel Westcott, certify that:

1. I have reviewed this annual report on Form 10-K of Legacy Reserves LP (the "registrant") for the year ended December 31, 2017;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 23, 2018

By: /s/ James Daniel Westcott
James Daniel Westcott
Executive Vice President and Chief Financial
Officer of Legacy Reserves GP, LLC,
general partner of Legacy Reserves LP
(Principal Financial Officer)

EXHIBIT 32.1

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350, AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Legacy Reserves LP (the "Partnership") on Form 10-K for the period ending December 31, 2017 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each of the undersigned hereby certifies, in his capacity as an officer of Legacy Reserves GP, LLC (the "Company"), the general partner of the Partnership, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

/s/ Paul T. Horne
Paul T. Horne
Chairman of the Board, President and
Chief Executive Officer

February 23, 2018

/s/ James Daniel Westcott
James Daniel Westcott
Executive Vice President and Chief Financial Officer

February 23, 2018

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request. The foregoing certification is being furnished to the Securities and Exchange Commission as an exhibit to the Report and shall not be considered filed as part of the Report.

EXHIBIT 99.1

January 18, 2018

Mr. James D. Westcott
Legacy Reserves LP
303 W. Wall Street, Suite 1800
Midland, TX 79701

Dear Mr. Westcott:

At your request, LaRoche Petroleum Consultants, Ltd. (LPC) has estimated the proved reserves and future cash flow, as of December 31, 2017, to the Legacy Reserves LP (Legacy) interest in certain properties located in the United States. The work for this report was completed as of the date of this letter. This report was prepared to provide Legacy with U.S. Securities and Exchange Commission (SEC) compliant reserve estimates. It is our understanding that the properties evaluated by LPC comprise 100 percent (100%) of Legacy's proved reserves. We believe the assumptions, data, methods, and procedures used in preparing this report, as set out below, are appropriate for the purpose of this report. This report has been prepared using constant prices and costs and conforms to our understanding of the SEC guidelines, reserves definitions, and applicable financial accounting rules.

Summarized below are LPC's estimates of net reserves and future net cash flow. Future net cash flow is after deducting production and ad valorem taxes, operating expenses, and future capital expenditures but before consideration of federal income taxes. The discounted cash flow values included in this report are intended to represent the time value of money and should not be construed to represent an estimate of fair market value. We estimate the net reserves and future net cash flow to the Legacy interest, as of December 31, 2017, to be:

	Net Reserves			Future Net Cash Flow ($)	
Category	**Oil (Barrels)**	**NGL (Barrels)**	**Gas (Mcf)**	**Total**	**Present Worth at 10%**
Proved Developed					
Producing	44,486,395	9,319,768	695,912,665	$ 1,955,039,171	$ 1,074,805,257
Non-Producing	558,113	13,206	9,766,430	25,081,777	12,002,998
Proved Undeveloped	6,101,424	118,824	10,453,934	180,590,936	85,339,998
Total Proved (1)	51,145,932	9,451,798	716,133,029	$ 2,160,711,884	$ 1,172,148,253

(1) The total proved values above may or may not match those values on the total proved summary page that follows this letter due to rounding by the economics program.

The oil reserves include crude oil and condensate. Oil and natural gas liquid (NGL) reserves are expressed in barrels which are equivalent to 42 United States gallons. Gas reserves are expressed in thousands of standard cubic feet (Mcf) at the contract temperature and pressure bases.

The estimated reserves and future cash flow shown in this report are for proved developed producing reserves and, for certain properties, proved developed non-producing and proved undeveloped reserves. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated.

Estimates of reserves for this report were prepared using standard geological and engineering methods generally accepted by the petroleum industry. The reserves in this report have been estimated using deterministic methods. The method or combination of methods utilized in the evaluation of each reservoir included consideration of the stage of development of the reservoir, quality and completeness of basic data, and production history. Recovery from various reservoirs and leases was estimated after consideration of the type of energy inherent in the reservoirs, the structural positions of the properties, and reservoir and well performance. In some instances, comparisons were made with similar properties where more complete data were available. We have used all methods and procedures that we considered necessary under the circumstances to prepare this report. We have excluded from our consideration all matters to which the controlling interpretation may be legal or accounting rather than engineering or geoscience.

The estimated reserves and future cash flow amounts in this report are related to hydrocarbon prices. Historical prices through December 2017 were used in the preparation of this report as required by SEC guidelines; however, actual future prices may vary significantly from the SEC prices. In addition, future changes in environmental and administrative regulations may significantly affect the ability of Legacy to produce oil and gas at the projected levels. Therefore, volumes of reserves actually recovered and amounts of cash flow actually received may differ significantly from the estimated quantities presented in this report.

Benchmark prices used in this report are based on the twelve-month, unweighted arithmetic average of the first day of the month price for the period January through December 2017. Gas prices used in this report are referenced to a Henry Hub price of $2.98 per MMBtu, as posted by Platts Gas Daily, and are adjusted for energy content, transportation fees, and regional price differentials. Oil and NGL prices used in this report are referenced to a West Texas Intermediate crude oil price of $47.79 per barrel, as posted by Plains Marketing, L.P., and are adjusted for gravity, crude quality, transportation fees, and regional price differentials. These reference prices are held constant in accordance with SEC guidelines. The weighted average prices after adjustments over the life of the properties are $47.72 per barrel for oil, $2.75 per Mcf for gas, and $26.50 per barrel for NGL.

Lease and well operating expenses are based on data obtained from Legacy. Expenses for the properties operated by Legacy include direct lease and field level costs as well as Legacy's estimate of the general and administrative overhead costs necessary to operate the properties. Leases and wells operated by others include all direct expenses as well as general and administrative overhead costs allowed under the specific joint operating agreements. Lease and well operating costs are held constant in accordance with SEC guidelines.

Capital costs and timing of all investments have been provided by Legacy and are included as required for workovers, new development wells, and production equipment. Legacy has represented to us that they have the ability and intent to implement their capital expenditure program as scheduled. Legacy's estimates of the cost to plug and abandon the wells net of salvage value are included and scheduled at the end of the economic life of individual properties. These costs are not included for wells that are currently producing below their economic limit. All capital costs are held constant.

LPC made no investigation of possible gas volume and value imbalances that may have resulted from the overdelivery or underdelivery to the Legacy interest. Our projections are based on the Legacy interest receiving its net revenue interest share of estimated future gross oil, gas, and NGL production.

Technical information necessary for the preparation of the reserve estimates herein was furnished by Legacy or was obtained from state regulatory agencies and commercially available data sources. No special tests were obtained to assist in the preparation of this report. For the purpose of this report, the individual well test and production data as reported by the above sources were accepted as represented together with all other factual data presented by Legacy including the extent and character of the interest evaluated.

An on-site inspection of the properties has not been performed nor has the mechanical operation or condition of the wells and their related facilities been examined by LPC. In addition, the costs associated with the continued operation of uneconomic properties are not reflected in the cash flows.

The evaluation of potential environmental liability from the operation and abandonment of the properties is beyond the scope of this report. In addition, no evaluation was made to determine the degree of operator compliance with current environmental rules, regulations, and reporting requirements. Therefore, no estimate of the potential economic liability, if any, from environmental concerns is included in the projections presented herein.

The reserves included in this report are estimates only and should not be construed as exact quantities. They may or may not be recovered; if recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. These estimates should be accepted with the understanding that future development, production history, changes in regulations, product prices, and operating expenses would probably cause us to make revisions in subsequent evaluations. A portion of these reserves are for behind-pipe zones, undeveloped locations, and producing wells that lack sufficient production history to utilize performance-related reserve estimates. Therefore, these reserves are based on estimates of reservoir volumes and recovery efficiencies along with analogies to similar production. These reserve estimates are subject to a greater degree of uncertainty than those based on substantial production and pressure data. It may be necessary to revise these estimates up or down in the future as additional performance data become available. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geological data; therefore, our conclusions represent informed professional judgments only, not statements of fact.

The results of our third party study were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by Legacy.

Legacy makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, Legacy has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Form S-3, Form S-4, and Form S-8 of Legacy of the references to our name as well as to the references to our third party report for Legacy which appears in the December 31, 2017 annual report on Form 10-K and/or 10-K/A of Legacy. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Legacy.

We have provided Legacy with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by Legacy and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The technical persons responsible for preparing the reserve estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. The technical person primarily responsible for overseeing the preparation of reserve estimates herein is Joe A. Young. Mr. Young is a Licensed Professional Engineer in the State of Texas who has 36 years of engineering experience in the oil and gas industry and has prepared and overseen preparation of reports for public filings for LPC for the past 21 years. LPC is an independent firm of petroleum engineers, geologists, and geophysicists; and are not employed on a contingent basis. Data pertinent to this report are maintained on file in our office.

Very truly yours,

LaRoche Petroleum Consultants, Ltd.
State of Texas Registration Number F-1360

/s/ Joe A. Young
Joe A. Young
Licensed Professional Engineer
State of Texas No. 62866


LEGACY
RESERVES

ABOUT LEGACY RESERVES

Legacy Reserves LP (NASDAQ: LGCY) is a master limited partnership headquartered in Midland, Texas, focused on the development of oil and natural gas properties primarily located in the Permian Basin, East Texas, Rocky Mountain and Mid-Continent regions of the United States.

EXECUTIVE MANAGEMENT

Paul T. Horne
Chairman of the Board and
Chief Executive Officer

James Daniel Westcott
President and
Chief Financial Officer

Kyle M. Hammond
Executive Vice President and
Chief Operating Officer

Kyle A. McGraw
Director, Executive Vice President
and Chief Development Officer

Dan G. LeRoy
Vice President, General Counsel
and Secretary

Micah C. Foster
Chief Accounting Officer and
Controller

BOARD OF DIRECTORS

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D. Dwight Scott

William D. Sullivan

[1] Chairman of the Board

[2] Lead Independent Director and Chairman of the Compensation Committee

[3] Chairman of the Nominating, Governance and Conflicts Committee

[4] Chairman of the Audit Committee

UNITHOLDER INFORMATION

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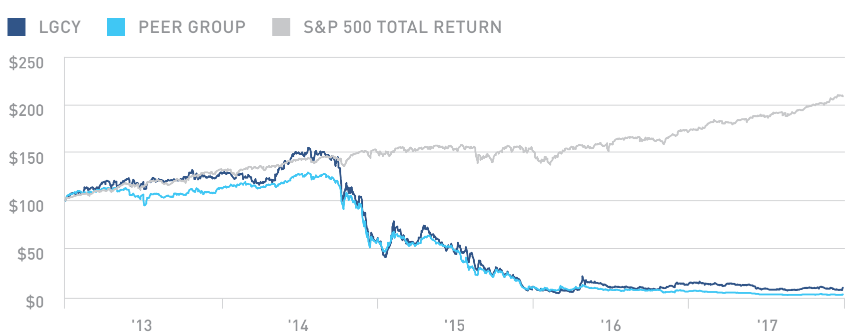
Richardson, TX 75080

K-1 Tax Reports
For questions or corrections, please call
(877) 504-5606
LegacyK1Help@deloitte.com

ANALYSIS OF INVESTMENT RETURN (VALUE IN $)



The value of $100 invested in LGCY on December 31, 2012 through December 31, 2017 versus an equally-weighted upstream MLP peer group index (AMPY, ARPJQ, BBEPQ, EVEP, LINEQ, MCEP, VNRSQ) and the S&P Total Return Index over the same time period; in all cases, assuming reinvestment of distributions.

LEGACY
RESERVES

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