LEGACY RESERVES LP
Form 10-K
February 22, 2017

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

Form 10-K

þ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2016

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

(Address of principal executive offices)
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 o No þ
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No þ
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ No o
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes þ No o
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements

incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o

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

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes o No þ

The aggregate market value of units held by non-affiliates of the registrant was approximately $117.3 million on June 30, 2016, based on $1.62 per unit, the last reported sales price of the units on the NASDAQ Global Select Market on such date.

72,625,147 units representing limited partner interests in the registrant were outstanding as of February 21, 2017.

DOCUMENTS INCORPORATED BY REFERENCE

Parts of the definitive proxy statement for the registrant’s 2017 annual meeting of unitholders are incorporated by reference into Part III of this annual report on Form 10-K.

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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.

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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.

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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.

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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 acquire and appropriately finance additional oil and natural gas properties at economically attractive prices;
- 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 facility and our term loan credit agreement;
- our ability to engage in capital markets activity which may include debt or equity exchanges or repurchases;
- 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,” 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.

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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 Legac 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 acquisition and 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, 2016 are as follows:

- we had proved reserves of approximately 144.8 MMBoe, of which 72% were natural gas, 28% were oil and natural gas liquids (“NGLs”) and 94% were classified as proved developed producing; and

- our proved reserves to production ratio was approximately 9.4 years based on the annualized production volumes for the three months ended December 31, 2016.

We have grown primarily through two activities: the acquisition of producing oil and natural gas properties and the development of properties in established producing trends. From 2007 through 2016, we completed 143 acquisitions of oil and natural gas properties for a total of approximately $2.7 billion. These acquisitions of primarily long-lived, oil and natural gas assets, along with our ongoing development activities and operational improvements, have allowed us to achieve significant growth during this time period.

Business Strategy

The key elements of our business strategy are to:

- Add proved reserves and maximize cash flow and production through development projects and operational efficiencies;

- Make accretive acquisitions of oil and natural gas properties; and

- Reduce commodity price risk through oil and natural gas derivative transactions.

2017 Operating Focus

Oil and natural gas prices experienced a significant drop in late 2014 and 2015. Prices recovered slightly in 2016, but still remain at levels lower than previously seen before the decline began in 2014, which has further challenged the state of the capital markets for oil and natural gas exploration and production companies. In response, we elected to maintain a modest capital program in 2017. Our development capital expenditures are expected to be approximately $55 million in 2017, compared to approximately $29.5 million in 2016 and $36.9 million in 2015. The increase in our capital program in 2017 as compared to 2016 is driven by increased net working interests and an anticipated higher number of total drilling days under our two-rig horizontal drilling program in the Permian Basin.

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Should oil and natural gas prices decline in 2017, we could breach certain financial covenants under our revolving credit facility or our term loan credit agreement, which would constitute a default under our revolving credit facility 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 facility or our term loan credit agreement or foreclosure on our oil and natural gas properties. Certain payment defaults or acceleration under our revolving credit facility or our term loan credit agreement could cause a cross-default or cross-acceleration of all of our other 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 2017 are to fund our operations and to reduce leverage from our internally generated cash flow and to preserve financial flexibility and liquidity.

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 mature 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 567 mile natural gas gathering system and plant we acquired as part of those acquisitions.

Rocky Mountain. We entered the Rocky Mountain region upon completing an acquisition in the Big Horn and Wind River Basins in Wyoming in February 2010. We subsequently added positions in the Powder River Basin through several smaller acquisitions. The properties in Wyoming are largely mature oil wells with a natural water drive that produce primarily from the Dinwoody-Phosphoria, Tensleep and Minnelusa formations. We expanded our footprint in this region with our acquisition of oil properties in North Dakota and Montana in May 2012 and our acquisition of non-operated oil and natural gas properties in Colorado in June 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 primarily in the Texas Panhandle and Oklahoma. The vast majority of these properties were acquired through several transactions from April 2007 through October 2008. Our Texas Panhandle wells produce mostly from shallow Granite Wash, Brown Dolomite and Red Cave formations. Our operated properties in the Texas Panhandle are mostly mature oil wells that also produce high-Btu casinghead gas with significant NGL content, while our non-operated properties are mostly mature, low pressure natural gas wells with high NGL content.

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Our proved reserves by operating region are as follows:

Proved Reserves by Operating Region as of December 31, 2016

Operating Regions	Oil (MBbls)	Natural Gas (MMcf)	NGLs(MBbls)	Total (MBoe)	% Liquids	% PDP	% Total
East Texas	63	339,034	95	56,664	0.3 %	98.1%	39.1 %
Permian Basin	25,491	89,446	932	41,331	63.9 %	83.4%	28.6 %
Rocky Mountain	4,970	188,277	4,474	40,823	23.1 %	99.2%	28.2 %
Mid-Continent	1,934	10,263	2,342	5,986	71.4 %	95.6%	4.1 %
Total	32,458	627,020	7,843	144,804	27.8 %	94.1%	100.0%

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 (miscible nitrogen and CO_2) recovery projects.

As of December 31, 2016, we identified 47 gross (17.0 net) proved undeveloped ("PUD") drilling locations, 16 of which were identified and economically viable at December 31, 2015. The table below details the activity in our PUD locations from December 31, 2015 to December 31, 2016:

	Gross Locations	Net Locations	Net Volume (MBoe)
Balance, December 31, 2015	44	17.5	2,458
PUDs converted to PDP by drilling	(4)	(0.2)	(327)
PUDs removed due to performance (a)	(6)	(0.1)	(137)
PUDs removed from future drilling schedule (b)	(16)	(11.4)	(721)
PUDs removed due to sale	(2)	(1.3)	(138)
Additions due to performance (a)	31	11.9	3,872
Other	—	0.6	636
Balance, December 31, 2016	47	17.0	5,643

(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. Substantially all of the reductions in PUDs due to performance were due to the removal of PUDs as they became uneconomic as of December 31, 2016 based on commodity price declines or 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, 2016, we identified 55 gross (34.6 net) recompletion and fracture stimulation projects.

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Excluding acquisitions, we expect to make capital expenditures of approximately $55 million during the year ending December 31, 2017.

During 2015, one of our wholly owned subsidiaries, Legacy Reserves Operating LP (the "Operating Partnership"), entered into a Development Agreement (as subsequently amended, the "Development Agreement") with Jupiter JV LP ("Investor"), which was formed by certain of TPG Special Situations Partners' investment funds. Pursuant to the Development Agreement, Legacy and Investor participated in the funding, exploration, development and operation of certain of our undeveloped oil and natural gas properties within approximately 3,938 net acres in the Permian Basin (collectively, the "Subject Assets"). Under the terms of the Development Agreement, Investor pays 95% of the costs to the parties' combined interests to develop the assets and 80% of the costs to the parties' combined interests to develop or construct associated saltwater disposal wells and other infrastructure assets. In exchange for funding a portion of the parties' combined costs, Investor received an undivided 80.0% of our working interest in the assets, subject to reversion as discussed below. Investor's portion of the development costs will be limited to $275 million for the initial carry period and may, subject to mutual consent, be expanded.

At the first instance of Investor achieving a 15% internal rate of return in the aggregate with respect to a tranche of wells, Investor's interest in the tranche of wells and related infrastructure (except saltwater disposal wells) will revert to 15% of the Operating Partnership's initial working interest while the remainder will revert to us, and all the remaining undeveloped Subject Assets will revert to us but remain available for future development subject to the Development Agreement.

The Development Agreement provides that Investor can suspend its future funding obligations at certain times upon the occurrence of certain events based on anticipated financial metrics, certain operating cost overruns and changes in commodity prices, provided that Investor will be obligated to complete funding of any wells or infrastructure in progress. We anticipate operating approximately $181.5 million of gross capital in 2017 under this program, of which $28.5 million will be funded by us as part of our anticipated $55 million 2017 capital budget.

During 2016, we completed several individually immaterial divestitures totaling $97.4 million 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 gain on disposal of assets of $50.1 million for the year ended December 31, 2016.

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, 2016, we had in place oil and natural gas derivatives covering portions of our estimated 2017 through 2019 oil and natural gas production. Our derivative contracts are in the form of fixed price swaps, enhanced swaps and three-way collars for NYMEX WTI oil; fixed price swaps and three-way collars for NYMEX Henry Hub, Northwest Pipeline, California SoCal and San Juan Basin; and fixed price swaps for the Midland-to-Cushing oil differential.

Marketing and Major Purchasers

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. For the year ended December 31, 2014, Legacy sold oil, NGL and natural gas production representing 10% or more of total revenues to purchasers as detailed in the table below:

	2016	2015	2014
Enterprise (Teppco) Crude Oil, LP	1 %	6 %	12 %

Plains Marketing, LP	6 %	7 %	10 %

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.

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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 properties, securing and retaining trained personnel and marketing oil and natural gas. Our competitors may be able to pay more for 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

Generally, but not always, the demand for natural gas decreases during the summer months and increases during the winter months thereby affecting the price we receive for natural gas. Seasonal anomalies, such as mild winters or hotter than normal summers, sometimes lessen this fluctuation. 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 Federal 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

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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, imposes 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. Congress has considered bills to repeal this exemption. The EPA has initiated a study of hydraulic fracturing and issued a draft report in June 2015.

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

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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.

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. 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, 2016. Additionally, as of the date of this document, we are not aware of any environmental issues or claims that require material capital expenditures during 2017. 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.

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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, the Department of Interior issued rules governing hydraulic fracturing on federal and Indian oil and gas leases that would require public disclosure of chemicals used in hydraulic fracturing, confirmation that wells used in fracturing operations meet appropriate construction standards, and development of appropriate plans for managing flowback water that returns to the surface. In addition, in November 2016, the BLM finalized regulations which update standards to reduce venting and flaring from oil and gas production on public lands.

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

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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, 2016, we had 328 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 and accounting staff and in The Woodlands, Texas for engineering and geology 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.

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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. In the event that we elect to resume such quarterly cash distributions to holders of our units and our Preferred Units, our reserve-based credit facility 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 facility, 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 a significant and sustained increase in commodity prices and/or the elimination or conversion to equity of a large portion of our debt, 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 we are not able to develop or acquire additional oil and natural gas reserves on economically acceptable terms, our reserves and production will decline, which would adversely affect our business, results of operations and financial condition.

Oil and natural gas reserves are characterized by declining production rates, and our future oil and natural gas reserves and production and, therefore, our cash flow is highly dependent on our success in economically developing or acquiring additional recoverable reserves and efficiently developing and exploiting our current reserves. 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, acquire or develop additional reserves to replace our current and future production at acceptable costs, which would adversely affect our business, results of operations and financial condition.

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 recently, we are beginning to see 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.

If oil and natural gas prices decline further or remain at current levels for a prolonged period, our cash flow from operations will decline.

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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, 2016, 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 13, 2017, the NYMEX WTI oil spot price was $52.96 per Bbl and the NYMEX-Henry Hub natural gas spot price was $2.93 per MMBtu. If oil and natural gas prices decline further or remain at current levels for a prolonged period, it may have a material adverse effect on our operations and financial condition.

If commodity prices decline further or remain at current levels for a prolonged period, 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 uneconomical and result in a downward adjustment of our reserve estimates, which would negatively impact our borrowing base under our revolving credit facility and ability to fund operations.

NYMEX-WTI oil prices have declined from $98.17 per Bbl on December 31, 2013 to $53.75 per Bbl on December 31, 2016. The reduction in price has been 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 2017. This environment could cause the prices for oil to remain at current levels or to fall to lower levels.

Furthermore, the continued decrease in oil and natural gas prices has rendered a significant portion of our development projects uneconomic. In addition, if oil and natural gas prices continue to remain depressed, 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, 2016 we incurred impairment charges

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of $61.8 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.

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 including regional demand, weather, demand for commodities, and new oil and natural gas pipelines. 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 2016, we have been adversely impacted by widening differentials in prior periods. For example, our realized oil price decreased $7.68 per Bbl to $82.94 per barrel for the year ended December 31, 2014 from $90.62 per barrel for the year ended December 31, 2013. This decrease in realized oil prices was caused by a larger average oil differential of $2.64 per barrel as well as a lower average WTI price. This increased oil differential was largely due to a significant increase in the Midland-Cushing/WTI differential in 2014 compared to 2013. If the differentials are at such levels, they 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, the Texas Panhandle, 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. Currently we use swaps on Northwest Pipeline, California SoCal NGI and San Juan Basin natural gas prices. 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 facility and our term loan credit agreement, any negative redetermination of our borrowing base under our revolving credit facility by our lenders and any potential disruptions of the financial markets could adversely affect our business, results of operations and financial condition.

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We depend on our revolving credit facility and our term loan credit agreement for future capital needs. Our revolving credit facility, 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, 2017, our borrowing base was $600.0 million and we had approximately $134.1 million available for borrowing. Our term loan credit agreement for second lien term loans maturing on August 31, 2020 (the "Second Lien Term Loans") provides for up to an aggregate principal amount of $300.0 million, of which we have used $60.0 million.

Our revolving credit facility 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 facility or our term loan credit agreement could result in a default under our revolving credit facility or our term loan credit agreement. A default under our revolving credit facility or our term loan credit agreement could cause all of our existing indebtedness, including our Second Lien Term Loans, 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"), to be immediately due and payable.

Outstanding borrowings 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 facility.

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.”

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

Should oil and natural gas prices decline in 2017, we could breach certain financial covenants under our revolving credit facility or our term loan credit agreement, which would constitute a default under our revolving credit facility 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 facility or our term loan credit agreement or foreclosure on our oil and natural gas properties. If the lenders under our revolving credit facility were to accelerate the indebtedness under our revolving credit facility 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. As of December 31, 2016, we had debt outstanding under our revolving credit facility of $463 million and under our term loan credit agreement of $60 million. 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.

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

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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.

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 acquire and 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.

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 facility, 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.

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

As of February 21, 2017, we had total long-term debt of approximately $1.2 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 continued 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 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, 2016, we recalculated the value of our proved reserves as of December 31, 2016 using the five-year average forward price as of February 14, 2017 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

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would increase by approximately 14% to 164.7 MMBoe from our previously reported 144.8 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.

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 borrowings under our revolving credit facility 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;
- the prices at which our oil and natural gas are sold; and
- our ability to acquire, locate and produce new reserves.

If our revenues or the borrowing base under our revolving credit facility 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 facility and our term loan credit agreement restricts our ability to obtain new financing. If additional capital is needed, we may not be able to obtain debt or equity financing. If cash generated by operations or available under our revolving credit facility 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.

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.

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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.

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 discover 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;
- 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.

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 facility 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.

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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 facility 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 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.

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

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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.

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.

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

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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.

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. We may incur substantial costs in order to maintain compliance with these existing laws and regulations. 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 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.

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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. We are currently reviewing this new rule and assessing its potential impacts. In addition, the EPA expects to issue rules this spring that will target methane emissions from the oil and natural gas sector. Compliance with these requirements could increase our costs of development and production, which costs may be significant.

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 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 and is required to adopt thereunder regulate the markets in certain derivative transactions, broadly referred to as "swaps" and which include some hedging and non-hedging oil and gas transactions and interest rate swaps, 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. Our efforts to comply with EMIR, and 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 was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Act is to lower commodity prices.

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

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. The Department of Interior issued rules regulating hydraulic fracturing activities on federal and tribal lands. 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 fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, the produced water from hydraulic fracturing must be disposed of properly, often in salt water disposal wells. Recently, certain groups have expressed concern that seismic activity could be tied to salt water disposal. In response to such concern, the Texas Railroad Commission 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.

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 15% 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.

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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 facility, our term loan credit agreement and our Senior Notes). We may incur additional debt under our revolving credit facility, 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 15% 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 15% 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;

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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;

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- 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;

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- 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.

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Our general partner may elect to cause us to issue units in connection with a resetting of incentive distribution levels without the approval of our limited partners. Our Incentive Distribution Units may be converted to units in certain circumstances. Any such election or conversion may result in lower distributions to our limited partners in certain situations.

Our general partner has the right, at any time when the partnership has paid distributions of at least $0.7375 for each of the prior four consecutive fiscal quarters and the amount of all distributions during each quarter within such four-quarter period did not exceed the adjusted operating surplus for each such quarter, to reset the initial target distribution levels at higher levels based on our cash distribution levels at the time of the exercise of the reset election.

We anticipate that our general partner would exercise this reset right in order to facilitate acquisitions or internal growth projects that would otherwise not be sufficiently accretive to cash distributions per unit, taking into account the existing levels of incentive distribution payments being made to the holders of Incentive Distribution Units. It is possible that our general partner exercises this reset right at a time when we are experiencing declines in our aggregate cash distributions or at a time when the holders of the Incentive Distribution Units expect that we will experience declines in our aggregate cash distributions in the foreseeable future. In such situations, the holders of the Incentive Distribution Units may be experiencing, or may expect to experience, declines in the cash distributions it receives related to the Incentive Distribution Units and may therefore desire to be issued our units, which are entitled to specified priorities with respect to our distributions and which therefore may be more advantageous for them to own in lieu of the right to receive incentive distribution payments based on increased target distribution levels that are less certain to be achieved. As a result, a reset election may cause our unitholders to experience dilution in the amount of cash distributions that they would have otherwise received had we not issued new units to the holders of the Incentive Distribution Units in connection with resetting the target distribution levels.

Further, our general partner and Incentive Distribution Unitholders may cause vested and outstanding Incentive Distribution Units to convert to units in certain other circumstances. Any such conversion may cause our unitholders to experience dilution in the amount of cash distributions that they would have otherwise received had we not issued new units to the holders of the Incentive Distribution Units in connection with any such conversion.

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, 2016, 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 United States 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, our unitholders may be allocated taxable income and gain resulting from the sale. For the year ended December 31, 2016, we completed 26 divestitures generating proceeds of $97.4 million. Further, if we engage in debt exchanges, debt repurchases, or modifications of our existing debt, these or similar transactions could result in COD income being allocated to our unitholders as taxable income. 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, it is possible, in certain circumstances, for a partnership such as ours to be treated as a corporation for U.S. federal income tax purposes. 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, which currently has a top marginal rate of 35%, 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 distributions associated with our Incentive Distribution Units 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. Further, final 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.

Any modification to the federal income tax laws may be applied retroactively and could make it more difficult or impossible for us to meet the exception for certain publicly traded partnerships to be treated as partnerships for federal income tax purposes. 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 recently issued 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 U.S. Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

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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.

Legislation applicable to partnership tax years beginning after 2017 alters the procedures for auditing partnerships and for assessing and collecting taxes due (including penalties and interest) as a result of a partnership-level federal income tax audit. Under these partnership tax rules, under certain circumstances the IRS may assess and collect taxes (including any applicable penalties and interest) directly from us in the year in which the audit is completed. If we are required to pay taxes, penalties and interest as a result of audit adjustments, cash available for distribution to our limited partners may be substantially reduced. In addition, because payment would be due for the taxable year in which the audit is completed, limited partners during that taxable year would bear the expense of the adjustment even if they were not limited partners during the audited tax year.

Tax-exempt entities and foreign persons 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. Distributions to non-U.S. persons will be reduced by withholding taxes imposed at the highest effective applicable tax rate, and non-U.S. persons will be required to file United States federal income tax returns and pay tax on their share of our taxable income. A unitholder that is a tax-exempt entity or a non-U.S. person should consult a tax advisor before investing in our units.

Tax gain or loss on the disposition of our 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 units.

If our unitholders sell any of their 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 units as having the same tax benefits without regard to the units purchased. The IRS may challenge this treatment, which could adversely affect the value of the units.

Because we cannot match transferors and transferees of 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.

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A limited partner whose limited partner interests are loaned 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 a limited partner whose limited partner interests are loaned to a "short seller" to cover a short sale of limited partner interests 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 to the short seller and the limited partner may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, 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 where our limited partner interests are loaned to a short seller to cover a short sale of our limited partner interests; therefore, limited partners desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller 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 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 will be considered to have technically terminated for U.S. federal income tax purposes due to a sale or exchange of 50% or more of our interests within a twelve-month period.

We will be considered to have technically terminated our partnership for U.S. federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest will be counted only once. Our technical termination would, among other things, result in the closing of our taxable year for all limited partners, which would result in us filing two tax returns (and our limited partners could receive two Schedules K-1 if relief was not available, as described below) for one fiscal year and could result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a limited partner reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but instead we would be treated as a new partnership for tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred. The IRS has announced a publicly traded partnership technical termination relief program whereby, if a publicly traded partnership that technically terminated requests relief and such relief is granted by the IRS, among other things, the partnership will only have to provide one Schedule K-1 to limited partners for the year notwithstanding two partnership tax years. We had a technical termination occur in 2016 and are currently seeking relief from the IRS.

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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.

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.
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. Distributions to non-U.S. holders of our preferred units will be treated as "effectively connected income" (which will subject such holders to U.S. net income taxation and possibly the branch profits tax) and 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 treatment of guaranteed payments for the use of capital to tax-exempt investors is not certain. Holders of our preferred units who are tax-exempt entities or non-U.S. persons should consult their tax advisor with respect to the tax consequences of owning our preferred units.

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ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

As of December 31, 2016 we owned interests in producing oil and natural gas properties in 627 fields in the Permian Basin, East Texas, Piceance Basin of Colorado, Texas Panhandle, Wyoming, North Dakota, Montana, Oklahoma and several other states, from 10,775 gross productive wells of which 3,799 are operated and 6,976 are non-operated. The following table sets forth information about our proved oil and natural gas reserves as of December 31, 2016. 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, 2016				
	Proved Reserves			Standardized Measure	
Field or Region	MMBoe	R/P (a)	% Oil and NGLs	Amount (b)	% of Total
				($ in Millions)	
East Texas (c)	56.4	11.8	— %	$153.2	26.6 %
Piceance Basin (d)	36.1	8.1	13	88.5	15.4
Spraberry/War San Fields	9.0	14.4	69	64.5	11.2
Lea Field	3.9	14.4	78	46.4	8.1
Panhandle Field	3.1	9.5	73	14.2	2.5
Deep Rock Field	1.3	10.2	98	12.3	2.1
Total — Top 6	109.8	10.3	16 %	$379.1	65.9 %
All others	35.0	7.4	64	196.5	34.1
Total	144.8	9.4	28 %	$575.6	100.0%

(a) Reserves as of December 31, 2016 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 56.4 MMBoe, or 39.0% of total proved reserves of 144.8 MMBoe, the following table presents the production, by product, for East Texas for 2016 and 2015. As we acquired our interests in East Texas during 2015, information for 2014 is not presented.

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

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(d) As the Piceance Basin contains 36.1 MMBoe, or 24.9% of total proved reserves of 144.8 MMBoe, the following table presents the production, by product, for the Piceance Basin for 2016, 2015 and 2014.

	Year Ended December 31,		
	2016	2015	2014
	(In thousands, except daily production)		
Oil (MBbls)	52	46	23
Natural gas liquids (Mgal)	22,288	24,448	12,439
Natural gas (MMcf)	24,206	23,639	11,767
Total (Mboe)	4,617	4,568	2,280
Average daily production (Boe per day)*	12,615	12,515	10,806

* Calculated using 211 days for the year ended December 31, 2014, the number of days between the closing date of the WPX Acquisition (as defined below) and December 31, 2014.

Summary of Oil and Natural Gas Properties and Projects

Our most significant fields and regions are East Texas, Piceance Basin, Spraberry/War San, Lea, Texas Panhandle and Deep Rock. As of December 31, 2016, these six fields accounted for approximately 66% of our standardized measure and 76% of our total estimated proved reserves.

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 929 active wells (923 producing, 6 injecting) in East Texas with working interests ranging from 19.2% to 100% and net revenue interests ranging from 16.6% to 87.2%. We also own another 572 non-operated wells (552 producing, 20 injecting). As of December 31, 2016, our properties in East Texas contained 56.4 MMBoe of net proved reserves with a standardized measure of $153.2 million. The average net daily production from this field was 13,125 Boe/d for the fourth quarter of 2016. The estimated reserve life (R/P) for this field is 11.8 years based on the annualized fourth quarter production rate.

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 2,677 active wells acquired from a subsidiary of WPX Energy, Inc. (the "WPX Acquisition") that escalated from an initial working interest of approximately 29% to approximately 37% on January 1, 2015 and 41% on January 1, 2016. As of December 31, 2016, our properties in the Piceance Basin contained 36.1 MMBoe (13% liquids) of net proved reserves with a standardized measure of $88.5 million. The average net daily production from this field was 12,250 Boe/d for the fourth quarter of 2016. The estimated reserve life (R/P) for this field is 8.1 years based on the annualized fourth quarter production rate.

Spraberry/War San Field. The Spraberry/War San field is located in Andrews, Howard, Midland, Martin, Reagan and Upton Counties, Texas. This Spraberry/War San 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 202 active wells (196 producing, 6 injecting) in this field with working interests ranging from 12.9% to 100% and net revenue interests ranging from 4.7% to 90.8%. We also own another 165 non-operated wells (161 producing, 4 injecting). As of December 31, 2016, our properties in the

Spraberry/War San field contained 9.0 MMBoe (69% liquids) of net proved reserves with a standardized measure of $64.5 million. The average net daily production from this field was 1,716 Boe/d for the fourth quarter of 2016. The estimated reserve life (R/P) for this field is 14.4 years based on the annualized fourth quarter production rate.

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Seven wells were drilled on our properties in the Spraberry/War San field in 2016. We have identified 14 more proved undeveloped projects, six of which are horizontal Wolfcamp or horizontal Spraberry locations and the remainder are primarily 40-acre infill drilling locations, and five behind-pipe or proved developed non-producing recompletion projects in this field. We have also identified numerous unproved drilling locations in this field.

Lea Field. The Lea field is located in Lea County, New Mexico. Our Lea field properties consist primarily of interests in the Lea Unit and Lea Federal 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 30 wells (29 producing, 1 injecting) in the Lea Field with working interests ranging from 4.6% to 100% and net revenue interests ranging from 4.1% to 81.3%. As of December 31, 2016, our properties in the Lea Field contained 3.9 MMBoe (78% liquids) of net proved reserves with a standardized measure of $46.4 million. The average net daily production from this field was 749 Boe/d for the fourth quarter of 2016. The estimated reserve life (R/P) of the field is 14.4 years based on the annualized fourth quarter production rate.

Four wells were drilled on our properties in the Lea field in 2016. Our engineers have identified 12 additional proved undeveloped horizontal Bone Spring drilling locations and one behind-pipe or proved developed non-producing recompletion projects in this field. We have also identified numerous unproved horizontal Bone Spring drilling locations in this field.

Texas Panhandle Fields. The Texas Panhandle fields are located in Carson, Gray, Hartley, Hutchinson, Moore, Potter, Sherman and Wheeler Counties, Texas. The fields are produced from multiple formations of Permian age which primarily include the shallow Granite Wash, Brown Dolomite, and Red Cave formations from 2,500 to 4,000 feet. We operate 422 wells (389 producing, 33 injecting) in the Texas Panhandle fields with working interests ranging from 33.3% to 100% and net revenue interests ranging from 25% to 100%. We also own another 414 non-operated wells (405 producing, 9 injecting). As of December 31, 2016, our properties in the Texas Panhandle fields contained 3.1 MMBoe (73% liquids) of net proved reserves with a standardized measure of $14.2 million. The average net daily production from these fields was 895 Boe/d for the fourth quarter of 2016. The estimated reserve life (R/P) for these fields is 9.5 years based on the annualized fourth quarter production rate.

Deep Rock Field. The Deep Rock field is located in Andrews County, Texas. Most of the production in the field is from the Glorieta formation at depths of 5,630 to 6,000 feet. The field also produces from the Pennsylvanian, Devonian and Ellenburger formations at depths from 4,000 to 12,200 feet. We operate 32 wells (28 producing, 4 injecting) in the field with working interests ranging from 50% to 100% and net revenue interests ranging from 43.8% to 81.3%. We also own 21 non-operated wells (15 producing, 6 injecting). As of December 31, 2016, our properties in the Deep Rock field contained 1.3 MMBoe (98% liquids) of net proved reserves with a standardized measure of $12.3 million. The average net daily production from this field was 337 Boe/d for the fourth quarter of 2016. The estimated reserve life (R/P) for the field is 10.2 years based on the annualized production rate. Our engineers have identified two proved developed non-producing project in the field. We also have several additional unproved drilling locations and multiple unproved developed non-producing projects in the field.

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, 2016, 2015 and 2014. 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, 2016, 2015 and 2014. As a result of this

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methodology, we used an average WTI posted price of $39.25 per Bbl for oil and an average Platts' Henry Hub natural gas price of $2.48 per MMBtu to calculate our estimate of proved reserves as of December 31, 2016. Please see the table below.

	As of December 31,		
	2016	2015	2014
Reserve Data:			
Estimated net proved reserves:			
Oil (MMBbls)	32.5	36.1	56.9
Natural Gas Liquids (MMBbls)	7.8	7.8	12.4
Natural Gas (Bcf)	627.0	721.6	418.0
Total (MMBoe)	144.8	164.2	139.0
Proved developed reserves (MMBoe)	139.2	161.7	126.4
Proved undeveloped reserves (MMBoe)	5.6	2.5	12.6
Proved developed reserves as a percentage of total proved reserves	96 %	98 %	91 %
Standardized measure (in millions)(a)	$575.6	$694.9	$1,754.6
Oil and Natural Gas Prices(b)			
Oil - WTI per Bbl	$39.25	$46.79	$91.48
Natural gas - Henry Hub per MMBtu	$2.48	$2.59	$4.35

(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

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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 2016, 2015 and 2014, we paid LaRoche approximately $395,740, $621,822 and $472,994, 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 39-year career with four publicly traded oil and natural gas producing companies, including Legacy. He has over 29 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.

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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, 2016, 2015 and 2014:

	Year Ended December 31,		
	2016	2015(a)	2014(b)
Production:			
Oil (MBbls)	4,019	4,608	4,784
Natural gas liquids (MGal)	36,757	42,210	30,861
Gas (MMcf)	66,824	50,687	25,936
Total (MBoe)	16,032	14,061	9,841
Average daily production (Boe per day)	43,803	38,523	26,962
Average sales price per unit (excluding commodity derivative cash settlements):			
Oil (per Bbl)	$37.95	$43.37	$82.94
NGL (per Gal)	$0.42	$0.39	$0.89
Gas (per Mcf)	$2.19	$2.41	$4.17
Combined (per Boe)	$19.61	$24.09	$54.09
Average sales price per unit (including commodity derivative cash settlements):			
Oil (per Bbl)	$47.27	$63.32	$81.80
NGL (per Gal)	$0.42	$0.39	$0.89
Gas (per Mcf)	$2.60	$3.22	$4.48
Combined (per Boe)	$23.63	$33.55	$54.36
Average unit costs per Boe:			
Production costs, excluding production and other taxes	$10.59	$13.03	$18.98
Ad valorem taxes	$0.60	$0.81	$1.22
Production and other taxes	$0.89	$1.17	$3.20
General and administrative	$2.72	$3.31	$3.96
Depletion, depreciation and amortization	$9.38	$12.61	$17.65

(a) Reflects 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.

(b) Reflects the production and operating results of the WPX Acquisition properties from the closing date on June 4, 2014 through December 31, 2014.

Productive Wells

The following table sets forth information at December 31, 2016 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	2,478	1,856	1,321	1,157	3,799	3,013
Non-operated	2,782	269	4,194	1,233	6,976	1,502
Total	5,260	2,125	5,515	2,390	10,775	4,515

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Developed and Undeveloped Acreage

The following table sets forth information as of December 31, 2016 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	1,039,876	511,675	181,912	52,214	1,221,788	563,889

(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, 2016, 2015 and 2014. 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,		
	2016	2015	2014
Gross:			
Development			
Productive	12	14	122
Dry	—	—	—
Total	12	14	122
Exploratory			
Productive	—	—	—
Dry	—	—	—
Total	—	—	—
Net:			
Development			
Productive	2.2	3.8	41.1
Dry	—	—	—
Total	2.2	3.8	41.1
Exploratory			
Productive	—	—	—
Dry	—	—	—

Total	—	—	—

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Summary of Development Projects

For the year ended December 31, 2016, we invested approximately $29.5 million in implementing our development strategy, including $2.8 million related to the development of proved undeveloped reserves. We estimate that our capital expenditures for the year ending December 31, 2017 will be approximately $55 million for development drilling, recompletions and fracture stimulation and other development-related projects to implement this strategy. All of these development projects are located in the Permian Basin, 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, 2016, we were in the process of drilling or completing 15 gross (3.8 net) wells, all of which were development wells. Further, 2 were classified as PDNP and 7 were classified as PUD within our year-end reserve report while 6 were classified as unproved and therefore not included in our year-end reserve report.

Operations

General

We operate approximately 60% 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, West Texas Waha natural gas, Northwest Pipeline natural gas, NGPL Midcon natural gas, California SoCal natural gas and San Juan Basin 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

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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.

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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, 2017, there were 72,625,147 units outstanding, held by approximately 127 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
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	$ —	$ —
	Price Ranges		Cash Distribution	Cash Distribution
2015	High	Low	per Unit	to General Partner
First Quarter	$15.55	$8.06	$ 0.350	$ 6,409
Second Quarter	$14.40	$8.43	$ 0.350	$ 6,409
Third Quarter	$10.49	$3.70	$ 0.150	$ 2,747
Fourth Quarter	$6.12	$1.04	$ —	$ —

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.

Recent Sales of Unregistered Securities

None.

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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,				
	2016	2015(a)	2014(b)	2013	2012(c)
	(In thousands, except per unit data)				
Statement of Operations Data:					
Revenues:					
Oil sales	$152,507	$199,841	$396,774	$405,536	$286,254
Natural gas liquids sales	15,406	16,645	27,483	14,095	14,592
Natural gas sales	146,444	122,293	108,042	65,858	45,614
Total revenues	314,357	338,779	532,299	485,489	346,460
Expenses:					
Oil and natural gas production	179,333	194,491	198,801	154,679	112,951
Production and other taxes	14,267	16,383	31,534	29,508	20,778
General and administrative	43,639	46,511	38,980	28,907	24,526
Depletion, depreciation, amortization and accretion	150,414	177,258	173,686	158,415	102,144
Impairment of long-lived assets	61,796	633,805	448,714	85,757	37,066
(Gain) loss on disposal of assets	(50,095)	(3,972)	(2,479)	579	(2,496)
Total expenses	399,354	1,064,476	889,236	457,845	294,969
Operating income (loss)	(84,997)	(725,697)	(356,937)	27,644	51,491
Other income (expense):					
Interest income	67	329	873	776	16
Interest expense	(79,060)	(76,891)	(67,218)	(50,089)	(20,260)
Gain on extinguishment of debt	150,802	—	—	—	—
Equity in income of equity method investees	—	126	428	559	111
Net gains (losses) on commodity derivatives	(41,224)	98,253	138,092	(13,531)	38,493
Other	(179)	841	258	18	(118)
Income (loss) before income taxes	(54,591)	(703,039)	(284,504)	(34,623)	69,733
Income tax (expense) benefit	(1,229)	1,498	859	(649)	(1,096)
Net income (loss)	(55,820)	(701,541)	(283,645)	(35,272)	68,637
Distributions to preferred unitholders	(19,000)	(19,000)	(11,694)	—	—
Net income (loss) attributable to unitholders	$(74,820)	$(720,541)	$(295,339)	$(35,272)	$68,637

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	Years Ended December 31,				
	2016	2015(a)	2014(b)	2013	2012(c)
	(In thousands, except per unit data)				
Income (loss) per unit					
Basic and diluted	$(1.06)	$(10.45)	$(4.92)	$(0.62)	$ 1.40
Distributions paid per unit	$—	$1.46	$2.41	$2.31	$ 2.23

Cash Flow Data:					
Net cash provided by (used in) operating activities	$(310)	$2,046	$207,216	$241,134	$149,641
Net cash provided by (used in) investing activities	$119,989	$(377,420)	$(632,414)	$(209,401)	$(696,279)
Net cash provided by (used in) financing activities	$(119,130)	$376,655	$423,339	$(32,658)	$546,996
Capital expenditures	$41,932	$579,463	$640,414	$204,911	$704,191

	Historical As of December 31,				
	2016	2015(a)	2014(b)	2013	2012(c)
	(In thousands)				
Balance Sheet Data					
Cash and cash equivalents	$2,555	$2,006	$725	$2,584	$3,509
Other current assets	80,217	127,453	191,529	72,115	84,401
Oil and natural gas properties, net of accumulated depletion, depreciation, amortization and impairment	1,181,909	1,408,956	1,639,974	1,535,429	1,571,926
Other assets	35,145	74,705	66,378	49,705	30,163
Total assets	$1,299,826	$1,613,120	$1,898,606	$1,659,833	$1,689,999
Current liabilities	$86,609	$81,093	$97,576	$93,890	$103,723
Long-term debt	1,161,394	1,427,614	938,876	878,693	775,838
Other long-term liabilities	273,902	284,090	224,949	176,854	140,158
Partners' equity (deficit)	(222,079)	(179,677)	637,205	510,396	670,280
Total liabilities and partners' equity (deficit)	$1,299,826	$1,613,120	$1,898,606	$1,659,833	$1,689,999

(a) Reflects 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.

(b) Reflects Legacy's purchase of the oil and natural gas properties acquired in the WPX 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.

(c) Reflects Legacy's purchase of the oil and natural gas properties located primarily in the Permian Basin from a subsidiary of Concho Resources, Inc. (the "COG 2012 Acquisition") as of the date of the acquisition. Consequently, the operations of these acquired properties are only included for the period from the closing date of the acquisition on December 20, 2012 through December 31, 2012 and thereafter.

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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 rapid 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 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. The operating results of the acquisition of certain oil and natural gas properties located in the Piceance Basin of Colorado from a subsidiary of WPX Energy, Inc. (the "WPX Acquisition") have been included since June 4, 2014.

Trends Affecting Our Business and Operations

Sustained periods of the current low prices for oil or natural gas have and could continue to 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.

Outlook. Oil and natural gas prices experienced a significant drop in late 2014 and 2015. Prices recovered in 2016 but still remain at levels lower than previously seen before the decline began in 2014. Crude oil prices declined from an average of $93.17 per Bbl in 2014 to $43.29 per Bbl in 2016 and natural gas prices declined from an average of $4.37 per MMBtu in 2014 to $2.52 per MMBtu in 2016. As a result of the continued suppressed commodity prices in 2016, we recognized additional impairment expense of $61.8 million in 2016 as compared to impairment of $633.8 million in 2015. A sustained period of reduced commodity prices will continue to have an adverse effect on our operating income in future periods resulting from decreased revenues and higher depletion rates. In response to this sustained low commodity price environment, we anticipate maintaining a modest capital expenditure budget for 2017 of approximately $55.0 million. The increase in our capital program in 2017 as compared to 2016 is driven by increased net working interests and a higher number of total drilling days under our two-rig horizontal program in the Permian Basin. To illustrate the sensitivity our proved reserves to fluctuations in commodity prices, we recalculated our proved reserves as of December 31, 2016, using the five-year average forward price as of February 14, 2017 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 increase by approximately 14% to 164.7 MMBoe from the reported 144.8 MMBoe, which is calculated as required by the SEC.

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Should we experience a decline in oil and natural gas prices in 2017, we could breach certain financial covenants under our revolving credit facility or our term loan credit agreement, which would constitute a default under our revolving credit facility 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 facility or our term loan credit agreement or foreclosure on our oil and natural gas properties. Certain payment defaults or acceleration under our revolving credit facility 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 2017 are to fund our operations and to reduce leverage from our internally generated cash flow and to seek financial flexibility and liquidity.

Oil and natural gas prices have declined significantly from 2014 levels. This has reduced, and will continue to reduce, our revenues and cash flows from operations from levels seen in that period. In order to mitigate the impact of lower oil and natural gas prices on our cash flows, we are a party to derivative contracts, and we intend to enter into derivative contracts in the future to reduce the impact of oil and natural gas price volatility on our cash flows. 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 continue to be depressed for an extended period of time, 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 facility.

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 acquiring more reserves than we produce, drilling to find additional reserves, utilizing multiple types of recovery techniques such as secondary (waterflood) and tertiary (CO_2 and nitrogen) recovery methods to re-pressure the reservoir and recover additional oil, recompleting or adding pay in existing wellbores and improving artificial lift.

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 acquisitions and development projects. Our ability to add reserves through acquisitions and development projects is dependent upon many factors including our ability to raise capital, obtain regulatory approvals and contract drilling rigs 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. 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 capital investment programs 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 facility.

Legacy does not specifically designate derivative instruments as cash flow hedges; therefore, the mark-to-market adjustment reflecting the change in fair value associated with these instruments is recorded in current earnings.

We strive to increase our production levels to maximize our revenue and cash flow. Additionally, we continuously monitor our operations to ensure that we are incurring operating costs at the optimal level. Accordingly, we continuously monitor our production and operating costs per well to determine if any wells or properties should be shut-in or recompleted.

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Such costs include, but are not limited to, the cost of electricity to lift produced fluids, chemicals to treat wells, field personnel to monitor the wells, well repair expenses to restore production, well workover expenses intended to increase production and ad valorem taxes. We incur and separately report severance taxes paid to the states and counties in which our properties are located. These taxes are reported as production taxes and are a percentage of oil and natural gas revenue. Ad valorem taxes are a percentage of property valuation. Gathering and transportation costs are generally borne by the purchasers of our oil and natural gas as the price paid for our products reflects these costs. We do not consider royalties paid to mineral owners an expense as we deduct hydrocarbon volumes owned by mineral owners from reported hydrocarbon sales volumes.

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 facility 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 facility 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. 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.

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Operating Data

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

	Year Ended December 31,		
	2016	2015(b)	2014(c)
	(In thousands, except per unit data and production)		
Revenues			
Oil sales	$152,507	$199,841	$396,774
Natural gas liquids sales	15,406	16,645	27,483
Natural gas sales	146,444	122,293	108,042
Total revenues	$314,357	$338,779	$532,299
Expenses:			
Oil and natural gas production	$169,755	$183,163	$186,750
Ad valorem taxes	9,578	11,328	12,051
Total	$179,333	$194,491	$198,801
Production and other taxes	$14,267	$16,383	$31,534
General and administrative, excluding transaction related costs and LTIP	$31,196	$30,919	$29,760
Transaction related costs	5,245	8,919	5,425
LTIP expense	7,198	6,673	3,795
Total general and administrative	$43,639	$46,511	$38,980
Depletion, depreciation, amortization and accretion	$150,414	$177,258	$173,686
Commodity derivative cash settlements:			
Oil derivative cash settlements received (paid)	37,464	91,953	(5,431)
Natural gas derivative cash settlements received	27,041	40,972	8,097
Total commodity derivative cash settlements	64,505	132,925	2,666
Production:			
Oil (MBbls)	4,019	4,608	4,784
Natural gas liquids (MGal)	36,757	42,210	30,861
Natural gas (MMcf)	66,824	50,687	25,936
Total (MBoe)	16,032	14,061	9,841
Average daily production (Boe/d)	43,803	38,523	26,962
Average sales price per unit (excluding commodity derivative cash settlements):			
Oil price (per Bbl)	$37.95	$43.37	$82.94
Natural gas liquids price (per Gal)	$0.42	$0.39	$0.89
Natural gas price (per Mcf)(a)	$2.19	$2.41	$4.17
Combined (per Boe)	$19.61	$24.09	$54.09
Average sales price per unit (including commodity derivative cash settlements):			
Oil price (per Bbl)	$47.27	$63.32	$81.80
Natural gas liquids price (per Gal)	$0.42	$0.39	$0.89
Natural gas price (per Mcf)(a)	$2.60	$3.22	$4.48
Combined (per Boe)	$23.63	$33.55	$54.36
Average WTI oil spot price (per Bbl)	$43.29	$48.66	$93.17
Average Henry Hub natural gas spot price (per MMBtu)	$2.52	$2.62	$4.37
Average unit costs per Boe:			
Production costs, excluding production and other taxes	$10.59	$13.03	$18.98
Ad valorem taxes	$0.60	$0.81	$1.22
Production and other taxes	$0.89	$1.17	$3.20
General and administrative, excluding acquisition costs and LTIP	$1.95	$2.20	$3.02

Total general and administrative	$2.72	$3.31	$3.96
Depletion, depreciation, amortization and accretion	$9.38	$12.61	$17.65

(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) Reflects 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.

(c) Reflects the production and operating results of the oil and natural gas properties acquired in the WPX Acquisition from the closing date of the acquisition on June 4, 2014 through December 31, 2014 and thereafter.

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Results of Operations

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.

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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 facility 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.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014

Legacy's revenues from the sale of oil were $199.8 million and $396.8 million for the years ended December 31, 2015 and 2014, respectively. Legacy's revenues from the sale of NGLs were $16.6 million and $27.5 million for the years ended December 31, 2015 and 2014, respectively. Legacy's revenues from the sale of natural gas were $122.3 million and $108.0 million for the years ended December 31, 2015 and 2014, respectively. The $196.9 million decrease in oil revenue reflects a decrease in average realized price of $39.57 per Bbl (48%) to $43.37 for the year ended December 31, 2015 from $82.94 for the year ended December 31, 2014, and a decrease in oil production of 176 MBbls (4%). The decrease in realized oil price was primarily caused by a decrease in the average WTI crude oil price of $44.10, partially offset by a decrease in realized regional differentials during the year ended December 31, 2015 compared to the same period in 2014. The decrease in production is due to natural declines and greatly reduced capital spending for the year ended December 31, 2015 compared to the same period in 2014. The $10.8 million decrease in NGL revenues reflects a decrease in realized NGL price of $0.50 per Gal (56%) to $0.39 per Gal for the year ended December 31, 2015 from $0.89 per Gal for the year ended December 31, 2014, partially offset by an increase in NGL production of 11,349 MGals (37%) during 2015. The increase in NGL production is due primarily to 12,009 MGals of additional production from a full year of inclusion of volumes from the WPX Acquisition, partially offset by natural declines in other fields. The $14.3 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 24,751 MMcf (95%), primarily due to our acquisitions, most notably the acquisitions of East Texas properties (12,548 MMcf), and additional production from a full year of inclusion of volumes from the WPX Acquisition (11,872 MMcf). Average realized gas prices decreased by $1.76 per Mcf (42%) to $2.41 per Mcf for the year ended December 31, 2015 from $4.17 per Mcf for the year ended December 31, 2014, primarily due to a decrease in the average NYMEX Henry Hub natural gas price of $1.63 per Mcf over the same time period.

For the year ended December 31, 2015, Legacy recorded $98.3 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 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. For the year ended December 31, 2014, Legacy recorded $138.1 million of net gains on oil and natural gas derivatives primarily due to the significant decrease in oil futures prices during 2014. Settlements of such contracts resulted in cash receipts of $132.9 million and $2.7 million during 2015 and 2014, respectively.

Legacy’s oil and natural gas production expenses, excluding ad valorem taxes, decreased to $183.2 million ($13.03 per Boe) for the year ended December 31, 2015 from $186.8 million ($18.98 per Boe) for the year ended December 31, 2014. 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 ($11.5 million). Additionally, production expenses per Boe decreased in 2015 compared to 2014 due to a full year of inclusion of lower cost production as a result of the WPX Acquisition, and the inclusion of lower cost production from the acquisition of natural gas weighted East Texas properties as well as a reduction in lifting costs in our historical properties. Legacy’s ad valorem tax expense decreased to $11.3 million ($0.81 per Boe) for the year ended December 31, 2015 from $12.1 million ($1.22 per Boe) for the year ended December 31, 2014 due to lower valuations of our oil and natural gas properties due to lower commodity prices, partially offset by increased well counts from our acquisition of additional oil and natural gas properties.

Legacy’s production and other taxes were $16.4 million and $31.5 million for the years ended December 31, 2015 and 2014, respectively. Production and other taxes decreased due to lower total revenues in 2015. On a per Boe basis, production and other taxes decreased to $1.17 for the year ended December 31, 2015 from $3.20 for the year ended December 31, 2014 due to lower total revenues and a full year of inclusion of WPX revenue, which is taxed at a significantly lower rate than our other properties.

Legacy’s general and administrative expenses were $46.5 million and $39.0 million for the years ended December 31, 2015 and 2014, respectively. General and administrative expenses increased approximately $7.5 million between periods primarily due to $3.5 million of increased acquisition-related expenses, $2.9 million of increased LTIP expenses and a $1.9 million increase in salary and benefit expenses, net of overhead recovery, due to the hiring of additional personnel commensurate with the growth of our asset base. These increases were partially offset by general cost reduction efforts.

Legacy’s depletion, depreciation, amortization and accretion expense, or DD&A, was $177.3 million and $173.7 million for the years ended December 31, 2015 and 2014, respectively. DD&A increased primarily due to the inclusion of depletion expense related to properties included in East Texas ($8.6 million), partially offset by lower depletion rates across our historical properties primarily related to impairment charges incurred in 2014 and 2015, which reduced our depletable cost basis. Our depletion rate per Boe for the year ended December 31, 2015 was $12.61 compared to $17.65 for the year ended December 31, 2014. 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 $633.8 million and $448.7 million for the years ended December 31, 2015 and 2014, respectively. In 2015, Legacy recognized $598.1 million of impairment expense 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. As we have historically grown through the acquisition of oil and natural gas properties, most of which were purchased during higher commodity price environments, the sharp decline in oil and natural gas prices during 2015 resulted in a corresponding decrease in the expected future cash flows of such assets from the date of their acquisition as compared to December 31, 2015. As evidenced above, this decrease was not limited to any one field or area of operation, as it impacted the value of oil and natural gas assets across our portfolio. 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. In 2014, Legacy recognized impairment expense of $413.3 million in 250 separate

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producing fields due primarily to the decrease in commodity prices during the year ended December 31, 2014, which decreased the expected future cash flows below the carrying value of the assets. Additionally, we recorded impairment of $35.0 million related to unproved properties acquired since 2010 that, in the 2014 price environment, were no longer economically viable.

Interest expense was $76.9 million and $67.2 million for the years ended December 31, 2015 and 2014, respectively. The increase in interest expense is primarily due to an increase of $7.3 million of interest expense related to a full year of interest on the Senior Notes issued in May 2014. Additionally, interest expenses related to our interest rate swaps increased by $1.0 million to $1.5 million in 2015 from $0.6 million in 2014. Cash payments on our interest rate swaps were $3.3 million and $3.2 million in 2015 and 2014, respectively.

As a result of the items described above, Legacy recorded a net loss of $701.5 million and $283.6 million for the years ended December 31, 2015 and 2014, respectively. The increase in net loss was primarily caused by an increase in impairment expense recorded from $448.7 million during the year ended December 31, 2014 to $633.8 million during the year ended December 31, 2015.

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;
- (Gain) loss 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 related expenses.

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The following table presents a reconciliation of Legacy's consolidated net income (loss) to Adjusted EBITDA for the years ended December 31, 2016, 2015 and 2014, respectively.

	Year Ended December 31,		
	2016	2015	2014
	(In thousands)		
Net loss	$(55,820)	$(701,541)	$(283,645)
Plus:			
Interest expense	79,060	76,891	67,218
Gain on extinguishment of debt	(150,802)	—	—
Income tax expense (benefit)	1,229	(1,498)	(859)
Depletion, depreciation, amortization and accretion	150,414	177,258	173,686
Impairment of long-lived assets	61,796	633,805	448,714
Gain on disposal of assets	(50,095)	(3,972)	(2,479)
Equity in income of equity method investees	—	(126)	(428)
Unit-based compensation expense	7,198	6,673	3,795
Minimum payments received in excess of overriding royalty interest earned(a)	1,659	1,130	1,381
Equity in EBITDA of equity method investee(b)	—	169	805
Net (gains) losses on commodity derivatives	41,224	(98,253)	(138,092)
Net cash settlements received (paid) on commodity derivatives	64,505	132,925	2,666
Transaction related expenses	5,245	8,919	5,425
Adjusted EBITDA	$155,613	$232,380	$278,187

(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, 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. For the year ended December 31, 2015, Adjusted EBITDA decreased 16% to $232.4 million from $278.2 million for the year ended December 31, 2014. This decrease is due primarily to significant declines in commodity prices. This decrease was partially offset by increased production from a full year of inclusion of the WPX Acquisition and the acquisitions of properties in East Texas as well as cash receipts of $132.9 million on our commodity derivatives during 2015 compared to cash receipts of $2.7 million during 2014.

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, the 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 on the open market.

Based upon current oil and natural gas price expectations and our commodity derivatives positions, we anticipate that our cash on hand, cash flow from operations and available borrowing capacity under our revolving credit facility and the Second Lien Term Loans will provide us sufficient liquidity to fund our operations in 2017 including our planned capital expenditures of $55 million. However, should oil and natural gas prices decline in 2017, we could breach certain financial covenants under our revolving credit facility or our term loan credit agreement, which

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would constitute a default under our revolving credit facility 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 facility or our term loan credit agreement or foreclosure on our oil and natural gas properties. Certain payment defaults or acceleration under our revolving credit facility 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 facility are re-determined at least semi-annually in April and October of each year. Pursuant to our entering into the Eighth Amendment to our revolving credit facility on October 25, 2016, our borrowing base was reduced to $600 million, leaving $134.1 million available for borrowing as of February 21, 2017. Our next such redetermination event will occur in April 2017.

Our commodity derivatives position, which we use to mitigate commodity price volatility and (if positive) support our borrowing capacity, resulted in $64.5 million of cash receipts in the year ended December 31, 2016.

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. During 2016, we repurchased approximately $169.4 million of original principal amount of our 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 to date, the "Development Agreement") with Jupiter JV LP ("Investor"), which was formed by certain of TPG Special Situations Partners' investment funds. Pursuant to the Development Agreement, Legacy and Investor participate in the funding, exploration, development and operation of certain undeveloped oil and natural gas properties covering approximately 3,938 net acres (the "Subject Assets"). Under the terms of the Development Agreement, Investor funds 95% of the costs to the parties' combined interests to develop the assets and 80% of the costs to the parties' combined interests to develop or construct associated saltwater disposal wells and other infrastructure assets. In exchange for funding a portion of the parties' combined costs, Investor receives an undivided 80.0% of our working interest in the assets, subject to a reversion to 15.0% of our initial working interest upon the occurrence of Investor achieving a 15% internal rate of return ("Development Hurdle Date") in the aggregate with respect to such tranche of wells. At the first instance of Investor achieving a Development Hurdle Date, all of the remaining undeveloped Subject Assets will revert to us but remain available for future development subject to the Development Agreement. The Development Agreement provides that Investor can suspend its future funding obligations at certain times upon the occurrence of certain events based on anticipated financial metrics, certain operating cost overruns and changes in commodity prices, provided that Investor will be obligated to complete funding of any wells or infrastructure in progress. Our capital resources and liquidity benefit from our interest in the development activity under the Development Agreement.

Cash Flow from Operations

Legacy's 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.

Legacy's net cash provided by operating activities was $2.0 million and $207.2 million for the years ended December 31, 2015 and 2014, respectively, with the 2015 period being unfavorably impacted by lower realized commodity prices, partially offset by lower production expenses and higher production volumes primarily related to acquisitions, most notably the Anadarko Acquisitions.

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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

Legacy's 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.

Legacy's cash capital expenditures were $577.2 million for the year ended December 31, 2015. The total includes $540.3 million related to the Anadarko Acquisitions and 3 individually immaterial acquisitions and $36.8 million of development projects. Included in the $540.3 million of properties acquired is $51.0 million of properties that were divested the day after their acquisition.

We currently anticipate that our development capital budget, which predominantly consists of drilling, recompletion, well stimulation projects and CO2 injection will be $55 million for the year ending December 31, 2017. Our available borrowing capacity under our revolving credit facility is $134.1 million as of February 21, 2017. The amount and timing of our capital expenditures is largely discretionary and within our control, with the exception of a CO2 purchase commitment and 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, 2017, we had in place oil, natural gas and price differential derivatives covering portions of our estimated 2017 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, 2017 covering the period from January 1, 2017 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, the price on the last trading day of front-month NYMEX Henry Hub natural gas and published West Texas Waha prices of natural gas.

Oil Swaps:

Calendar Year	Volumes (Bbls)	Average Price per Bbl	Price Range per Bbl
2017	182,500	$84.75	$84.75
2018	730,000	$55.04	$55.00 - $55.15

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Natural Gas Swaps:

Calendar Year	Volumes (MMBtu)	Average Price per MMBtu	Price Range per MMBtu
2017	27,600,000	$3.36	$3.29 - $3.39
2018	42,200,000	$3.25	$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, 2017, covering the period from January 1, 2017 though December 31, 2017:

Time Period	Volumes (Bbls)	Average Price per Bbl	Price Range per Bbl
2017	2,190,000	$(0.30)	$(0.75) - $(0.05)
2018	1,460,000	$(1.25)	$(1.25)

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 $45.00, $50.00 and $59.02, respectively for 2017 and $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, 2017, covering the period from January 1, 2017 through December 31, 2018:

Time Period	Volumes (Bbls)	Average Long Put Price per Bbl	Average Short Call Price per Bbl
2017	2,190,000	$45.00	$59.02
2018	1,551,250	$47.06	$60.29

We have also entered into multiple NYMEX West Texas Intermediate crude oil derivative three-way collar contracts. Each contract combines a long put, a short put and a short call. The use of the short put allows us to buy a put and sell a call at higher prices, thus establishing a higher ceiling and limiting our exposure to future settlement payments while also restricting our downside risk. If the market price is below the long put fixed price but above the short put fixed price, a three-way collar allows us to settle for the long put fixed price. A three-way collar also allows us to settle for WTI market plus the spread between the short put and the long put in a case where the market price has fallen below the short put fixed price. For example, at an annual average WTI market price of $40.00, $50.00 and $65.00, the summary position below would result in a net price of $65.00, $75.00 and $85.00, respectively. The following table summarizes the three-way oil collar contracts currently in place as of February 21, 2017, covering the period from January 1, 2017 through December 31, 2017:

Calendar Year	Volumes (Bbls)	Average Short Put Price per Bbl	Average Long Put Price per Bbl	Average Short Call Price per Bbl
2017	72,400	$60.00	$85.00	$104.20

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

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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 $65.85, $65.85 and $73.85, respectively for 2017 and $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, 2017, covering the period from January 1, 2017 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
2017	182,500	$57.00	$82.00	$90.85
2018	127,750	$57.00	$82.00	$90.50

We have also entered into multiple NYMEX Henry Hub natural gas costless collar contracts. Each contract combines a long put option or "floor" with a short call option or "ceiling." At an annual Henry Hub price of $2.50, $3.00 and $3.50, the summary position below would result in a net price of $2.90, $3.00 and $3.44, respectively. The following table summarizes the costless natural gas collar contracts currently in place as of February 21, 2017, covering the period from January 1, 2017 through December 31, 2017:

Time Period	Volumes (MMBtu)	Average Long Put Price per MMBtu	Average Short Call Price per MMBtu
2017	14,600,000	$2.90	$3.44

We have also entered into multiple NYMEX Henry Hub natural gas derivative three-way collar contracts. Each contract combines a long put, a short put and a short call. The use of the short put allows us to buy a put and sell a call at higher prices, thus establishing a higher ceiling and limiting our exposure to future settlement payments while also restricting our downside risk. If the market price is below the long put fixed price but above the short put fixed price, a three-way collar allows us to settle for the long put fixed price. A three-way collar also allows us to settle for market plus the spread between the short put and the long put in a case where the market price has fallen below the short put fixed price. For example, at an annual average Henry Hub market price of $2.50, $3.00 and $3.50, the summary position below would result in a net price of $3.00, $3.50 and $4.00, respectively for 2017. The following table summarizes the three-way natural gas collar contracts currently in place as of February 21, 2017, covering the period from January 1, 2017 through December 31, 2017:

Calendar Year	Volumes (MMBtu)	Average Short Put Price per MMBtu	Average Long Put Price per MMBtu	Average Short Call Price per MMBtu
2017	5,040,000	$3.75	$4.25	$5.53

We have also entered into multiple Henry Hub NYMEX to Northwest Pipeline, California SoCal and San Juan Basin natural gas differential swaps paying a floating differential and receiving a fixed differential for a portion of its future natural gas production as of February 21, 2017 as indicated below, covering the period from January 1, 2017 through December 31, 2017:

	2017	
	Volumes (MMBtu)	Average Price per MMBtu
NWPL	7,300,000	$(0.16)
SoCal	2,500,250	$0.11
San Juan	2,500,250	$(0.10)

Financing Activities

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 facility were $145.0 million. We

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raised $58.8 million in proceeds, net of original issue discount, but excluding other offering expenses paid by Legacy, from the issuance of our Second Lien Term Loans. Legacy's net cash provided by financing activities was $376.7 million for the year ended December 31, 2015, compared to $423.3 million for the year ended December 31, 2014. During the year ended December 31, 2015, total net borrowings under our revolving credit facility were $499.0 million. Finally, Legacy 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. Cash provided by financing activities during the year ended December 31, 2014, included $239.0 million in net repayments under our revolving credit facility while we raised $297.0 million in proceeds, net of original issue discount, but excluding other offering expenses paid by Legacy, in our private offering of 6.625% senior notes due 2021, resulting in total net borrowings of $58.0 million. Additionally we received net proceeds from the issuance of our 8% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the "Series A Preferred Units") and 8.00% Series B Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the "Series B Preferred Units") in the amount of $229.5 million as well as $303.5 million of proceeds from our October public offering of units. Finally, Legacy had cash outflow during the year ended December 31, 2014 in the amount of $157.6 million for distributions to unitholders and our Series A and Series B Preferred unitholders, which was funded from cash flow from operations.

On April 17, 2014, Legacy issued 2,000,000 of its Series A Preferred Units in a public offering at a price of $25.00 per unit. On May 12, 2014 Legacy issued an additional 300,000 Series A Preferred Units pursuant to the underwriters' option to purchase additional Series A Preferred Units. Legacy received aggregate net proceeds of approximately $55.2 million, after deducting underwriting discounts and offering expenses, from the offering of Series A Preferred Units during the year ended December 31, 2014.

On June 17, 2014, Legacy issued 7,000,000 of its Series B Preferred Units in a public offering at a price of $25.00 per unit. On July 1, 2014 Legacy issued an additional 200,000 Series B Preferred Units pursuant to the underwriters' option to purchase additional Series B Preferred Units. Legacy received aggregate net proceeds of approximately $174.3 million, after deducting underwriting discounts and offering expenses, from the offering of Series B Preferred Units during the year ended December 31, 2014.

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 June 4, 2014, Legacy issued 300,000 incentive distribution units representing limited partner interests in Legacy (the "Incentive Distribution Units") to WPX Energy Rocky Mountain, LLC ("WPX"), an affiliate of WPX Energy, Inc. ("WPX Energy"), as part of the WPX 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 Legacy's treasury for the benefit of all limited partners until such time as Legacy may make future issuances of Incentive Distribution Units. 66,666 of the Unvested IDUs were forfeited on each of June 4, 2015 and June 4, 2016. Effective January 1, 2016, WPX has assigned its vested and unvested IDUs to WPX Energy Holdings, LLC, a controlled affiliate of WPX Energy.

Our Revolving Credit Facility

Current Credit Agreement

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, 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

Eighth Amendment to the credit facility on October 25, 2016 (as amended, the “Current Credit Agreement”). Borrowings under the Current Credit Agreement mature on April 1, 2019. Legacy's obligations under the Current 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 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 $600 million, and as of February 21, 2017, we have approximately $464 million drawn under the Current Credit Agreement leaving approximately $134.1 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 Legacy 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 Current 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 Current Credit Agreement so long as it does not increase the borrowing base then in effect.

The Current Credit Agreement permits Legacy to issue additional senior notes, whose proceeds are used to refinance such senior notes as well as an additional $300 million in aggregate principal amount of new senior notes, in each case, subject to specified conditions in the Current 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 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 Current 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, Legacy must prepay any amount outstanding under the Current 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 Current 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 equal 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 Current 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 Current Credit Agreement also contains various covenants that limit our ability to:

- incur indebtedness;

- enter into certain leases;
- grant certain liens;
- enter into certain derivatives;

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- make certain loans, acquisitions, capital expenditures and investments;
- make distributions;
- merge, consolidate or allow any material change in the character of our business;
- repurchase Senior Notes or repay second lien 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 Current Credit Agreement also contains covenants that, among other things, require us to maintain specified ratios or conditions as follows:

- first lien debt to EBITDA for the four fiscal quarters ending on last day of the fiscal quarter immediately preceding the date of determination for which financial statements are available to not be greater than: (i) 3.50 to 1.00, at any time during the period from and including February 19, 2016 through December 31, 2016, (ii) 3.25 to 1.00, at any time during the fiscal quarter ending March 31, 2017, (iii) 3.00 to 1.00, at any time during the fiscal quarter ending June 30, 2017 and (iv) 2.50 to 1.00, at any time on or after July 1, 2017;
- 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 1.0 to 1.0, excluding 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 beginning with the fiscal quarter ending June 30, 2017, 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 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 Current 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 Current 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 35% of the aggregate ordinary voting power of our equity securities, (ii) 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), (iii) the direct or indirect sale, transfer or other disposition in one or a series of related transactions of all or substantially all of the properties or assets (including equity interests of subsidiaries) of us and our subsidiaries to any person, (iv) the adoption of a plan related to our liquidation or dissolution or (v) 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 Second Lien Term Loan Credit Agreement (as defined below).

As of December 31, 2016, Legacy was in compliance with all financial and other covenants of the Current Credit Agreement. Should oil and natural gas prices decline in 2017, we could breach certain financial covenants under our revolving credit facility, which would constitute a default under our revolving credit facility. 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 facility or foreclosure on our oil and natural gas properties. As previously noted, if the lenders under our revolving credit facility were to accelerate the indebtedness under our revolving credit facility 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, Legacy entered into a Term Loan Credit Agreement (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 Second Lien Term Loans up to an aggregate principal amount of $300.0 million. 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 Current 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 Current Credit Agreement.

Legacy used the initial $60.0 million of gross loan proceeds from its Second Lien Term Loans to repay outstanding indebtedness and pay associated transaction expenses. Additional Second Lien Term Loans up to an aggregate amount of $240.0 million are available at Legacy's discretion for twelve months following the date of the Second Lien Term Loan Credit Agreement. 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

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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 Legacy 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 Legacy's consent. The Second Lien Term Loan Credit Agreement matures on August 31, 2021; provided 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.

Legacy will pay a quarterly fee of 0.250% on the average daily amount of the unused commitments under the Second Lien Term Loan Credit Agreement.

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, beginning with the fiscal quarter ending June 30, 2017, 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 1.0 to 1.0;
- 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.

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 Second Lien Term Loan Credit Agreement, subject to the terms of the Intercreditor Agreement, the lenders will be able to accelerate the maturity of the Second Lien Term Loan Credit Agreement and exercise other rights and remedies.

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 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 Legacy, and used the net proceeds from this offering to fund a portion of the consideration paid for the COG 2012 Acquisition.

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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
2016	104.000 %
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 Legacy) 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 Legacy's 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 Legacy; (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 Legacy and our subsidiaries will cease to be subject to such covenants. The indenture also includes customary events of default. Legacy is in compliance with all financial and other covenants of the 2020 Senior Notes. As previously noted, if the lenders under our revolving credit facility were to accelerate the indebtedness under our revolving credit facility 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, 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.

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On June 1, 2016, Legacy exchanged 2,719,124 units 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 our 2021 Senior Notes. The 2021 Senior Notes were issued at 98.405% of par. Legacy received approximately $240.7 million of net cash proceeds, after deducting the discount to initial purchasers and offering expenses paid by Legacy.

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. Legacy received approximately $291.8 million of net cash proceeds, after deducting the discount to initial purchasers and offering expenses payable by Legacy.

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. 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 %

Prior to June 1, 2017, Legacy may redeem all or any part of the 2021 Senior Notes at the “make-whole” redemption price as defined in the indenture. 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. The Partnership is 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.

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.

Off-Balance Sheet Arrangements

None.

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Contractual Obligations

A summary of our contractual obligations as of December 31, 2016 is provided in the following table.

Contractual Cash Obligations	Obligations Due in Period 2017	2018-2019	2020-2021	Thereafter	Total
	(In thousands)				
Long-term debt					
Revolving credit facility(a)	$—	$463,000	$—	$—	$463,000
Interest on revolving credit facility(b)	18,103	22,629	—	—	40,732
Second Lien Term Loans	—	—	60,000	—	60,000
Interest on Second Lien Term Loans	7,200	14,400	4,800	—	26,400
Senior Notes	—	—	665,645	—	665,645
Interest on Senior Notes	47,303	94,605	57,692	—	199,600
Derivative obligations(c)	3,429	—	—	—	3,429
Management compensation(d)	2,155	4,310	4,310	—	10,775
Employee compensation(e)	2,011	2,817	—	—	4,828
Asset retirement obligation(f)	2,980	5,960	5,960	257,248	272,148
CO_2 purchase commitment(g)	4,751	17,275	17,553	9,049	48,628
Office lease	1,477	2,678	1,024	—	5,179
Total contractual cash obligations	$89,409	$627,674	$816,984	$266,297	$1,800,364

(a) Represents amounts outstanding under our revolving credit facility as of December 31, 2016.

(b) Based upon our weighted average interest rate of 3.91% under our revolving credit facility as of December 31, 2016.

(c) Derivative obligations represent net liabilities for commodity and interest rate derivatives that were valued as of December 31, 2016, the ultimate settlement of which are unknown because they are subject to continuing market risk. Please read "Quantitative and Qualitative Disclosure about Market Risk" for additional information regarding our derivative obligations.

(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 2020.

(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.

(f) Asset retirement obligations of oil and natural gas assets, excluding salvage value and accretion, the ultimate settlement and timing of which cannot be precisely determined in advance.

(g) Represents the value of the minimum volume of CO_2 required to be purchased in the respective annual period. As the contract price per Mcf of CO_2 is based on NYMEX WTI price on the date of purchase, we have assumed the NYMEX WTI strip price as of December 31, 2016.

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 these 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,

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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, 2016 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

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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, 2016, 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.

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As of December 31, 2016, 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 25.5%.

Recently Issued Accounting Pronouncements

In August 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2016-15, Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments (a consensus of the Emerging Issues Task Force) to address diversity in how certain cash receipts and cash payments are presented and classified in the statement of cash flows. The adoption of this ASU will not have any material impact on our results of operations, cash flows or financial position.

In May 2016, the FASB issued ASU No. 2016-12, Revenue from Contracts with Customers (Topic 606): Narrow-Scope Improvements and Practical Expedients (“ASU No. 2016-12”). The amendments under this ASU do not change the core revenue recognition principle in Topic 606. In addition, ASU No. 2016-12 provide clarifying guidance in certain narrow areas and add some practical expedients. These amendments are also effective at the same date that Topic 606 is effective.

In May 2016, the FASB issued ASU No. 2016-11, Revenue Recognition (Topic 605) and Derivatives and Hedging (Topic 815): Rescission of SEC Guidance Because of Accounting Standards Updates 2014-09 and 2014-16 Pursuant to Staff Announcements at the March 3, 2016 EITF Meeting. Under this ASU, the SEC Staff is rescinding certain SEC Staff Observer comments that are codified in Topic 605, Revenue Recognition, and Topic 932, Extractive Activities-Oil and Gas, effective upon adoption of Topic 606. Revenue from Contracts with Customers (Topic 606) is effective for public entities for fiscal years, and interim periods within the fiscal years, beginning after December 15, 2017.

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 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 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 are currently determining the impacts of the new standard on our contract portfolio. Our approach includes performing a detailed review of key contracts representative of our business and comparing historical accounting policies and practices to the new standard. Our contracts are primarily short-term in nature, and our assessment at this stage is that we do not expect the new revenue recognition standard will have a material impact on our financial statements upon adoption.

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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, 2016, the fair market value of Legacy’s commodity derivative positions was a net asset of $12.7 million. As of December 31, 2015, the fair market value of Legacy’s commodity derivative positions was a net asset of $118.4 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 2017 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, 2016 would decline from $575.6 million to $558.1 million, or 3.0%. If natural gas prices decline by $0.10 per Mcf, then the standardized measure of our combined proved reserves as of December 31, 2016 would decline from $575.6 million to $547.3 million, or 4.9%. However, larger decreases in oil and natural gas prices, such as the recent drop in oil prices, may have a disproportionate impact on our standardized measure.

Interest Rate Risks

At December 31, 2016, Legacy had debt outstanding under the revolving credit facility of $463 million, which incurred interest at floating rates in accordance with its revolving credit facility. The average annual interest rate incurred by Legacy for the year ended December 31, 2016 on its floating rate borrowings was 3.55%. A 1% increase in LIBOR on Legacy’s outstanding floating rate debt as of December 31, 2016 would result in an estimated $1.1 million increase in annual interest expense as Legacy has entered into two tranches of interest rate swaps to mitigate the volatility of interest rates. The first tranche expires on September 1, 2017 and covers $115 million of floating rate debt with a weighted-average fixed rate of 0.85%. The second tranche expires on September 1, 2019 and covers $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.

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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, 2016. 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, 2016, 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.

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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, 2016, 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, 2016, 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, 2016, which is set forth below under "Attestation Report."

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Attestation Report

Report of Independent Registered Public Accounting Firm

Board of Directors and Unitholders
Legacy Reserves LP
Midland, Texas

We have audited Legacy Reserves LP's internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Legacy Reserves LP'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. Controls and Procedures - Management's Annual Report on Internal Control Over Financial Reporting." Our responsibility is to express an opinion on Legacy Reserves LP's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). 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.

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.

In our opinion, Legacy Reserves LP maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Legacy Reserves LP as of December 31, 2016 and 2015, and the related consolidated statements of operations, unitholders' equity, and cash flows for each of the three years in the period ended December 31, 2016, and our report dated February 22, 2017 expressed an unqualified opinion thereon.

/s/ BDO USA, LLP

Houston, Texas
February 22, 2017

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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 2017 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, 2016.

ITEM 11. EXECUTIVE COMPENSATION

We intend to include information with respect to executive compensation in Legacy's definitive proxy statement for its 2017 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, 2016.

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 2017 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, 2016.

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 2017 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, 2016.

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 2017 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, 2016.

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.

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(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	—	Fourth Amended and Restated Agreement of Limited Partnership of Legacy Reserves LP, as amended by Amendment No. 1 thereto, dated May 10, 2016 (Incorporated by reference to Legacy Reserves LP's quarterly report on Form 10-Q filed on August 3, 2016, Exhibit 3.2)
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)

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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)

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Exhibit Number		Description
10.11†	—	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)
10.12†	—	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)
10.13†	—	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)
10.14†	—	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)
10.15†	—	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)
10.16†	—	Employment Agreement dated as of March 15, 2006, between Cary D. Brown 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 10.9)
10.17†	—	Section 409A Compliance Amendment to Employment Agreement dated December 31, 2008, between Cary D. Brown 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 10.1)
10.18†	—	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)
10.19†	—	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)
10.20†	—	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)
10.21†	—	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)
10.22†	—	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)
10.23†	—	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)
10.24†	—	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)
10.25†	—	Non-Executive Chairman Agreement by and among Legacy Reserves GP, LLC, Legacy Reserves Services, Inc. and Cary D. Brown, dated as of February 3, 2015. (Incorporated by reference to

Legacy Reserves LP's current report on Form 8-K (File No. 001-33249) filed on February 6, 2015, Exhibit 10.1)

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Exhibit Number	Description
10.26†	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)
10.27†	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)
10.28†	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)
10.29†	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)
10.30†	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)
10.31†	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)
10.32†	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)
10.33†	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)
10.34†	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)
10.35†	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)
10.36†	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)
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.

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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 22nd day of February, 2017.

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	Chairman of the Board, President and Chief Executive Officer	February 22, 2017
Paul T. Horne	(Principal Executive Officer)	
/S/ JAMES DANIEL WESTCOTT	Executive Vice President and Chief Financial Officer	February 22, 2017
James Daniel Westcott	(Principal Financial Officer)	
/S/ MICAH C. FOSTER	Chief Accounting Officer and Controller	February 22, 2017
Micah C. Foster	(Principal Accounting Officer)	
/S/ KYLE A. MCGRAW	Executive Vice President, Chief Development Officer and Director	February 22, 2017
Kyle A. McGraw		
/S/ CARY D. BROWN	Director	February 22, 2017
Cary D. Brown		

/S/ DALE A. BROWN Dale A. Brown	Director	February 22, 2017
/S/ WILLIAM R. GRANBERRY William R. Granberry	Director	February 22, 2017
/S/ G. LARRY LAWRENCE G. Larry Lawrence	Director	February 22, 2017
/S/ WILLIAM D. SULLIVAN William D. Sullivan	Director	February 22, 2017
/S/ KYLE D. VANN Kyle D. Vann	Director	February 22, 2017
/S/ D. DWIGHT SCOTT D. Dwight Scott	Director	February 22, 2017

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INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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Report of Independent Registered Public Accounting Firm

Board of Directors and Unitholders
Legacy Reserves LP
Midland, Texas

We have audited the accompanying consolidated balance sheets of Legacy Reserves LP as of December 31, 2016 and 2015 and the related consolidated statements of operations, unitholders' equity, and cash flows for each of the three years in the period ended December 31, 2016. These financial statements are the responsibility of Legacy Reserves LP's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Legacy Reserves LP at December 31, 2016 and 2015 and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2016, 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), Legacy Reserves LP's internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 22, 2017 expressed an unqualified opinion thereon.

/s/ BDO USA, LLP

Houston, Texas
February 22, 2017

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LEGACY RESERVES LP

CONSOLIDATED BALANCE SHEETS
AS OF DECEMBER 31, 2016 AND 2015

	2016	2015
	(In thousands)	
ASSETS		
Current assets:		
Cash	$2,555	$2,006
Accounts receivable, net:		
Oil and natural gas	43,192	33,944
Joint interest owners	23,414	25,378
Other	2	86
Fair value of derivatives (Notes 8 and 9)	6,162	63,711
Prepaid expenses and other current assets	7,447	4,334
Total current assets	82,772	129,459
Oil and natural gas properties, at cost:		
Proved oil and natural gas properties using the successful efforts method of accounting	3,305,856	3,485,634
Unproved properties	13,448	13,424
Accumulated depletion, depreciation, amortization and impairment	(2,137,395)	(2,090,102)
Total oil and natural gas properties, net	1,181,909	1,408,956
Other property and equipment, net of accumulated depreciation and amortization of $10,412 and $8,915, respectively	3,423	4,575
Operating rights, net of amortization of $5,369 and $4,953, respectively	1,648	2,064
Fair value of derivatives (Notes 8 and 9)	20,553	56,373
Other assets	8,874	11,047
Investments in equity method investees	647	646
Total assets	$1,299,826	$1,613,120
LIABILITIES AND PARTNERS’ DEFICIT		
Current liabilities:		
Accounts payable	$9,092	$13,581
Accrued oil and natural gas liabilities (Note 1)	53,248	50,573
Fair value of derivatives (Notes 8 and 9)	9,743	2,019
Asset retirement obligation (Note 11)	2,980	3,496
Other (Notes 8 and 13)	11,546	11,424
Total current liabilities	86,609	81,093
Long-term debt (Note 3)	1,161,394	1,427,614
Asset retirement obligation (Note 11)	269,168	282,909
Fair value of derivatives (Notes 8 and 9)	4,091	—
Other long-term liabilities	643	1,181
Total liabilities	1,521,905	1,792,797
Commitments and contingencies (Note 6)		
Partners’ equity (deficit):		
Series A Preferred equity - 2,300,000 units issued and outstanding at December 31, 2016 and December 31, 2015	55,192	55,192
Series B Preferred equity - 7,200,000 units issued and outstanding at December 31, 2016 and December 31, 2015	174,261	174,261
Incentive distribution equity - 100,000 units issued and outstanding at December 31, 2016 and December 31, 2015	30,814	30,814

Limited partners' deficit - 72,056,097 and 68,949,961 units issued and outstanding at December 31, 2016 and 2015, respectively	(482,200)	(439,811)
General partner's deficit (approximately 0.03%)	(146)	(133)
Total partners' deficit	(222,079)	(179,677)
Total liabilities and partners' deficit	$1,299,826	$1,613,120

See accompanying notes to consolidated financial statements.

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LEGACY RESERVES LP

CONSOLIDATED STATEMENTS OF OPERATIONS
FOR THE YEARS ENDED DECEMBER 31, 2016, 2015 AND 2014

	2016	2015	2014
	(In thousands, except per unit data)		
Revenues:			
Oil sales	$152,507	$199,841	$396,774
Natural gas liquids (NGL) sales	15,406	16,645	27,483
Natural gas sales	146,444	122,293	108,042
Total revenues	314,357	338,779	532,299
Expenses:			
Oil and natural gas production	179,333	194,491	198,801
Production and other taxes	14,267	16,383	31,534
General and administrative	43,639	46,511	38,980
Depletion, depreciation, amortization and accretion	150,414	177,258	173,686
Impairment of long-lived assets	61,796	633,805	448,714
Gain on disposal of assets	(50,095)	(3,972)	(2,479)
Total expenses	399,354	1,064,476	889,236
Operating loss	(84,997)	(725,697)	(356,937)
Other income (expense):			
Interest income	67	329	873
Interest expense (Notes 3, 8 and 9)	(79,060)	(76,891)	(67,218)
Gain on extinguishment of debt	150,802	—	—
Equity in income of equity method investees	—	126	428
Net gains (losses) on commodity derivatives (Notes 8 and 9)	(41,224)	98,253	138,092
Other	(179)	841	258
Loss before income taxes	(54,591)	(703,039)	(284,504)
Income tax (expense) benefit	(1,229)	1,498	859
Net loss	$(55,820)	$(701,541)	$(283,645)
Distributions to preferred unitholders	(19,000)	(19,000)	(11,694)
Net loss attributable to unitholders	$(74,820)	$(720,541)	$(295,339)
Loss per unit — basic and diluted (Note 12)	$(1.06)	$(10.45)	$(4.92)
Weighted average number of units used in computing loss per unit —			
Basic and Diluted	70,605	68,928	60,053

See accompanying notes to consolidated financial statements.

LEGACY RESERVES LP

CONSOLIDATED STATEMENTS OF UNITHOLDERS' EQUITY
FOR THE YEARS ENDED DECEMBER 31, 2016, 2015 AND 2014

	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, 2013	—	$—	—	$—	—	$—	57,280	$510,322	$74	$510,396
Units issued to Legacy Board of Directors for services	—	—	—	—	—	—	18	499	—	499
Issuance of preferred units, net	2,300	55,192	7,200	174,261	—	—	—	—	—	229,453
Unit-based compensation	—	—	—	—	—	—	—	3,797	—	3,797
Vesting of restricted and phantom units	—	—	—	—	—	—	113	—	—	—
Issuance of units, net	—	—	—	—	—	—	11,500	303,457	—	303,457
Incentive Distribution Units issued in exchange for oil and natural gas properties	—	—	—	—	100	30,814	—	—	—	30,814
Distributions to preferred unitholders	—	—	—	—	—	—	—	(11,694)	—	(11,694)
Distributions to unitholders, $2.405 per unit	—	—	—	—	—	—	—	(145,872)	—	(145,872)
Net loss	—	—	—	—	—	—	—	(283,624)	(21)	(283,645)
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)

See accompanying notes to consolidated financial statements.

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LEGACY RESERVES LP

CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2016, 2015 AND 2014

	2016	2015	2014
	(In thousands)		
Cash flows from operating activities:			
Net loss	$(55,820)	$(701,541)	$(283,645)
Adjustments to reconcile net loss to net cash (used in) provided by operating activities:			
Depletion, depreciation, amortization and accretion	150,414	177,258	173,686
Amortization of debt discount and issuance costs	10,319	5,532	4,637
Gain on extinguishment of debt	(150,802)	—	—
Impairment of long-lived assets	61,796	633,805	448,714
(Gain) loss on derivatives	40,679	(99,971)	(140,771)
Equity in income of equity method investees	—	(126)	(428)
Distribution from equity method investee	—	191	1,467
Unit-based compensation	7,035	6,451	2,089
Gain on disposal of assets	(50,095)	(3,972)	(2,479)
Changes in assets and liabilities:			
(Increase) decrease in accounts receivable, oil and natural gas	(9,248)	15,447	(1,962)
(Increase) decrease in accounts receivable, joint interest owners	1,964	(9,143)	297
Decrease in accounts receivable, other	84	151	389
(Increase) decrease in other assets	(940)	333	(1,193)
Increase (decrease) in accounts payable	(4,489)	10,794	(3,228)
Increase (decrease) in accrued oil and natural gas liabilities	2,675	(28,042)	15,454
Decrease in other liabilities	(3,882)	(5,121)	(5,811)
Total adjustments	55,510	703,587	490,861
Net cash (used in) provided by operating activities	(310)	2,046	207,216
Cash flows from investing activities:			
Investment in oil and natural gas properties	(41,496)	(577,186)	(638,942)
Proceeds from sale of assets	97,416	69,118	5,334
Investment in other equipment	(436)	(2,277)	(1,472)
Net cash settlements on commodity derivatives	64,505	132,925	2,666
Net cash provided by (used in) investing activities	119,989	(377,420)	(632,414)
Cash flows from financing activities:			
Proceeds from long-term debt	266,000	840,000	1,333,000
Payments of long-term debt	(376,402)	(341,000)	(1,275,000)
Payments of debt issuance costs	(8,728)	(1,891)	(10,005)
Proceeds from issuance of limited partner interests, net	—	(103)	532,910
Distributions to unitholders	—	(120,351)	(157,566)
Net cash (used in) provided by financing activities	(119,130)	376,655	423,339
Net increase (decrease) in cash	549	1,281	(1,859)
Cash, beginning of period	2,006	725	2,584
Cash, end of period	$2,555	$2,006	$725
Non-Cash Investing and Financing Activities:			
Asset retirement obligation costs and liabilities	$1	$92	$941
Asset retirement obligations associated with property acquisitions	$24	$60,526	$50,487
Asset retirement obligations associated with properties sold	$(24,605)	$(9,386)	$(5,891)

Units acquired in exchange for investment in equity method investee	$—	$(1,349)	$—
Units issued in exchange for Senior Notes	$6,607	$—	$—
Incentive Distribution units issued in exchange for oil and natural gas properties	$—	$—	$30,814

See accompanying notes to consolidated financial statements.

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LEGACY RESERVES LP

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, 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. For the year ended December 31, 2014, Legacy recognized $448.7 million of impairment expense, $413.3 million of which was in 250 separate producing fields, due to the significant decline in commodity prices during the year ended December 31, 2014, which decreased the expected future cash flows below the carrying value of the assets. As Legacy has historically grown through the acquisition of oil and natural gas properties, most of which were acquired during higher commodity price environments, the sharp decline in oil and natural gas prices during the latter portion of 2014 resulted in a corresponding decrease in the expected future cash flows of such assets from the date of their acquisition as compared to December 31, 2014. As evidenced above, this decrease was not limited to any one field or area of operation, as it impacted the value of assets across Legacy's portfolio. 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 year ended December 31, 2016. During the years ended December 31, 2015 and 2014, Legacy recognized $35.7 million and $35.0 million of impairment of unproven properties, respectively.

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(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 1% 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 $(1.2) million, $1.5 million and $0.9 million for the years ended December 31, 2016, 2015 and 2014, 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 $1.3 billion at December 31, 2016.

(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, 2016, 2015 and 2014.

(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 2017, 2018, 2019, 2020 and 2021 are $396,000, $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, 2016, do not include 484,447 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, 2016 and 2015.

	December 31,	
	2016	2015
	(In thousands)	
Revenue payable to joint interest owners	$19,576	$15,253
Accrued lease operating expense	17,696	19,007

Accrued capital expenditures	7,019	2,881
Accrued ad valorem tax	5,300	8,723
Other	3,657	4,709
	$53,248	$50,573

(p) Restricted Cash

Restricted cash of $3.6 million as of December 31, 2016 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. There was no restricted cash recorded at December 31, 2015.

(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. Please read "—Footnote 3—Long-Term Debt" for further discussion regarding this reclassification.

(r) Recent Accounting Pronouncements

In August 2016, the Financial Accounting Standards Board ("FASB") issued ASU No. 2016-15, Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments (a consensus of the Emerging Issues Task Force) to address diversity in how certain cash receipts and cash payments are presented and classified in the statement of cash flows. The adoption of this ASU will not have any material impact on our results of operations, cash flows or financial position.

In May 2016, the FASB issued ASU No. 2016-12, Revenue from Contracts with Customers (Topic 606): Narrow-Scope Improvements and Practical Expedients (“ASU No. 2016-12”). The amendments under this ASU do not change the core revenue recognition principle in Topic 606. In addition, ASU No. 2016-12 provide clarifying guidance in certain narrow areas and add some practical expedients. These amendments are also effective at the same date that Topic 606 is effective.

In May 2016, the FASB issued ASU No. 2016-11, Revenue Recognition (Topic 605) and Derivatives and Hedging (Topic 815): Rescission of SEC Guidance Because of Accounting Standards Updates 2014-09 and 2014-16 Pursuant to Staff Announcements at the March 3, 2016 EITF Meeting. Under this ASU, the SEC Staff is rescinding certain SEC Staff Observer comments that are codified in Topic 605, Revenue Recognition, and Topic 932, Extractive Activities-Oil and Gas, effective upon adoption of Topic 606. Revenue from Contracts with Customers (Topic 606) is effective for public entities for fiscal years, and interim periods within the fiscal years, beginning after December 15, 2017.

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). We are currently evaluating the impact of our pending adoption of ASU 2014-09 on our consolidated financial statements and do not anticipate the standard will have a material impact on our consolidated financial statements. We are currently determining the impacts of the new standard on our contract portfolio. Our approach includes performing a detailed review of key contracts representative of our business and comparing historical accounting policies and practices to the new standard. Our contracts are primarily short-term in nature, and our assessment at this stage is that we do not expect the new revenue recognition standard will have a material impact on our financial statements upon adoption.

(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 $179.4 million and $302.0 million, respectively, as of December 31, 2016. 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, 2016 and 2015:

	December 31,	
	2016	2015
	(In thousands)	
Credit Facility due 2019	$463,000	$608,000
Second Lien Term Loans due 2020	60,000	—
8% Senior Notes due 2020	232,989	300,000
6.625% Senior Notes due 2021	432,656	550,000
	1,188,645	1,458,000
Unamortized discount on Second Lien Term Loans and Senior Notes	(12,802)	(17,604)
Unamortized debt issuance costs (a)	(14,449)	(12,782)
Total long term debt	$1,161,394	$1,427,614

(a) In order to comply with Accounting Standards Update No. 2015-03, unamortized debt issuance costs are now recorded as a direct deduction from the carrying amount of debt. As such, debt issuance costs have been reclassified from other assets to long-term debt on a retrospective basis. This reclassification had no impact on historical income from continuing operations or retained earnings.

Credit Facility

Previous Credit Agreement: On March 10, 2011, Legacy entered into a five-year $1 billion secured revolving credit facility (as amended, the "Previous Credit Agreement"). Borrowings under the Previous Credit Agreement were set to mature on March 10, 2016.

Current Credit Agreement: 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 Seventh Amendment, (the "Current Credit Agreement") which replaced the Previous Credit Agreement. Borrowings under the Current Credit Agreement mature on April 1, 2019. Legacy's obligations under the Current 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, 2016 was set at $600 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 Current 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 Current Credit Agreement so long as it does not increase the borrowing base then in effect. Under the Current 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 Current 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 any material change in the character of its business and (viii) engage in certain asset dispositions, including a sale of all or substantially all of its assets. Effective October 25, 2016, Legacy entered into an amendment (the “Eighth Amendment”) to the Current 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 Current 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, 2016 these covenants were as follows: (i) 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 beginning with the fiscal quarter ending on December 31, 2018, (ii) 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, (iii) 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 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 (iv) 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 beginning with the fiscal quarter ending June 30, 2017.

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

As of December 31, 2016, Legacy had outstanding borrowings of $463 million under the Current Credit Agreement at a weighted average interest rate of 3.91%. Thus, Legacy had approximately $135.1 million of borrowing availability remaining. As of February 21, 2017, Legacy had approximately $134.1 million of borrowing availability remaining. For the year ended December 31, 2016, Legacy paid $19.0 million of interest expense on the Current Credit Agreement.

At December 31, 2016, Legacy was in compliance with all covenants contained in the Current Credit Agreement. Depending on future oil and natural gas prices, we could breach certain financial covenants under our revolving credit facility, which would constitute a default under our revolving credit facility. 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 facility or foreclosure on our 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, 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 asset sales, will be viewed positively by our 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 (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 aggregate principal amount of $300.0 million (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 Current 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 Current 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. Additional Second Lien Term Loans up to an aggregate amount of $240.0 million are available at Legacy's discretion for twelve months following the date of the Second Lien Term Loan Credit Agreement. 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 Legacy 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 the Partnership's consent. The Second Lien

Term Loan Credit Agreement matures on August 31, 2021; provided 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.

Legacy will pay a quarterly fee of 0.250% on the average daily amount of the unused commitments under the Term Loan Credit Agreement.

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, beginning with the fiscal quarter ending June 30, 2017, 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 1.00 to 1.00;

- 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.

For the year ended December 31, 2016, Legacy paid cash interest expense of $1.4 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 our 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

2016	104.000 %
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 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 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 Current Credit Agreement were to accelerate the indebtedness under Legacy's Current 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, 2016, 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 our 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 our 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 %

Prior to June 1, 2017, Legacy may redeem all or any part of the 2021 Senior Notes at the “make-whole” redemption price as defined in the indenture. 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 Current Credit Agreement were to accelerate the indebtedness under Legacy's Current 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, 2016, 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.

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, 2016, Legacy paid $47.9 million of cash interest expense for the 2020 Senior Notes and 2021 Senior Notes.

(4) Acquisitions

WPX Acquisition

On June 4, 2014, Legacy purchased a non-operated interest in oil and natural gas properties located in the Piceance Basin in Garfield County, Colorado from WPX Energy Rocky Mountain, LLC , a subsidiary of WPX Energy, Inc., (the "WPX Acquisition") for a net purchase price of $360.0 million. Consideration included both cash and 300,000 Incentive Distribution Units representing limited partner interests in the Partnership (the "Incentive Distribution Units"), 100,000 of which vested immediately and the remainder of which are available to vest and also subject to forfeiture pursuant to the terms of a related Incentive Distribution Units Holders Agreement. This acquisition was accounted for as a business combination. The 100,000 vested Incentive Distribution Units have been reflected in the financial statements at their estimated issuance date fair value of $30.8 million. No value was ascribed to the unvested Incentive Distribution Units upon the closing of the WPX Acquisition as the vesting of the unvested Incentive Distribution Units is dependent upon the consummation of future transactions with WPX and such Incentive Distribution Units will be a portion of the consideration of any such future transactions. During the year ended December 31, 2014, Legacy incurred acquisition costs, recorded in general and administrative expense, of approximately $5.4 million related to the WPX Acquisition and other acquisitions.

The allocation of the WPX Acquisition 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	$422,739
Future abandonment costs	(62,748)
Fair value of net assets acquired	$359,991

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

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Pro Forma Operating Results

The following table reflects the unaudited pro forma results of operations as though the WPX Acquisition had occurred on January 1, 2013 and 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	2014
	(In thousands)	
Revenues	$380,619	$687,829
Net loss attributable to unitholders	$(713,364)	$(243,197)
Loss per unit — basic and diluted	$(10.35)	$(4.05)
Units used in computing loss per unit:		
Basic	68,928	60,053
Diluted	68,928	60,053

The amounts of revenues and revenues in excess of direct operating expenses included in our consolidated statements of operations for the WPX Acquisition and the Anadarko Acquisitions are shown in the table that follows. Direct operating expenses include lease operating expenses and production and other taxes.

	Year Ended December 31,		
	2016	2015	2014
WPX Acquisition	(In thousands)		
Revenues	$62,522	$69,504	$48,470
Excess of revenues over direct operating expenses	$23,622	$22,324	$22,333
Anadarko Acquisitions			
Revenues	$51,177	$22,881	$—
Excess of revenues over direct operating expenses	$23,319	$12,373	$—

(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 $98,297, $382,629 and $84,470 in 2016, 2015 and 2014, 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.

Cary D. Brown and Kyle A. McGraw, Director and Legacy’s Executive Vice President and Chief Development Officer, own interests in partnerships which, in turn, own a combined non-controlling 4.16% interest as limited partners in a partnership which, until November 10, 2014, owned the building that Legacy occupies. Monthly rent is

$111,299 without respect to property taxes and insurance. The lease expires in September 2020.

(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 party to a contractual agreement, extending through 2022, to purchase CO2 volumes from a third party. The contract requires Legacy to purchase minimum annual volumes, the pricing of which is calculated as a percentage of NYMEX-WTI oil prices, with a floor of $57.14. Based upon the minimum required volumes and the NYMEX-WTI strip prices as of December 31, 2016, we estimate the value of our total future obligation to be approximately $48.6 million.

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 2016, 2015 or 2014. 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, 2016, Legacy’s commodity derivative transactions have a fair value favorable to the Partnership of $12.7 million, collectively. Legacy enters into commodity derivative transactions with members of its revolving credit facility, who Legacy’s management believes are major, creditworthy financial institutions. 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.

As required by ASC 820-10, 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, 2016 and 2015:

Description	Fair Value Measurements Using 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)	$—	$(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

LTIP liability(a)	$—	$—	$ —	$—
Oil and natural gas derivatives	—	122,920	(4,493)	118,427
Interest rate swaps	—	(362)	—	(362)
Total as of December 31, 2015	$—	$122,558	$ (4,493)	$118,065

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(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 the 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 our 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 our 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 our 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 such current counterparties (or their affiliates) are also current or former bank lenders under the Partnership's revolving credit facility. 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,		
	2016	2015	2014
	(In thousands)		
Beginning balance	$(4,493)	$555	$20,615
Total gains (losses)	253	(10,029)	(6,185)
Settlements	4,248	4,981	677
Transfers	—	—	(14,552)(a)
Ending balance	$8	$(4,493)	$555
Gains included in earnings relating to derivatives still held as of December 31, 2016, 2015 and 2014	$68	$(4,493)	$555

(a) During 2014, as part of a routine review of accounting policies and practices, Legacy reviewed the assumptions and inputs used to value its derivative instruments and determined the material inputs (such as quoted market prices and oil and natural gas volatility) for its commodity derivatives more accurately correlate to the description of Level 2 instruments. As such, all instruments previously classified as Level 3 (oil and natural gas collars, swaptions and natural gas swaps for those derivatives indexed to the West Texas Waha, ANR-Oklahoma and CIG Indices) with the exception of our Midland-Cushing crude oil differential swaps were transferred to Level 2 instruments.

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 our consolidated financial statements and the period-to-period changes in value could vary significantly. Decreases in value may have a material adverse effect on our 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, 2016 and 2015 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)		
2016			
Impairment(a)	$—	$ —	$ 60,729
Acquisitions(b)	$—	$ —	$ 11,998
2015			
Impairment(a)	$—	$ —	$ 385,506
Acquisitions(b)	$—	$ —	$ 540,347

(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, 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. During the year ended December 31, 2015, Legacy incurred impairment charges of $598.1 million as oil and natural gas properties with a net cost basis of $983.6 million were written down to their fair value of $385.5 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.

The remaining $35.7 million of impairment during the year ended December 31, 2015 was related to unproved properties acquired since 2010 that were no longer viable.

(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. During the year ended December 31, 2015, Legacy acquired oil and natural gas properties with a fair value of $540.3 million in the Anadarko Acquisitions and 6 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, 2016, 2015, and 2014.

	December 31,		
	2016	2015	2014
	(In thousands)		
Beginning fair value of commodity derivatives	$118,427	$153,099	$17,673
Total gain (loss) crude oil derivatives	(9,410)	25,715	101,813
Total gain (loss) natural gas derivatives	(31,814)	72,538	36,279
Crude oil derivative cash settlements paid (received)	(37,464)	(91,953)	5,431
Natural gas derivative cash settlements received	(27,041)	(40,972)	(8,097)
Ending fair value of commodity derivatives	$12,698	$118,427	$153,099

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, 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)

	December 31, 2015		
	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	$177,082	$ (58,655)	$ 118,427
Interest rate derivatives	1,982	(325)	1,657

Total derivative assets	$179,064	$ (58,980)	$ 120,084
Offsetting Derivative Liabilities:			
Commodity derivatives	$(58,655)	$ 58,655	$ —
Interest rate derivatives	(2,344)	325	(2,019)
Total derivative liabilities	$(60,999)	$ 58,980	$ (2,019)

As of December 31, 2016, 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
2017	182,500	$84.75	$84.75
2018	730,000	$55.04	$55.00-$55.15

As of December 31, 2016, 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
2017	2,190,000	$(0.30)	$(0.75) - $(0.05)

As of December 31, 2016, 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
2017	2,190,000	$45.00	$59.02
2018	1,095,000	$45.83	$59.97

As of December 31, 2016, Legacy had the following NYMEX WTI crude oil derivative three-way collar contracts that combine a long and short put with a short call as indicated below:

Calendar Year	Volumes (Bbls)	Average Short Put Price per Bbl	Average Long Put Price per Bbl	Average Short Call Price per Bbl
2017	72,400	$60.00	$85.00	$104.20

As of December 31, 2016, 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
2017	182,500	$57.00	$82.00	$90.85
2018	127,750	$57.00	$82.00	$90.50

As of December 31, 2016, Legacy had the following NYMEX Henry Hub and Waha 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
2017	27,600,000	$3.36	$3.29 - $3.39
2018	42,200,000	$3.25	$3.04 - $3.39
2019	25,800,000	$3.36	$3.29 - $3.39

As of December 31, 2016, Legacy had the following NYMEX Henry Hub costless collars that combine a long put with a short call as indicated below:

Time Period	Volumes (MMBtu)	Average Long Put Price per MMBtu	Average Short Call Price per MMBtu
2017	14,600,000	$2.90	$3.44

As of December 31, 2016, Legacy had the following NYMEX Henry Hub natural gas derivative three-way collar contracts that combine a long put, a short put and a short call as indicated below:

Calendar Year	Volumes (MMBtu)	Average Short Put Price per MMBtu	Average Long Put Price per MMBtu	Average Short Call Price per MMBtu
2017	5,040,000	$3.75	$4.25	$5.53

As of December 31, 2016, Legacy had the following Henry Hub NYMEX to Northwest Pipeline, SoCal and San Juan Basin natural gas differential swaps paying a floating differential and receiving a fixed differential for a portion of its future natural gas production as indicated below:

	2017	
	Volumes (MMBtu)	Average Price per MMBtu
NWPL	7,300,000	$(0.16)
SoCal	2,500,250	$0.11
San Juan	2,500,250	$(0.10)

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,		
	2016	2015	2014
	(In thousands)		
Beginning fair value of interest rate swaps	$(362)	$(2,080)	$(4,759)
Total loss on interest rate swaps	(2,108)	(1,548)	(551)
Cash settlements paid	2,653	3,266	3,230
Ending fair value of interest rate swaps	$183	$(362)	$(2,080)

The table below summarizes the interest rate swap assets and liabilities as of December 31, 2016.

Weighted Average Fixed	Effective	Maturity	Estimated Fair Market

Notional Amount	Rate	Date	Date	Value at December 31, 2016
	(Dollars in thousands)			
$115,000	0.850%	9/1/2015	9/1/2017	(11)
$235,000	1.363%	9/1/2015	9/1/2019	194
Total fair value of interest rate derivatives				$ 183

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LEGACY RESERVES LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

(10) Sales to Major Customers

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. For the year ended December 31, 2014, Legacy sold oil, NGL and natural gas production representing 10% or more of total revenues to purchasers as detailed in the table below:

	2016	2015	2014
Enterprise (Teppco) Crude Oil, LP	1%	6%	12%
Plains Marketing, LP	6%	7%	10%

(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 income statement in the disposal of assets line item.

The following table reflects the changes in the ARO during the years ended December 31, 2016, 2015 and 2014.

	December 31,		
	2016	2015	2014
	(In thousands)		
Asset retirement obligation — beginning of period	$286,405	$226,525	$175,786
Liabilities incurred with properties acquired	24	60,526	50,487
Liabilities incurred with properties drilled	1	92	941
Liabilities settled during the period	(2,351)	(2,615)	(2,918)
Liabilities associated with properties sold	(24,605)	(9,386)	(5,891)
Current period accretion	12,674	11,263	8,120
Asset retirement obligation — end of period	$272,148	$286,405	$226,525

Each year the Partnership reviews and, to the extent necessary, revises its ARO estimates. During 2014, 2015 and 2016, no revisions of previous estimates were deemed necessary.

(12) Partners' Equity

On April 17, 2014, Legacy issued 2,000,000 of its 8% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the "Series A Preferred Units") in a public offering at a price of $25.00 per unit. On May 12, 2014 Legacy issued an additional 300,000 Series A Preferred Units pursuant to the underwriters’ option to purchase additional Series A Preferred Units. Legacy received aggregate net proceeds of approximately $55.2 million, after deducting underwriting discounts and offering expenses, from the offering of Series A Preferred Units during the year ended December 31, 2014.

On June 17, 2014, Legacy issued 7,000,000 of its 8.00% Series B Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the "Series B Preferred Units") in a public offering at a price of $25.00 per unit. On July 1, 2014, Legacy issued an additional 200,000 Series B Preferred Units pursuant to the underwriters' option to purchase additional Series B Preferred Units. Legacy received aggregate net proceeds of approximately $174.3 million, after deducting underwriting discounts and offering expenses, from the offering of Series B Preferred Units during the year ended December 31, 2014.

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, 2016, $1.92 of distributions per unit were in arrears, representing a total cumulative arrearage of approximately $18.2 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 WPX 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. The Unvested IDUs do not participate in cash distributions from Legacy until vested. The Unvested IDUs will automatically be forfeited on each of the first two anniversaries of the closing date of the WPX Acquisition in an amount per forfeiture equal to 66,666 Incentive Distribution Units and on the third anniversary of the closing date of the WPX Acquisition in an amount equal to 66,668 Incentive Distribution Units. 66,666 unvested IDUs were forfeited on each of June 4, 2015 and June 4, 2016. Unvested IDUs that have not been forfeited will vest ratably at a rate of 10,000 Incentive Distribution Units per $35.5 million of additional cash consideration that is paid by Legacy to WPX or to a third party (along with the fair market value of any non-cash consideration) in connection with the consummation of any transaction by which Legacy acquires oil and natural gas properties (or rights therein or other assets related thereto) from WPX or jointly with WPX.

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,		
	2016	2015	2014
	(In thousands)		
Net loss	$(55,820)	$(701,541)	$(283,645)
Distributions to preferred unitholders	(19,000)	(19,000)	(11,694)
Net loss attributable to unitholders	$(74,820)	$(720,541)	$(295,339)
Weighted average number of units outstanding	70,605	68,928	60,053
Effect of dilutive securities:			
Restricted and phantom units	—	—	—
Weighted average units and potential units outstanding	70,605	68,928	60,053
Basic and diluted loss per unit	$(1.06)	$(10.45)	$(4.92)

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. 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, 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. As of December 31, 2014, 254,183 restricted units and 323,965 phantom units were excluded from the calculation of diluted earnings per unit due to their anti-dilutive effect.

(13) Unit-Based Compensation

Long Term Incentive Plan

On March 15, 2006, a Long-Term Incentive Plan ("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, 2016 grants of awards net of forfeitures and, in the case of phantom units, historical exercises covering 2,926,889 units have been made, comprised of 266,014 unit option awards, 1,014,499 restricted unit awards, 1,212,692 phantom unit awards and 433,684 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, 2014, Legacy issued (i) 136,100 UARs to employees which vest ratably over a three-year period and (ii) 105,174 UARs to employees which cliff-vest at the end of a three-year period. 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 year ended December 31, 2016. All of the UARs granted in 2015 and 2014 expire seven years from the grant date and are exercisable when they vest.

For the years ended December 31, 2016, 2015 and 2014, Legacy recorded compensation expense (benefit) of $223.6 thousand, $(10.7) thousand and $(1,260.0) thousand, 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, 2016, 2015 and 2014 fair value of these UARs (see Note 8). As of December 31, 2016, there was a total of $129,093 of unrecognized compensation costs related to the unexercised and non-vested portion of the UARs. At December 31, 2016, this cost was expected to be recognized over a weighted-average period of 1.59 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 87% and employed the Black-Scholes model to estimate the December 31, 2016 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 5.3%. 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, 2016, 2015 and 2014 is as follows:

	Units	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1, 2014	627,043	$ 25.99		
Granted	243,274	$ 28.21		
Exercised	(137,252)	$ 24.35		
Forfeited	(61,836)	$ 27.27		
Outstanding at December 31, 2014	671,229	$ 26.97	5.15	$ —
UARs exercisable at December 31, 2014	220,056	$ 25.50	3.51	$ —
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	$ —

The following table summarizes the status of the Partnership’s non-vested UARs since January 1, 2016:

	Non-Vested UARs	
	Number of Units	Weighted-Average Exercise Price
Non-vested at January 1, 2016	566,067	$ 16.80
Vested	(221,387)	20.14
Forfeited	(30,503)	19.80
Non-vested at December 31, 2016	314,177	$ 14.16

Legacy has used a weighted-average risk free interest rate of 1.6% in its Black-Scholes calculation of fair value, which approximates the U.S. Treasury interest rates at December 31, 2016. 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,		
	2016	2015	2014
Expected life (years)	4.02	4.91	5.15
Annual interest rate	1.6 %	1.7 %	1.6 %

Annual distribution rate per unit	$0.00	$0.60	$2.44
Volatility	87 %	59 %	38 %

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 2014, the Compensation Committee approved the award of 117,197 subjective, or service-based, phantom units and 102,572 objective, or performance-based, phantom units to Legacy’s five executive officers. 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 that, upon vesting, settle in cash to Legacy's executive officers.

Compensation expense related to the phantom units and associated DERs was $3.7 million, $3.4 million and $2.3 million for the years ended December 31, 2016, 2015 and 2014, respectively.

Restricted Units

During the year ended December 31, 2014, Legacy issued an aggregate of 127,845 restricted units to non-executive employees . The majority of these restricted units awarded vest ratably over a three-year period. 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. Compensation expense related to restricted units was $2.7 million, $2.7 million and $2.3 million for the years ended December 31, 2016, 2015 and 2014, respectively. As of December 31, 2016, there was a total of $2.4 million of unrecognized compensation costs related to the non-vested portion of these restricted units. At December 31, 2016, this cost was expected to be recognized over a weighted-average period of 1.8 years.

Pursuant to the provisions of ASC 718, Legacy’s issued units as reflected in the accompanying consolidated balance sheet at December 31, 2016, do not include 484,447 units related to unvested restricted unit awards.

Board Units

On May 15, 2014, Legacy granted and issued 3,628 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 $27.50 at the time of issuance. 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. None of these units were subject to vesting. Legacy recognized the expense associated with the unit grants on the date of grant.

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(14) Subsidiary Guarantors

On October 17, 2014, we 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, our 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 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 our 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.

SUPPLEMENTARY INFORMATION

Costs Incurred in Oil and Natural Gas Property Acquisition and Development Activities

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

	Year Ended December 31,		
	2016	2015	2014
	(In thousands)		
Development costs	$29,499	$36,934	$134,364
Exploration costs	—	—	—
Acquisition costs:			
Proved properties	11,998	598,693	562,649
Unproved properties	24	2,180	24,172
Total acquisition, development and exploration costs	$41,521	$637,807	$721,185

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, 2016, 2015 and 2014. 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, 2016, 2015 and 2014.

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, 2013	57,030	4,075	159,020	87,608
Purchases of minerals-in-place	7,506	8,480	289,523	64,240
Sales of minerals-in-place	(176)	—	(808)	(311)
Extensions and discoveries	—	—	—	—
Revisions from drilling and recompletions	888	33	2,594	1,353
Revisions of previous estimates due to price	(3,110)	371	(969)	(2,901)
Revisions of previous estimates due to performance	(429)	149	(5,449)	(1,188)
Production	(4,784)	(735)	(25,936)	(9,842)
Balance, December 31, 2014	56,925	12,373	417,975	138,959
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)	(35,880)
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)
Revisions from ownership changes	(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
Proved Developed Reserves:				
December 31, 2013	48,775	3,870	139,789	75,943
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
Proved Undeveloped Reserves:				
December 31, 2013	8,255	205	19,231	11,665
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

(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 2014, 2015 and 2016 are described in more detail below.

2014: The increase in proved reserve quantities for the year ended December 31, 2015 was due primarily to our acquisition of producing properties in 7 separate transactions, including the WPX Acquisition. This increase was partially offset by a net decrease in reserves due to the decline in average NYMEX-WTI oil prices during 2015.

2015: The increase in proved reserve quantities for the year ended December 31, 2016 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 2016 which removed a significant part of our PUD inventory.

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.

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, 2016, 2015 and 2014. 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,		
	2016	2015	2014
	(In thousands)		
Future production revenues	$2,814,259	$3,471,519	$7,243,050
Future costs:			
Production	(1,618,241)	(2,015,514)	(3,457,818)
Development	(202,304)	(205,213)	(473,954)
Future net cash flows before income taxes	993,714	1,250,792	3,311,278
10% annual discount for estimated timing of cash flows	(418,088)	(555,851)	(1,556,664)
Standardized measure of discounted net cash flows	$575,626	$694,941	$1,754,614

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,		
	2016	2015	2014
Oil (per Bbl) (a)	$39.25	$46.79	$91.48
Natural Gas (per MMBtu) (b)	$2.48	$2.59	$4.35

(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 2016, 2015 and 2014.

(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 2016, 2015 and 2014.

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

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	Year ended December 31,		
	2016	2015	2014
	(In thousands)		
Increase (decrease):			
Sales, net of production costs	$(120,757)	$(127,905)	$(301,964)
Net change in sales prices, net of production costs	(109,125)	(1,367,523)	(213,617)
Changes in estimated future development costs	99	9,428	64,273
Revisions of previous estimates due to infill drilling, recompletions and stimulations	15,632	24,694	39,228
Revisions of previous quantity estimates due to performance	57,188	38,083	(39,227)
Previously estimated development costs incurred	2,097	14,136	51,085
Purchases of minerals-in-place	294	218,463	472,057
Sales of minerals-in-place	(14,781)	(19,095)	(2,932)
Ownership interest changes	(3,886)	(7,341)	—
Other	(9,028)	(10,854)	(26,758)
Accretion of discount	62,952	168,241	155,489
Net increase (decrease)	(119,315)	(1,059,673)	197,634
Standardized measure of discounted future net cash flows:			
Beginning of year	694,941	1,754,614	1,556,980
End of year	$575,626	$694,941	$1,754,614

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.

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SUPPLEMENTARY INFORMATION — (Continued)

Selected Quarterly Financial Data (Unaudited)

For the three-month periods ended:

	March 31	June 30	September 30	December 31
2016	(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 (loss) 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
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

SUPPLEMENTARY INFORMATION — (Continued)

For the three-month periods ended:

	March 31	June 30	September 30	December 31
2015	(In thousands, except per unit data)			
Revenues:				
Oil sales	$50,296	$59,113	$49,779	$40,653
Natural gas liquids sales	4,192	5,729	2,946	3,778
Natural gas sales	27,051	22,959	36,773	35,510
Total revenues	81,539	87,801	89,498	79,941
Expenses:				
Oil and natural gas production	49,220	45,220	48,446	51,605
Production and other taxes	4,218	3,986	4,834	3,345
General and administrative	8,869	10,390	16,246	11,006
Depletion, depreciation, amortization and accretion	41,068	36,197	45,041	54,952
Impairment of long-lived assets	209,402	—	98,054	326,349
(Gain) loss on disposal of assets	1,941	(934)	560	(5,539)
Total expenses	314,718	94,859	213,181	441,718
Operating loss	(233,179)	(7,058)	(123,683)	(361,777)
Interest income	206	176	(55)	2
Interest expense	(17,792)	(17,760)	(23,351)	(17,988)
Equity in income of equity method investee	79	24	(6)	29
Net gains (losses) on commodity derivatives	20,480	(13,497)	57,000	34,270
Other	605	97	19	120
Loss before income taxes	$(229,601)	$(38,018)	$(90,076)	$(345,344)
Income taxes	747	(456)	(1)	1,208
Net loss	$(228,854)	$(38,474)	$(90,077)	$(344,136)
Distributions to preferred unitholders	$(4,750)	$(4,750)	$(4,750)	$(4,750)
Net loss attributable to unitholders	$(233,604)	$(43,224)	$(94,827)	$(348,886)
Net loss per unit — basic and diluted	$(3.39)	$(0.63)	$(1.38)	$(5.06)
Production volumes:				
Oil (MBbl)	1,200	1,171	1,149	1,088
Natural gas liquids (Mgal)	9,686	11,566	10,084	10,874
Natural gas (MMcf)	9,658	9,649	14,383	16,997
Total (MBoe)	3,040	3,055	3,786	4,180