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

Form 10-K

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

For the fiscal year ended December 31, 2018

☐ **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: 333-225927

Riviera Resources, Inc.

(Exact name of registrant as specified in its charter)

Delaware	**82-5121920**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
600 Travis Street, Suite 1700 **Houston, Texas**	**77002**
(Address of principal executive offices)	*(Zip Code)*

Registrant's telephone number, including area code
(281) 840-4000

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

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

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

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

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

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

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

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

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

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

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

As of June 30, 2018, the last business day of the registrant's most recently completed second quarter, the registrant's common stock was not publicly traded. The registrant's common stock began trading on the OTCQX Market on August 8, 2018.

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

As of January 31, 2019, there were 69,065,373 shares of common stock, par value $0.01 per share, outstanding.

Documents Incorporated By Reference:

Portions of the registrant's definitive proxy statement relating to its 2019 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days after December 31, 2018, are incorporated by reference to the extent set forth in Part III, Items 10-14 of this Annual Report on Form 10-K.

TABLE OF CONTENTS

Glossary of Terms

As commonly used in the oil and natural gas industry and as used in this Annual Report on Form 10-K, the following terms have the following meanings:

Basin. A large area with a relatively thick accumulation of sedimentary rocks.

Bbl. One stock tank barrel or 42 United States gallons liquid volume.

Bcf. One billion cubic feet.

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

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

Development well. A well drilled within the proved area of a 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.

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

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

Formation. A stratum of rock that is recognizable from adjacent strata consisting primarily of a certain type of rock or combination of rock types with thickness that may range from less than two feet to hundreds of feet.

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

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

MBbls/d. MBbls per day.

Mcf. One thousand cubic feet.

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

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

MMBtu. One million British thermal units.

MMcf. One million cubic feet.

MMcf/d. MMcf per day.

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

MMcfe/d. MMcfe per day.

MMMBtu. One billion British thermal units.

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

Glossary of Terms – Continued

NGL. Natural gas liquids, which are the hydrocarbon liquids contained within natural gas.

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

Proved developed reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Proved reserves. Reserves that 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. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

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

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

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

Royalty interest. An interest that entitles the owner of such interest to a share of the mineral production from a property or to a share of the proceeds there from. It does not contain the rights and obligations of operating the property and normally does not bear any of the costs of exploration, development and operation of the property.

Spacing. The number of wells which conservation laws allow to be drilled on a given area of land.

Standardized measure of discounted future net cash flows. The after-tax present value of estimated future net cash flows of proved reserves, determined in accordance with the regulations of the Securities and Exchange Commission and discounted using an annual discount rate of 10%.

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

Unproved reserves. Reserves that are considered less certain to be recovered than proved reserves. Unproved reserves may be further sub-classified to denote progressively increasing uncertainty of recoverability and include probable reserves and possible reserves.

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

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

Zone. A stratigraphic interval containing one or more reservoirs.

Part I

Item 1. Business

This Annual Report on Form 10-K contains forward-looking statements based on expectations, estimates and assumptions as of the date of this filing. These statements by their nature are subject to a number of risks and uncertainties. Actual results may differ materially from those discussed in the forward-looking statements. For more information, see "Cautionary Statement Regarding Forward-Looking Statements" included at the end of this Item 1. "Business" and see also Item 1A. "Risk Factors."

References

Unless otherwise indicated or the context otherwise requires, references herein to the "Company," "we," "our," and "us" refer (i) prior to the Spin-off (as defined below) to Linn Energy, Inc. (the "Parent") and its consolidated subsidiaries, and (ii) after the Spin-off, to Riviera Resources, Inc. ("Riviera") and its consolidated subsidiaries. Unless otherwise indicated or the context otherwise requires, references herein to "LINN Energy" refer to Linn Energy, Inc. and its consolidated subsidiaries. References to "Successor" relate to the financial position and results of operations of the Company subsequent to LINN Energy's emergence from bankruptcy on February 28, 2017. References to "Predecessor" relate to the financial position of the Company prior to, and results of operations through and including February 28, 2018. Riviera is a successor issuer of the Parent pursuant to Rule 15d-5 of the Securities Exchange Act of 1934, as amended (the "Exchange Act").

The reference to a "Note" herein refers to the accompanying Notes to Consolidated and Combined Financial Statements contained in Item 8. "Financial Statements and Supplementary Data."

Overview

In April 2018, the Parent announced its intention to separate Riviera from LINN Energy.

To effect the separation, the Parent and certain of its then direct and indirect subsidiaries undertook an internal reorganization (including the conversion of Riviera Resources, LLC from a limited liability company to a corporation named Riviera Resources, Inc.), following which Riviera holds, directly or through its subsidiaries, substantially all of the assets of LINN Energy, other than LINN Energy's 50% equity interest in Roan Resources LLC ("Roan"). A subsidiary of the Company held the equity interest in Roan until the Parent's internal reorganization on July 25, 2018 (the "Reorganization Date"). Following the internal reorganization, the Parent distributed all of the outstanding shares of Riviera common stock to the Parent's shareholders on a pro rata basis (the "Spin-off"). The Spin-off was completed on August 7, 2018.

Following the Spin-off, Riviera is an independent reporting company quoted for trading on the OTCQX Market under the ticker "RVRA," and the Parent did not retain any ownership interest in Riviera.

Prior to the Spin-off, the accompanying consolidated and combined financial statements were prepared on a stand-alone basis and derived from the Parent's consolidated financial statements and accounting records for the periods presented as the Company was historically managed as a subsidiary of the Parent. After the Spin-off, Riviera is an independent company.

The Company's upstream reporting segment properties are currently located in six operating regions in the United States ("U.S."): the Hugoton Basin, East Texas, Michigan/Illinois, the Mid-Continent, North Louisiana and the Uinta Basin. Proved reserves at December 31, 2018, were approximately 1,618 Bcfe, of which approximately 78% were natural gas, 21% were natural gas liquids ("NGL") and 1% were oil. Approximately 96% were classified as proved developed, with a total standardized measure of discounted future net cash flows of approximately $747 million. In addition, the Company estimates the total discounted future net cash flows of its helium reserves are approximately $110 million, net of income taxes. At December 31, 2018, the Company operated 7,078 or approximately 57% of its 12,354 gross productive wells.

The Blue Mountain reporting segment consists of a state of the art cryogenic natural gas processing facility and a network of gathering pipelines and compressors located in the Merge/SCOOP/STACK play, each of which is owned by Blue Mountain Midstream LLC ("Blue Mountain Midstream"), a wholly owned subsidiary of the Company.

Item 1. Business - Continued

Strategy

Riviera is an independent oil and natural gas company with a strategic focus on efficiently operating its mature low-decline assets, developing its growth-oriented assets, and returning capital to shareholders. Blue Mountain Midstream is an emerging midstream company with assets in central Oklahoma focused on providing its customers with comprehensive natural gas, oil, natural gas liquids, and water solutions in a safe and environmentally sound manner, including gas gathering and processing, water gathering and treatment, and delivery of product to lucrative downstream markets. In the future, Blue Mountain Midstream looks to expand the scale and scope of its service capabilities in the Merge/SCOOP/STACK through organic growth and strategic acquisitions.

Recent Developments

Divestitures

Below are the Company's completed divestitures in 2018:

On April 10, 2018, the Company completed the sale of its conventional properties located in New Mexico. Cash proceeds received from the sale of these properties were approximately $14 million and the Company recognized a net gain of approximately $12 million.

On April 4, 2018, the Company completed the sale of its interest in properties located in the Altamont Bluebell Field in Utah. Cash proceeds received from the sale of these properties were approximately $129 million, net of costs to sell of approximately $2 million, and the Company recognized a net gain of approximately $83 million.

On March 29, 2018, the Company completed the sale of its interest in conventional properties located in west Texas. Cash proceeds received from the sale of these properties were approximately $105 million, net of costs to sell of approximately $2 million, and the Company recognized a net gain of approximately $54 million.

On February 28, 2018, the Company completed the sale of its Oklahoma waterflood and Texas Panhandle properties. Cash proceeds received from the sale of these properties were approximately $108 million (including a deposit of approximately $12 million received in 2017), net of costs to sell of approximately $1 million, and the Company recognized a net gain of approximately $46 million.

Divestiture – Subsequent Event

On January 17, 2019, the Company completed the sale of its interest in properties located in the Arkoma Basin in Oklahoma and received cash proceeds of approximately $65 million (including a deposit of approximately $5 million received in 2018).

Water Services Agreement

On January 31, 2019, the Company entered into an agreement with Roan to exclusively manage all of Roan's water needs for its drilling and completion operations in Central Oklahoma. Blue Mountain Midstream will provide comprehensive water management services including pipeline gathering, disposal, treatment and redelivery of recycled water for re-use. The agreement is supported by a 10-year acreage dedication in 67 Townships covering portions of seven Oklahoma Counties.

Construction of Cryogenic Plant

In July 2017, the Company's subsidiary Blue Mountain Midstream entered into a definitive agreement with BCCK Engineering, Inc. to construct a 225 MMcf/d cryogenic natural gas processing facility with a total capacity of 250 MMcf/d ("Cryo 1"). The facility was successfully commissioned in the second quarter of 2018.

In August 2018, the Company's Board of Directors (the "Board") approved Blue Mountain Midstream's plan to initiate the engineering and design of a second cryogenic natural gas processing plant ("Cryo 2") servicing the Merge/SCOOP/STACK play in central Oklahoma. Blue Mountain Midstream has completed the conceptual engineering and design for Cryo 2 and has the ability to execute on Cryo 2 quickly if the election is eventually made to proceed.

Item 1. Business - Continued

2018 Oil and Natural Gas and Midstream Capital Expenditures

During the year ended December 31, 2018, the Company had total capital expenditures, excluding acquisitions, of approximately $170 million, including approximately $36 million related to its oil and natural gas capital program and approximately $125 million related to Blue Mountain Midstream.

2019 Oil and Natural Gas Capital Budget

For 2019, the Company estimates its total capital expenditures, excluding acquisitions and Blue Mountain, will be approximately $66 million, including approximately $61 million related to its oil and natural gas capital program. This estimate is under continuous review and subject to ongoing adjustments.

Financing Activities

Blue Mountain Credit Facility
On August 10, 2018, Blue Mountain Midstream entered into a credit agreement with Royal Bank of Canada, as administrative agent, and the lenders and agents party thereto, providing for a new senior secured revolving loan facility (the “Blue Mountain Credit Facility” and together with Riviera Credit Facility, the “Credit Facilities”), providing for an initial borrowing commitment of $200 million.

Before Blue Mountain Midstream completes certain operational milestones (such completion of the operational milestones, the “Covenant Changeover Date”), a condition to any borrowing is that Blue Mountain Midstream’s consolidated total indebtedness to capitalization ratio (the “Debt/Cap Ratio”) be not greater than 0.35 to 1.00 upon giving effect to such borrowing. As such, prior to the Covenant Changeover Date, the available borrowing capacity under the Blue Mountain Credit Facility may be less than the aggregate amount of the lenders’ commitments at such time. On and after the Covenant Changeover Date, Blue Mountain Midstream will no longer have to comply with the Debt/Cap Ratio as a condition to drawing and may borrow up to the total amount of the lenders’ aggregate commitments. The Blue Mountain Credit Facility also provides for the ability to increase the aggregate commitments of the lenders to up to $400 million after the Covenant Changeover Date, subject to obtaining commitments for any such increase, which may result in an increase in Blue Mountain Midstream’s available borrowing capacity. As of December 31, 2018, total borrowings outstanding under the Blue Mountain Credit Facility were $4.5 million and there was approximately $72 million of available borrowing capacity (in addition, there was $12 million of outstanding letters of credit). The Covenant Changeover Date occurred February 8, 2019, which increased the current borrowing commitment to $200 million. At February 28, 2019, total borrowings outstanding under the Blue Mountain Credit Facility were approximately $19 million and there was approximately $169 million of available borrowing capacity (which includes a $12 million reduction for outstanding letters of credit). The Blue Mountain Credit Facility matures on August 10, 2023.

Share Repurchase Program
On August 16, 2018, the Board authorized the repurchase of up to $100 million of the Company’s outstanding shares of common stock. During the period from August 2018 through December 31, 2018, the Company repurchased an aggregate of 945,979 shares of common stock at an average price of $19.21 per share for a total cost of approximately $18 million. For the period from January 1, 2019 through February 22, 2019, the Company repurchased 221,788 shares of common stock at an average price of $15.27 for a total cost of approximately $3 million. At February 22, 2019, approximately $78 million was available for share repurchase under the program.

In accordance with the SEC’s regulations regarding issuer tender offers, the Company’s share repurchase program was suspended concurrent with the September 24, 2018, announcement of the intent to commence a tender offer. The program was resumed in November 2018 following the expiration of the tender offer.

Any share repurchases are subject to restrictions in the Company’s senior secured reserve-based revolving loan facility (the “Riviera Credit Facility”).

Tender Offer
On September 24, 2018, the Company announced the intention to commence a tender offer to purchase $100 million of the Company’s common stock. In October 2018, upon the terms and subject to the conditions described in the Offer to Purchase dated September 25, 2018, as amended, the Company repurchased an aggregate of 6,062,179 shares of common stock at a

price of $22.00 per share for a total cost of approximately $133 million (excluding expenses of approximately $2 million related to the tender offer).

Upstream Segment Operating Regions

The Company's upstream segment properties are located in six operating regions in the U.S.:

- Hugoton Basin, which includes oil and natural gas properties, as well as the Jayhawk natural gas processing plant, located in Kansas;
- East Texas, which includes oil and natural gas properties producing primarily from the Travis Peak, Cotton Valley and Bossier formations;
- Michigan/Illinois, which includes properties producing from the Antrim Shale formation located in northern Michigan and oil properties in southern Illinois;
- Mid-Continent, which includes properties in the Northwest STACK in northwestern Oklahoma and various other oil and natural gas producing properties throughout Oklahoma;
- North Louisiana, which includes oil and natural gas properties producing primarily from the Hosston, Cotton Valley Bossier and Smackover formations; and
- Uinta Basin, which includes non-operated properties located in the Dunkards Wash field in Utah (which was included in the Company's previous Rockies operating region).

Historically, a subsidiary of the Company also owned a 50% equity interest in Roan. The Company's equity earnings (losses), consisting of its share of Roan's earnings or losses, are included in the consolidated financial statements through the Reorganization Date. However, on the Reorganization Date, the equity interest in Roan was distributed to the Parent and is no longer affiliated with Riviera. As such, the Company has classified the investment and equity earnings (losses) in Roan as discontinued operations on its consolidated financial statements. See Note 4 for additional information.

During 2018, the Company divested all of its properties located in the previous Permian Basin operating region. During 2017, the Company divested all of its properties located in the previous California and South Texas operating regions. As a result of the Company's strategic exit from California in 2017 (completed by the sale of its interest in properties located in the San Joaquin Basin and the Los Angeles Basin in California), the Company classified the results of operations and cash flows of its California properties as discontinued operations on its consolidated and combined financial statements. See below and Note 4 for details of the Company's divestitures.

Hugoton Basin

The Hugoton Basin is a large oil and natural gas producing area located in southwest Kansas. The Company's Hugoton Basin properties primarily produce from the Council Grove and Chase formations at depths ranging from 2,200 feet to 3,100 feet. The Company's properties in this region are primarily mature, low-decline natural gas wells.

The Company also owns and operates the Jayhawk natural gas processing plant in southwest Kansas with a capacity of approximately 450 MMcf/d, allowing it to receive maximum value from the liquids-rich natural gas produced in the area. The Company's production in the area is delivered to the plant via a system of approximately 3,120 miles of pipeline and related facilities operated by the Company, of which approximately 1,005 miles of pipeline are owned by the Company.

Hugoton Basin proved reserves represented approximately 50% of total proved reserves at December 31, 2018, all of which were classified as proved developed. This region produced approximately 138 MMcfe/d of the Company's 2018 average daily production. During 2018, the Company invested approximately $5 million for plant and pipeline construction activities in this region.

East Texas

The East Texas region consists of properties located in east Texas primarily producing natural gas from the Travis Peak, Cotton Valley and Bossier formations at depths ranging from 7,000 feet to 12,500 feet. The Company's properties in this region are primarily mature, low-decline natural gas wells. To more efficiently transport its natural gas in east Texas to market, the Company owns and operates a network of natural gas gathering systems comprised of approximately 590 miles of pipeline and associated compression and metering facilities that connect to numerous sales outlets in the area.

East Texas proved reserves represented approximately 17% of total proved reserves at December 31, 2018, of which 88% were classified as proved developed. This region produced approximately 50 MMcfe/d of the Company's 2018 average daily production. During 2018, the Company invested approximately $2 million to develop the properties in this region and approximately $2 million in exploration activity.

Michigan/Illinois

The Michigan/Illinois region consists primarily of natural gas properties in the Antrim Shale formation in north Michigan and oil properties in south Illinois. These wells produce at depths ranging from 500 feet to 4,000 feet. To more efficiently transport its natural gas in Michigan to market, the Company owns and operates a network of natural gas gathering systems comprised of approximately 1,480 miles of pipeline and associated compression and metering facilities that connect to numerous sales outlets in the area.

Michigan/Illinois proved reserves represented approximately 14% of total proved reserves at December 31, 2018, all of which were classified as proved developed. This region produced approximately 28 MMcfe/d of the Company's 2018 average daily production. During 2018, the Company invested approximately $1 million to develop the properties in this region.

Mid-Continent

The Mid-Continent region consists of properties located in the Northwest STACK, as well as other Oklahoma properties. The Company's properties in this diverse region produce from both oil and natural gas reservoirs at depths ranging from 3,500 feet to 19,000 feet.

Mid-Continent proved reserves represented approximately 11% of total proved reserves at December 31, 2018, all of which were classified as proved developed. This region produced approximately 53 MMcfe/d of the Company's 2018 average daily production. During 2018, the Company invested approximately $10 million to develop the properties in this region and approximately $15 million in exploration activity.

North Louisiana

The North Louisiana region consists of properties located in north Louisiana and primarily producing natural gas from the Hosston, Cotton Valley, Bossier and Smackover formations at depths ranging from 7,000 feet to 12,500 feet.

North Louisiana proved reserves represented approximately 5% of total proved reserves at December 31, 2018, of which 64% were classified as proved developed. This region produced approximately 26 MMcfe/d of the Company's 2018 average daily production. During 2018, the Company invested approximately $2 million to develop the properties in this region.

Uinta Basin

The Uinta Basin region consists of non-operated properties located in the Drunkards Wash field in Utah. The Uinta Basin properties were included in the Company's previous Rockies operating region. During 2017 and 2018, the Company divested its Rockies region properties located in Wyoming (Green River, Washakie and Powder River basins), North Dakota (Williston Basin) and certain Utah properties (Altamont Bluebell Field in the Uinta Basin).

Uinta Basin proved reserves represented approximately 3% of total proved reserves at December 31, 2018, all of which were classified as proved developed. The Uinta Basin region produced approximately 23 MMcfe/d of the Company's 2018 average daily production. During 2018, the Company invested approximately $4 million to develop the properties in the Uinta Basin region.

Blue Mountain Segment

Blue Mountain Midstream currently provides natural gas gathering, compression and processing services to producers in the Merge/SCOOP/Stack play in the Mid-Continent Region of Oklahoma. Blue Mountain Midstream's assets primarily consist of the state of the art 250 MMcf/d design-capacity Cryo 1 natural gas plant as well as a network of natural gas gathering pipelines and compressors (collectively, the "Blue Mountain System"). The Cryo 1 natural gas plant was successfully commissioned in the second quarter of 2018. As of July 2018, the plant had an initial design capacity of approximately 150 MMcf/d of processing capacity. In the fourth quarter of 2018, Blue Mountain Midstream commissioned 25,000 horsepower compression at its Cryo 1, increasing the processing capacity to the full 250 MMcf/d. Blue Mountain Midstream's gathering and processing agreements for its gathering and processing system include long-term, fee-based or percent of proceeds contracts. Based on Blue Mountain Midstream's contracts it gathers natural gas and NGLs from the producers which it then processes and delivers to third party customers.

Blue Mountain Midstream is aggressively pursuing growth to its midstream business primarily in Oklahoma. Additions to the Blue Mountain System are continually underway adding low and high-pressure gathering pipelines and interconnections that will accommodate incremental volume throughput. During 2018, the Blue Mountain Midstream invested approximately $125 million for plant and pipeline construction activities primarily associated with the Blue Mountain System.

Blue Mountain Midstream has completed the conceptual engineering and design for Cryo 2 and has the ability to execute on Cryo 2 quickly if the election is eventually made to proceed.

Drilling and Acreage

The following table sets forth the wells drilled during the years indicated:

	Year Ended December 31,		
	2018	**2017**	**2016**
Gross wells:			
Productive	52	90	211
Dry	—	—	1
	52	90	212
Net development wells:			
Productive	1	12	26
Dry	—	—	—
	1	12	26
Net exploratory wells:			
Productive	2	9	7
Dry	—	—	—
	2	9	7

There were no lateral segments added to existing vertical wellbores during the years ended December 31, 2018, December 31, 2017, or December 31, 2016. As of December 31, 2018, the Company had 21 gross (4 net) wells in progress, and no wells were temporarily suspended.

This information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled and the quantities or economic value of reserves found. Productive wells are those that produce commercial quantities of oil, natural gas or NGL, regardless of whether they generate a reasonable rate of return.

Productive Wells

The following table sets forth information relating to the productive wells in which the Company owned a working interest as of December 31, 2018. Productive wells consist of producing wells and wells capable of production, including wells

Item 1. Business - Continued

awaiting pipeline or other connections to commence deliveries. The number of wells below does not include approximately 2,620 gross productive wells in which the Company owns a royalty interest only.

	Natural Gas Wells		Oil Wells		Total Wells (1)	
	Gross	Net	Gross	Net	Gross	Net
Operated (2)	6,893	6,077	185	144	7,078	6,221
Nonoperated (3)	5,141	1,838	135	20	5,276	1,858
	12,034	7,915	320	164	12,354	8,079

(1) Includes 424 gross and 138 net wells divested in 2019.

(2) The Company had five operated wells with multiple completions at December 31, 2018.

(3) The Company had one nonoperated wells with multiple completions at December 31, 2018.

Developed and Undeveloped Acreage

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

	Developed Acreage		Undeveloped Acreage		Total Acreage (1)	
	Gross	Net	Gross	Net	Gross	Net
			(in thousands)			
Leasehold acreage	3,170	1,912	38	13	3,208	1,925

(1) Includes approximately 81,000 gross and 39,000 net acres divested in 2019.

Future Acreage Expirations

The Company's investment in developed and undeveloped acreage comprises numerous leases. The terms and conditions under which the Company maintains exploration or production rights to the acreage are property-specific, contractually defined and vary significantly from property to property. If production is not established or the Company takes no other action to extend the terms of the related leases, undeveloped acreage will expire. The Company currently has no material undeveloped acreage due to expire during the next three years.

Programs are designed to ensure that the exploration potential of any property is fully evaluated before expiration. In some instances, the Company may elect to relinquish acreage in advance of the contractual expiration date if the evaluation process is complete and there is not a business basis for extension. In cases where additional time may be required to fully evaluate acreage, the Company has generally been successful in obtaining extensions. The Company utilizes various methods to manage the expiration of leases, including drilling the acreage prior to lease expiration or extending lease terms.

Production, Price and Cost History

The Company's natural gas production is primarily sold under short-term market-sensitive contracts that are typically priced at a differential to the published natural gas index price for the producing area due to the natural gas quality and the proximity to major consuming markets. In certain circumstances, the Company has entered into natural gas processing contracts whereby the residue natural gas is sold under short-term contracts but the related NGL are sold under long-term contracts. In all such cases, the residue natural gas and NGL are sold at market-sensitive index prices. As of December 31, 2018, the Company had no natural gas or NGL delivery commitments under a long-term contracts.

The Company's natural gas production is sold to purchasers under spot price contracts, percentage-of-index contracts or percentage-of-proceeds contracts. Under percentage-of-index contracts, the Company receives a price for natural gas and NGL based on indexes published for the producing area. Under percentage-of-proceeds contracts, the Company receives a percentage of the resale price received by the purchaser for sales of residue natural gas and NGL recovered after transportation and processing of natural gas. These purchasers sell the residue natural gas and NGL based primarily on spot market prices.

Item 1. Business - Continued

The Company's natural gas is transported through its own and third-party gathering systems and pipelines. The Company incurs processing, gathering and transportation expenses to move its natural gas from the wellhead to a purchaser specified delivery point. These expenses vary based on the volume, distance shipped and the fee charged by the third-party processor or transporter.

The Company's oil production is primarily sold under short-term market-sensitive contracts that are typically priced at a differential to the New York Mercantile Exchange ("NYMEX") price or at purchaser posted prices for the producing area. As of December 31, 2018, the Company had no oil delivery commitments under long-term contracts.

The following table sets forth information regarding total production, average daily production, average prices and average costs for each of the years indicated:

	Successor		Predecessor	
	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
Total production:				
Natural gas (MMcf)	90,091	118,110	29,223	187,068
Oil (MBbls)	1,186	5,442	1,191	8,088
NGL (MBbls)	3,762	6,287	1,263	9,281
Total (MMcfe)	119,781	188,481	43,945	291,285
Average daily production:				
Natural gas (MMcf/d)	247	386	495	511
Oil (MBbls/d)	3.2	17.8	20.2	22.1
NGL (MBbls/d)	10.3	20.5	21.4	25.4
Total (MMcfe/d)	328	616	745	796
Weighted average prices: (1)				
Natural gas (Mcf)	$ 2.78	$ 2.69	$ 3.41	$ 2.28
Oil (Bbl)	$ 62.99	$ 47.42	$ 49.16	$ 39.00
NGL (Bbl)	$ 25.14	$ 21.28	$ 24.37	$ 14.26
Average NYMEX prices:				
Natural gas (MMBtu)	$ 3.09	$ 3.00	$ 3.66	$ 2.46
Oil (Bbl)	$ 64.77	$ 50.53	$ 53.04	$ 43.32
Costs per Mcfe of production:				
Lease operating expenses	$ 1.00	$ 1.11	$ 1.13	$ 1.02
Transportation expenses	$ 0.70	$ 0.60	$ 0.59	$ 0.55
General and administrative expenses (2)	$ 2.05	$ 0.62	$ 1.63	$ 0.82
Depreciation, depletion and amortization	$ 0.79	$ 0.71	$ 1.07	$ 1.18
Taxes, other than income taxes	$ 0.25	$ 0.25	$ 0.34	$ 0.23
Total production – discontinued operations:				
Equity method investment – Total (MMcfe) (3)	23,355	9,235	—	—
California – Total (MMcfe) (4)	—	4,326	1,755	11,849

(1) Does not include the effect of gains (losses) on derivatives.

(2) General and administrative expenses for the year ended December 31, 2018, the ten months ended December 31, 2017, the two months ended February 28, 2017, and the year ended December 31, 2016, include approximately $132 million, $41 million, $50 million and $34 million, respectively, of share-based compensation expenses and approximately $27 million, $2 million, $787,000 and $2 million, respectively of severance costs. General and administrative expenses for the year ended December 31, 2018, include

approximately $8 million of Spin-off related costs. In addition, general and administrative expenses for the two months ended February 28, 2017, and the year ended December 31, 2016, include expenses incurred by LINN Energy associated with the operations of Berry. On February 28, 2017, LINN Energy and Berry emerged from bankruptcy as stand-alone, unaffiliated entities.

(3) Represents the Company’s historical 50% equity interest in Roan. Production of Roan for 2018 is for the period from January 1, 2018 through July 25, 2018. Production of Roan for 2017 is for the period from September 1, 2017 through December 31, 2017.

(4) Total production of the Company’s California properties reported as discontinued operations for 2017 is for the period from January 1, 2017 through July 31, 2017.

The following table sets forth information regarding production volumes for fields with greater than 15% of the Company’s total proved reserves for each of the years indicated:

	Year Ended December 31,		
	2018	**2017**	**2016**
Total production:			
Hugoton Basin Field:			
Natural gas (MMcf)	33,510	34,363	38,501
Oil (MBbls)	24	45	27
NGL (MBbls)	2,581	2,968	2,983
Total (MMcfe)	49,137	52,437	56,566
East Texas Basin:			
Natural gas (MMcf)	17,355	*	*
Oil (MBbls)	66	*	*
NGL (MBbls)	113	*	*
Total (MMcfe)	18,432	*	*
Green River Basin Field:			
Natural gas (MMcf)	*	*	44,668
Oil (MBbls)	*	*	477
NGL (MBbls)	*	*	1,349
Total (MMcfe)	*	*	55,625

* Represented less than 15% of the Company’s total proved reserves for the year indicated. The Company sold its properties in the Green River Basin Field in May 2017.

Reserve Data

Proved Reserves

The following table sets forth estimated proved oil, natural gas and NGL reserves and the standardized measure of discounted future net cash flows at December 31, 2018, based on reserve reports prepared by independent engineers, DeGolyer and MacNaughton:

	Proved Reserves			
	Natural Gas (Bcf)	**Oil (MMBbls)**	**NGL (MMBbls)**	**Total (Bcfe)**
Proved reserves:				
Proved developed reserves	1,203	4	55	1,553
Proved undeveloped reserves	57	—	1	65
Total proved reserves	1,260	4	56	1,618

Standardized measure of discounted future net cash flows (in millions) (1)	$	747
Representative NYMEX prices: (2)		
Natural gas (MMBtu)	$	3.10
Oil (Bbl)	$	65.66

(1) This measure is not intended to represent the market value of estimated reserves.

(2) In accordance with Securities and Exchange Commission ("SEC") regulations, reserves were estimated using the average price during the 12-month period, determined as an unweighted average of the first-day-of-the-month price for each month, excluding escalations based upon future conditions. The average price used to estimate reserves is held constant over the life of the reserves.

During the year ended December 31, 2018, the Company's PUDs increased to 65 Bcfe from 60 Bcfe at December 31, 2017, representing an increase of approximately 5 Bcfe. The increase was primarily due to revisions as a result of additional PUD locations being added. During the year ended December 31, 2018, the Company did not convert any reserves that were classified as PUDs at December 31, 2017, to proved developed reserves.

Based on the December 31, 2018, reserve reports, the amounts of capital expenditures estimated to be incurred in 2019, 2020 and 2021 to develop the Company's PUDs are approximately $5 million, $5 million and $40 million, respectively. The amount and timing of these expenditures will depend on a number of factors, including actual drilling results, service costs and product prices. None of the 65 Bcfe of PUDs at December 31, 2018, has remained undeveloped for five years or more. All PUD properties are included in the Company's current five-year development plan.

Reserve engineering is inherently a subjective process of estimating underground accumulations of oil, natural gas and NGL that cannot be measured exactly. The accuracy of any reserve estimate is a function of the quality of available data and engineering and geological interpretation and judgment. Accordingly, reserve estimates may vary from the quantities of oil, natural gas and NGL that are ultimately recovered. Future prices received for production may vary, perhaps significantly, from the prices assumed for the purposes of estimating the standardized measure of discounted future net cash flows. The standardized measure of discounted future net cash flows should not be construed as the market value of the reserves at the dates shown. The 10% discount factor required to be used under the provisions of applicable accounting standards may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with the Company or the oil and natural gas industry. The standardized measure of discounted future net cash flows is materially affected by assumptions regarding the timing of future production, which may prove to be inaccurate.

The reserve estimates reported herein were prepared by independent engineers, DeGolyer and MacNaughton. The process performed by the independent engineers to prepare reserve amounts included their estimation of reserve quantities, future production rates, future net revenue and the present value of such future net revenue, based in part on data provided by the Company. When preparing the reserve estimates, the independent engineering firm did not independently verify the accuracy and completeness of the information and data furnished by the Company with respect to ownership interests, production, well test data, historical costs of operation and development, product prices, or any agreements relating to current and future operations of the properties and sales of production. However, if in the course of their work, something came to their attention that brought into question the validity or sufficiency of any such information or data, they did not rely on such information or data until they had satisfactorily resolved their questions relating thereto. The estimates of reserves conform to the guidelines of the SEC, including the criteria of "reasonable certainty," as it pertains to expectations about the recoverability of reserves in future years. The independent engineering firm also prepared estimates with respect to reserve categorization, using the definitions of proved reserves set forth in Regulation S-X Rule 4-10(a) and subsequent SEC staff interpretations and guidance.

The Company's internal control over the preparation of reserve estimates is a process designed to provide reasonable assurance regarding the reliability of the Company's reserve estimates in accordance with SEC regulations. The preparation of reserve estimates was overseen by the Company's Director of Reserves and Business Development who has a Master of Petroleum Engineering degree and 10 years of oil and natural gas industry experience. The reserve estimates were reviewed and approved by the Company's senior engineering staff and management, with final approval by its Executive Vice President and Chief Operating Officer. For additional information regarding estimates of reserves, including the standardized measure of discounted future net cash flows, see "Supplemental Oil and Natural Gas Data (Unaudited)" in Item 8. "Financial Statements and Supplementary Data." The Company has not filed reserve estimates with any federal authority or agency, with the exception of the SEC.

Operational Overview

General

The Company generally seeks to be the operator of its properties so that it can develop drilling programs and optimization projects intended to not only replace production, but also to add value through reserve and production growth and future operational synergies. Many of the Company's wells are completed in multiple producing zones with commingled production and long economic lives.

Principal Customers

For the year ended December 31, 2018, sales to ONEOK Hydrocarbon, L.P. accounted for approximately 22% of the Company's total revenues. If the Company were to lose any one of its major oil and natural gas purchasers, the loss could temporarily cease or delay production and sale of its oil and natural gas in that particular purchaser's service area. If the Company were to lose a purchaser, it believes it could identify a substitute purchaser. However, if one or more of the large purchasers ceased purchasing oil and natural gas altogether, it could have a detrimental effect on the oil and natural gas market in general and on the prices and volumes of oil, natural gas and NGL that the Company is able to sell.

Competition

The oil and natural gas industry is highly competitive. The Company encounters strong competition from other independent operators in contracting for drilling and other related services, as well as hiring trained personnel. The Company is also affected by competition for drilling rigs and the availability of related equipment. In the past, the oil and natural gas industry has experienced shortages of drilling rigs, equipment, pipe and personnel, which has delayed development drilling and has caused significant price increases. The Company is unable to predict when, or if, such shortages may occur or how they would affect its drilling program.

Operating Hazards and Insurance

The oil and natural gas industry involves a variety of operating hazards and risks that could result in substantial losses from, among other things, injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, cleanup responsibilities, regulatory investigation and penalties, and suspension of operations. The Company may be liable for environmental damages caused by previous owners of property it purchases and leases. As a result, the Company may incur substantial liabilities to third parties or governmental entities, the payment of which could reduce or eliminate funds otherwise available, or result in the loss of properties. In addition, the Company participates in wells on a non-operated basis, and therefore may be limited in its ability to control the risks associated with the operation of such wells.

In accordance with customary industry practices, the Company maintains insurance against some, but not all, potential losses. The Company cannot provide assurance that any insurance it obtains will be adequate to cover any losses or liabilities. The Company has elected to self-insure for certain items for which it has determined that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event not fully covered by insurance could have a material adverse effect on the Company's financial position, results of operations and cash flows. For more information about potential risks that could affect the Company, see Item 1A. "Risk Factors."

Title to Properties

Prior to the commencement of drilling operations, the Company conducts a title examination and performs curative work with respect to significant defects. To the extent title opinions or other investigations reflect title defects on those properties, the Company is typically responsible for curing any title defects at its expense prior to commencing drilling operations. Prior to completing an acquisition of producing leases, the Company performs title reviews on the most significant leases and, depending on the materiality of properties, the Company may obtain a title opinion or review previously obtained title opinions. As a result, the Company has obtained title opinions on a significant portion of its properties and believes that it has satisfactory title to its producing properties in accordance with standards generally accepted in the industry.

Item 1. Business - Continued

Seasonality and Cyclicality

Seasonal weather conditions and lease stipulations can limit the drilling and producing activities and other operations in regions of the U.S. in which the Company operates. These seasonal conditions can pose challenges for meeting the well drilling objectives and increase competition for equipment, supplies and personnel, which could lead to shortages and increase costs or delay operations. For example, the Company's operations may be impacted by ice and snow in the winter and by electrical storms and high temperatures in the spring and summer, as well as by wild fires in the fall.

The demand for natural gas typically decreases during the summer months and increases during the winter months. Seasonal anomalies sometimes lessen this fluctuation. In addition, certain natural gas consumers utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer, which can also lessen seasonal demand fluctuations.

Environmental Matters and Regulation

The Company's operations are subject to stringent federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. The Company's operations are subject to the same environmental laws and regulations as other companies in the oil and natural gas industry. These laws and regulations may:

- require the acquisition of various permits before drilling commences;
- require notice to stakeholders of proposed and ongoing operations;
- require the installation of expensive pollution control equipment;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities;
- limit or prohibit drilling activities on lands located within wilderness, wetlands, areas inhabited by endangered species and other protected areas;
- require remedial measures to prevent pollution from former operations, such as pit closure, reclamation and plugging and abandonment of wells;
- impose substantial liabilities for pollution resulting from operations; and
- require preparation of a Resource Management Plan, an Environmental Assessment, and/or an Environmental Impact Statement with respect to operations affecting federal lands or leases.

These laws and regulations may also restrict the production rate of oil, natural gas and NGL below the rate that would otherwise be possible. The regulatory burden on the industry increases the cost of doing business and consequently affects profitability. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary fines or penalties, the imposition of investigatory or remedial requirements, and the issuance of orders enjoining future operations. Moreover, accidental releases or spills may occur in the course of the Company's operations, which may result in significant costs and liabilities, including third-party claims for damage to property, natural resources or persons. Additionally, Congress and federal and state agencies frequently revise environmental laws and regulations, and any changes that result in more stringent and costly requirements for the oil and natural gas industry could have a significant impact on operating costs.

The environmental laws and regulations applicable to the Company and its operations include, among others, the following U.S. federal laws and regulations:

- Clean Air Act, which governs air emissions;
- Clean Water Act ("CWA"), which governs discharges to and excavations within the waters of the U.S.;
- Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), which imposes liability where hazardous releases have occurred or are threatened to occur (commonly known as "Superfund");
- The Oil Pollution Act of 1990, which amends and augments the CWA and imposes certain duties and liabilities related to the prevention of oil spills and damages resulting from such spills;
- Energy Independence and Security Act of 2007, which prescribes new fuel economy standards and other energy saving measures;
- National Environmental Policy Act, which governs oil and natural gas production activities on federal lands;
- Resource Conservation and Recovery Act ("RCRA"), which governs the management of solid waste;

Item 1. Business - Continued

- Safe Drinking Water Act (“SDWA”), which governs the underground injection and disposal of wastewater;
- Endangered Species Act (“ESA”), which restricts activities that may affect endangered and threatened species or their habitats; and
- U.S. Department of Interior regulations, which impose liability for pollution cleanup and damages.

Various states regulate the drilling for, and the production, gathering and sale of, oil, natural gas and NGL, including imposing production taxes and requirements for obtaining drilling permits. States also regulate the method of developing new fields, the spacing and operation of wells and the prevention of waste of resources. States may regulate rates of production and may establish maximum daily production allowables from wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulations, 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 oil, natural gas and NGL that may be produced from the Company’s wells and to limit the number of wells or locations it can drill. The oil and natural gas industry is also subject to compliance with various other federal, state and local regulations and laws. Some of those laws relate to occupational safety, resource conservation and equal opportunity employment.

The Company believes that it substantially complies with all current applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on its business, financial condition, results of operations or cash flows. Future regulatory issues that could impact the Company includes new rules or legislation relating to the items discussed below.

Climate Change

In December 2009, the United States Environmental Protection Agency (“EPA”) determined that emissions of carbon dioxide, methane and other “greenhouse gases” (“GHG”) present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth’s atmosphere and other climatic changes. Based on these findings, the EPA has adopted and implemented regulations to restrict emissions of GHGs under existing provisions of the Clean Air Act. In May 2016, the EPA finalized rules that set additional emissions limits for volatile organic compounds and established new controls for emissions of methane from new, modified or reconstructed sources in the oil and natural gas source category, including production, processing, transmission and storage activities. The rules include first-time standards to address emissions of methane from equipment and processes across the source category, including hydraulically fractured oil and natural gas well completions. However, in September 2018, under a new administration, the EPA proposed amendments that would relax requirements of these rules. In addition, in April 2018, a coalition of states filed a lawsuit in federal district court aiming to force the EPA to establish guidelines for limiting methane emissions from existing sources in the oil and natural gas sector; that lawsuit is pending. The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the U.S., including certain onshore oil and natural gas production facilities, on an annual basis.

On an international level, the U.S. was one of 175 countries to sign an international climate change agreement in Paris, France that requires member countries to set their own GHG emission reduction goals beginning in 2020 (the “Paris Agreement”). However, on June 1, 2017, President Trump announced that the U.S. would withdraw from the Paris Agreement. It is not clear what steps the Trump Administration plans to take to withdraw from the Paris Agreement, whether a new agreement can be negotiated, or what terms would be included in such an agreement. Certain U.S. city and state governments have announced their intention to satisfy their proportionate obligations under the Paris Agreement. In addition, legislation has from time to time been introduced in Congress that would establish measures restricting GHG emissions in the U.S., and a number of states have begun taking actions to control and/or reduce emissions of GHGs.

Any legislation or regulatory programs to reduce GHG emissions could increase the cost of consuming, and thereby reduce demand for, the oil and natural gas the Company produces. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on the Company’s business, financial condition and results of operations. Moreover, incentives to conserve energy or use alternative energy sources as a means of addressing climate change could reduce demand for the oil and natural gas the Company produces. In addition, parties concerned about the potential effects of climate change have directed their attention at sources of funding for energy companies, which has resulted in certain financial institutions, funds and other sources of capital, restricting or eliminating their investment in oil and natural gas activities. Finally, most 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 adversely affect or delay demand for the oil or natural gas produced or cause the Company to incur significant costs in preparing for or responding to those effects.

Hydraulic Fracturing

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The Company performs hydraulic fracturing as part of its operations. Hydraulic fracturing operations have historically been overseen by state regulators as part of their oil and natural gas regulatory programs. However, in February 2014, the EPA published permitting guidance under the SDWA addressing the use of diesel in fracturing hydraulic operations, and in May 2014, the EPA issued an advance notice of proposed rulemaking under the Toxic Substances Control Act ("TSCA") relating to chemical substances and mixtures used in oil and natural gas exploration or production. Further, in March 2015, the Department of the Interior's Bureau of Land Management ("BLM") adopted a rule requiring, among other things, public disclosure to the BLM of chemicals used in hydraulic fracturing operations after fracturing operations have been completed and strengthening standards for well-bore integrity and management of fluids that return to the surface during and after fracturing operations on federal and Indian lands. Following years of litigation, the BLM rescinded the rule in December 2017; however that rescission has been challenged by several environmental groups and states in ongoing litigation. In addition, from time to time legislation has been introduced before Congress that would provide for federal regulation of hydraulic fracturing and would require disclosure of the chemicals used in the fracturing process. If enacted, these or similar laws or regulations could result in additional permitting requirements for hydraulic fracturing operations as well as various restrictions on those operations. These permitting requirements and restrictions could result in delays in operations at well sites and also increased costs to make wells productive.

There may be other attempts to further regulate hydraulic fracturing under the SDWA, TSCA and/or other statutory or regulatory mechanisms. In December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources, concluding that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources under certain circumstances. Moreover, some states and local governments have adopted, and other states and local governments are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances. For example, many states in which the Company operates have adopted disclosure regulations requiring varying degrees of disclosure of the constituents in hydraulic fracturing fluids. In addition, the regulation or prohibition of hydraulic fracturing is the subject of significant political activity in a number of jurisdictions, some of which have resulted in tighter regulation, bans, and/or recognition of local government authority to implement such restrictions. In many instances, litigation has ensued, some of which remains pending. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for the Company to perform fracturing to stimulate production from tight formations. In addition, any such additional regulation could lead to operational delays, increased operating costs and additional regulatory burdens, and reduced production of oil and natural gas, which could adversely affect the Company's revenues, results of operations and net cash provided by operating activities.

Hydraulic fracturing operations require the use of a significant amount of water. The Company's inability to locate sufficient amounts of water, or dispose of or recycle water used in its drilling and production operations, could adversely impact its operations. Moreover, new environmental initiatives and regulations could include restrictions on the Company's ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the development or production of natural gas.

The Company disposes of wastewater generated from oil and natural gas production operations, including hydraulic fracturing operations, directly or through the use of third parties. In some instances, the operation of underground injection or large volume disposal wells has been alleged to cause earthquakes in some of the states where the Company operates. Such issues have sometimes led to orders prohibiting continued injection or disposal or the suspension of drilling in certain wells identified as possible sources of seismic activity. Such concerns also have resulted in stricter regulatory requirements in some jurisdictions relating to the location and operation of underground injection wells. For example, Oklahoma issued rules for wastewater disposal wells that imposed certain permitting and operating restrictions, required additional seismicity protocols in certain defined areas, and from time to time, directs certain injection wells in proximity to seismic events to restrict or suspend operations. Future orders or regulations addressing concerns about seismic activity from well injection or water disposal could affect the Company, either directly or indirectly, depending on the wells affected, which materially affect its capital expenditures and operating costs.

Item 1. Business - Continued

Solid and Hazardous Waste

Although oil and natural gas wastes generally are exempt from regulation as hazardous wastes under RCRA and some comparable state statutes, it is possible some wastes the Company generates presently or in the future may be subject to regulation under RCRA or other applicable statutes. The EPA and various state agencies have limited the disposal options for certain wastes, including hazardous wastes, and there is no guarantee that the EPA or the states will not adopt more stringent requirements in the future. For example, in December 2016, the EPA and several environmental groups entered into a consent decree to address the EPA's alleged failure to timely assess its regulations exempting certain exploration and production related oil and gas wastes from regulation as hazardous wastes under RCRA. The consent decree requires the EPA to propose a rulemaking no later than March 15, 2019, for revision of certain regulations pertaining to oil and gas wastes or to sign a determination that revision of the regulations is not necessary. If the EPA proposes revised oil and gas regulations, the consent decree requires that the EPA take final action following notice and comment rulemaking no later than July 15, 2021. Furthermore, certain wastes generated by the Company's oil and natural gas operations that are currently exempt from designation as hazardous wastes may in the future be designated as hazardous wastes under RCRA or other applicable statutes, and therefore be subject to more rigorous and costly operating and disposal requirements.

In addition, CERCLA, also known as the Superfund law, imposes cleanup obligations, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include the owner or operator of the disposal site or sites where the release occurred and companies that transported or disposed of or arranged for the transport or disposal of the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA and any state analogs may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file corresponding common law claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. While petroleum and crude oil fractions are not included in the definition of hazardous substances under CERCLA and some of its state analogs because of the so-called "petroleum exclusion," adulterated petroleum products containing other hazardous substances have been treated as hazardous substances under CERCLA in the past.

Endangered Species Act

Some of the Company's operations may be located in areas that are designated as habitats for endangered or threatened species under the ESA. In February 2016, the U.S. Fish and Wildlife Service published a final policy which alters how it identifies critical habitat for endangered and threatened species. A critical habitat designation could result in further material restrictions to federal and private land use and could delay or prohibit land access or development. Moreover, the U.S. Fish and Wildlife Service continues to make listing decisions and critical habitat designations where necessary, including for over 250 species as required under a 2011 settlement approved by the U.S. District Court for the District of Columbia, and many hundreds of additional anticipated listing decisions have already been identified beyond those recognized in the 2011 settlement. The Company believes that it is currently in substantial compliance with the ESA. However, the designation of previously unprotected species as being endangered or threatened, if located in the areas of the Company's operations, could cause the Company to incur additional costs or become subject to operating restrictions in areas where the species are known to exist.

Air Emissions

The New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants programs under the Clean Air Act impose specific requirements affecting the oil and gas industry under both programs for compressors, controllers, dehydrators, storage tanks, natural gas processing plants, completions, and certain other equipment and processes. Periodic review and revision of these and other rules by federal and state agencies may require changes to the Company's operations, including possible installation of new equipment to control emissions. For example, as described above, in May 2016, the EPA finalized rules to reduce methane and volatile organic compound emissions from new, modified or reconstructed sources in the oil and natural gas sector; however, in September 2018, under a new administration, the EPA proposed amendments that would relax requirements of the rules. Similarly, in September 2018, the BLM issued a rule that relaxes or rescinds certain requirements of regulations it previously enacted to reduce methane emissions from venting, flaring, and leaks during oil and gas operations on public lands; California and New Mexico have challenged the rule in ongoing litigation. In addition, in April 2018, a coalition of states filed a lawsuit aiming to force the EPA to establish guidelines for limiting methane emissions from existing sources in the oil and natural gas sector; that lawsuit is pending. Several states are pursuing similar measures to regulate emissions of methane from new and existing sources within the oil and natural gas source category. In addition, in May 2016, the EPA finalized rules regarding criteria for aggregating multiple small surface sites into a single source for air-quality permitting purposes applicable to the oil and gas industry. This rule could cause small facilities, on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting requirements. Further, the EPA lowered the National Ambient Air Quality Standard ("NAAQS") for ozone from 75 to 70 parts per billion in October 2015. State implementation of the revised NAAQS could result in stricter permitting requirements or delay, or limit the Company's ability to obtain permits, and result in increased expenditures for pollution control equipment. Compliance with these and other air pollution control and permitting requirements has the potential to delay the development of oil and natural gas projects and increase the Company's costs of development, which costs could be significant.

Water Resources

The CWA and analogous state laws restrict the discharge of pollutants, including produced waters and other oil and natural gas wastes, into "waters of the United States" ("WOTUS"), a term broadly defined to include, among other things, certain wetlands. Under the CWA, permits must be obtained for the discharge of pollutants into WOTUS. The CWA provides for administrative, civil and criminal penalties for unauthorized discharges, both routine and accidental, of pollutants and of oil and hazardous substances. It imposes substantial potential liability for the costs of removal or remediation associated with discharges of oil or hazardous substances. State laws governing discharges to water also provide varying civil, criminal and administrative penalties and impose liabilities in the case of a discharge of petroleum or its derivatives, or other hazardous substances, into state waters. In addition, the EPA has promulgated regulations that may require permits to discharge storm water runoff, including discharges associated with construction activities. The CWA also prohibits the discharge of fill materials to regulated waters including wetlands without a permit. In addition, the EPA and the Army Corps of Engineers ("Corps") released a rule to revise the definition of WOTUS for all CWA programs, which went into effect in August 2015. In October 2015, the U.S. Court of Appeals for the Sixth Circuit stayed the rule revising the WOTUS definition nationwide pending further action of the court. In response to this decision, the EPA and the Corps resumed nationwide use of the agencies' prior regulations defining the term WOTUS. However, in January 2018, the U.S. Supreme Court ruled that the rule revising the WOTUS definition must be reviewed first in the federal district courts, which resulted in a withdrawal of the stay by the Sixth Circuit. In addition, the EPA has proposed to repeal the rule revising the WOTUS definition, and in January 2018, the EPA released a final rule that delays implementation of the rule revising the WOTUS definition until 2020 to allow time for the EPA to reconsider the definition of WOTUS. Subsequent litigation in the federal district courts has resulted in patchwork application of the rule in some states, but not others. In December 2018, EPA released revisions to the definition of WOTUS that would provide discrete categories of jurisdictional waters and tests for determining whether a particular waterbody meets any of those classifications. Several groups have already announced their intentions to challenge the proposed rule. To the extent the rule is enforced in jurisdictions in which the Company operates or a replacement rule expands the scope of the CWA's jurisdiction, the Company could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas.

Also, in June 2016, the EPA finalized wastewater pretreatment standards that prohibit onshore unconventional oil and natural gas extraction facilities from sending wastewater to publicly-owned treatment works; for certain facilities, compliance is required by August 2019. This pending restriction of disposal options for hydraulic fracturing waste and other changes to CWA requirements may result in increased costs.

Economic Regulation

Regulation of pipeline gathering and transportation services, natural gas, NGLs, and crude oil sales, and transportation of natural gas, NGLs, and crude oil may affect certain aspects of the Company's business and the market for its products and services.

Regulation of Interstate Natural Gas Pipelines

Blue Mountain Midstream owns and operates the Blue Mountain Delivery Line, which is a natural gas pipeline that extends approximately 10 miles from the Blue Mountain Chisholm Trail Cryogenic Gas Complex to delivery points on the interstate pipelines owned and operated by Southern Star Central Gas Pipeline, Inc. and Enable Gas Transmission, LLC. Blue Mountain Midstream has obtained a limited jurisdiction certificate of public convenience and necessity under the Natural Gas

Item 1. Business - Continued

Act of 1938 ("NGA") for the Blue Mountain Delivery Line. In the certificate order, among other things, the Federal Energy Regulatory Commission ("FERC") waived requirements pertaining to the filing of an initial rate for service, the filing of a tariff and compliance with specified accounting and reporting requirements. As such, the Blue Mountain Delivery Line is not currently subject to conventional rate regulation; to requirements FERC imposes on "open access" interstate natural gas pipelines; to the obligation to file and maintain a tariff; or to the obligation to conform to certain business practices and to file certain reports. If, however, the Company receives a *bona fide* request for firm service on the Driver Residue Pipeline from a third party, FERC would reexamine the waivers it has granted the Company and would require the Company to file for authorization to offer "open access" transportation under its regulations, which would impose additional costs upon the Company.

Gathering Pipeline Regulation

The Company's natural gas gathering operations are typically subject to ratable take and common purchaser statutes in the states in which it operates. The common purchaser statutes generally require gathering pipelines to purchase or take without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another or one source of supply over another. The regulations under these statutes can have the effect of imposing some restrictions on the Company's ability as an owner of gathering facilities to decide with whom it contracts to gather natural gas. The states in which the Company operates have adopted complaint-based regulation of natural gas gathering activities, which allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to gathering access and rate discrimination. The rates the Company charges for gathering are deemed just and reasonable unless challenged in a complaint. The Company cannot predict whether such a complaint will be filed against it in the future. Failure to comply with state regulations can result in the imposition of administrative, civil and criminal penalties.

Section 1(b) of the NGA exempts natural gas gathering facilities from regulation as a natural gas company by FERC under the NGA. Although the FERC has not made any formal determinations with respect to any of the Company's facilities, the Company believes that the natural gas pipelines in its gathering systems meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to regulation as a natural gas company.

Natural Gas Processing

The Company's natural gas processing operations are not presently subject to FERC regulation. There can be no assurance that its processing operations will continue to be exempt from other FERC regulation in the future.

Sales of Natural Gas, NGLs and Crude Oil

The price at which the Company buys and sells natural gas, NGLs and crude oil is currently not subject to federal rate regulation and, for the most part, is not subject to state rate regulation. However, with regard to the Company's physical purchases and sales of these energy commodities and any related hedging activities that it undertakes, it is required to observe anti-market manipulation laws and related regulations enforced by FERC and/or the Commodities Futures Trading Commission ("CFTC"). See "−Other Federal Laws and Regulations Affecting the Company's Industry−*EP Act of 2005*" and "−Other Federal Laws and Regulations Affecting the Company's Industry−*Derivatives Regulation*." Should the Company violate the anti-market manipulation laws and regulations, it could also be subject to related third-party damage claims by, among others, market participants, sellers, royalty owners and taxing authorities.

Other State and Local Regulation of Operations

The Company's business activities are subject to various state and local laws and regulations, as well as orders of regulatory bodies pursuant thereto, governing a wide variety of matters, including marketing, production, pricing, community right-to-know, protection of the environment, safety and other matters.

Other Federal Laws and Regulations Affecting the Company's Industry

The Energy Policy Act of 2005 (the "EP Act 2005") is a comprehensive compilation of tax incentives, authorized appropriations for grants and guaranteed loans, and significant changes to the statutory policy that affects all segments of the energy industry. Among other matters, the EP Act of 2005 amends the NGA to add an anti-market manipulation provision which makes it unlawful for any entity to engage in prohibited behavior to be prescribed by FERC, and furthermore provides FERC with additional civil penalty authority. The EP Act of 2005 provides FERC with the power to assess civil penalties of up to $1 million per day for violations of the NGA and $1 million per violation per day for violations of the Natural Gas Policy Act ("NGPA"). The civil penalty provisions are applicable to entities that engage in the sale of natural gas for resale in interstate commerce. In 2006, FERC issued Order No. 670 to implement the anti-market manipulation provision of the EP Act of 2005. Order No. 670 does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of gas pipelines and storage companies that provide interstate services, as well as otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, FERC and the courts. The Company cannot predict the ultimate impact of these or the above regulatory changes to its natural gas operations. The Company does not believe that it would be affected by any such FERC action materially differently than other upstream and midstream natural gas companies with whom it competes.

Pipeline Safety Regulations

Some of the Company's pipelines are subject to regulation by the Pipeline and Hazardous Materials Safety Administration ("PHMSA") pursuant to the Natural Gas Pipeline Safety Act of 1968 ("NGPSA") with respect to natural gas, and the Hazardous Liquids Pipeline Safety Act of 1979, ("HLPSA") with respect to crude oil and NGLs. Both the NGPSA and the HLPSA have subsequently been amended legislatively and are implemented through regulations promulgated by the PHMSA (collectively, "Pipeline Safety Laws"). These laws and regulations establish minimum safety requirements in the design, construction, operation and maintenance of certain natural gas, crude oil and NGL pipeline facilities, as well as requirements for inspections and pipeline integrity

For example, pipeline operators must implement integrity management programs, including frequent inspections and other measures to ensure pipeline safety in high-consequence areas ("HCAs"), such as:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact a HCA;
- improve data collection, integration and analysis;
- repair and remediate pipelines as necessary; and
- implement preventive and mitigating actions.

The PHMSA has issued rules applying safety regulations to certain rural low-stress hazardous liquid pipelines that were not covered previously by its regulations. Further regulatory changes have been directed by Congress in other areas where the PHMSA has yet to take final action, notably requirements for certain shut-off valves on transmission lines, mapping all HCAs, and shortening the deadline for accident and incident notifications.

Violations of the Pipeline Safety Laws are punishable by administrative civil penalties of $209,002 per violation per day, with a maximum of $2,090,022 for a series of violations. The PHMSA may also issue corrective orders to pipeline operators to enforce compliance with the Pipeline Safety Laws. In 2016, Congress amended the Pipeline Safety Laws to, among other things, grant the PHMSA authority to issue emergency orders requiring owners and operators of regulated pipeline facilities to address imminent hazards without prior notice or an opportunity for a hearing, as well as enhanced release reporting requirements. Other changes related to integrity management programs and the creation of a working group to consider information-sharing for integrity risk analyses. In April 2016, PHMSA published a notice of proposed rulemaking ("NPRM"), addressing natural gas transmission and gathering lines. The proposed rule would, among other things, change integrity management requirements, expand assessment and repair requirements to pipelines in "moderate-consequence areas," including areas of medium population density, and increase requirements for monitoring and inspection of pipeline segments not located in HCAs. The NPRM would also require that records or other data relied on to determine operating pressures must be traceable, verifiable and complete. Locating such records and, in the absence of any such records, verifying maximum pressures through physical testing or modifying or replacing facilities, could significantly increase the Company's costs. Failure to locate such records or verify maximum pressures could also result in the reduction of allowable operating pressures, which would reduce available capacity on the Company's pipelines. PHMSA, however, has yet to finalize this rulemaking, and the contents and timing of any final rule are uncertain.

The federal Pipeline Safety Laws largely preempt state regulation of pipeline safety for interstate lines but most states are certified by the U.S. Department of Transportation to assume responsibility for enforcing federal intrastate pipeline regulations and inspection of intrastate pipelines. States may adopt stricter standards for intrastate pipelines than those imposed by the federal government for interstate lines; however, states vary considerably in their authority and capacity to address pipeline safety. State standards may include requirements for facility design and management in addition to requirements for pipelines. The Company does not anticipate any significant difficulty in complying with applicable state laws and regulations.

The Company's natural gas pipelines have inspection and compliance programs designed to keep the facilities in compliance with pipeline safety and pollution control requirements. The Company regularly reviews all existing and proposed pipeline safety requirements and works to incorporate the new requirements into procedures and budgets. The Company expects to incur increasing regulatory compliance costs, based on the intensification of the regulatory environment and upcoming changes to regulations. Costs may also be incurred if there were an accidental release of a commodity transported by the Company's system, or if a regulatory inspection identified a deficiency in the Company's required programs.

Worker Safety

The Occupational Safety and Health Act ("OSHA") and analogous state laws regulate the protection of the safety and health of workers. The OSHA hazard communication standard requires maintenance of information about hazardous materials used or produced in operations and provision of such information to employees. Other OSHA standards regulate specific worker safety aspects of the Company's operations. For example, under a new OSHA standard limiting respirable silica exposure, the oil and gas industry must implement engineering controls and work practices to limit exposures below the new limits by June 2021. Failure to comply with OSHA requirements can lead to the imposition of penalties.

Derivatives Regulation

Comprehensive financial reform legislation was signed into law by the President on July 21, 2010 ("Dodd-Frank Act"). The legislation called for the CFTC to regulate certain markets for derivative products, including over-the-counter derivatives. The CFTC has issued several new relevant regulations and other rulemakings are pending at the CFTC, the product of which would are rules that implement the mandates in the new legislation to cause significant portions of derivatives markets to clear through clearinghouses. While some of these rules have been finalized, some have not and, as a result, the final form and timing of the implementation of the new regulatory regime affecting commodity derivatives remains uncertain.

In particular, on October 18, 2011, the CFTC adopted final rules under the establishing position limits for certain energy commodity futures and options contracts and economically equivalent swaps, futures and options. The position limit levels set the maximum amount of covered contracts that a trader may own or control separately or in combination, net long or short. The final rules also contained limited exemptions from position limits which would be phased in over time for certain bona fide hedging transactions and positions. The CFTC's original position limits rule was challenged in court by two industry associations and was vacated and remanded by a federal district court. However, the CFTC proposed and revised new rules in November 2013 and December 2016, respectively, that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. The CFTC has sought comment on the position limits rule as reproposed, but these new position limit rules are not yet final and the impact of those provisions on the Company is uncertain at this time. The CFTC has withdrawn its appeal of the court order vacating the original position limits rule.

Pursuant to the Dodd-Frank Act, mandatory clearing is now required for all market participants, unless an exception is available. The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing. The CFTC has not yet required the clearing of any other classes of swaps, including physical commodity swaps, and the trade execution requirement does not apply to swaps not subject to a clearing mandate. Although the Company expects to qualify for the end-user exception from the clearing requirement for its swaps entered into to hedge its commercial risks, the application of the mandatory clearing requirements to other market participants, such as swap dealers, along with changes to the markets for swaps as a result of the trade execution requirement, may change the cost and availability of the swaps the Company uses for hedging. If any of the Company's swaps do not qualify for the commercial end-user exception, or if the cost of entering into uncleared swaps becomes prohibitive, the Company may be required to clear such transactions or execute them on a derivatives contract market or swap execution facility. The ultimate effect of the proposed rules and any additional regulations on the Company's business is uncertain.

Item 1. Business - Continued

In December 2015, the CFTC issued final rules establishing minimum margin requirements for uncleared swaps for swap dealers and major swap participants. The final rules do not impose margin requirements on commercial end users. Although the Company expects to qualify for the end-user exception from the margin requirements for swaps entered into to hedge its commercial risks, the application of such requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps the Company uses for hedging. If any of the Company's swaps do not qualify for the commercial end-user exception, the posting of collateral could reduce the Company's liquidity and cash available for capital expenditures and could reduce its ability to manage commodity price volatility and the volatility in its cash flows.

Other rules, including the restrictions on proprietary trading adopted under Section 619 of the Dodd-Frank Act, also known as the Volcker Rule, may alter the business practices of some of the Company's counterparties and in some cases may cause them to stop transacting in or making markets in derivatives. Moreover, federal banking regulators are reevaluating the authorization under which banking entities subject to their authority may engage in physical commodities transactions.

Although the Company cannot predict the ultimate outcome of these rulemakings, new rules and regulations, to the extent applicable to the Company or its derivative counterparties, may result in increased costs and cash collateral requirements for the types of derivative instruments the Company uses to manage its financial and commercial risks related to fluctuations in commodity prices. Additional effects of the new regulations, including increased regulatory reporting and recordkeeping costs, increased regulatory capital requirements for the Company's counterparties, and market dislocations or disruptions, among other consequences, could have an adverse effect on the Company's ability to hedge risks associated with its business.

The Company's sales of oil and natural gas are also subject to anti-manipulation and anti-disruptive practices authority under (i) the Commodity Exchange Act ("CEA"), as amended by the Dodd-Frank Act, and regulations promulgated thereunder by the CFTC and (ii) the Energy Independence and Security Act of 2007 ("EISA") and regulations promulgated thereunder by the FTC. The CEA, as amended by the Dodd-Frank Act, prohibits any person from using or employing any manipulative or deceptive device in connection with any swap, or a contract of sale of any commodity, or for future delivery on such commodity, in contravention of the CFTC's rules and regulations. The CEA, as amended by the Dodd-Frank Act, also prohibits knowingly delivering or causing to be delivered false or misleading or inaccurate reports concerning market information or conditions that affect or tend to affect the price of any commodity. The FTC issued its Petroleum Market Manipulation Rule pursuant to EISA, which became effective in November 2009, which also prohibits fraudulent or deceptive conduct (including false or misleading statements of material fact) in connection with wholesale purchases or sales of crude oil or refined petroleum products. Under both the CEA and the EISA, fines for violations can be up to $1,000,000 per day per violation and certain knowing or willful violations may also lead to a felony conviction.

Additional proposals and proceedings that may affect the crude oil and natural gas industry are pending before the U.S. Congress, the FERC and the courts. The Company cannot predict the ultimate impact these or the above laws and regulations may have on its crude oil and natural gas operations. The Company does not believe it will be affected by any such action in a materially different way than its similarly situated competitors.

Future Impacts and Current Expenditures

The Company cannot predict how future environmental laws and regulations may impact its properties or operations. For the year ended December 31, 2018, the Company did not incur any material capital expenditures for installation of remediation or pollution control equipment at any of its facilities. The Company is not aware of any environmental issues or claims that will require material capital expenditures during 2019 or that will otherwise have a material impact on its financial position, results of operations or cash flows.

Employees

As of December 31, 2018, the Company employed approximately 487 personnel. None of the employees are represented by labor unions or covered by any collective bargaining agreement. The Company believes that its relationship with its employees is satisfactory.

Principal Executive Offices

The Company is a Delaware corporation with headquarters in Houston, Texas. The principal executive offices are located at 600 Travis, Suite 1700, Houston, Texas 77002. The main telephone number is (281) 840-4000.

Item 1. Business - Continued

Available Information

The Company's internet website is www.rivieraresourcesinc.com. The Company's Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and any amendments to these reports and all other filings pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, are available free of charge on or through its website as soon as reasonably practicable after they are electronically filed with, or furnished to, the SEC. Information on the Company's website should not be considered a part of, or incorporated by reference into, this Annual Report on Form 10-K.

The SEC maintains an internet website that contains reports, proxy and information statements, and other information regarding the Company at www.sec.gov.

Cautionary Statement Regarding Forward-Looking Statements

This Annual Report on Form 10-K contains forward-looking statements that are subject to a number of risks and uncertainties, many of which are beyond the Company's control. These statements may include discussions about the Company's:

- business strategy;
- acquisition and disposition strategy;
- financial strategy;
- ability to comply with the covenants under the Credit Facilities;
- effects of legal proceedings;
- drilling locations;
- oil, natural gas and NGL reserves;
- realized oil, natural gas and NGL prices;
- production volumes;
- capital expenditures;
- economic and competitive advantages;
- credit and capital market conditions;
- regulatory changes;
- lease operating expenses, general and administrative expenses and development costs;
- future operating results;
- plans, objectives, expectations and intentions; and
- taxes.

All of these types of statements, other than statements of historical fact included in this Annual Report on Form 10-K, are forward-looking statements. These forward-looking statements may be found in Item 1. "Business;" Item 1A. "Risk Factors;" Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" and other items within this Annual Report on Form 10-K. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expect," "plan," "project," "intend," "anticipate," "believe," "estimate," "predict," "potential," "pursue," "target," "continue," the negative of such terms or other comparable terminology.

The forward-looking statements contained in this Annual Report on Form 10-K are largely based on Company expectations, which reflect estimates and assumptions made by Company management. These estimates and assumptions reflect management's best judgment based on currently known market conditions and other factors. Although the Company believes such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties beyond its control. In addition, management's assumptions may prove to be inaccurate. The Company cautions that the forward-looking statements contained in this Annual Report on Form 10-K are not guarantees of future performance, and it cannot assure any reader that such statements will be realized or the events will occur. Actual results may differ materially from those anticipated or implied in forward-looking statements due to factors set forth in Item 1A. "Risk Factors" and elsewhere in this Annual Report on Form 10-K. The forward-looking statements speak only as of the date made and, other than as required by law, the Company undertakes no obligation to publicly update or revise any forward-looking statement, whether as a result of new information, future events or otherwise.

Item 1A. Risk Factors

Our business has many risks. Factors that could materially adversely affect our business, financial condition, operating results or liquidity and the trading price of our shares are described below. This information should be considered carefully, together with other information in this report and other reports and materials we file with the SEC.

Business Risks

Commodity prices are volatile, and prolonged depressed prices or a further decline in prices would reduce our revenues, profitability and net cash provided by operating activities and would significantly affect our financial condition and results of operations.

Our revenues, profitability, cash flow and the carrying value of our properties depend on the prices of and demand for oil, natural gas and NGL. Historically, the oil, natural gas and NGL markets have been very volatile and are expected to continue to be volatile in the future, and prolonged depressed prices or a further decline in prices will significantly affect our financial results and impede our growth. Changes in oil, natural gas and NGL prices have a significant impact on the value of our reserves and on our net cash provided by operating activities. In addition, revenues from certain wells may exceed production costs and nevertheless not generate sufficient return on capital. Prices for these commodities may fluctuate widely in response to relatively minor changes in the supply of and demand for them, market uncertainty and a variety of additional factors that are beyond our control, such as:

- the domestic and foreign supply of and demand for oil, natural gas and NGL;
- the price and level of foreign imports;
- the level of consumer product demand;
- weather conditions;
- overall domestic and global economic conditions;
- political and economic conditions in oil and natural gas producing and consuming countries;
- the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain price and production controls;
- the impact of the U.S. dollar exchange rates on oil, natural gas and NGL prices;
- technological advances affecting energy consumption;
- domestic and foreign governmental regulations and taxation;
- the impact of energy conservation efforts;
- the proximity and capacity of pipelines and other transportation facilities;
- activities by non-governmental organizations to restrict the exploration, development, and production of oil and natural gas; and
- the price and availability of alternative fuels.

Prolonged depressed prices or a further decline in prices would reduce our revenues, profitability and net cash provided by operating activities and would significantly affect our financial condition and results of operations.

Future declines in commodity prices, changes in expected capital development, increases in operating costs or adverse changes in well performance may result in write-downs of the carrying amounts of our assets, which could materially and adversely affect our results of operations in the period incurred.

We evaluate the impairment of our oil and natural gas properties on a field-by-field basis whenever events or changes in circumstances indicate that the carrying value may not be recoverable. Future declines in oil, natural gas and NGL prices, changes in expected capital development, increases in operating costs or adverse changes in well performance, among other things, may result in us having to make material write-downs of the carrying amounts of our assets, which could materially and adversely affect our results of operations in the period incurred.

Disruptions in the capital and credit markets, continued low commodity prices and other factors may restrict our ability to raise capital on favorable terms, or at all.

Disruptions in the capital and credit markets, in particular with respect to companies in the energy sector, could limit our ability to access these markets or may significantly increase our cost to borrow. Continued low commodity prices, among other factors, have caused some lenders to increase interest rates, enact tighter lending standards which we may not satisfy, and in certain instances have reduced or ceased to provide funding to borrowers. If we are unable to access the capital and credit markets on favorable terms or at all, it could adversely affect our business and financial condition.

We may not be able to obtain funding under the Credit Facilities because of a decrease in our borrowing base, or obtain new financing, which could adversely affect our operations and financial condition.

On August 4, 2017, the Parent entered into the Riviera Credit Facility with $500 million in borrowing commitments and an initial borrowing base of $500 million. The maximum commitment amount was $425 million at December 31, 2018. As of December 31, 2018, total borrowings outstanding under the Riviera Credit Facility were $20 million and there was approximately $371 million of available borrowing capacity (which includes a $34 million reduction for outstanding letters of credit). In connection with the Spin-off, Riviera assumed the obligations of the Parent under the Riviera Credit Facility on August 7. 2018.

Redeterminations of the borrowing base under the Riviera Credit Facility are based primarily on reserve reports using lender commodity price expectations at such time. The borrowing base will be redetermined semi-annually, on April 1 and October 1. There was no change to the borrowing base as a result of the October 2018 redetermination. The next scheduled borrowing base redetermination will take place on April 1, 2019. Any reduction in the borrowing base will reduce our available liquidity, and, if the reduction results in the outstanding amount under the Riviera Credit Facility exceeding the borrowing base, we will be required to prepay an amount equal to the excess. We may not have the financial resources in the future to make such mandatory prepayments required under the Riviera Credit Facility, which could result in an event of default.

In addition, on August 10, 2018, Blue Mountain Midstream entered into the Blue Mountain Credit Facility with an initial borrowing commitment of $200 million. The maximum commitment amount is $400 million after the Covenant Changeover Date, subject to obtaining commitments for any such increase. The Covenant Changeover Date occurred February 8, 2019, increasing the current borrowing commitment of $200 million. At February 28, 2019, total borrowings outstanding under the Blue Mountain Credit Facility were approximately $19 million and there was approximately $169 million of available borrowing capacity (which includes a $12 million reduction for outstanding letters of credit). The Blue Mountain Credit Facility matures on August 10, 2023.

In the future, we may not be able to access adequate funding under our Credit Facilities as a result of (i) a decrease in our borrowing base due to the outcome of a borrowing base redetermination or (ii) an unwillingness or inability on the part of our lending counterparties to meet their funding obligations. Since the process for determining the borrowing base under the Riviera Credit Facility involves evaluating the estimated value of some of our oil and natural gas properties using pricing models determined by the lenders at that time, a decline in those prices used, or further downward reductions of our reserves, likely will result in a redetermination of our borrowing base and a decrease in the available borrowing amount at the time of the next scheduled redetermination. In such case, we would be required to repay any indebtedness in excess of the borrowing base.

The Credit Facilities also restrict our ability to obtain new financing. If additional capital is needed, we may not be able to obtain debt or equity financing on terms favorable to us, or at all. If net cash provided by operating activities or cash available under the Credit Facilities is not sufficient to meet our capital requirements, the failure to obtain such additional debt or equity financing could result in a curtailment of our development operations, which in turn could lead to a decline in our reserves.

We may be unable to maintain compliance with the covenants in the Credit Facilities, which could result in an event of default under the Credit Facilities that, if not cured or waived, would have a material adverse effect on our business and financial condition.

Under the Riviera Credit Facility, we are required to maintain (i) a maximum total net debt to last twelve months EBITDA ratio of 4.0 to 1.0, and (ii) a minimum adjusted current ratio of 1.0 to 1.0, as well as various affirmative and negative covenants. In addition, under the Blue Mountain Credit Facility, Blue Mountain Midstream is required to maintain (i) for certain periods, a ratio of consolidated total debt (subject to certain carve-outs) to the sum of (a) total debt (subject to certain carve-outs) and (b) consolidated owners' equity interest in Blue Mountain Midstream and its subsidiaries of no greater than 0.35 to 1.00, and (ii) subject to satisfaction of certain conditions and for certain periods, (a) a ratio of consolidated EBITDA to consolidated interest expense no less than 2.50 to 1.00, (b) a ratio of consolidated net debt to consolidated EBITDA (the “consolidated total leverage ratio”) no greater than 4.50 to 1.00 or 5.00 to 1.00, as applicable, and (c) in case certain other kinds of debt are outstanding, a ratio of consolidated net debt secured by a lien on property of Blue Mountain Midstream to consolidated EBITDA no greater than 3.00 to 1.00. If we were to violate any of the covenants under the Riviera Credit Facility or the Blue Mountain Credit Facility and were unable to obtain a waiver or amendment, it would be considered a default after the expiration of any applicable grace period. If we were in default under the Riviera Credit Facility or the Blue Mountain Credit Facility, then the lenders may exercise certain remedies including, among others, declaring all borrowings outstanding thereunder, if any, immediately due and payable. This could adversely affect our operations and our ability to satisfy our obligations as they come due.

Restrictive covenants in the Credit Facilities could limit our growth and our ability to finance our operations, fund our capital needs, respond to changing conditions and engage in other business activities that may be in our best interests.

Restrictive covenants in the Credit Facilities impose significant operating and financial restrictions on us and our subsidiaries. These restrictions limit our ability to, among other things:

- incur additional liens;
- incur additional indebtedness;
- merge, consolidate or sell our assets;
- pay dividends or make other distributions or repurchase or redeem our stock;
- make certain investments; and
- enter into transactions with our affiliates.

The Credit Facilities also require us to comply with certain financial maintenance covenants as discussed above. A breach of any of these covenants could result in a default under the Credit Facilities. If a default occurs and remains uncured or unwaived, the administrative agent or majority lenders under the Credit Facilities may elect to declare all borrowings outstanding thereunder, if any, together with accrued interest and other fees, to be immediately due and payable. The administrative agent or majority lenders under the Credit Facilities would also have the right in these circumstances to terminate any commitments they have to provide further borrowings. If we are unable to repay our indebtedness when due or declared due, the applicable administrative agent will also have the right to proceed against the collateral pledged to it to secure the indebtedness under the applicable Credit Facility. If such indebtedness were to be accelerated, our assets may not be sufficient to repay in full our secured indebtedness.

We may be prevented from taking advantage of business opportunities that arise because of the limitations imposed on us by the restrictive covenants in the Credit Facilities. The restrictions contained in the Credit Facilities could:

- limit our ability to plan for, or react to, market conditions, to meet capital needs or otherwise restrict our activities or business plan; and
- adversely affect our ability to finance our operations, enter into acquisitions or to engage in other business activities that would be in our interest.

We may be subject to risks in connection with divestitures.

In 2017 and 2018, we completed divestitures of a significant portion of our assets, as discussed in Item 1. “Business–Recent Developments.” In future transactions we may sell our core or non-core assets in order to increase capital resources available for other core assets, create organizational or other operational efficiencies or for other purposes. Though we continue to evaluate various options for the divestiture of such assets, there is no assurance that this evaluation will result in any specific action.

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

Item 1A. Risk Factors - Continued

Our financial information after the impact of fresh start accounting and numerous divestitures may not be meaningful to investors.

Upon LINN Energy's emergence from bankruptcy in February 2017, the Company adopted fresh start accounting and, as a result, our assets and liabilities were recorded at fair value as of the fresh start reporting date, which differ materially from the recorded values of assets and liabilities on our historical consolidated and combined balance sheets. As a result of the adoption of fresh start accounting, along with the numerous divestitures of properties in 2017 and 2018, our historical results of operations and period-to-period comparisons of those results and certain other financial data may not be meaningful or indicative of future results. The lack of comparable historical financial information may discourage investors from purchasing our common stock.

Our commodity derivative activities could result in financial losses or could reduce our income, which may adversely affect our net cash provided by operating activities, financial condition and results of operations.

To achieve more predictable net cash provided by operating activities and to reduce our exposure to adverse fluctuations in the prices of oil, natural gas and NGLs, we have entered into commodity derivative contracts for a portion of our production and costs. Commodity derivative arrangements expose us to the risk of financial loss in some circumstances, including situations when production is less than expected. If we experience a sustained material interruption in our production or if we are unable to perform our drilling activity as planned, we might be forced to satisfy all or a portion of our derivative obligations without the benefit of the sale of our underlying physical commodity, which may adversely affect our net cash provided by operating activities, financial condition and results of operations.

We may be unable to hedge anticipated production and purchased volumes on attractive terms or at all, which would subject us to further potential commodity price uncertainty and could adversely affect our net cash provided by operating activities, financial condition and results of operations.

While we have hedged a portion of our estimated production and purchases for 2019 and 2020, our anticipated production and purchase volumes remain mostly unhedged. Based on current expectations for future commodity prices, reduced hedging market liquidity and potential reduced counterparty willingness to enter into new hedges with us, we may be unable to hedge anticipated production volumes on attractive terms or at all, which would subject us to further potential commodity price uncertainty and could adversely affect our net cash provided by operating activities, financial condition and results of operations.

Counterparty failure may adversely affect our derivative positions.

We cannot be assured that our counterparties will be able to perform under our derivative contracts. If a counterparty fails to perform and the derivative arrangement is terminated, our net cash provided by operating activities, financial condition and results of operations could be adversely affected.

Unless we replace our reserves, our future reserves and production will decline, which would adversely affect our net cash provided by operating activities, financial condition and results of operations.

Producing oil, natural gas and NGL reservoirs are characterized by declining production rates that vary depending on reservoir characteristics and other factors. The overall rate of decline for our production will change if production from our existing wells declines in a different manner than we have estimated and may change when we drill additional wells, make acquisitions and under other circumstances. Thus, our future oil, natural gas and NGL reserves and production and, therefore, our cash flow and income, are highly dependent on our success in efficiently developing our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs, which would adversely affect our net cash provided by operating activities, financial condition and results of operations. In addition, given restrictive covenants under the Riviera Credit Facility and general market conditions, we may be unable to finance potential acquisitions of reserves on terms that are acceptable to us or at all. Our ability to make the necessary capital investment to maintain or expand our asset base of oil and natural gas reserves would be impaired to the extent cash flow from operations is reduced and external sources of capital become limited or unavailable.

Item 1A. Risk Factors - Continued

Our estimated reserves are based on many assumptions that 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.

No one can measure underground accumulations of oil, natural gas and NGL in an exact manner. Reserve engineering requires subjective estimates of underground accumulations of oil, natural gas and NGL and assumptions concerning future oil, natural gas and NGL 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. An independent petroleum engineering firm prepares estimates of our proved reserves. Some of our reserve estimates are made without the benefit of a lengthy production history, which are less reliable than estimates based on a lengthy production history. Also, we make certain assumptions regarding future oil, natural gas and NGL prices, production levels and operating and development costs that may prove incorrect. Any significant variance from these assumptions by actual amounts could greatly affect our estimates of reserves, the economically recoverable quantities of oil, natural gas and NGL attributable to any particular group of properties, the classifications of reserves based on risk of recovery and estimates of the future net cash flows. Decreases in commodity prices can result in a reduction of our estimated reserves if development of those reserves would not be economic at those lower prices. Numerous changes over time to the assumptions on which our reserve estimates are based, as described above, often result in the actual quantities of oil, natural gas and NGL we ultimately recover being different from our reserve estimates.

The present value of future net cash flows from our proved reserves is not necessarily the same as the current market value of our estimated oil, natural gas and NGL reserves. We base the estimated discounted future net cash flows from our proved reserves on an unweighted average of the first-day-of-the month price for each month during the 12-month calendar year and year-end costs. However, actual future net cash flows from our oil and natural gas properties also will be affected by factors such as:

- actual prices we receive for oil, natural gas and NGL;
- the amount and timing of actual production;
- capital and operating expenditures;
- the timing and success of development activities;
- supply of and demand for oil, natural gas and NGL; and
- changes in governmental regulations or taxation.

In addition, the 10% discount factor required to be used under the provisions of applicable accounting standards when calculating discounted future net cash flows, may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general.

Our development and midstream operations require substantial capital expenditures. We may be unable to obtain needed capital or financing on satisfactory terms, which could adversely affect our ability to sustain our operations at current levels and could lead to a decline in our reserves and affect our future growth.

The oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business for the development and production of oil, natural gas and NGL reserves and to expand our midstream operations and activities. These expenditures will reduce our cash available for other purposes. Our net cash provided by operating activities and access to capital are subject to a number of variables, including:

- our proved reserves;
- the level of oil, natural gas and NGL we are able to produce from existing wells;
- the prices at which we are able to sell our oil, natural gas and NGL;
- the level of operating expenses;
- our ability to acquire, locate and produce new reserves;
- the costs of constructing, operating and maintaining our midstream facilities; and
- our ability to attract third-party customers for our midstream services.

If our net cash provided by operating activities decreases, we may have limited ability to obtain the capital or financing necessary to sustain our operations at current levels and could lead to a decline in our reserves.

Item 1A. Risk Factors - Continued

We may decide not to drill some of the prospects we have identified, and locations that we decide to drill may not yield oil, natural gas and NGL in commercially viable quantities.

Our prospective drilling locations are in various stages of evaluation, ranging from a prospect that is ready to drill to a prospect that will require additional geological and engineering analysis. Based on a variety of factors, including future oil, natural gas and NGL prices, the generation of additional seismic or geological information, the current and future availability of drilling rigs and other factors, we may decide not to drill one or more of these prospects. In addition, the cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a well. Our efforts will be uneconomic if we drill dry holes or wells that are productive but do not produce enough oil, natural gas and NGL to be commercially viable after drilling, operating and other costs. As a result, we may not be able to increase or sustain our reserves or production, which in turn could have an adverse effect on our business, financial condition, results of operations and cash flows.

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

Our drilling activities are subject to many risks, including the risk that we will not discover commercially productive reservoirs. Drilling for oil, natural gas and NGL 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 problems;
- pipeline ruptures or spills;
- compliance with environmental and other governmental requirements;
- 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 and NGL or well fluids.

Any of these events can cause increased costs or restrict our ability to drill the wells and conduct the operations which we currently have planned. Any delay in the drilling program or significant increase in costs could adversely affect our financial position, results of operations and cash flows.

Our business depends on gathering and transportation facilities, including our midstream facilities constructed and operated by Blue Mountain Midstream, and other market factors that we do not control. Limitations on the availability to those facilities or adverse pricing differentials could adversely affect our business, results of operations and cash flows by interfering with our ability to consistently market oil, natural gas and NGL.

The marketability of our oil, natural gas and NGL production depends in part on the availability, proximity and capacity of gathering systems and pipelines, including our midstream facilities constructed and operated by our wholly owned subsidiary, Blue Mountain Midstream. Our development and maintenance of our midstream infrastructure can involve significant risks, including those relating to timing, cost overruns and operational efficiency that could, in turn, materially impact our production, cash flow and results of operation. The amount of oil, natural gas and NGL that can be produced and sold is subject to limitation in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, 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. In addition, some of our wells are drilled in locations that are not serviced by gathering and transportation pipelines, or the gathering and transportation pipelines in the area may not have sufficient capacity to transport additional production. As a result, we may not be able to sell the oil, natural gas and NGL production from these wells until the necessary gathering and transportation systems are constructed. Any significant curtailment in gathering system or pipeline capacity, or significant delay in the construction of necessary gathering and transportation facilities, would interfere with our ability to market the oil, natural gas and NGL we produce, and could adversely affect our business, results of operations and cash flows.

Additionally, certain of our contracts may provide for pricing at a market hub that is different than the delivery market hub where our oil, natural gas or NGL production is delivered and sold. If the differential between the two pricing is hubs is unfavorable, it could adversely affect our business, results of operations or cash flows.

Our construction of Blue Mountain Midstream's new natural gas gathering, processing and compression and water treatment or other assets, may not be completed on schedule, at the budgeted cost or at all, and they may not result in revenue increases and may be subject to regulatory, environmental, political, legal and economic risks, which could adversely affect our cash flows, results of operations and financial condition and, as a result, our ability to distribute cash to our unitholders.

The construction of additions or modifications to our existing systems and the construction or purchase of new assets, involves numerous regulatory, environmental, political and legal uncertainties beyond our control and may require the expenditure of significant amounts of capital. Financing may not be available on economically acceptable terms or at all. If we undertake these projects, we may not be able to complete them on schedule, at the budgeted cost or at all. Moreover, our revenues may not increase immediately upon the expenditure of funds on a particular project.

Moreover, we may construct facilities to capture anticipated future production growth in an area in which such growth does not materialize. As a result, new natural gas gathering, processing and compression and water treatment or other assets may not be able to attract enough throughput to achieve our expected investment return, which could adversely affect our results of operations and financial condition. In addition, the construction of additions to our existing assets may require us to obtain new rights-of-way prior to constructing new pipelines or facilities. We may be unable to timely obtain such rights-of-way to connect new natural gas supplies to our existing gathering pipelines or capitalize on other attractive expansion opportunities. Additionally, it may become more expensive for us to obtain new rights-of-way or to expand or renew existing rights-of-way. If the cost of renewing or obtaining new rights-of-way increases, our cash flows could be adversely affected.

Blue Mountain Midstream's natural gas gathering, processing and compression and water management services agreements are not supported by minimum volume commitments.

Blue Mountain Midstream's natural gas gathering, processing and compression and water management services agreements with Roan are not supported by minimum volume commitments from Roan. Any decrease in the current levels of throughput on Blue Mountain Midstream's gathering, processing and compression or water management systems could adversely affect Blue Mountain Midstream's business, results of operations and cash flows.

Because substantially all revenue in the Blue Mountain segment is derived from selling volumes purchased from Roan, any development that materially and adversely affects Roan's operations, financial condition or market reputation could have a material and adverse impact on us.

Roan is the most significant counterparty for our wholly owned subsidiary, Blue Mountain Midstream, and selling volumes purchased from Roan accounted for substantially all the revenues for the Blue Mountain segment in 2018. We expect Blue Mountain Midstream to derive a material portion of its revenues from selling volumes purchased from Roan for the foreseeable future. As a result, any event, whether in our area of operations or otherwise, that adversely affects Roan's production, drilling and completion schedule, financial condition, leverage, market reputation, liquidity, results of operations or cash flows may adversely affect Blue Mountain Midstream's business, results of operations and cash flows.

For example, Blue Mountain Midstream's acreage dedication and commitments from Roan cover midstream and water management services in a number of areas that are at the early stages of development and in areas that Roan is still determining whether to develop. In addition, Roan owns acreage in areas that are not dedicated to Blue Mountain Midstream. We cannot predict which of these areas Roan will determine to develop and at what time. Roan may decide to explore and develop areas in which Blue Mountain Midstream has a smaller operating interest in the midstream or water treatment assets that service that area, or where the acreage is not dedicated to Blue Mountain Midstream, rather than areas in which Blue Mountain Midstream has a larger operating interest in the midstream or water management assets that service that area. Roan's decision to develop acreage that is not dedicated to Blue Mountain Midstream or in which Blue Mountain

Midstream has a smaller operating interest in may adversely affect our business, financial condition, results of operations and cash flows.

Further, Blue Mountain Midstream is subject to the risk of non-performance by Roan, with respect to our natural gas gathering, processing and compression and water management services agreements. We cannot predict the extent to which Roan's business would be impacted if conditions in the energy industry deteriorate, nor can we estimate the impact such conditions would have on Roan's ability to execute its drilling and development program or perform under our natural gas gathering, processing and compression and water management services agreements. Any material non-performance by Roan could adversely affect the Blue Mountain segment's business, results of operations and cash flows.

If Roan sells any of the dedicated acreage to a third party, the third party's financial condition could be materially worse than Roan's, and thus we could be subject to the non-payment or non-performance by the third party.

Under Blue Mountain Midstream's natural gas dedication agreement with Roan, Roan is required to deliver its natural gas production from the specified contract area (the "dedicated acreage") to Blue Mountain Midstream through November 2030. If Roan sells any of the dedicated acreage to a third party, the third party's financial condition could be materially worse than Roan's. In such a case, we may be subject to risks of loss resulting from non-payment or non-performance by the third party, which risks may increase during periods of economic uncertainty. Furthermore, the third party may be subject to their own operating and regulatory risks, which could increase the risk that that third party may default on its obligations to Blue Mountain Midstream. Any material non-payment or non-performance by the third party could adversely affect Blue Mountain Midstream's business, results of operations and cash flows.

Blue Mountain Midstream may not be successful in balancing our purchases and sales and may be subject to adverse pricing differentials.

Blue Mountain Midstream is party to certain long-term gas, NGL and condensate sales commitments that it satisfies through supplies purchased under long-term gas and NGL purchase agreements. Over time, the supplies that it has under contract may decline due to reduced drilling or other causes, and it risks losing offtake capacity. In addition, a producer could fail to deliver expected volumes or deliver in excess of expected volumes. Any of these actions could cause our purchases and sales not to be balanced. Over time, the costs of covering those imbalances could affect Blue Mountain's competitive position and its financial results. If Blue Mountain Midstream's purchases and sales are not balanced, we will face increased exposure to commodity price risks and could have increased volatility in our operating income.

In addition, Blue Mountain Midstream has in the past experienced a negative impact on its financial results from the spread between the index price at which it is committed to purchase natural gas and associated natural gas liquids in production areas and the index price at which it can sell natural gas liquids into market areas. Changes in this basis spread could significantly affect our margins or even result in losses.

We are subject to regulation by multiple governmental agencies, which could adversely impact our business, results of operations and financial condition.

We are subject to regulation by multiple federal, state and local governmental agencies. Proposals and proceedings that affect the midstream industry are regularly considered by Congress, as well as by state legislatures and federal and state regulatory commissions, agencies and courts. We cannot predict when or whether any such proposals or proceedings may become effective or the magnitude of the impact changes in laws and regulations may have on our business. However, additions to the regulatory burden on our industry can increase our cost of doing business and affect our profitability.

If third party pipelines or other midstream facilities interconnected to our gathering and compression systems become partially or fully unavailable, or if the volumes we gather or treat do not meet the quality requirements of such pipelines or facilities, our business, financial condition, results of operations and cash flows could be adversely affected.

Our gathering and compression assets connect to other pipelines or facilities owned and operated by unaffiliated third parties. The continuing operation of third-party pipelines, compressor stations and other midstream facilities is not within our control. These pipelines, plants and other midstream facilities may become unavailable because of testing, turnarounds, line repair, maintenance, reduced operating pressure, lack of operating capacity, regulatory requirements and curtailments of receipt or deliveries due to insufficient capacity or because of damage from severe weather conditions or other operational issues. In addition, if the costs to us to access and transport on these third-party pipelines significantly increase, our profitability could be reduced. If any such increase in costs occurs or if any of these pipelines or other midstream facilities become unable to receive or transport natural gas, or if the volumes we gather or transport do not meet the quality requirements of such pipelines or midstream facilities, our business, financial condition, results of operations and cash flows could be adversely affected.

Our business relies on certain key personnel.

Our management believes that our continued success will depend to a significant extent upon the efforts and abilities of certain of our key personnel. The loss of the services of any of these key personnel could have a material adverse effect on our business. We do not maintain "key man" life insurance on any of our officers or other employees.

We have limited control over the activities on properties we do not operate.

Other companies operate some of the properties in which we have an interest. As of December 31, 2018, non-operated wells represented approximately 43% of our owned gross wells, or approximately 23% of our owned net wells. We have limited ability to influence or control the operation or future development of these non-operated properties, including timing of drilling and other scheduled operations activities, compliance with environmental, safety and other regulations, or the amount of capital expenditures that we are required to fund with respect to them. The failure of an operator of our wells to adequately perform operations, an operator's breach of the applicable agreements or an operator's failure to act in ways that are in our best interest could reduce our production and revenues, and lead to unexpected future costs.

Our business could be adversely affected by security threats, including cyber-security threats, and related disruptions.

We face from time to time various security threats, including cyber-security threats, to gain unauthorized access to our sensitive information or to render our information or systems unusable, and threats to the security of our facilities and infrastructure or third-party facilities and infrastructure, such as gathering and processing and other facilities, refineries and pipelines. These security threats subject our operations to increased risks that could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our implementation of various procedures and controls to monitor and mitigate such security threats and to increase security for our information, systems, facilities and infrastructure may result in increased costs. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. We rely heavily on our information systems, and the availability and integrity of these systems are essential for us to conduct our business and operations. If any security breaches were to occur, they could lead to losses of, or damage to, sensitive information or facilities, infrastructure and systems essential to our business and operations, as well as data corruption, communication interruptions or other disruptions to our operations, which, in turn, could have a material adverse effect on our business, financial position, results of operations and cash flows.

Damage to our reputation could damage our business.

Our reputation is a critical factor in our relationships with employees, investors, customers, suppliers and joint venture partners. If we fail to address, or appear to fail to address, issues that give rise to reputational risk, including those described throughout this "Risk Factors" section, we could significantly harm our reputation. Our reputation may also be damaged by how we respond to corporate crises. Corporate crises can arise from catastrophic events as well as from incidents involving unethical behavior or misconduct; allegations of legal noncompliance; internal control failures; corporate governance issues; data breaches; workplace safety incidents; environmental incidents; media statements; the conduct of our suppliers or representatives; and other issues or incidents that, whether actual or perceived, result in adverse publicity. If we fail to respond quickly and effectively to address such crises, the ensuing negative public reaction could significantly harm our reputation and could lead to increases in litigation claims and asserted damages or subject us to regulatory actions or restrictions.

Damage to our reputation could negatively affect the demand for our services and consequently, have a material adverse effect on our business, financial condition, and results of operations. It could also reduce investor confidence in us, adversely affecting our stock price. Moreover, repairing our reputation may be difficult, time-consuming and expensive.

Item 1A. Risk Factors - Continued

Risks Relating to Regulation of Our Business

Because we handle oil, natural gas and NGL and other hydrocarbons, we may incur significant costs and liabilities in the future resulting from a failure to comply with new or existing environmental regulations or an accidental release of hazardous substances into the environment.

The operations of our wells, gathering systems, turbines, pipelines and other facilities are subject to stringent and complex federal, state and local environmental laws and regulations. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of orders enjoining future operations. There is an inherent risk that we may incur environmental costs and liabilities due to the nature of our business, the substances we handle and the ownership or operation of our properties. Certain environmental statutes, including the RCRA, CERCLA and analogous state laws and regulations, impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances have been disposed of or otherwise released. In addition, an accidental release from one of our wells or gathering pipelines could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage and fines or penalties for related violations of environmental laws or regulations.

Moreover, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase our compliance costs and the cost of any remediation that may become necessary, and these costs may not be recoverable from insurance. For a more detailed discussion of environmental and regulatory matters impacting our business, see Item 1. “Business–Environmental Matters and Regulation.”

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

Our operations are regulated extensively at the federal, state and local levels. Environmental and other governmental laws and regulations have resulted in delays and increased the costs to plan, design, drill, install, operate and abandon oil and natural gas wells. Under these laws and regulations, we could also be liable for personal injuries, property damage and other damages. Failure to comply with these laws and regulations may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, public interest in environmental protection has increased in recent years, and environmental organizations have opposed, with some success, certain drilling projects.

Part of the regulatory environment in which we operate includes, in some cases, legal requirements for obtaining environmental assessments, environmental impact studies and/or plans of development before commencing drilling and production activities. In addition, our activities are subject to the regulations regarding conservation practices and protection of correlative rights. These regulations affect our operations and limit the quantity of oil, natural gas and NGL we may produce and sell. A major risk inherent in our drilling plans is the need to obtain drilling permits from state and local authorities. Delays in obtaining regulatory approvals or drilling permits, the failure to obtain a drilling permit for a well or the receipt of a permit with unreasonable conditions or costs could have a material adverse effect on our ability to develop our properties. Additionally, the regulatory environment could change in ways that might substantially increase the financial and managerial costs of compliance with these laws and regulations and, consequently, adversely affect our financial condition and results of operations. For a description of the laws and regulations that affect us, see Item 1. “Business–Environmental Matters and Regulation.”

We could also be affected by more stringent laws and regulations adopted in the future, including any related to climate change, engine emissions, greenhouse gases and hydraulic fracturing. Changes in environmental laws and regulations occur frequently, and any changes that result in delays or restrictions in permitting or development of projects or more stringent or costly construction, drilling, water management, or completion activities or waste handling, storage, transport, remediation or disposal, emission or discharge requirements could require significant expenditures by us or other operators of the properties to attain and maintain compliance and may otherwise have a material adverse effect on our results of operations or financial condition. Increased scrutiny of the oil and natural gas industry may occur as a result of the EPA’s fiscal year 2017-2019 National Enforcement Initiatives, through which the EPA will purportedly address incidences of noncompliance from natural gas extraction and production activities that may cause or contribute to significant harm to public health and/or the environment.

Legislation and regulation of hydraulic fracturing, including with respect to seismic activity allegedly related to hydraulic fracturing and underground water injection or disposal wells, could adversely affect our business.

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. For a description of the laws and regulations that affect us, including our hydraulic fracturing operations, see Item . "Business–Environmental Matters and Regulation." If adopted, certain bills could result in additional permitting and disclosure requirements for hydraulic fracturing operations as well as various restrictions on those operations. Any such added regulation could lead to operational delays, increased operating costs and additional regulatory burdens, and reduced production of oil and natural gas, which could adversely affect our business, financial position, results of operations and net cash provided by operating activities.

Hydraulic fracturing operations require the use of a significant amount of water. Our inability to locate sufficient amounts of water, or dispose of or recycle water used in our drilling and production operations, could adversely impact our operations. Moreover, new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the development or production of natural gas.

We dispose of wastewater generated from oil and natural gas production operations, including hydraulic fracturing operations, directly or through the use of third parties. In some instances, the operation of underground injection wells has been alleged to cause earthquakes in some of the states where we operate. Such issues have sometimes led to orders prohibiting continued injection or disposal or the suspension of drilling in certain wells identified as possible sources of seismic activity. Such concerns also have resulted in stricter regulatory requirements in some jurisdictions relating to the location and operation of underground injection wells. For example, Oklahoma issued rules for wastewater disposal wells that imposed certain permitting and operating restrictions, required additional seismicity protocols in certain defined areas, and from time to time, directs certain injection wells in proximity to seismic events to restrict or suspend operations. Future orders or regulations addressing concerns about seismic activity from well injection could affect us, either directly or indirectly, depending on the wells affected, which materially affect our capital expenditures and operating costs.

A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets, which may cause our operating expenses to increase, limit the rates we charge for certain services and decrease the amount of cash we have available for distribution.

With the exception of the Blue Mountain Delivery Line, which is subject to limited FERC regulation, our natural gas pipeline operations are generally exempt from FERC regulation under the NGA, we believe that our natural gas gathering pipelines meet the traditional tests that FERC has used to determine that pipelines perform primarily a gathering function and are, therefore, not subject to FERC jurisdiction. However, the distinction between FERC-regulated interstate transportation services and federally unregulated gathering services has been the subject of litigation, and FERC determines whether facilities are gathering facilities on a case-by-case basis, so the classification and regulation of our gathering facilities is subject to change based on future determinations by FERC, the courts or Congress. If FERC were to consider the status of an individual facility and determine that the facility or services provided by it are not exempt from FERC regulation under the NGA, and that the facility provides interstate transportation service, the rates for, and terms and conditions of, services provided by such facility would be subject to regulation by FERC under the NGA or the NGPA. Such regulation could decrease revenue, increase operating costs, and, depending upon the facility in question, adversely affect our results of operations and cash flow. In addition, if any of our facilities were found to have provided services or otherwise operated in violation of the NGA or NGPA, this could result in the imposition of substantial civil penalties, as well as a requirement to disgorge revenues collected for such services in excess of the maximum rates established by FERC. Under the EP Act of 2005, FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1 million per day for each violation and disgorgement of profits associated with any violation.

Even though we consider our natural gas gathering pipelines to be exempt from the jurisdiction of FERC under the NGA, FERC regulation of interstate natural gas transportation pipelines may indirectly impact gathering services. FERC's policies and practices across the range of its natural gas regulatory activities, including, for example, its policies on interstate open access transportation, ratemaking, capacity release, and market center promotion may indirectly affect gathering services. In recent years, FERC has pursued pro-competitive policies in its regulation of interstate natural gas pipelines on which we ship natural gas. However, we cannot assure you that the FERC will continue to pursue this approach as it considers matters such as pipeline rates and rules and policies that may indirectly affect the natural gas gathering services.

Natural gas gathering may receive greater regulatory scrutiny at the state level, therefore, our natural gas gathering operations could be adversely affected should they become subject to the application of state regulation of rates and services. Our gathering operations could also be subject to safety and operational regulations relating to the design, construction, testing, operation, replacement and maintenance of gathering facilities. We cannot predict what effect, if any, such changes might have on our operations, but we could be required to incur additional capital expenditures and increased operating costs depending on future legislative and regulatory changes.

New laws, policies, regulations, rulemaking and oversight, as well as changes to those currently in effect, could adversely impact our earnings, cash flows and operations.

Our assets and operations are subject to regulation and oversight by federal, state, provincial and local regulatory authorities. Legislative changes, as well as regulatory actions taken by these agencies, have the potential to adversely affect our profitability. In addition, a certain degree of regulatory uncertainty is created by the current U.S. presidential administration because it remains unclear specifically what the current administration may do with respect to future policies and regulations that may affect us. Regulation affects almost every part of our business and extends to such matters as (i) federal, state, provincial and local taxation; (ii) rates (which include tax, reservation, commodity, surcharges, fuel and gas lost and unaccounted for), operating terms and conditions of service; (iii) the types of services we may offer to our customers; (iv) the contracts for service entered into with our customers; (v) the certification and construction of new facilities; (vi) the costs of raw materials, such as steel; (vii) the integrity, safety and security of facilities and operations; (viii) the acquisition of other businesses; (ix) the acquisition, extension, disposition or abandonment of services or facilities; (x) reporting and information posting requirements; (xi) the maintenance of accounts and records; and (xii) relationships with affiliated companies involved in various aspects of the energy businesses. Should we fail to comply with any applicable statutes, rules, regulations, and orders of regulatory authorities, we could be subject to substantial penalties and fines and potential loss of government contracts. Furthermore, new laws, regulations or policy changes sometimes arise from unexpected sources.

Federal and state legislative and regulatory initiatives relating to pipeline safety that require the use of new or more stringent safety controls or result in more stringent enforcement of applicable legal requirements could subject us to increased capital costs, operational delays and costs of operation.

The U.S. Department of Transportation, through the PHMSA and state agencies, enforces safety regulations with respect to the design, construction, operation, maintenance, inspection and management of certain of our pipeline facilities. The PHMSA requires pipeline operators to implement integrity management programs, including more frequent inspections and other measures to ensure pipeline safety in high-consequence areas, or HCAs, defined as those areas that are unusually sensitive to environmental damage, that cross a navigable waterway, or that have a high population density. The regulations require operators to (i) perform ongoing assessments of pipeline integrity, (ii) identify and characterize applicable threats to pipeline segments that could impact a HCA, (iii) improve data collection, integration and analysis, (iv) repair and remediate pipelines as necessary and (v) implement preventive and mitigating actions. These regulations contain requirements for the development and implementation of pipeline integrity management programs, which include the inspection and testing of pipelines and the correction of anomalies. The PHMSA's regulations also require that pipeline operation and maintenance personnel meet certain qualifications and that pipeline operators develop comprehensive spill response plans, including extensive spill response training for pipeline personnel.

Legislation and regulation of greenhouse gases could adversely affect our business, and we are subject to risks associated with climate change.

In December 2009, the EPA determined that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA has adopted and implemented regulations to restrict emissions of GHGs under existing provisions of the Clean Air Act. In May 2016, the EPA finalized rules that set additional emissions limits for volatile organic compounds and established new controls for emissions of methane from new, modified or reconstructed sources in the oil and natural gas source category, including production, processing, transmission and storage activities. The rule includes first-time standards to address emissions of methane from equipment and processes across the source category, including hydraulically fractured oil and natural gas well completions.

Item 1A. Risk Factors - Continued

However, in September 2018, under a new administration, the EPA proposed amendments that would relax requirements of these rules. In addition, in April 2018, a coalition of states filed a lawsuit in federal district court aiming to force the EPA to establish guidelines for limiting methane emissions from existing sources in the oil and natural gas sector; that lawsuit is pending. The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the U.S., including, among other things, certain onshore oil and natural gas production facilities, on an annual basis.

On an international level, the U.S. was one of 175 countries to sign an international climate change agreement in Paris, France that requires member countries to set their own GHG emission reduction goals beginning in 2020 (the "Paris Agreement"). However, on June 1, 2017, President Trump announced that the U.S. would withdraw from the Paris Agreement. It is not clear what steps the Trump Administration plans to take to withdraw from the Paris Agreement, whether a new agreement can be negotiated, or what terms would be included in such an agreement. Certain U.S. city and state governments have announced their intention to satisfy their proportionate obligations under the Paris Agreement. In addition, legislation has from time to time been introduced in Congress that would establish measures restricting GHG emissions in the U.S., and a number of states have begun taking actions to control and/or reduce emissions of GHGs. Any such additional regulation could lead to operational delays, increased operating costs and additional regulatory burdens, and reduced production of oil and natural gas, which could adversely affect our business, financial position, results of operations and net cash provided by operating activities.

Any legislation or regulatory programs to reduce GHG emissions could increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations. Moreover, incentives to conserve energy or use alternative energy sources as a means of addressing climate change could reduce demand for the oil and natural gas we produce. In addition, parties concerned about the potential effects of climate change have directed their attention at sources of funding for energy companies, which has resulted in certain financial institutions, funds and other sources of capital, restricting or eliminating their investment in oil and natural gas activities. Finally, most 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 adversely affect or delay demand for the oil or natural gas produced or cause us to incur significant costs in preparing for or responding to those effects.

Uncertainty regarding derivatives legislation could have an adverse impact on our ability to hedge risks associated* with *our business.

Title VII of the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"), enacted in 2010, expands federal oversight and regulation of the derivatives markets and entities, such as us, that participate in those markets. Those markets involve derivative transactions, which include certain instruments, such as interest rate swaps, forward contracts, option contracts, financial contracts and other contracts, used in our risk management activities. The Dodd-Frank Act requires that most swaps ultimately will be cleared through a registered clearing facility and that they be traded on a designated exchange or swap execution facility, with certain exceptions for entities that use swaps to hedge or mitigate commercial risk. The Dodd-Frank Act requirements relating to derivative transactions have not been fully implemented by the SEC and the Commodities Futures Trading Commission and the current presidential administration has indicated a desire to repeal and/or replace certain provisions of the Dodd-Frank Act. Uncertainty regarding the current law and any new regulations could increase the operational and transactional cost of derivatives contracts and affect the number and/or creditworthiness of available counterparties. Even though monitored by management, our hedging activities may fail to protect us and could reduce our earnings and cash flow. Our hedging activity may be ineffective or adversely affect cash flow and earnings because, among other factors, hedging can be expensive, particularly during periods of volatile prices; our counterparty in the hedging transaction may default on its obligation to pay or otherwise fail to perform; and available hedges may not correspond directly with the risks against which we seek protection.

In addition, we may transact with counterparties based in the European Union, Canada or other jurisdictions which are in the process of implementing regulations to regulate derivatives transactions, some of which are currently in effect and impose operational and transactional costs on our derivatives activities.

Item 1A. Risk Factors - Continued

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

In past years, legislation has been proposed that would, if enacted into law, make significant changes to U.S. 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. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, and (iii) an extension of the amortization period for certain geological and geophysical expenditures. Although these provisions were largely unchanged in the Tax Cuts and Jobs Act of 2017 (which was signed on December 22, 2017), Congress could consider, and could include, some or all of these proposals as part of future tax reform legislation. It is unclear whether any of the foregoing or similar proposals will be considered and enacted as part of future tax reform legislation and if enacted, how soon any such changes could become effective. The passage of any legislation as a result of these proposals or any other similar changes in 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 have an adverse effect on our financial position, results of operations and cash flows.

Recent changes in U.S. federal income tax law may have an adverse effect on our cash flows, results of operations or financial condition.

The Tax Cuts and Jobs Act of 2017 may affect our cash flows, results of operations and financial condition. Among other items, the Tax Cuts and Jobs Act of 2017 repealed the deduction for certain U.S. production activities and provided for a new limitation on the deduction for interest expense. Given the scope of this law and the potential interdependency of its changes, it is difficult at this time to assess whether the overall effect of the Tax Cuts and Jobs Act of 2017 will be cumulatively positive or negative for our earnings and cash flow, but such changes may adversely impact our financial results.

Risks Relating to Our Common Stock

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

Funds associated with Elliott Associates, L.P., Fir Tree Capital Management LP, York Capital Management, L.P. and P. Schoenfeld Asset Management LP collectively owned approximately 60% of our common stock as of December 31, 2018. Circumstances may arise in which these stockholders may have an interest in pursuing or preventing acquisitions, divestitures or other transactions that, in their judgment, could enhance their investment in the Company. Such transactions might adversely affect us or other holders of our common stock.

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

As of December 31, 2018, approximately 60% of our common stock was beneficially owned by four holders each of which has a representative on the Board. Our significant concentration of share ownership may adversely affect the trading price of our common stock because of the lack of trading volume in our common stock and because investors may perceive disadvantages in owning shares in companies with significant stockholders.

Our ability to pay dividends may impact the trading price of our common stock.

We are not currently paying a cash dividend; however, the Board of Directors periodically reviews our liquidity position to evaluate whether or not to pay a cash dividend. Any future payment of cash dividends would be subject to the restrictions in the Riviera Credit Facility. Our ability to pay dividends or for us to receive dividends from our operating companies may negatively impact the trading price of our common stock.

Certain provisions in our certificate of incorporation, bylaws and Delaware law may make it difficult for stockholders to change the composition of our Board of Directors and may prevent or delay an acquisition of Riviera, which could decrease the trading price of our common stock.

Our certificate of incorporation, bylaws and Delaware corporate law contain provisions that may have the effect of deterring or delaying coercive takeover practices and inadequate takeover bids. For example, our certificate of incorporation and

Item 2. Properties - Continued

bylaws require advance notice for stockholder proposals to nominate directors or present matters at stockholder meetings, place limitations on convening stockholder meetings and authorize our board of directors to issue one or more series of preferred stock. These provisions could enable our board of directors to delay or prevent a transaction that some, or a majority, of our stockholders may believe to be in their best interests and, in that case, may discourage or prevent attempts to remove and replace incumbent directors. These provisions may also discourage or prevent any attempts by our stockholders to replace or remove our current management by making it more difficult for stockholders to replace members of our board of directors, which is responsible for appointing the members of our management.

Item 1B. Unresolved Staff Comments

None

Item 2. Properties

Information concerning proved reserves, production, wells, acreage and related matters are contained in Item 1. "Business."

The Company's obligations under its Credit Facilities are secured by mortgages on substantially all of the Company's oil and natural gas properties. See Note 6 for additional details about the Credit Facilities.

Offices

The Company's principal corporate office is located at 600 Travis, Suite 1700, Houston, Texas 77002. The Company maintains additional offices in Illinois, Kansas, Louisiana, Michigan, Oklahoma and Texas.

Item 3. Legal Proceedings

As discussed further in Note 2, on May 11, 2016, Linn Energy, LLC, certain of its direct and indirect subsidiaries, and LinnCo, LLC (collectively, the "LINN Debtors") and Berry Petroleum Company, LLC ("Berry" and collectively with the LINN Debtors, the "Debtors"), filed voluntary petitions for relief under Chapter 11 of the U.S. Bankruptcy Code in the U.S. Bankruptcy Court for the Southern District of Texas ("Bankruptcy Court"). The Debtors' Chapter 11 cases were administered jointly under the caption In re Linn Energy, LLC, et al., Case No. 16-60040.

On December 3, 2016, the LINN Debtors filed the Amended Joint Chapter 11 Plan of Reorganization of Linn Energy, LLC and Its Debtor Affiliates Other Than Linn Acquisition Company, LLC and Berry Petroleum Company, LLC (the "Plan"). The LINN Debtors subsequently filed amended versions of the Plan with the Bankruptcy Court.

On January 27, 2017, the Bankruptcy Court entered an order approving and confirming the Plan (the "Confirmation Order"). Consummation of the Plan was subject to certain conditions set forth in the Plan. On February 28, 2017, all of the conditions were satisfied or waived and the Plan became effective and was implemented in accordance with its terms. On September 27, 2018, the Bankruptcy Court closed the LINN Debtors' Chapter 11 cases, but retained jurisdiction as provided in the Confirmation Order, including to potentially reopen the Chapter 11 cases if certain matters currently on appeal in the U.S. Court of Appeals for the Fifth Circuit are overturned, including the Default Interest Appeal as defined below.

The commencement of the Chapter 11 proceedings automatically stayed certain actions against the Company, including actions to collect prepetition liabilities or to exercise control over the property of the Company's bankruptcy estates. However, the Company is, and will continue to be until the final resolution of all claims, subject to certain contested matters and adversary proceedings stemming from the Chapter 11 proceedings, which are not affected by the closure of the LINN Debtors' Chapter 11 cases.

On March 17, 2017, Wells Fargo Bank, National Association ("Wells Fargo"), the administrative agent under the Predecessor's credit facility, filed a motion in the Bankruptcy Court seeking payment of post-petition default interest of approximately $31 million. The Company has vigorously disputed that Wells Fargo is entitled to any default interest based on the plain language of the Plan and Confirmation Order. On November 13, 2017, the Bankruptcy Court ruled that the secured lenders are not entitled to payment of post-petition default interest. That ruling was appealed by Wells Fargo and on March 29, 2018, the U.S. District Court for the Southern District of Texas affirmed the Bankruptcy Court's ruling. On April 30, 2018, the Bankruptcy Court approved the substitution of UMB Bank, National Association ("UMB Bank") as successor to Wells Fargo as

Item 3. Legal Proceedings - Continued

administrative agent under the Predecessor’s credit facility. UMB Bank then immediately filed a notice of appeal to the U.S. Court of Appeals for the Fifth Circuit from the decision by the U.S. District Court for the Southern District of Texas, which affirmed the decision of the Bankruptcy Court. The Fifth Circuit heard oral arguments on February 6, 2019. That appeal (“the Default Interest Appeal”) remains pending.

The Company is not currently a party to any litigation or pending claims that it believes would have a material adverse effect on its overall business, financial position, results of operations or liquidity; however, cash flow could be significantly impacted in the reporting periods in which such matters are resolved.

Item 4. Mine Safety Disclosures

Not applicable

Part II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

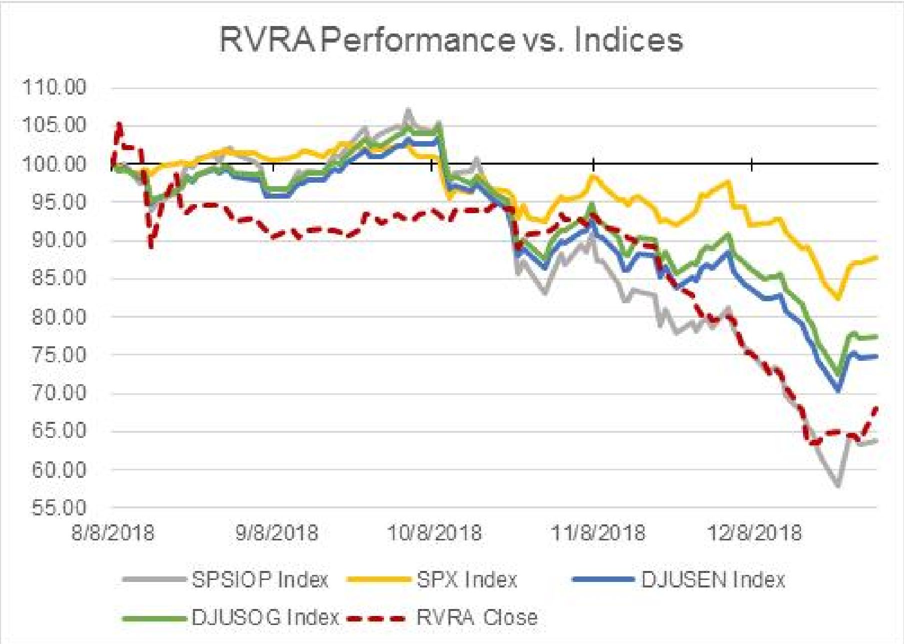
Riviera's common stock is quoted on the OTCQX Market under the trading symbol "RVRA" and has been trading since August 8, 2018. No established public trading market existed for the Company's common stock prior to August 8, 2018. Over-the-counter market quotations reflect inter-dealer prices, without retail mark-up, mark-down or commission and may not necessarily represent actual transactions.

At the close of business on January 31, 2019, there were approximately 9 stockholders of record based on information provided by the Company's transfer agent.

Dividends

The Company is not currently paying a cash dividend; however, the Board of Directors periodically reviews the Company's liquidity position to evaluate whether or not to pay a cash dividend. Any future payment of cash dividends would be subject to the restrictions in the Riviera Credit Facility.

The performance graph below compares the total stockholder return on Riviera's common stock, with the total return of the Standard & Poor's Oil & Gas Exploration & Production Index ("S&P Oil & Gas Index"), the Dow Jones U.S. Oil & Gas Index ("Dow Oil & Gas Index"), the Dow Jones U.S. Oil & Gas Producers Index ("Dow Oil & Gas Producers Index") and the Standard & Poor's 500 Index (the "S&P 500 Index"). Total return includes the change in the market price, adjusted for reinvested dividends, for the period shown on the performance graph and assumes that $100 was invested in the Company on August 8, 2018, the date Riviera's common stock began trading, and each comparative index on the same date. The results shown in the graph below are not necessarily indicative of future performance.



Item 5.Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities - Continued

	August 8, 2018	December 31, 2018
Riviera (RVRA)	$ 100	$ 68
S&P Oil & Gas Index (SPSIOP)	$ 100	$ 64
Dow Oil & Gas Index (DJUSEN)	$ 100	$ 75
Dow Oil & Gas Producers Index (DJUSOG)	$ 100	$ 78
S&P 500 Index (SPX)	$ 100	$ 88

Notwithstanding anything to the contrary set forth in any of the Company's previous or future filings under the Securities Act of 1933, as amended or the Securities Exchange Act of 1934, as amended that might incorporate this Annual Report on Form 10-K or future filings with the SEC, in whole or in part, the preceding performance information shall be deemed furnished and shall neither be deemed to be "soliciting material" or to be "filed" with the SEC or incorporated by reference into any filing except to the extent this performance presentation is specifically incorporated by reference therein.

Securities Authorized for Issuance Under Equity Compensation Plans

See the information incorporated by reference in Item 12. "Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters" regarding securities authorized for issuance under the Company's equity compensation plans, which information is incorporated by reference into this Item 5.

Sales of Unregistered Securities

None

Issuer Purchases of Equity Securities

The Board has authorized the repurchase of up to $100 million of the Company's outstanding shares of common stock. Purchases may be made from time to time in negotiated purchases or in the open market, including through Rule 10b5-1 prearranged stock trading plans designed to facilitate the repurchase of the Company's shares during times it would not otherwise be in the market due to self-imposed trading blackout periods or possible possession of material nonpublic information. The timing and amounts of any such repurchases of shares will be subject to market conditions and certain other factors, and will be in accordance with applicable securities laws and other legal requirements, including restrictions contained in the Company's then current credit facility. The repurchase plan does not obligate the Company to acquire any specific number of shares and may be discontinued at any time.

The following sets forth information with respect to the Company's repurchases of shares of its common stock during the fourth quarter of 2018.

Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (1)
				(in thousands)
October 1 – 31	6,062,179	$ 22.00	—	$ 92,459
November 1– 30	233,450	$ 20.28	233,450	$ 87,725
December 1 – 31	357,873	$ 16.47	357,873	$ 81,831
Total	6,653,502	$ 21.64	591,323	

(1) On August 16, 2018, the Board authorized the repurchase of up to $100 million of the Company's outstanding shares of common stock. During the period from August 2018 through December 31, 2018, the Company repurchased an aggregate of 945,979 shares of common stock at an average price of $19.21 per share for a total cost of approximately $18 million. On September 24, 2018, the

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities - Continued

Company announced the intention to commence a tender offer to purchase $100 million of the Company's common stock. In October 2018, upon the terms and subject to the conditions described in the Offer to Purchase dated September 25, 2018, as amended, the Company repurchased an aggregate of 6,062,179 shares of common stock at a price of $22.00 per share for a total cost of approximately $133 million (excluding expenses of approximately $2 million related to the tender offer). In accordance with the SEC's regulations regarding issuer tender offers, the Company's share repurchase program was suspended concurrent with the September 24, 2018, announcement of the intent to commence a tender offer. The program was resumed in November 2018 following the expiration of the tender offer.

Table of Contents

Item 6. Selected Financial Data

The selected financial data set forth below should be read in conjunction with Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Item 8. "Financial Statements and Supplementary Data."

Because of numerous acquisitions and divestitures of properties, as well as the impact of the adoption of fresh start accounting on February 28, 2017, the Company's historical results of operations and period-to-period comparisons of those results and certain other financial data may not be meaningful or indicative of future results. The Company's historical investment in Roan is reported as discontinued for the period from September 1, 2017 through July 25, 2018. The results of operations of its California properties are reported as discontinued operations for the period from January 1, 2017 through July 31, 2017, and the years ended December 31, 2016, December 31, 2015, and December 31, 2014 (see Note 4).

	Successor		Predecessor			
				For the Year Ended December 31,		
(in thousands, except per share amounts)	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	2016	2015	2014
Statement of operations data:						
Oil, natural gas and natural gas liquids sales	$ 420,102	$ 709,363	$ 188,885	$ 874,161	$ 1,065,795	$ 2,305,573
Gains (losses) on commodity derivatives	(23,404)	13,533	92,691	(164,330)	1,027,014	1,127,395
Depreciation, depletion and amortization	94,958	133,711	47,155	342,614	513,508	758,996
Interest expense, net of amounts capitalized	2,417	12,380	16,725	184,870	456,749	496,210
Income tax expense (benefit)	29,587	385,654	(166)	11,300	(6,307)	4,368
Income (loss) from continuing operations	20,933	345,131	2,587,557	(343,733)	(3,812,416)	(461,984)
Income (loss) from discontinued operations	19,674	90,064	(548)	(18,354)	9,586	(12,381)
Net income (loss)	40,607	435,195	2,587,009	(362,087)	(3,802,830)	(474,365)
Income (loss) from continuing operations per share:						
Basic	0.28	4.53	33.96	(4.51)	(50.04)	(6.07)
Diluted	0.28	4.53	33.96	(4.51)	(50.04)	(6.07)
Income (loss) from discontinued operations per share:						
Basic	0.26	1.18	(0.01)	(0.24)	0.13	(0.16)
Diluted	0.26	1.18	(0.01)	(0.24)	0.13	(0.16)
Net income (loss) per share:						
Basic	0.54	5.71	33.95	(4.75)	(49.91)	(6.23)
Diluted	0.54	5.71	33.95	(4.75)	(49.91)	(6.23)
Weighted average shares outstanding:						
Basic	74,935	76,191	76,191	76,191	76,191	76,191
Diluted	75,360	76,191	76,191	76,191	76,191	76,191

Item 6.Selected Financial Data - Continued

(in thousands)	Successor: At or for the Year Ended December 31, 2018	Successor: At or for Ten Months Ended December 31, 2017	Predecessor: Two Months Ended February 28, 2017	Predecessor: At or for the Year Ended December 31, 2016	2015	2014
Cash flow data:						
Net cash provided by (used in):						
Operating activities	$ (6,594)	$ 231,021	$ 152,714	$ 875,306	$ 1,127,700	$ 1,128,855
Investing activities	168,162	1,257,352	(58,756)	(230,438)	(276,023)	(1,389,765)
Financing activities	(632,713)	(1,111,473)	(437,730)	(164,150)	(850,886)	260,735
Balance sheet data:						
Total assets	$ 1,592,834	$ 2,868,125		$ 4,444,151	$ 6,018,375	$ 11,665,356
Current portion of long-term debt, net	—	—		1,937,729	2,841,518	—
Long-term debt, net	24,500	—		—	4,447,308	8,125,213
Liabilities subject to compromise	—	—		4,280,005	—	—
Total equity (deficit)	1,262,374	2,339,046		(2,587,009)	(2,110,804)	2,128,329

Item 6.Selected Financial Data - Continued

	Successor		Predecessor			
	At or for the Year Ended December 31, 2018	At or for the Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	At or for the Year Ended December 31, 2016	2015	2014
Production data:						
Average daily production – continuing operations:						
Natural gas (MMcf/d)	247	386	495	511	549	492
Oil (MBbls/d)	3.2	17.8	20.2	22.1	27.4	34
NGL (MBbls/d)	10.3	20.5	21.4	25.4	25.6	32
Total (MMcfe/d)	328	616	745	796	867	885
Average daily production – discontinued operations:						
Equity method investments – Total (MMcfe/d) (1)	64	30	—	—	—	—
California - Total (MMcfe/d) (2)	—	14	30	32	30	15
Reserves data: (3)						
Proved reserves – continuing operations:						
Natural gas (Bcf)	1,260	1,377		2,290	2,212	3,552
Oil (MMBbls)	4	27		73	74	148
NGL (MMBbls)	56	72		104	97	146
Total (Bcfe)	1,618	1,968		3,350	3,240	5,318
Proved reserves – discontinued operations:						
Equity method investments – Total (Bcfe) (1)	—	694		—	—	—
California - Total (Bcfe) (2)	—	—		170	195	313

(1) Represents the Company’s historical 50% equity interest in Roan. Production of Roan for 2018 is for the period from January 1, 2018 through July 25, 2018. Production of Roan for 2017 is for the period from September 1, 2017 through December 31, 2017.

(2) Production of the Company’s California properties reported as discontinued operations for 2017 is for the period from January 1, 2017 through July 31, 2017.

(3) In accordance with Securities and Exchange Commission regulations, reserves were estimated using the average price during the 12-month period, determined as an unweighted average of the first-day-of-the-month price for each month, excluding escalations based upon future conditions. The average price used to estimate reserves is held constant over the life of the reserves.

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 financial statements and related notes included in this Annual Report on Form 10-K in Item 8. "Financial Statements and Supplementary Data." The following discussion contains forward-looking statements based on expectations, estimates and assumptions. Actual results may differ materially from those discussed in the forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, market prices for oil, natural gas and NGL, production volumes, estimates of proved reserves, capital expenditures, economic and competitive conditions, credit and capital market conditions, regulatory changes and other uncertainties, as well as those factors set forth in "Cautionary Statement Regarding Forward-Looking Statements" in Item 1. "Business" and in Item 1A. "Risk Factors."

Unless otherwise indicated or the context otherwise requires, references herein to the "Company" refer (i) prior to the Spin-off (as defined below) to Linn Energy, Inc. (the "Parent") and its consolidated subsidiaries, and (ii) after the Spin-off, to Riviera Resources, Inc. ("Riviera") and its consolidated subsidiaries. Unless otherwise indicated or the context otherwise requires, references herein to "LINN Energy" refer to Linn Energy, Inc. and its consolidated subsidiaries. References to "Successor" relate to the financial position and results of operations of the Company subsequent to LINN Energy's emergence from bankruptcy on February 28, 2017. References to "Predecessor" relate to the financial position of the Company prior to, and results of operations through and including, February 28, 2018.

The reference to a "Note" herein refers to the accompanying Notes to Consolidated and Combined Financial Statements contained in Item 8. "Financial Statements and Supplementary Data."

In April 2018, the Parent announced its intention to separate Riviera from LINN Energy. Following the Spin-off, Riviera is an independent oil and natural gas company with a strategic focus on efficiently operating its mature low-decline assets, developing its growth-oriented assets, and returning capital to shareholders. Blue Mountain Midstream is an emerging midstream company with assets in central Oklahoma focused on providing its customers with comprehensive natural gas, oil, natural gas liquids, and water solutions in a safe and environmentally sound manner, including gas gathering and processing, water gathering and treatment, and delivery of product to lucrative downstream markets. In the future, Blue Mountain Midstream looks to expand the scale and scope of its service capabilities in the Merge/SCOOP/STACK through organic growth and strategic acquisitions.

To effect the separation, the Parent and certain of its then direct and indirect subsidiaries undertook an internal reorganization (including the conversion of Riviera Resources, LLC from a limited liability company to a corporation named Riviera Resources, Inc.), following which Riviera holds, directly or through its subsidiaries, substantially all of the assets of LINN Energy, other than LINN Energy's 50% equity interest in Roan Resources LLC ("Roan"). A subsidiary of the Company held the equity interest in Roan until the Parent's internal reorganization on July 25, 2018 (the "Reorganization Date"). Following the internal reorganization, the Parent distributed all of the outstanding shares of Riviera common stock to the Parent's shareholders on a pro rata basis (the "Spin-off"). The Spin-off was completed on August 7, 2018. Prior to the completion of the Spin-off, a then subsidiary of the Parent distributed $40 million to the Parent to pay the Parent's obligations during the transition period under the TSA (as defined below). Linn Energy, Inc. returned such $40 million to Riviera on September 24, 2018, which included approximately $7 million for the reimbursement of cash paid to settle the Parent's restricted stock units held by Riviera's employees and approximately $1 million for the payment of income taxes on shares withheld from participants upon vesting (see Note 13).

Following the Spin-off, Riviera is an independent reporting company quoted for trading on the OTCQX Market under the ticker "RVRA," and the Parent did not retain any ownership interest in Riviera.

On August 7, 2018, Riviera entered into a Transition Services Agreement (the "TSA") with the Parent to facilitate an orderly transition following the Spin-off. Pursuant to the TSA, Riviera agreed to provide the Parent with certain finance, financial reporting, information technology, investor relations, legal, payroll, tax and other services during the term of the TSA. Riviera reimbursed the Parent for, or paid on the Parent's behalf, all direct and indirect costs and expenses incurred by the Parent during the term of the TSA in connection with the fees for any such services. The TSA terminated in accordance with its terms on September 24, 2018.

During the reporting period, the Parent was a successor issuer of Linn Energy, LLC pursuant to Rule 15d-5 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). As discussed further in Note 2, on May 11, 2016 (the "Petition Date"), Linn Energy, LLC, certain of its direct and indirect subsidiaries, and LinnCo, LLC (collectively, the "LINN Debtors") and Berry Petroleum Company, LLC ("Berry" and collectively with the LINN Debtors, the "Debtors"), filed voluntary petitions for relief under Chapter 11 of the U.S. Bankruptcy Code ("Bankruptcy Code") in the U.S. Bankruptcy Court for the Southern District of Texas ("Bankruptcy Court"). The Debtors' Chapter 11 cases were administered jointly under the caption In re Linn Energy, LLC, et al., Case No. 16-60040. During the pendency of the Chapter 11 proceedings, the Debtors operated their businesses as "debtors-in-possession" under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code. LINN Energy emerged from bankruptcy effective February 28, 2017 (the "Effective Date").

Riviera is a successor issuer of the Parent pursuant to Rule 15d-5 of the Exchange Act.

Executive Overview

The Company's upstream reporting segment properties are currently located in six operating regions in the United States ("U.S."):

- Hugoton Basin, which includes oil and natural gas properties, as well as the Jayhawk natural gas processing plant, located in Kansas (the "Jayhawk Plant");
- East Texas, which includes oil and natural gas properties producing primarily from the Travis Peak, Cotton Valley and Bossier formations;
- Michigan/Illinois, which includes properties producing from the Antrim Shale formation located in northern Michigan and oil properties in southern Illinois;
- Mid-Continent, which includes properties in the Northwest STACK in northwestern Oklahoma and various other oil and natural gas producing properties throughout Oklahoma;
- North Louisiana, which includes oil and natural gas properties producing primarily from the Hosston, Cotton Valley Bossier and Smackover formations; and
- Uinta Basin, which includes non-operated properties located in the Dunkards Wash field in Utah (which was included in the Company's previous Rockies operating region).

During 2018, the Company divested all of its properties located in the previous Permian Basin operating region. During 2017, the Company divested all of its properties located in the previous California and South Texas operating regions. As a result of the Company's strategic exit from California in 2017 (completed by the sale of its interest in properties located in the San Joaquin Basin and the Los Angeles Basin in California), the Company classified the results of operations and cash flows of its California properties as discontinued operations on its consolidated and combined financial statements. See below and Note 4 for details of the Company's divestitures.

The Blue Mountain reporting segment consists of a state of the art cryogenic natural gas processing facility and a network of gathering pipelines and compressors located in the Merge/SCOOP/STACK play, each of which is owned by Blue Mountain Midstream LLC ("Blue Mountain Midstream"), a wholly owned subsidiary of the Company.

Historically, a subsidiary of the Company also owned a 50% equity interest in Roan. The Company's equity earnings (losses), consisting of its share of Roan's earnings or losses, are included in the consolidated financial statements through the Reorganization Date. However, on the Reorganization Date, the equity interest in Roan was distributed to the Parent and is no longer affiliated with Riviera. As such, the Company has classified the investment and equity earnings (losses) in Roan as discontinued operations on its consolidated financial statements. See Note 4 for additional information.

For the year ended December 31, 2018, the Company's results included the following:

- oil, natural gas and NGL sales of approximately $420 million compared to $709 million and $189 million for the ten months ended December 31, 2017, and the two months ended February 28, 2017, respectively;
- average daily production of approximately 328 MMcfe/d compared to 616 MMcfe/d and 745 MMcfe/d for the ten months ended December 31, 2017, and the two months ended February 28, 2017, respectively;
- net income of approximately $41 million compared to net income of $435 million and $2.6 billion for the ten months ended December 31, 2017, and the two months ended February 28, 2017, respectively;
- net cash used in operating activities from continuing operations of approximately $7 million compared to net cash provided by operating activities of approximately $215 million and $144 million for the ten months ended December 31, 2017, and the two months ended February 28, 2017, respectively;

- capital expenditures of approximately $170 million compared to $299 million and $46 million for the ten months ended December 31, 2017, and the two months ended February 28, 2017, respectively; and
- 52 wells drilled (all successful) compared to 90 wells drilled (all successful) for 2017.

Predecessor and Successor Reporting

As a result of the application of fresh start accounting (see Note 2), the Company’s consolidated and combined financial statements and certain note presentations are separated into two distinct periods, the period before the Effective Date (labeled Predecessor) and the period after that date (labeled Successor), to indicate the application of a different basis of accounting between the periods presented. Despite this separate presentation, there was continuity of the Company’s operations.

Divestitures

Below are the Company’s completed divestitures in 2018:

On April 10, 2018, the Company completed the sale of its conventional properties located in New Mexico (the “New Mexico Assets Sale”). Cash proceeds received from the sale of these properties were approximately $14 million and the Company recognized a net gain of approximately $12 million.

On April 4, 2018, the Company completed the sale of its interest in properties located in the Altamont Bluebell Field in Utah (the “Altamont Bluebell Assets Sale”). Cash proceeds received from the sale of these properties were approximately $129 million, net of costs to sell of approximately $2 million, and the Company recognized a net gain of approximately $83 million.

On March 29, 2018, the Company completed the sale of its interest in conventional properties located in west Texas (the “West Texas Assets Sale”). Cash proceeds received from the sale of these properties were approximately $105 million, net of costs to sell of approximately $2 million, and the Company recognized a net gain of approximately $54 million.

On February 28, 2018, the Company completed the sale of its Oklahoma waterflood and Texas Panhandle properties (the “Oklahoma and Texas Assets Sale”). Cash proceeds received from the sale of these properties were approximately $108 million (including a deposit of approximately $12 million received in 2017), net of costs to sell of approximately $1 million, and the Company recognized a net gain of approximately $46 million.

Divestiture – Subsequent Event

On January 17, 2019, the Company completed the sale of its interest in properties located in the Arkoma Basin (“the Arkoma Assets Sale”) in Oklahoma and received cash proceeds of approximately $65 million (including a deposit of approximately $5 million received in 2018).

Water Services Agreement

On January 31, 2019, the Company entered into an agreement with Roan to exclusively manage all of Roan’s water needs for its drilling and completion operations in Central Oklahoma. Blue Mountain Midstream will provide comprehensive water management services including pipeline gathering, disposal, treatment and redelivery of recycled water for re-use. The agreement is supported by a 10-year acreage dedication in 67 Townships covering portions of seven Oklahoma Counties.

Construction of Cryogenic Plant

In July 2017, the Company’s subsidiary Blue Mountain Midstream entered into a definitive agreement with BCCK Engineering, Inc. to construct a 225 MMcf/d cryogenic natural gas processing facility with a total capacity of 250 MMcf/d. The facility was successfully commissioned in the second quarter of 2018.

In August 2018, the Company’s Board of Directors (the “Board”) approved Blue Mountain Midstream’s plan to initiate the engineering and design of a second cryogenic natural gas processing plant (“Cryo 2”) servicing the Merge/SCOOP/STACK play in central Oklahoma. Blue Mountain Midstream has completed the conceptual engineering and design for Cryo 2 and has the ability to execute on Cryo 2 quickly if the election is eventually made to proceed.

2018 Oil and Natural Gas and Midstream Capital Expenditures

During the year ended December 31, 2018, the Company had total capital expenditures, excluding acquisitions, of approximately $170 million, including approximately $36 million related to its oil and natural gas capital program and approximately $125 million related to Blue Mountain Midstream.

2019 Oil and Natural Gas Capital Budget

For 2019, the Company estimates its total capital expenditures, excluding acquisitions and Blue Mountain, will be approximately $66 million, including approximately $61 million related to its oil and natural gas capital program. This estimate is under continuous review and subject to ongoing adjustments.

Financing Activities

Blue Mountain Credit Facility
On August 10, 2018, Blue Mountain Midstream entered into a credit agreement with Royal Bank of Canada, as administrative agent, and the lenders and agents party thereto, providing for a new senior secured revolving loan facility (the "Blue Mountain Credit Facility" and together with Riviera Credit Facility, the "Credit Facilities"), providing for an initial borrowing commitment of $200 million.

Before Blue Mountain Midstream completes certain operational milestones (such completion of the operational milestones, the "Covenant Changeover Date"), a condition to any borrowing is that Blue Mountain Midstream's consolidated total indebtedness to capitalization ratio (the "Debt/Cap Ratio") be not greater than 0.35 to 1.00 upon giving effect to such borrowing. As such, prior to the Covenant Changeover Date, the available borrowing capacity under the Blue Mountain Credit Facility may be less than the aggregate amount of the lenders' commitments at such time. On and after the Covenant Changeover Date, Blue Mountain Midstream will no longer have to comply with the Debt/Cap Ratio as a condition to drawing and may borrow up to the total amount of the lenders' aggregate commitments. The Blue Mountain Credit Facility also provides for the ability to increase the aggregate commitments of the lenders to up to $400 million after the Covenant Changeover Date, subject to obtaining commitments for any such increase, which may result in an increase in Blue Mountain Midstream's available borrowing capacity. As of December 31, 2018, total borrowings outstanding under the Blue Mountain Credit Facility were $4.5 million and there was approximately $72 million of available borrowing capacity (in addition, there was $12 million of outstanding letters of credit). The Covenant Changeover Date occurred February 8, 2019, which increased the current borrowing commitment to $200 million. Currently, total borrowings outstanding under the Blue Mountain Credit Facility are approximately $19 million and there is approximately $169 million of available borrowing capacity (which includes a $12 million reduction for outstanding letters of credit). The Blue Mountain Credit Facility matures on August 10, 2023.

Share Repurchase Program
On August 16, 2018, the Board authorized the repurchase of up to $100 million of the Company's outstanding shares of common stock. During the period from August 2018 through December 31, 2018, the Company repurchased an aggregate of 945,979 shares of common stock at an average price of $19.21 per share for a total cost of approximately $18 million. For the period from January 1, 2019 through February 22, 2019, the Company repurchased 221,788 shares of common stock at an average price of $15.27 for a total cost of approximately $3 million. At February 22, 2019, approximately $78 million was available for share repurchase under the program.

In accordance with the SEC's regulations regarding issuer tender offers, the Company's share repurchase program was suspended concurrent with the September 24, 2018, announcement of the intent to commence a tender offer. The program was resumed in November 2018 following the expiration of the tender offer.

Any share repurchases are subject to restrictions in the Company's senior secured reserve-based revolving loan facility (the "Riviera Credit Facility").

Tender Offer

On September 24, 2018, the Company announced the intention to commence a tender offer to purchase $100 million of the Company's common stock. In October 2018, upon the terms and subject to the conditions described in the Offer to Purchase dated September 25, 2018, as amended, the Company repurchased an aggregate of 6,062,179 shares of common stock at a price of $22.00 per share for a total cost of approximately $133 million (excluding expenses of approximately $2 million related to the tender offer).

Listing on the OTCQX Market

As a result of completing the Spin-off, the Company's common stock began trading on the OTCQX market under the symbol "RVRA" on August 8, 2018.

Commodity Derivatives

During the year ended December 31, 2018, the Company entered into commodity derivative contracts consisting of natural gas basis swaps for March 2018 through December 2020, oil fixed price swaps for October 2018 through December 2020, natural gas fixed price swaps for 2019 and 2020 and natural gas collars for 2019. In addition, the Company entered into NGL fixed price swaps for 2019 to hedge purchase costs and margins of its Blue Mountain Midstream Business. In April 2018, in connection with the closing of the Altamont Bluebell Assets Sale, the Company canceled its oil collars for 2018 and 2019. The Company paid net cash settlements of approximately $20 million for the cancellations.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Continued

Results of Operations

The following table reflects the Company's results of operations for each of the Successor and Predecessor periods presented:

(in thousands)	Successor: Year Ended December 31, 2018	Successor: Ten Months Ended December 31, 2017	Predecessor: Two Months Ended February 28, 2017
Revenues and other:			
Natural gas sales	$ 250,831	$ 317,529	$ 99,561
Oil sales	74,696	258,055	58,560
NGL sales	94,575	133,779	30,764
Total oil, natural gas and NGL sales	420,102	709,363	188,885
Gains (losses) on commodity derivatives	(23,404)	13,533	92,691
Marketing and other revenues [1]	268,961	103,782	16,551
	665,659	826,678	298,127
Expenses:			
Lease operating expenses	120,097	208,446	49,665
Transportation expenses	83,562	113,128	25,972
Marketing expenses	220,971	69,008	4,820
General and administrative expenses [2]	245,291	117,347	71,745
Exploration costs	5,178	3,137	93
Depreciation, depletion and amortization	94,958	133,711	47,155
Impairment of long-lived assets	15,697	—	—
Taxes, other than income taxes	29,730	47,553	14,877
(Gains) losses on sale of assets and other, net	(208,598)	(623,583)	672
	606,886	68,747	214,999
Other income and (expenses)	(3,094)	(18,613)	(16,874)
Reorganization items, net	(5,159)	(8,533)	2,521,137
Income from continuing operations before income taxes	50,520	730,785	2,587,391
Income tax expense (benefit)	29,587	385,654	(166)
Income from continuing operations	20,933	345,131	2,587,557
Income (loss) from discontinued operations, net of income taxes	19,674	90,064	(548)
Net income	$ 40,607	$ 435,195	$ 2,587,009

(1) Marketing and other revenues for the two months ended February 28, 2017, include approximately $6 million of management fee revenues recognized by the Company from Berry. Management fee revenues are included in "other revenues" on the consolidated and combined statement of operations.

(2) General and administrative expenses for the year ended December 31, 2018, the ten months ended December 31, 2017, and the two months ended February 28, 2017, include approximately $132 million, $41 million and $50 million, respectively, of share-based compensation expenses and approximately $27 million, $2 million and $787,000, respectively, of severance costs. General and administrative expenses for the year ended December 31, 2018, include approximately $8 million of Spin-off related costs. In addition, general and administrative expenses for the two months ended February 28, 2017, include expenses incurred by LINN Energy associated with the operations of Berry. On February 28, 2017, LINN Energy and Berry emerged from bankruptcy as stand-alone, unaffiliated entities.

Item 7.Management's Discussion and Analysis of Financial Condition and Results of Operations - Continued

	Successor		Predecessor
	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017
Average daily production:			
Natural gas (MMcf/d)	247	386	495
Oil (MBbls/d)	3.2	17.8	20.2
NGL (MBbls/d)	10.3	20.5	21.4
Total (MMcfe/d)	328	616	745
Weighted average prices: (1)			
Natural gas (Mcf)	$ 2.78	$ 2.69	$ 3.41
Oil (Bbl)	$ 62.99	$ 47.42	$ 49.16
NGL (Bbl)	$ 25.14	$ 21.28	$ 24.37
Average NYMEX prices:			
Natural gas (MMBtu)	$ 3.09	$ 3.00	$ 3.66
Oil (Bbl)	$ 64.77	$ 50.53	$ 53.04
Costs per Mcfe of production:			
Lease operating expenses	$ 1.00	$ 1.11	$ 1.13
Transportation expenses	$ 0.70	$ 0.60	$ 0.59
General and administrative expenses (2)	$ 2.05	$ 0.62	$ 1.63
Depreciation, depletion and amortization	$ 0.79	$ 0.71	$ 1.07
Taxes, other than income taxes	$ 0.25	$ 0.25	$ 0.34
Average daily production – discontinued operations:			
Equity method investments – Total (MMcfe/d) (3)	64	30	—
California – Total (MMcfe/d) (4)	—	14	30

(1) Does not include the effect of gains (losses) on derivatives.

(2) General and administrative expenses for the year ended December 31, 2018, the ten months ended December 31, 2017, and the two months ended February 28, 2017, include approximately $132 million, $41 million and $50 million, respectively, of share-based compensation expenses and approximately $27 million, $2 million and $787,000, respectively, of severance costs. General and administrative expenses for the year ended December 31, 2018, include approximately $8 million of Spin-off related costs. In addition, general and administrative expenses for the two months ended February 28, 2017, include expenses incurred by LINN Energy associated with the operations of Berry. On February 28, 2017, LINN Energy and Berry emerged from bankruptcy as stand-alone, unaffiliated entities.

(3) Represents the Company's historical 50% equity interest in Roan. Production of Roan for 2018 is for the period from January 1, 2018 through July 25, 2018. Production of Roan for 2017 is for the period from September 1, 2017 through December 31, 2017.

(4) Production of California properties is for the period from January 1, 2017 through July 31, 2017.

Upstream Reporting Segment

	Successor		Predecessor
(in thousands)	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017
Oil, natural gas and NGL sales	$ 420,102	$ 709,363	$ 188,885
Marketing and other revenues	126,943	96,595	15,914
	547,045	805,958	204,799
Lease operating expenses	120,097	208,446	49,665
Transportation expenses	83,562	113,128	25,972
Marketing expenses	91,869	64,225	4,602
Severance taxes and ad valorem taxes	28,598	47,290	14,773
Total direct operating expenses	324,126	433,089	95,012
Field level cash flow (1)	$ 222,919	$ 372,869	$ 109,787

(1) Refer to Note 19 for a reconciliation of field level cash flow to income from continuing operations before income taxes.

Oil, Natural Gas and NGL Sales

Oil, natural gas and NGL sales decreased by approximately $478 million or 53% to approximately $420 million for the year ended December 31, 2018, from approximately $709 million and $189 million for the ten months ended December 31, 2017, and the two months ended February 28, 2017, respectively, due to lower production volumes as a result of divestitures completed in 2017 and 2018 partially offset by higher commodity prices. Higher oil and NGL prices resulted in an increase in revenues of approximately $18 million and $12 million, respectively. Lower natural gas prices resulted in a decrease in revenues of approximately $3 million.

Average daily production volumes decreased to approximately 328 MMcfe/d for the year ended December 31, 2018, from approximately 616 MMcfe/d and 745 MMcfe/d for the ten months ended December 31, 2017, and the two months ended February 28, 2017, respectively. Lower oil, natural gas and NGL production volumes resulted in a decrease in revenues of approximately $260 million, $162 million and $83 million, respectively.

The following table sets forth average daily production by region:

	Successor		Predecessor
	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017
Average daily production (MMcfe/d):			
Hugoton Basin	138	166	158
Mid-Continent	53	98	110
East Texas	50	53	52
Michigan/Illinois	28	29	29
North Louisiana	26	29	28
Uinta Basin	23	184	294
Permian Basin	10	44	49
South Texas	—	13	25
	328	616	745

The decrease in average daily production volumes in the Mid-Continent region primarily reflects lower production volumes as a result of LINN Energy's contribution of certain upstream assets located in Oklahoma to Roan on August 31, 2017, in exchange for a 50% equity interest in Roan (the "Roan Contribution") partially offset by increased development capital spending in the region. The decreases in average daily production volumes in the Hugoton Basin, Uinta Basin, Permian Basin and South Texas regions primarily reflect lower production volumes as a result of divestitures completed during 2017 and 2018. See Note 4 for additional information of divestitures. In addition, the decreases in average daily production volumes in these and the remaining regions reflect lower production volumes as a result of natural declines and reduced development capital spending driven by continued low commodity prices and other capital allocation decisions.

Marketing and Other Revenues

	Successor		Predecessor
(in thousands)	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017
Jayhawk Plant	$ 99,361	$ 71,990	$ 5,242
Helium	22,135	19,461	3,795
Other	5,447	5,144	6,877
	$ 126,943	$ 96,595	$ 15,914

Marketing and other revenues increased by approximately $14 million or 13% to approximately $127 million for the year ended December 31, 2018, from approximately $97 million and $16 million for the ten months ended December 31, 2017, and the two months ended February 28, 2017, respectively. Jayhawk Plant revenues increased primarily due to a change in contract terms. Other primarily includes revenues from other midstream systems in the East Texas and North Louisiana regions as well as management fee revenues recognized by the Company from Berry in the Predecessor period.

Lease Operating Expenses

Lease operating expenses include expenses such as labor, field office, vehicle, supervision, maintenance, tools and supplies, and workover expenses. Lease operating expenses decreased by approximately $138 million or 53% to approximately $120 million for the year ended December 31, 2018, from approximately $208 million and $50 million for the ten months ended December 31, 2017, and the two months ended February 28, 2017, respectively. The decrease was primarily due to the divestitures completed in 2017 and 2018 and reduced labor costs for field operations as a result of cost savings initiatives. Lease operating expenses per Mcfe decreased to $1.00 per Mcfe for the year ended December 31, 2018, from $1.11 per Mcfe and $1.13 per Mcfe for the ten months ended December 31, 2017, and the two months ended February 28, 2017, respectively, due to change in the asset mix.

Transportation Expenses

Transportation expenses decreased by approximately $55 million or 40% to approximately $84 million for the year ended December 31, 2018, from approximately $113 million and $26 million for the ten months ended December 31, 2017, and the two months ended February 28, 2017, respectively. The decrease was due to reduced costs as a result of lower production volumes primarily as a result of the divestitures completed in 2017 and 2018. Transportation expenses per Mcfe increased to $0.70 per Mcfe for the year ended December 31, 2018, from $0.60 per Mcfe and $0.59 per Mcfe for the ten months ended December 31, 2017, and the two months ended February 28, 2017, respectively, due to change in the asset mix.

Marketing Expenses

Marketing expenses represent third-party activities associated with company-owned gathering systems, plants and facilities. Marketing expenses increased by approximately $23 million or 33% to approximately $92 million for the year ended December 31, 2018, from approximately $64 million and $5 million for the ten months ended December 31, 2017, and the two months ended February 28, 2017, respectively. The increase was primarily due to higher expenses associated with the Jayhawk Plant, principally driven by a change in contract terms.

Severance and Ad Valorem Taxes

(in thousands)	Successor Year Ended December 31, 2018	Successor Ten Months Ended December 31, 2017	Predecessor Two Months Ended February 28, 2017
Severance taxes	$ 14,447	$ 30,074	$ 9,107
Ad valorem taxes	14,151	17,216	5,666
	$ 28,598	$ 47,290	$ 14,773

Severance taxes, which are a function of revenues generated from production, decreased primarily due to lower production volumes. Ad valorem taxes, which are based on the value of reserves and production equipment and vary by location, decreased primarily due to divestitures completed in 2017 and 2018.

Field Level Cash Flow

Field level cash flow decreased by approximately $260 million to approximately $223 million for the year ended December 31, 2018, from approximately $373 million and $110 million for the ten months ended December 31, 2017, and the two months ended February 28, 2017, respectively. The decrease was primarily due to the divestitures completed in 2017 and 2018.

Blue Mountain Reporting Segment

(in thousands)	Successor Year Ended December 31, 2018	Successor Ten Months Ended December 31, 2017	Predecessor Two Months Ended February 28, 2017
Marketing revenues	$ 142,018	$ 7,187	$ 637
Marketing expenses	127,263	4,783	218
Severance taxes and ad valorem taxes	883	121	78
Total direct operating expenses	128,146	4,904	296
Field level cash flow (1)	$ 13,872	$ 2,283	$ 341

(1) Refer to Note 19 for a reconciliation of field level cash flow to income from continuing operations before income taxes.

Marketing Revenues

Marketing revenues increased by approximately $134 million to approximately $142 million for the year ended December 31, 2018, from approximately $7 million and $637,000 for the ten months ended December 31, 2017, and the two months ended February 28, 2017, respectively. The increase was due to higher throughput volumes sold related to the commissioning of the cryogenic natural gas processing facility at the end of the second quarter of 2018. In addition, the Company implemented a new accounting standard related to revenues from contracts with customers adopted on January 1, 2018. As of January 1, 2018, the Company recognizes service fees for the processing of commodities purchased as a reduction to the purchase price of those commodities rather than as revenues. This recognition results in a decrease to revenues and expenses with no impact on net income.

Marketing Expenses

Marketing expenses increased by approximately $122 million to approximately $127 million for the year ended December 31, 2018, from approximately $5 million and $218,000 for the ten months ended December 31, 2017, and the two months ended February 28, 2017, respectively. The increase was due to higher throughput volumes purchased related to the commissioning of the cryogenic natural gas processing facility at the end of the second quarter of 2018. In addition, the Company implemented a new accounting standard related to revenues from contracts with customers adopted on January 1,

2018. As of January 1, 2018, the Company recognizes service fees for the processing of commodities purchased as a reduction to the purchase price of those commodities rather than as revenues. This recognition results in a decrease to revenues and expenses with no impact on net income.

Field Level Cash Flow
Field level cash flow increased by approximately $11 million primarily due to increased throughput volumes and the operations of the cryogenic natural gas processing facility during the second half of 2018.

Indirect Income and Expenses Not Allocated to Segments

Gains (Losses) on Commodity Derivatives
Gains and losses on commodity derivatives were losses of approximately $23 million for the year ended December 31, 2018, compared to gains of approximately $14 million and $93 million for the ten months ended December 31, 2017, and the two months ended February 28, 2017, respectively, representing a variance of approximately $130 million. Gains and losses on commodity derivatives were primarily due to changes in fair value of the derivative contracts. The fair value on unsettled derivative contracts changes as future commodity price expectations change compared to the contract prices on the derivatives. If the expected future commodity prices increase compared to the contract prices on the derivatives, losses are recognized; and if the expected future commodity prices decrease compared to the contract prices on the derivatives, gains are recognized.

The Company determines the fair value of its commodity derivatives utilizing pricing models that use a variety of techniques, including market quotes and pricing analysis. See "–Quantitative and Qualitative Disclosures About Market Risk" and Note 7 and Note 8 for additional details about the Company's commodity derivatives. For information about the Company's credit risk related to derivative contracts, see "–Liquidity and Capital Resources–Counterparty Credit Risk" below.

General and Administrative Expenses
General and administrative expenses are costs not directly associated with field operations and reflect the costs of employees including executive officers, related benefits, office leases and professional fees. In addition, general and administrative expenses in the Predecessor period includes costs incurred by LINN Energy associated with the operations of Berry. General and administrative expenses increased by approximately $56 million or 30% to approximately $245 million for the year ended December 31, 2018, from approximately $117 million and $72 million for the ten months ended December 31, 2017, and the two months ended February 28, 2017, respectively. The increase was primarily due to higher share-based compensation expenses, higher severance costs, transition service fees received from Berry in the prior year, higher professional services expenses primarily related to the Spin-off and accelerated rent expense, partially offset by lower salaries and benefits related expenses. General and administrative expenses per Mcfe increased to $2.05 per Mcfe for the year ended December 31, 2018, from $0.62 per Mcfe and $1.63 per Mcfe for the ten months ended December 31, 2017, and the two months ended February 28, 2017, respectively.

For professional services expenses related to the Chapter 11 proceedings that were incurred since the Petition Date, see "Reorganization Items, Net."

Exploration Costs
Exploration costs increased by approximately $2 million to approximately $5 million for the year ended December 31, 2018, from approximately $3 million and $93,000 for the ten months ended December 31, 2017, and the two months ended February 28, 2017, respectively. The increase was primarily due to higher seismic data expenses in the Northwest STACK.

Depreciation, Depletion and Amortization
Depreciation, depletion and amortization decreased by approximately $86 million or 47% to approximately $95 million for the year ended December 31, 2018, from approximately $134 million and $47 million for the ten months ended December 31, 2017, and the two months ended February 28, 2017, respectively. The decrease was primarily due to lower total production volumes, as well as lower rates as a result of the application of fresh start accounting. Depreciation, depletion and amortization per Mcfe was $0.79 per Mcfe for the year ended December 31, 2018, compared to $0.71 per Mcfe and $1.07 per Mcfe for the ten months ended December 31, 2017, and the two months ended February 28, 2017, respectively.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Continued

Impairment of Long-Lived Assets
During the year ended December 31, 2018, the Company recorded an impairment charge of approximately $16 million associated with proved oil and natural gas properties in the Uinta Basin and Michigan/Illinois regions due to a decline in commodity prices and higher operating costs. The Company recorded no impairment charges for the ten months ended December 31, 2017, or the two months ended February 28, 2017.

(Gains) Losses on Sale of Assets and Other, Net
During the year ended December 31, 2018, the Company recorded the following net gains on divestitures (see Note 4):

- Net gain of approximately $12 million on the New Mexico Assets Sale;
- Net gain of approximately $83 million, including costs to sell of approximately $2 million, on the Altamont Bluebell Assets Sale;
- Net gain of approximately $54 million, including costs to sell of approximately $2 million, on the West Texas Assets Sale; and
- Net gain of approximately $46 million, including costs to sell of approximately $1 million, on the Oklahoma and Texas Assets Sale.

During the ten months ended December 31, 2017, the Company recorded the following amounts related to divestitures (see Note 4):

- Net gain of approximately $277 million, including costs to sell of approximately $6 million, on the sale of its interest in properties located in western Wyoming to Jonah Energy LLC on May 31, 2017 (the "Jonah Assets Sale");
- Net gain of approximately $175 million, including costs to sell of approximately $2 million, on the sale of its interest in properties located in Wyoming on November 30, 2017 (the "Washakie Assets Sale);
- Net gain of approximately $116 million, including costs to sell of approximately $3 million, on the sale of its interest in properties located in the Williston Basin on November 30, 2017 (the "Williston Assets Sale");
- Net gain of approximately $30 million, including costs to sell of approximately $1 million, on the Salt Creek Assets Sale");
- Net gain of approximately $29 million on the sale of its interest in certain properties located in Texas and New Mexico on August 31, 2017 (the "Permian Assets Sales");
- Advisory fees of approximately $17 million associated with the Roan Contribution; and
- Net gain of approximately $14 million, including costs to sell of approximately $1 million, on the sales of its interests in certain properties located in south Texas on September 12, 2017, August 1, 2017, and July 31, 2017 (collectively, the "South Texas Assets Sales").

Other Income and (Expenses)

	Successor		Predecessor
(in thousands)	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017
Interest expense, net of amounts capitalized	$ (2,417)	$ (12,380)	$ (16,725)
Other, net	(677)	(6,233)	(149)
	$ (3,094)	$ (18,613)	$ (16,874)

Interest expense decreased primarily due to lower outstanding debt during 2018. For the two months ended February 28, 2017, contractual interest, which was not recorded, on the Predecessor's senior notes was approximately $37 million. For the year ended December 31, 2018, interest expense is primarily related to amortization of financing fees. See "Debt" under "Liquidity and Capital Resources" below for additional details. For the year ended December 31, 2018, "other, net" is primarily related to interest income, partially offset by commitment fees for the undrawn portion of the Credit Facilities. For the ten months ended December 31, 2017, "other, net" is primarily related to commitment fees for the undrawn portion of the Riviera Credit Facility and the write-off of financing fees.

Reorganization Items, Net

The Company incurred significant costs and recognized significant gains associated with the reorganization of the Company in connection with the Chapter 11 proceedings. Reorganization items represent costs and income directly associated with the Chapter 11 proceedings since the Petition Date, and also include adjustments to reflect the carrying value of certain liabilities subject to compromise at their estimated allowed claim amounts, as such adjustments were determined. The following table summarizes the components of reorganization items included on the consolidated and combined statements of operations:

	Successor		Predecessor
(in thousands)	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017
Gain on settlement of liabilities subject to compromise	$ —	$ —	$ 3,914,964
Recognition of an additional claim for the Predecessor’s second lien notes settlement	—	—	(1,000,000)
Fresh start valuation adjustments	—	—	(591,525)
Income tax benefit related to implementation of the Plan	—	—	264,889
Legal and other professional fees	(5,055)	(8,584)	(46,961)
Terminated contracts	—	—	(6,915)
Other	(104)	51	(13,315)
Reorganization items, net	$ (5,159)	$ (8,533)	$ 2,521,137

Income Tax Expense (Benefit)

The Successor was formed as a C corporation. For federal and state income tax purposes (with the exception of the state of Texas), the Predecessor was a limited liability company treated as a partnership, in which income tax liabilities and/or benefits were passed through to the Predecessor’s unitholders. Limited liability companies are subject to Texas margin tax. In addition, certain of the Predecessor’s subsidiaries were C corporations subject to federal and state income taxes. The Company recognized income tax expense of approximately $30 million for the year ended December 31, 2018, compared to income tax expense of approximately $386 million and an income tax benefit of approximately $166,000 for the ten months ended December 31, 2017, and the two months ended February 28, 2017, respectively. The decrease is primarily due to a decrease in taxable earnings and a decrease in the federal statutory income tax rate. For the year ended December 31, 2018, the effective tax rate is higher than the statutory tax rate primarily due to nondeductible compensation in connection with the Spin-off.

Income (Loss) from Discontinued Operations, Net of Income Taxes

As a result of the Company’s internal reorganization in connection with the Spin-off, the equity interest in Roan was distributed to the Parent on the Reorganization Date and is no longer affiliated with Riviera. As such, the Company has classified the equity earnings in Roan as discontinued operations. As a result of the Company’s strategic exit from California in 2017, the Company classified the results of operations of its California properties as discontinued operations. In addition, in 2018, the Company recorded a gain of approximately $5 million for a contingent payment received related to the sale of its California properties. Income from discontinued operations, net of income taxes was approximately $20 million, $90 million and a loss of $548,000 for the year ended December 31, 2018, the ten months ended December 31, 2017, and the two months ended February 28, 2017, respectively. See Note 4 for additional information.

Net Income

Net income decreased by approximately $3.0 billion to approximately $41 million for the year ended December 31, 2018, from a net income of approximately $435 million and $2.6 billion for the ten months ended December 31, 2017, and the two months ended February 28, 2017, respectively. The decrease was primarily due to gains included in reorganization items in the Predecessor period, lower production revenue, lower gains on sales of assets and losses compared to gains on commodity derivatives, partially offset by lower expenses. See discussion above for explanations of variances.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Continued

Results of Operations

The following table reflects the Company's results of operations for each of the Successor and Predecessor periods presented:

	Successor	Predecessor	
(in thousands)	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
Revenues and other:			
Natural gas sales	$ 317,529	$ 99,561	$ 426,307
Oil sales	258,055	58,560	315,472
NGL sales	133,779	30,764	132,382
Total oil, natural gas and NGL sales	709,363	188,885	874,161
Gains (losses) on commodity derivatives	13,533	92,691	(164,330)
Marketing and other revenues (1)	103,782	16,551	129,813
	826,678	298,127	839,644
Expenses:			
Lease operating expenses	208,446	49,665	296,891
Transportation expenses	113,128	25,972	161,574
Marketing expenses	69,008	4,820	29,736
General and administrative expenses (2)	117,347	71,745	237,841
Exploration costs	3,137	93	4,080
Depreciation, depletion and amortization	133,711	47,155	342,614
Impairment of long-lived assets	—	—	165,044
Taxes, other than income taxes	47,553	14,877	67,644
(Gains) losses on sale of assets and other, net	(623,583)	672	15,558
	68,747	214,999	1,320,982
Other income and (expenses)	(18,613)	(16,874)	(187,215)
Reorganization items, net	(8,533)	2,521,137	336,120
Income (loss) from continuing operations before income taxes	730,785	2,587,391	(332,433)
Income tax expense (benefit)	385,654	(166)	11,300
Income (loss) from continuing operations	345,131	2,587,557	(343,733)
Income (loss) from discontinued operations, net of income taxes	90,064	(548)	(18,354)
Net income (loss)	$ 435,195	$ 2,587,009	$ (362,087)

(1) Marketing and other revenues for the two months ended February 28, 2017, and the year ended December 31, 2016, include approximately $6 million and $69 million, respectively, of management fee revenues recognized by the Company from Berry. Management fee revenues are included in "other revenues" on the consolidated statements of operations.

(2) General and administrative expenses for the ten months ended December 31, 2017, the two months ended February 28, 2017, and the year ended December 31, 2016, include approximately $41 million, $50 million and $34 million, respectively, of noncash share-based compensation expenses. In addition, general and administrative expenses for the two months ended February 28, 2017, and the year ended December 31, 2016, include expenses incurred by LINN Energy associated with the operations of Berry. On February 28, 2017, LINN Energy and Berry emerged from bankruptcy as stand-alone, unaffiliated entities.

Item 7.Management's Discussion and Analysis of Financial Condition and Results of Operations - Continued

	Successor		Predecessor			
	Ten Months Ended December 31, 2017		Two Months Ended February 28, 2017		Year Ended December 31, 2016	
Average daily production:						
Natural gas (MMcf/d)		386		495		511
Oil (MBbls/d)		17.8		20.2		22.1
NGL (MBbls/d)		20.5		21.4		25.4
Total (MMcfe/d)		616		745		796
Weighted average prices: (1)						
Natural gas (Mcf)	$	2.69	$	3.41	$	2.28
Oil (Bbl)	$	47.42	$	49.16	$	39.00
NGL (Bbl)	$	21.28	$	24.37	$	14.26
Average NYMEX prices:						
Natural gas (MMBtu)	$	3.00	$	3.66	$	2.46
Oil (Bbl)	$	50.53	$	53.04	$	43.32
Costs per Mcfe of production:						
Lease operating expenses	$	1.11	$	1.13	$	1.02
Transportation expenses	$	0.60	$	0.59	$	0.55
General and administrative expenses (2)	$	0.62	$	1.63	$	0.82
Depreciation, depletion and amortization	$	0.71	$	1.07	$	1.18
Taxes, other than income taxes	$	0.25	$	0.34	$	0.23
Average daily production – discontinued operations:						
Equity method investments – Total (MMcfe/d) (3)		30		—		—
California – Total (MMcfe/d) (4)		14		30		32

(1) Does not include the effect of gains (losses) on derivatives.

(2) General and administrative expenses for the ten months ended December 31, 2017, the two months ended February 28, 2017, and the year ended December 31, 2016, include approximately $41 million, $50 million and $34 million, respectively, of noncash share-based compensation expenses. In addition, general and administrative expenses for the two months ended February 28, 2017, and the year ended December 31, 2016, include expenses incurred by LINN Energy associated with the operations of Berry. On February 28, 2017, LINN Energy and Berry emerged from bankruptcy as stand-alone, unaffiliated entities.

(3) Represents the Company's 50% equity interest in Roan. Production of Roan for 2017 is for the period from September 1, 2017 through December 31, 2017.

(4) Production of the Company's California properties reported as discontinued operations for 2017 is for the period from January 1, 2017 through July 31, 2017.

Upstream Reporting Segment

	Successor	Predecessor	
	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
(in thousands)			
Oil, natural gas and NGL sales	$ 709,363	$ 188,885	$ 874,161
Marketing and other revenues	96,595	15,914	129,648
	805,958	204,799	1,003,809
Lease operating expenses	208,446	49,665	296,891
Transportation expenses	113,128	25,972	161,574
Marketing expenses	64,225	4,602	28,510
Severance taxes and ad valorem taxes	47,290	14,773	66,616
Total direct operating expenses	433,089	95,012	553,591
Field level cash flow (1)	$ 372,869	$ 109,787	$ 450,218

(1) Refer to Note 19 for a reconciliation of field level cash flow to income (loss) from continuing operations before income taxes.

Oil, Natural Gas and NGL Sales

Oil, natural gas and NGL sales increased by approximately $24 million or 3% to approximately $709 million and $189 million for the ten months ended December 31, 2017, and the two months ended February 28, 2017, respectively, from approximately $874 million for the year ended December 31, 2016, due to higher commodity prices, partially offset by lower production volumes. Higher natural gas, oil and NGL prices resulted in an increase in revenues of approximately $81 million, $58 million and $57 million, respectively.

Average daily production volumes decreased to approximately 616 MMcfe/d and 745 MMcfe/d for the ten months ended December 31, 2017, and the two months ended February 28, 2017, respectively, from approximately 796 MMcfe/d for the year ended December 31, 2016. Lower natural gas, oil and NGL production volumes resulted in a decrease in revenues of approximately $91 million, $56 million and $25 million, respectively.

The following table sets forth average daily production by region:

	Successor	Predecessor	
	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
Average daily production (MMcfe/d):			
Hugoton Basin	166	158	180
Mid-Continent	98	110	101
East Texas	53	52	57
Michigan/Illinois	29	29	30
North Louisiana	29	28	15
Uinta Basin	184	294	330
Permian Basin	44	49	56
South Texas	13	25	27
	616	745	796

The increase from 2016 in average daily production volumes in the North Louisiana region primarily reflects increased development capital spending in the region. The decrease from 2016 in average daily production volumes in the Mid-Continent region primarily reflects lower production volumes as a result of the Roan Contribution on August 31, 2017, partially offset by increased development capital spending in the region. The decreases in average daily production volumes in the Uinta Basin, Permian Basin and South Texas regions primarily reflect lower production volumes as a result of divestitures completed during 2017. See Note 4 for additional information of divestitures. In addition, the decreases in average daily production volumes in these and the remaining regions reflect lower production volumes as a result of reduced development capital spending, as well as marginal well shut-ins, driven by continued low commodity prices.

Marketing and Other Revenues

	Successor	Predecessor	
	Ten Months Ended December 31, 2017	**Two Months Ended February 28, 2017**	**Year Ended December 31, 2016**
(in thousands)			
Jayhawk Plant	$ 71,990	$ 5,242	$ 26,845
Helium	19,461	3,795	24,188
Other	5,144	6,877	78,615
	$ 96,595	$ 15,914	$ 129,648

Marketing and other revenues decreased by approximately $17 million or 13% to approximately $97 million and $16 million for the ten months ended December 31, 2017, and the two months ended February 28, 2017, respectively, from approximately $130 million for the year ended December 31, 2016. Jayhawk Plant revenues increased primarily due to a change in contract terms. Other primarily includes revenues from other midstream systems in the East Texas and North Louisiana regions as well as management fee revenues recognized by the Company from Berry in the Predecessor periods.

Lease Operating Expenses

Lease operating expenses include expenses such as labor, field office, vehicle, supervision, maintenance, tools and supplies, and workover expenses. Lease operating expenses decreased by approximately $39 million or 13% to approximately $208 million and $50 million for the ten months ended December 31, 2017, and the two months ended February 28, 2017, respectively, from approximately $297 million for the year ended December 31, 2016. The decrease was primarily due to reduced labor costs for field operations as a result of cost savings initiatives and the divestitures completed in 2017. Lease operating expenses per Mcfe increased to $1.11 per Mcfe and $1.13 per Mcfe for the ten months ended December 31, 2017, and the two months ended February 28, 2017, respectively, from $1.02 per Mcfe for the year ended December 31, 2016.

Transportation Expenses

Transportation expenses decreased by approximately $23 million or 14% to approximately $113 million and $26 million for the ten months ended December 31, 2017, and the two months ended February 28, 2017, respectively, from approximately $162 million for the year ended December 31, 2016. The decrease was primarily due to reduced costs as a result of lower production volumes and as a result of the divestitures completed in 2017. Transportation expenses per Mcfe increased to $0.60 per Mcfe and $0.59 per Mcfe per Mcfe for the ten months ended December 31, 2017, and the two months ended February 28, 2017, respectively, from $0.55 per Mcfe for the year ended December 31, 2016.

Marketing Expenses

Marketing expenses represent third-party activities associated with company-owned gathering systems, plants and facilities. Marketing expenses increased by approximately $40 million or 141% to approximately $64 million and $5 million for the ten months ended December 31, 2017, and the two months ended February 28, 2017, respectively, from approximately $29 million for the year ended December 31, 2016. The increase was primarily due to higher expenses associated with the Jayhawk natural gas processing plant in Kansas, principally driven by a change in contract terms.

Severance and Ad Valorem Taxes

	Successor	Predecessor	
	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
(in thousands)			
Severance taxes	$ 30,074	$ 9,107	$ 38,166
Ad valorem taxes	17,216	5,666	28,450
	$ 47,290	$ 14,773	$ 66,616

Severance taxes, which are a function of revenues generated from production, increased primarily due to higher commodity prices, partially offset by lower production volumes. Ad valorem taxes, which are based on the value of reserves and production equipment and vary by location, decreased primarily due to divestitures completed in 2017 and lower estimated valuations on certain of the Company's properties.

Field Level Cash Flow
Field level cash flow increased by approximately $33 million to $373 million and $110 million for the ten months ended December 31, 2017, and the two months ended February 28, 2017, from approximately $450 million for the year ended December 31, 2016. The increase was primarily due to higher commodity revenues as a result of higher commodity prices and lower expenses due to divestitures in 2017, partially offset by lower management fee revenues from Berry.

Blue Mountain Reporting Segment

	Successor	Predecessor	
	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
(in thousands)			
Marketing revenues	$ 7,187	$ 637	$ 165
Marketing expenses	4,783	218	1,226
Severance taxes and ad valorem taxes	121	78	—
Total direct operating expenses	4,904	296	1,226
Field level cash flow (1)	$ 2,283	$ 341	$ (1,061)

(1) Refer to Note 19 for a reconciliation of field level cash flow to income (loss) from continuing operations before income taxes.

Marketing Revenues
Marketing revenues increased by approximately $8 million to approximately $7 million and $637,000 for the ten months ended December 31, 2017, and the two months ended February 28, 2017, respectively, from approximately $165,000 for the year ended December 31, 2016. The increase was due to higher throughput volumes sold related to the commissioning of the refrigeration plant commissioned during the fourth quarter of 2017.

Marketing Expenses
Marketing expenses increased by approximately $4 million to approximately $5 million and $218,000 for the ten months ended December 31, 2017, and the two months ended February 28, 2017, respectively, from approximately $1 million for the year ended December 31, 2016. The increase was due to higher throughput volumes sold related to the commissioning of the refrigeration plant commissioned during the fourth quarter of 2017.

Field Level Cash Flow
Field level cash flow increased by approximately $4 million primarily due to increased throughput volumes.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Continued

Indirect Income and Expenses Not Allocated to Segments

Gains (Losses) on Commodity Derivatives
Gains on commodity derivatives were approximately $14 million and $93 million for the ten months ended December 31, 2017, and the two months ended February 28, 2017, respectively, compared to losses on commodity derivatives of approximately $164 million for the year ended December 31, 2016, representing a variance of approximately $271 million. Gains on commodity derivatives were primarily due to changes in fair value of the derivative contracts. The fair value on unsettled derivative contracts changes as future commodity price expectations change compared to the contract prices on the derivatives. If the expected future commodity prices increase compared to the contract prices on the derivatives, losses are recognized; and if the expected future commodity prices decrease compared to the contract prices on the derivatives, gains are recognized.

The Company determines the fair value of its commodity derivatives utilizing pricing models that use a variety of techniques, including market quotes and pricing analysis. See "–Quantitative and Qualitative Disclosures About Market Risk" and Note 7 and Note 8 for additional details about the Company's commodity derivatives. For information about the Company's credit risk related to derivative contracts, see "–Liquidity and Capital Resources–Counterparty Credit Risk" below.

General and Administrative Expenses
General and administrative expenses are costs not directly associated with field operations and reflect the costs of employees including executive officers, related benefits, office leases and professional fees. In addition, general and administrative expenses in the Predecessor periods include costs incurred by LINN Energy associated with the operations of Berry. General and administrative expenses decreased by approximately $49 million or 20% to approximately $117 million and $72 million for the ten months ended December 31, 2017, and the two months ended February 28, 2017, respectively, from approximately $238 million for the year ended December 31, 2016. The decrease was primarily due to lower salaries and benefits related expenses, the costs associated with the operations of Berry in the Predecessor periods, lower various other administrative expenses including insurance and rent, and lower professional services expenses, partially offset by higher noncash share-based compensation expenses principally driven by the immediate vesting of certain awards on the Effective Date. General and administrative expenses per Mcfe were $0.62 per Mcfe and $1.63 per Mcfe for the ten months ended December 31, 2017, and the two months ended February 28, 2017, respectively, compared to $0.82 per Mcfe for the year ended December 31, 2016.

For professional services expenses related to the Chapter 11 proceedings that were incurred since the Petition Date, see "Reorganization Items, Net."

Exploration Costs
Exploration costs decreased by approximately $1 million to approximately $3 million and $93,000 for the ten months ended December 31, 2017, and the two months ended February 28, 2017, respectively, from approximately $4 million for the year ended December 31, 2016. The decrease was primarily due to lower seismic data expenses.

Depreciation, Depletion and Amortization
Depreciation, depletion and amortization decreased by approximately $162 million or 47% to approximately $134 million and $47 million for the ten months ended December 31, 2017, and the two months ended February 28, 2017, respectively, from approximately $343 million for the year ended December 31, 2016. The decrease was primarily due to lower rates as a result of the application of fresh start accounting, as well as lower total production volumes. Depreciation, depletion and amortization per Mcfe also decreased to $0.71 per Mcfe and $1.07 per Mcfe for the ten months ended December 31, 2017, and the two months ended February 28, 2017, respectively, from $1.18 per Mcfe for the year ended December 31, 2016.

Impairment of Long-Lived Assets
The Company recorded no impairment charges for the ten months ended December 31, 2017, or the two months ended February 28, 2017. During the year ended December 31, 2016, the Company recorded an impairment charge of approximately $165 million associated with proved oil and natural gas properties in the Mid-Continent and Uinta Basin regions due to a decline in commodity prices, changes in expected capital development and a decline in the Company's estimates of proved reserves.

(Gains) Losses on Sale of Assets and Other, Net

During the ten months ended December 31, 2017, the Company recorded the following amounts related to divestitures (see Note 4):

- Net gain of approximately $277 million, including costs to sell of approximately $6 million, on the Jonah Assets Sale;
- Net gain of approximately $175 million, including costs to sell of approximately $2 million, on the Washakie Assets Sale;
- Net gain of approximately $116 million, including costs to sell of approximately $3 million, on the Williston Assets Sale;
- Net gain of approximately $30 million, including costs to sell of approximately $1 million, on the Salt Creek Assets Sale;
- Net gain of approximately $29 million on the Permian Assets Sales;
- Advisory fees of approximately $17 million associated with the Roan Contribution; and
- Net gain of approximately $14 million, including costs to sell of approximately $1 million, on the South Texas Assets Sales.

Other Income and (Expenses)

	Successor	Predecessor	
	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
(in thousands)			
Interest expense, net of amounts capitalized	$ (12,380)	$ (16,725)	$ (184,870)
Other, net	(6,233)	(149)	(2,345)
	$ (18,613)	$ (16,874)	$ (187,215)

Interest expense decreased primarily due to lower outstanding debt during 2017, the Company's discontinuation of interest expense recognition on the senior notes for the two months ended February 28, 2017, as a result of the Chapter 11 proceedings, and lower amortization of discounts and financing fees. For the two months ended February 28, 2017, and the period from May 12, 2016 through December 31, 2016, contractual interest, which was not recorded, on the senior notes was approximately $37 million and $143 million, respectively. See "Debt" under "Liquidity and Capital Resources" below for additional details.

The second lien notes were accounted for as a troubled debt restructuring which requires that interest payments on the second lien notes reduce the carrying value of the debt with no interest expense recognized. For the two months ended February 28, 2017, and the period from May 12, 2016 through December 31, 2016, unrecorded contractual interest on the second lien notes was approximately $20 million and $76 million, respectively.

Reorganization Items, Net

The Company incurred significant costs and recognized significant gains associated with the reorganization of the Company in connection with the Chapter 11 proceedings. Reorganization items represent costs and income directly associated with the Chapter 11 proceedings since the Petition Date, and also include adjustments to reflect the carrying value of certain liabilities subject to compromise at their estimated allowed claim amounts, as such adjustments were determined. The following table summarizes the components of reorganization items included on the consolidated and combined statements of operations:

	Successor	Predecessor	
(in thousands)	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
Gain on settlement of liabilities subject to compromise	$ —	$ 3,914,964	$ —
Recognition of an additional claim for the Predecessor's second lien notes settlement	—	(1,000,000)	—
Fresh start valuation adjustments	—	(591,525)	—
Income tax benefit related to implementation of the Plan	—	264,889	—
Legal and other professional fees	(8,584)	(46,961)	(56,656)
Unamortized deferred financing fees, discounts and premiums	—	—	(52,045)
Gains related to interest payable on Predecessor's second lien notes	—	—	551,000
Terminated contracts	—	(6,915)	(66,052)
Other	51	(13,315)	(40,127)
Reorganization items, net	$ (8,533)	$ 2,521,137	$ 336,120

Income Tax Expense (Benefit)

The Successor was formed as a C corporation. For federal and state income tax purposes (with the exception of the state of Texas), the Predecessor was a limited liability company treated as a partnership, in which income tax liabilities and/or benefits were passed through to the Predecessor's unitholders. Limited liability companies are subject to Texas margin tax. In addition, certain of the Predecessor's subsidiaries were C corporations subject to federal and state income taxes. The Company recognized income tax expense of approximately $386 million and an income tax benefit of approximately $166,000 for the ten months ended December 31, 2017, and the two months ended February 28, 2017, respectively, compared to income tax expense of approximately $11 million for the year ended December 31, 2016.

Income (Loss) from Discontinued Operations, Net of Income Taxes

As a result of the Company's internal reorganization in connection with the Spin-off, the equity interest in Roan was distributed to the Parent on the Reorganization Date and is no longer affiliated with Riviera. As such, the Company has classified the equity earnings in Roan as discontinued operations. As a result of the Company's strategic exit from California (completed by the San Joaquin Basin Sale and Los Angeles Basin Sale), the Company has classified the results of operations of its California properties as discontinued operations. Income from discontinued operations, net of income taxes was approximately $90 million for the ten months ended December 31, 2017, compared to losses of approximately $548,000 and $18 million for the two months ended February 28, 2017, and the year ended December 31, 2016, respectively. See Note 4 for additional information.

Net Income (Loss) Attributable to Common Stockholders/Unitholders

Net income increased by approximately $3.4 billion to net income of approximately $435 million and $2.6 billion for the ten months ended December 31, 2017, and the two months ended February 28, 2017, respectively, from a net loss of approximately $362 million for the year ended December 31, 2016. The increase was primarily due to higher gains included in reorganization items, gains on the divestitures completed in 2017, gains compared to losses on commodity derivatives, lower expenses, lower impairment charges, income compared to losses from discontinued operations and higher production revenues. See discussion above for explanations of variances.

Liquidity and Capital Resources

The Company's sources of cash have primarily consisted of proceeds from its divestitures of oil and natural gas properties and net cash provided by operating activities. As a result of divesting certain oil and natural gas properties during the year ended December 31, 2018, the Company received approximately $367 million in net cash proceeds. The Company has also used its cash to fund capital expenditures, principally for the development of its oil and natural gas properties, and plant and pipeline construction, the Parent's repurchases of LINN Energy, Inc. Class A common stock prior to the Spin-off, and repurchases of Riviera's common stock subsequent to the Spin-off. Based on current expectations, the Company believes its liquidity and capital resources will be sufficient to conduct its business and operations.

See below for details regarding capital expenditures for the periods presented:

	Successor		Predecessor	
(in thousands)	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
Oil and natural gas	$ 36,251	$ 199,866	$ 39,409	$ 126,876
Plant and pipeline	131,576	93,318	4,990	36,433
Other	2,434	5,626	1,243	8,315
Capital expenditures, excluding acquisitions	$ 170,261	$ 298,810	$ 45,642	$ 171,624
Capital expenditures, excluding acquisitions – discontinued operations	$ —	$ 2,033	$ 436	$ 1,109

The decrease in capital expenditures was primarily due to lower oil and natural gas development activities, partially offset by higher plant and pipeline construction activities associated with Blue Mountain Midstream. For 2019, the Company estimates its total capital expenditures, excluding acquisitions and Blue Mountain, will be approximately $66 million, including approximately $61 million related to its oil and natural gas capital program. This estimate is under continuous review and subject to ongoing adjustments.

Statements of Cash Flows

The following is a comparative cash flow summary:

	Successor	Predecessor		
(in thousands)	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
Net cash:				
Net cash provided by (used in) operating activities	$ (6,594)	$ 231,021	$ 152,714	$ 875,306
Net cash provided by (used in) investing activities	168,162	1,257,352	(58,756)	(230,438)
Net cash used in financing activities	(632,713)	(1,111,473)	(437,730)	(164,150)
Net increase (decrease) in cash, cash equivalents and restricted cash	$ (471,145)	$ 376,900	$ (343,772)	$ 480,718

Operating Activities

Cash used in operating activities was approximately $7 million for the year ended December 31, 2018, compared to cash provided by operating activities of approximately $231 million and $153 million for the ten months ended December 31, 2017, and the two months ended February 28, 2017, respectively. The decrease was primarily due to lower production related revenues principally due to lower production volumes, the cash settlement of liability classified share-based payment awards, higher severance costs and cash settlements on canceled commodity derivatives.

Cash provided by operating activities was approximately $231 million and $153 million for the ten months ended December 31, 2017, and the two months ended February 28, 2017, respectively, compared to approximately $875 million for the year ended December 31, 2016. The decrease was primarily due to lower cash settlements on derivatives, partially offset by higher production related revenues principally due to higher commodity prices.

Investing Activities
The following provides a comparative summary of cash flow from investing activities:

	Successor		Predecessor	
(in thousands)	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
Cash flow from investing activities:				
Capital expenditures	$ (207,129)	$ (260,316)	$ (58,006)	$ (215,857)
Proceeds from sale of properties and equipment and other	368,291	1,172,025	(166)	(4,690)
Net cash provided by (used in) operating activities – continuing operations	161,162	911,709	(58,172)	(220,547)
Net cash provided by (used in) operating activities – discontinued operations	7,000	345,643	(584)	(9,891)
Net cash provided by (used in) operating activities	$ 168,162	$ 1,257,352	$ (58,756)	$ (230,438)

The primary use of cash in investing activities is for the development of the Company's oil and natural gas properties and construction of Blue Mountain Midstream's cryogenic natural gas processing facility. Capital expenditures decreased primarily due to lower oil and natural gas capital spending, partially offset by higher spending on plant and pipeline construction related to Blue Mountain Midstream. The Company made no material acquisitions of properties during the year ended December 31, 2018. The Company has classified the cash flows of its California properties as discontinued operations.

Proceeds from sale of properties and equipment and other for the year ended December 31, 2018, include cash proceeds received of approximately $107 million from the West Texas Assets Sale, approximately $97 million (excluding a deposit of approximately $12 million received in 2017) from the Oklahoma and Texas Assets Sale, approximately $131 million related to the Altamont Bluebell Assets Sale, approximately $14 million related to the New Mexico Assets Sale and a deposit of approximately $5 million received from the Arkoma Assets Sale. Proceeds from sale of properties and equipment and other for the ten months ended December 31, 2017, include cash proceeds received of approximately $258 million from the Williston Asset Sale, approximately $195 million from the Washakie Asset Sale, approximately $49 million from the South Texas Assets Sales, approximately $31 million from the Permian Basin Asset Sales, approximately $74 million from the Salt Creek Assets Sale and approximately $565 million from the Jonah Assets Sale. In addition, $3 million received from the 2017 divestitures and approximately $12 million received from divestitures that closed in 2018 were in escrow and classified as restricted cash. See Note 4 for additional details of divestitures.

Financing Activities
Cash used in financing activities was approximately $633 million for the year ended December 31, 2018, compared to approximately $1.1 billion and $438 million for the ten months ended December 30, 2017, and the two months ended February 28, 2017, respectively. During the year ended December 31, 2018, prior to the Spin-off the primary use of cash in financing activities was transfers to the Parent to fund repurchases of the Parent's common stock and settlement of the Parent's restricted stock units (see Note 13). Since the Spin-off, the primary use of cash in financing activities was for repurchases of Riviera's common stock. During the ten months ended December 31, 2017, and the two months ended February 28, 2017, the primary use of cash in financing activities was for repayments of debt. During the year ended December 31, 2016, the Company borrowed approximately $979 million under its credit facility, including approximately $919 million in February 2016, which represented the remaining undrawn amount that was available. In addition, during the year ended December 31, 2016, the Company repaid approximately $913 million under its credit facility and term loan, primarily using the net cash proceeds from canceled derivative contracts (see Note 7).

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Continued

The following provides a comparative summary of proceeds from borrowings and repayments of debt:

	Successor		Predecessor	
(in thousands)	Year Ended December 31, 2018	Ten Months Ended December 30, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
Proceeds from borrowings:				
Riviera Credit Facility	$ 40,000	$ —	$ —	$ —
Blue Mountain Credit Facility	4,500	—	—	—
Successor's previous credit facility	—	190,000	—	—
Predecessor's credit facility	—	—	—	978,500
	$ 44,500	$ 190,000	$ —	$ 978,500
Repayments of debt:				
Riviera Credit Facility	$ (20,000)	$ —	$ —	$ —
Successor's previous credit facility	—	(790,000)	—	—
Successor term loan	—	(300,000)	—	—
Predecessor's credit facility	—	—	(1,038,986)	(814,298)
Predecessor's bridge loan and term loan	—	—	—	(98,911)
	$ (20,000)	$ (1,090,000)	$ (1,038,986)	$ (913,209)

On February 28, 2017, the Company canceled its obligations under the Predecessor's credit facility and entered into the Successor's previous credit facility, which was a net transaction and is reflected as such on the consolidated and combined statement of cash flows. In addition, in February 2017, the Company made a $30 million payment to holders of claims under the Predecessor's second lien notes. See Note 16 for details about the Company's borrowings and repayments of debt that were reflected as noncash transactions.

Debt

At February 28, 2019, there were no borrowings outstanding and approximately $351 million of available borrowing capacity under the Riviera Credit Facility (which includes a $34 million reduction for outstanding letters of credit). In addition, at February 28, 2019, total borrowings outstanding under the Blue Mountain Credit Facility were approximately $19 million and there was approximately $169 million of available borrowing capacity (which includes a $12 million reduction for outstanding letters of credit).

For additional information related to the Company's debt, see Note 6.

Share Repurchase Program

On August 16, 2018, the Board authorized the repurchase of up to $100 million of the Company's outstanding shares of common stock. During the period from August 2018 through December 31, 2018, the Company repurchased an aggregate of 945,979 shares of common stock at an average price of $19.21 per share for a total cost of approximately $18 million. For the period from January 1, 2019 through February 22, 2019, the Company repurchased 221,788 shares of common stock at an average price of $15.27 for a total cost of approximately $3 million. At February 22, 2019, approximately $78 million was available for share repurchase under the program.

In accordance with the SEC's regulations regarding issuer tender offers, the Company's share repurchase program was suspended concurrent with the September 24, 2018, announcement of the intent to commence a tender offer. The program was resumed in November 2018 following the expiration of the tender offer.

Any share repurchases are subject to restrictions in the Riviera Credit Facility.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Continued

Tender Offer

On September 24, 2018, the Board announced the intention to commence a tender offer to purchase $100 million of the Company's common stock. In October 2018, upon the terms and subject to the conditions described in the Offer to Purchase dated September 25, 2018, as amended, the Company repurchased an aggregate of 6,062,179 shares of common stock at a price of $22.00 per share for a total cost of approximately $133 million (excluding expenses of approximately $2 million related to the tender offer).

Counterparty Credit Risk

The Company accounts for its commodity derivatives at fair value. The Company's counterparties are participants in the Credit Facilities. The Credit Facilities are secured by certain of the Company's and its subsidiaries' oil, natural gas and NGL reserves and personal property; therefore, the Company is not required to post any collateral. The Company does not receive collateral from its counterparties. The Company minimizes the credit risk in derivative instruments by: (i) limiting its exposure to any single counterparty; (ii) entering into derivative instruments only with counterparties that meet the Company's minimum credit quality standard, or have a guarantee from an affiliate that meets the Company's minimum credit quality standard; and (iii) monitoring the creditworthiness of the Company's counterparties on an ongoing basis. In accordance with the Company's standard practice, its commodity derivatives are subject to counterparty netting under agreements governing such derivatives and therefore the risk of loss due to counterparty non-performance is somewhat mitigated.

Dividends

The Company is not currently paying a cash dividend; however, the Board of Directors periodically reviews the Company's liquidity position to evaluate whether or not to pay a cash dividend. Any future payment of cash dividends would be subject to the restrictions in the Riviera Credit Facility.

Contingencies

See Part I. Item 3. "Legal Proceedings" for information regarding legal proceedings that the Company is party to and any contingencies related to these legal proceedings.

Off-Balance Sheet Arrangements

The Company enters into certain off-balance sheet arrangements and transactions, including operating lease arrangements and undrawn letters of credit. In addition, the Company enters into other contractual agreements in the normal course of business for processing and transportation as well as for other oil and natural gas activities. Other than the items discussed above, there are no other arrangements, transactions or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect the Company's liquidity or capital resource positions.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Continued

Commitments and Contractual Obligations

The following is a summary of the Company's commitments and contractual obligations as of December 31, 2018:

	Payments Due				
Contractual Obligations	**Total**	**2019**	**2020-2021**	**2022-2023**	**2024-Beyond**
Long-term debt obligations:					
Credit Facilities	$ 24,500	$ —	$ 20,000	$ 4,500	$ —
Interest (1)	2,526	1,201	998	327	
Operating lease obligations:					
Office, property and equipment leases	4,611	4,054	553	4	—
Other:					
Commodity derivatives	4,719	4,719	—	—	—
Asset retirement obligations	105,259	1,445	3,236	3,190	97,388
	$ 141,615	$ 11,419	$ 24,787	$ 8,021	$ 97,388

(1) Represents interest on the Riviera Credit Facility and Blue Mountain Credit Facility computed at approximately 5.0% and 4.5%, respectively, through maturities in August 2020 and August 2023, respectively.

Critical Accounting Policies and Estimates

The discussion and analysis of the Company's financial condition and results of operations is based on the consolidated and combined financial statements, which have been prepared in accordance with U.S. generally accepted accounting principles. The preparation of these financial statements requires management of the Company to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosures of contingent assets and liabilities. These estimates and assumptions are based on management's best estimates and judgment. Management evaluates its estimates and assumptions on an ongoing basis using historical experience and other factors that are believed to be reasonable under the circumstances. Such estimates and assumptions are adjusted when facts and circumstances dictate. Actual results may differ from these estimates and assumptions used in the preparation of the financial statements.

Below are expanded discussions of the Company's more significant accounting policies, estimates and judgments, i.e., those that reflect more significant estimates and assumptions used in the preparation of its financial statements. See Note 1 for details about additional accounting policies and estimates made by Company management.

Recently Issued Accounting Standards

For a discussion of recently issued accounting standards, see Note 1.

Oil and Natural Gas Reserves

Proved reserves are based on the quantities of oil, natural gas and NGL that 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. The independent engineering firm, DeGolyer and MacNaughton, prepared a reserve and economic evaluation of all of the Company properties on a well-by-well basis as of December 31, 2018, and the reserve estimates reported herein were prepared by DeGolyer and MacNaughton. The reserve estimates were reviewed and approved by the Company's senior engineering staff and management, with final approval by its Executive Vice President and Chief Operating Officer.

Reserves and their relation to estimated future net cash flows impact the Company's depletion and impairment calculations as well as the Company's application of fresh start accounting and the deferred tax asset recorded upon completion of the Spin-off. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. The process performed by the independent engineers to prepare reserve amounts included their estimation of reserve quantities, future production rates, future net revenue and the present value of such future net revenue, based in part on data provided by the Company. The estimates of reserves conform to the guidelines of the SEC, including the criteria of "reasonable certainty," as it pertains to expectations about the recoverability of reserves in future years.

The accuracy of 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 economic assumptions and the judgments of the individuals preparing the estimates. In addition, 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, natural gas and NGL eventually recovered. For additional information regarding estimates of reserves, including the standardized measure of discounted future net cash flows, see "Supplemental Oil and Natural Gas Data (Unaudited)" in the Consolidated and Combined Financial Statements.

Oil and Natural Gas Properties

Proved Properties

The Company accounts for oil and natural gas properties in accordance with the successful efforts method. In accordance with this method, all leasehold and development costs of proved properties are capitalized and amortized on a unit-of-production basis over the remaining life of the proved reserves and proved developed reserves, respectively. Costs of retired, sold or abandoned properties that constitute a part of an amortization base are charged or credited, net of proceeds, to accumulated depreciation, depletion and amortization unless doing so significantly affects the unit-of-production amortization rate, in which case a gain or loss is recognized currently. Gains or losses from the disposal of other properties are recognized currently. Expenditures for maintenance and repairs necessary to maintain properties in operating condition are expensed as incurred. Estimated dismantlement and abandonment costs are capitalized, net of salvage, at their estimated net present value and amortized on a unit-of-production basis over the remaining life of the related proved developed reserves. The Company capitalizes interest on borrowed funds related to its share of costs associated with the drilling and completion of new oil and natural gas wells. Interest is capitalized only during the periods in which these assets are brought to their intended use.

The Company evaluates the impairment of its proved oil and natural gas properties on a field-by-field basis whenever events or changes in circumstances indicate that the carrying value may not be recoverable. The carrying values of proved properties are reduced to fair value when the expected undiscounted future cash flows of proved and risk-adjusted probable and possible reserves are less than net book value. The fair values of proved properties are measured using valuation techniques consistent with the income approach, converting future cash flows to a single discounted amount. 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. These inputs require assumptions by the Company's management at the time of the valuation and are the most sensitive and subject to change. The underlying commodity prices embedded in the Company's estimated cash flows are the product of a process that begins with NYMEX forward curve pricing, adjusted for estimated location and quality differentials, as well as other factors that Company management believes will impact realizable prices.

Based on the analysis described above, for the years ended December 31, 2018, and December 31, 2016, the Company recorded noncash impairment charges of approximately $16 million and $165 million, respectively, associated with proved oil and natural gas properties. The carrying values of the impaired proved properties were reduced to fair value, estimated using inputs characteristic of a Level 3 fair value measurement. The impairment charges are included in "impairment of long-lived assets" on the consolidated and combined statements of operations. The Company recorded no impairment charges associated with proved oil and natural gas properties during 2017.

Unproved Properties

Costs related to unproved properties include costs incurred to acquire unproved reserves. Because these reserves do not meet the definition of proved reserves, the related costs are not classified as proved properties. Unproved leasehold costs are capitalized and amortized on a composite basis if individually insignificant, based on past success, experience and average lease-term lives. Individually significant leases are reclassified to proved properties if successful and expensed on a lease by lease basis if unsuccessful or the lease term expires. Unamortized leasehold costs related to successful exploratory drilling are reclassified to proved properties and depleted on a unit-of-production basis.

The Company evaluates the impairment of its unproved oil and natural gas properties whenever events or changes in circumstances indicate that the carrying value may not be recoverable. The carrying values of unproved properties are reduced to fair value based on management's experience in similar situations and other factors such as the lease terms of the properties and the relative proportion of such properties on which proved reserves have been found in the past.

The Company recorded no impairment charges associated with unproved properties for the years ended December 31, 2018, December 31, 2017, or December 31, 2016.

Share-Based Compensation

The Company recognizes expense for share-based compensation over the requisite service period in an amount equal to the fair value of share-based awards granted. The fair value of liability classified awards is remeasured at each reporting date through the settlement date with the change in fair value recognized as compensation expense over that period. The Company has made a policy decision to recognize compensation expense for service-based awards on a straight-line basis over the requisite service period for the entire award. The Company accounts for forfeitures as they occur. See Note 13 for additional details about the Company's accounting for share-based compensation.

Income Taxes

The Company has recorded deferred taxes for temporary differences and operating losses. Deferred tax assets may be reduced by a valuation allowance if it is more likely than not that some portion or all of the deferred tax assets will not be realized. The Company routinely assesses whether its deferred tax assets are realizable by considering the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies.

For periods prior to the Spin-off, income tax expense and deferred tax balances were calculated on a separate tax return basis although Riviera's operations have historically been included in the tax returns filed by the Parent, of which Riviera's business was a part. Beginning August 8, 2018, as a stand-alone entity, Riviera will file tax returns on its own behalf and its deferred taxes and effective tax rate may differ from those in the historical periods. Upon completion of the Spin-off, on August 8, 2018, the Company recorded a deferred tax asset, the calculation of which, relied on estimates and assumptions related to the value of the company and its oil and natural gas reserves. The Company believes that the assumptions and estimates used to determine these tax amounts are reasonable.

Fresh Start Accounting

Upon LINN Energy's emergence from Chapter 11 bankruptcy, it adopted fresh start accounting in accordance with the provisions of ASC 852 which resulted in the Parent becoming a new entity for financial reporting purposes. In accordance with ASC 852, the Parent was required to adopt fresh start accounting upon its emergence from Chapter 11 because (i) the holders of existing voting ownership interests of the Predecessor of the Parent received less than 50% of the voting shares of the Successor of the Parent and (ii) the reorganization value of the Parent's assets immediately prior to confirmation of the Plan was less than the total of all postpetition liabilities and allowed claims.

Upon adoption of fresh start accounting, the reorganization value derived from the enterprise value as disclosed in the Plan was allocated to the Company's assets and liabilities based on their fair values (except for deferred income taxes) in accordance with ASC 805 "Business Combinations." The amount of deferred income taxes recorded was determined in accordance with ASC 740 "Income Taxes." The Effective Date fair values of the Company's assets and liabilities differed materially from their recorded values as reflected on the historical balance sheet. The effects of the Plan and the application of fresh start accounting were reflected on the consolidated and combined balance sheet as of February 28, 2017, and the related adjustments thereto were recorded on the consolidated and combined statement of operations for the two months ended February 28, 2017. As a result of the application of fresh start accounting and the effects of the implementation of the plan of reorganization, the consolidated and combined financial statements on or after February 28, 2017, are not comparable with the consolidated and combined financial statements prior to that date. See Note 2 for additional information.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The Company's primary market risk is attributable to fluctuations in commodity prices. This risk can affect the Company's business, financial condition, operating results and cash flows. See below for quantitative and qualitative information about this risk.

The following should be read in conjunction with the financial statements and related notes included elsewhere in this Annual Report on Form 10-K. The reference to a "Note" herein refers to the accompanying Notes to Consolidated and Combined Financial Statements contained in Item 8. "Financial Statements and Supplementary Data."

Commodity Price Risk

The Company's most significant market risk relates to prices of oil, natural gas and NGL. The Company expects commodity prices to remain volatile and unpredictable. As commodity prices decline or rise significantly, revenues and cash flows are likewise affected. In addition, future declines in commodity prices may result in noncash write-downs of the Company's carrying amounts of its assets.

Historically, the Company has hedged a portion of its forecasted production to reduce exposure to fluctuations in oil and natural gas prices and provide long-term cash flow predictability to manage its business. The Company does not enter into derivative contracts for trading purposes. The appropriate level of production to be hedged is an ongoing consideration based on a variety of factors, including among other things, current and future expected commodity market prices, the Company's overall risk profile, including leverage and size and scale considerations, as well as any requirements for or restrictions on levels of hedging contained in any credit facility or other debt instrument applicable at the time. In addition, when commodity prices are depressed and forward commodity price curves are flat or in backwardation, the Company may determine that the benefit of hedging its anticipated production at these levels is outweighed by its resultant inability to obtain higher revenues for its production if commodity prices recover during the duration of the contracts. As a result, the appropriate percentage of production volumes to be hedged may change over time.

At December 31, 2018, the fair value of fixed price swaps and collars was a net asset of approximately $17 million. A 10% increase in the NYMEX WTI oil and NYMEX Henry Hub natural gas prices above the December 31, 2018, prices would result in a net liability of approximately $4 million, which represents a decrease in the fair value of approximately $21 million; conversely, a 10% decrease in the NYMEX oil and Henry Hub natural gas prices below the December 31, 2018, prices would result in a net asset of approximately $38 million, which represents an increase in the fair value of approximately $21 million.

At December 31, 2017, the fair value of fixed price swaps and collars was a net liability of approximately $2 million. A 10% increase in the NYMEX WTI oil and NYMEX Henry Hub natural gas prices above the December 31, 2017, prices would result in a net liability of approximately $45 million, which represents a decrease in the fair value of approximately $43 million; conversely, a 10% decrease in the NYMEX oil and Henry Hub natural gas prices below the December 31, 2017, prices would result in a net asset of approximately $38 million, which represents an increase in the fair value of approximately $40 million.

The Company determines the fair value of its commodity derivatives utilizing pricing models that use a variety of techniques, including market quotes and pricing analysis. Inputs to the pricing models include publicly available prices and forward price curves generated from a compilation of data gathered from third parties. Company management 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 that those instruments trade in active markets.

The prices of oil, natural gas and NGL have been extremely volatile, and the Company expects this volatility to continue. Prices for these commodities may fluctuate widely in response to relatively minor changes in the supply of and demand for such commodities, market uncertainty, including regional conditions and a variety of additional factors that are beyond its control. Actual gains or losses recognized related to the Company's derivative contracts depend exclusively on the price of the commodities on the specified settlement dates provided by the derivative contracts. Additionally, the Company cannot be assured that its counterparties will be able to perform under its derivative contracts. If a counterparty fails to perform and the derivative arrangement is terminated, the Company's cash flows could be impacted.

Interest Rate Risk

At December 31, 2018, the Company had debt outstanding under the Credit Facilities of $24.5 million in the aggregate which debt incurred interest at floating rates. A 1% increase in the respective market rates would result in an estimated $245,000 increase in annual interest expense. At December 31, 2017, the Company had no debt outstanding under the Riviera Credit Facility.

Item 8. Financial Statements and Supplementary Data

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended. The Company's internal control over financial reporting is a process designed under the supervision of its Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with accounting principles generally accepted in the United States.

Because of its inherent limitations, internal control over financial reporting may not detect or prevent misstatements. Projections of any evaluation of the effectiveness to future periods are subject to risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or processes may deteriorate.

As of December 31, 2018, management assessed the effectiveness of the Company's internal control over financial reporting based on the criteria for effective internal control over financial reporting established in *Internal Control – Integrated Framework (2013)* by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on the assessment, management determined that the Company maintained effective internal control over financial reporting as of December 31, 2018, based on those criteria.

KPMG LLP, the independent registered public accounting firm that audited the consolidated financial statements of the Company included in this Annual Report on Form 10-K, has issued an attestation report on the effectiveness of the Company's internal control over financial reporting as of December 31, 2018, which is included herein.

/s/ Riviera Resources, Inc.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and Board of Directors
Riviera Resources, Inc.:

Opinion on the Consolidated and Combined Financial Statements

We have audited the accompanying consolidated balance sheets of Riviera Resources, Inc. and subsidiaries (the Company) as of December 31, 2018 and 2017 (Successor), the related consolidated and combined statements of operations, equity (deficit), and cash flows for the year ended December 31, 2018 (Successor) for the ten months ended December 31, 2017 (Successor), the two months ended February 28, 2017 and for the year ended December 31, 2016 (Predecessor), and the related notes (collectively, the consolidated and combined financial statements). In our opinion, the consolidated and combined financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017 (Successor), and the results of its operations and its cash flows for the year ended December 31, 2018, the ten months ended December 31, 2017 (Successor), the two months ended February 28, 2017 and the year ended December 31, 2016 (Predecessor), in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2018, 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 28, 2019 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Change in Accounting Principle

As discussed in note 1 to the consolidated financial statements, the Company has changed its method of accounting for revenue recognition in 2018 due to the adoption of Accounting Standards Codification (ASC) 606, *Revenue from Contracts with Customers*.

Basis of Presentation

As discussed in note 1 to the consolidated and combined financial statements, the Company completed its spin-off from Linn Energy, Inc., the former parent company of Riviera Resources, on August 7, 2018. Prior to the spin-off, the accompanying consolidated and combined financial statements were prepared on a carve-out combined basis and derived from the former parent's consolidated financial statements and accounting records for the periods presented.

As discussed in note 2 to the consolidated and combined financial statements, Linn Energy, Inc. (formerly known as Linn Energy, LLC), the former parent company of Riviera Resources emerged from bankruptcy on February 28, 2017. Accordingly, the consolidated and combined financial statements have been prepared in conformity with ASC 852-10, *Reorganizations*, for the Successor as a new entity with assets, liabilities and a capital structure having carrying amounts not comparable with the amounts presented on or prior to February 28, 2017.

Basis for Opinion

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

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated and combined financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the consolidated and combined financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated and combined financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated and combined financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ KPMG LLP

We have served as the Company's auditor since 2017.

Houston, Texas
February 28, 2019

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and Board of Directors
Riviera Resources, Inc.:

Opinion on Internal Control Over Financial Reporting

We have audited Riviera Resources, Inc. and subsidiaries' (the Company) internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets as of December 31, 2018 and 2017 (Successor), the related consolidated and combined statements of operations, equity (deficit), and cash flows for the year ended December 31, 2018 (Successor), the ten months ended December 31, 2017 (Successor), the two months ended February 28, 2017 and the year ended December 31, 2016 (Predecessor), and the related notes (collectively, the consolidated and combined financial statements), and our report dated February 28, 2019 expressed an unqualified opinion on those consolidated and combined financial statements.

Basis for Opinion

The Company'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 management's report on internal control over financial reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

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

Definition and Limitations of Internal Control Over Financial Reporting

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

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ KPMG LLP

Houston, Texas
February 28, 2019

RIVIERA RESOURCES, INC.

CONSOLIDATED BALANCE SHEETS

	December 31, 2018	December 31, 2017
	(in thousands, except share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 18,529	$ 464,477
Accounts receivable – trade, net	114,489	140,485
Derivative instruments	10,758	9,629
Restricted cash	31,248	56,445
Other current assets	26,721	76,683
Assets held for sale	38,396	106,963
Total current assets	240,141	854,682
Noncurrent assets:		
Oil and natural gas properties (successful efforts method)	756,552	950,083
Less accumulated depletion and amortization	(93,507)	(49,619)
	663,045	900,464
Other property and equipment	606,244	480,729
Less accumulated depreciation	(62,368)	(28,658)
	543,876	452,071
Derivative instruments	4,603	469
Deferred income taxes	129,091	188,538
Other noncurrent assets	12,078	14,256
Noncurrent assets of discontinued operations	—	457,645
	145,772	660,908
Total noncurrent assets	1,352,693	2,013,443
Total assets	$ 1,592,834	$ 2,868,125
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 159,228	$ 253,975
Derivative instruments	4,719	10,103
Other accrued liabilities	34,474	58,130
Liabilities held for sale	3,725	43,302
Total current liabilities	202,146	365,510
Noncurrent liabilities:		
Long-term debt	24,500	—
Derivative instruments	—	2,849
Asset retirement obligations and other noncurrent liabilities	103,814	160,720
Total noncurrent liabilities	128,314	163,569
Commitments and contingencies (Note 10)		
Equity:		
Preferred Stock ($0.01 par value, 30,000,000 shares authorized and no shares issued at December 31, 2018; no shares authorized or issued at December 31, 2017)	—	—
Common Stock ($0.01 par value, 270,000,000 shares authorized and 69,197,284 shares issued at December 31, 2018; no shares authorized or issued at December 31, 2017)	692	—
Additional paid-in capital	1,256,730	—
Retained earnings	4,952	—
Net parent company investment	—	2,339,046
Total equity	1,262,374	2,339,046
Total liabilities and equity	$ 1,592,834	$ 2,868,125

The accompanying notes are an integral part of these consolidated and combined financial statements.

RIVIERA RESOURCES, INC.

CONSOLIDATED AND COMBINED STATEMENTS OF OPERATIONS

	Successor		Predecessor	
(in thousands, except per share amounts)	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
Revenues and other:				
Oil, natural gas and natural gas liquids sales	$ 420,102	$ 709,363	$ 188,885	$ 874,161
Gains (losses) on commodity derivatives	(23,404)	13,533	92,691	(164,330)
Marketing revenues	245,081	82,943	6,636	36,505
Other revenues	23,880	20,839	9,915	93,308
	665,659	826,678	298,127	839,644
Expenses:				
Lease operating expenses	120,097	208,446	49,665	296,891
Transportation expenses	83,562	113,128	25,972	161,574
Marketing expenses	220,971	69,008	4,820	29,736
General and administrative expenses	245,291	117,347	71,745	237,841
Exploration costs	5,178	3,137	93	4,080
Depreciation, depletion and amortization	94,958	133,711	47,155	342,614
Impairment of long-lived assets	15,697	—	—	165,044
Taxes, other than income taxes	29,730	47,553	14,877	67,644
(Gains) losses on sale of assets and other, net	(208,598)	(623,583)	672	15,558
	606,886	68,747	214,999	1,320,982
Other income and (expenses):				
Interest expense, net of amounts capitalized	(2,417)	(12,380)	(16,725)	(184,870)
Other, net	(677)	(6,233)	(149)	(2,345)
	(3,094)	(18,613)	(16,874)	(187,215)
Reorganization items, net	(5,159)	(8,533)	2,521,137	336,120
Income (loss) from continuing operations before income taxes	50,520	730,785	2,587,391	(332,433)
Income tax expense (benefit)	29,587	385,654	(166)	11,300
Income (loss) from continuing operations	20,933	345,131	2,587,557	(343,733)
Income (loss) from discontinued operations, net of income taxes	19,674	90,064	(548)	(18,354)
Net income (loss)	$ 40,607	$ 435,195	$ 2,587,009	$ (362,087)
Income (loss) per share:				
Income (loss) from continuing operations per share – Basic	$ 0.28	$ 4.53	$ 33.96	$ (4.51)
Income (loss) from continuing operations per share – Diluted	$ 0.28	$ 4.53	$ 33.96	$ (4.51)
Income (loss) from discontinued operations per share – Basic	$ 0.26	$ 1.18	$ (0.01)	$ (0.24)
Income (loss) from discontinued operations per share – Diluted	$ 0.26	$ 1.18	$ (0.01)	$ (0.24)
Net income (loss) per share – Basic	$ 0.54	$ 5.71	$ 33.95	$ (4.75)
Net income (loss) per share – Diluted	$ 0.54	$ 5.71	$ 33.95	$ (4.75)
Weighted average shares outstanding – Basic	74,935	76,191	76,191	76,191
Weighted average shares outstanding – Diluted	75,360	76,191	76,191	76,191

The accompanying notes are an integral part of these consolidated and combined financial statements.

Table of Contents

RIVIERA RESOURCES, INC.

CONSOLIDATED AND COMBINED STATEMENTS OF EQUITY (DEFICIT)

	Common Stock		Additional Paid-in Capital	Retained Earnings	Net Parent Company Investment	Total Equity (Deficit)
	Shares	Amount				
				(in thousands)		
December 31, 2015 (Predecessor)	—	$ —	$ —	$ —	$ (2,110,804)	$ (2,110,804)
Net loss		—	—	—	(362,087)	(362,087)
Net transfers to parent		—	—	—	(114,118)	(114,118)
December 31, 2016 (Predecessor)	—	—	—	—	(2,587,009)	(2,587,009)
Net income		—	—	—	2,587,009	2,587,009
February 28, 2017 (Predecessor)	—	—	—	—	—	—
Issuances of equity		—	—	—	2,064,331	2,064,331
February 28, 2017 (Successor)	—	—	—	—	2,064,331	2,064,331
Net income		—	—	—	435,195	435,195
Net transfers to parent		—	—	—	(160,480)	(160,480)
December 31, 2017 (Successor)	—	—	—	—	2,339,046	2,339,046
Net income		—	—	4,952	35,655	40,607
Net transfers to parent		—	—	—	(966,724)	(966,724)
Spin-off related adjustments		—	—	—	2,973	2,973
Issuances of common stock and reclassification of former parent company investment	76,191	762	1,410,188	—	(1,410,950)	—
Repurchases of common stock	(6,994)	(70)	(153,458)	—	—	(153,528)
December 31, 2018 (Successor)	69,197	$ 692	$ 1,256,730	$ 4,952	$ —	$ 1,262,374

The accompanying notes are an integral part of these consolidated and combined financial statements.

RIVIERA RESOURCES, INC.

CONSOLIDATED AND COMBINED STATEMENTS OF CASH FLOWS

(in thousands)	Successor: Year Ended December 31, 2018	Successor: Ten Months Ended December 31, 2017	Predecessor: Two Months Ended February 28, 2017	Predecessor: Year Ended December 31, 2016
Cash flow from operating activities:				
Net income (loss)	$ 40,607	$ 435,195	$ 2,587,009	$ (362,087)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:				
(Income) loss from discontinued operations	(19,674)	(90,064)	548	18,354
Depreciation, depletion and amortization	94,958	133,711	47,155	342,614
Impairment of long-lived assets	15,697	—	—	165,044
Deferred income taxes	29,701	378,512	(166)	11,367
Total (gains) losses on derivatives, net	25,243	(13,533)	(92,691)	164,330
Cash settlements on derivatives	(38,739)	26,793	(11,572)	860,778
Share-based compensation expenses	16,605	41,285	50,255	44,218
Amortization and write-off of deferred financing fees	1,909	3,711	1,338	13,356
(Gains) losses on sale of assets and other, net	(204,534)	(656,198)	1,069	13,007
Reorganization items, net	—	—	(2,456,074)	(390,367)
Changes in assets and liabilities:				
(Increase) decrease in accounts receivable – trade, net	26,956	41,094	(7,216)	(71,059)
(Increase) decrease in other assets	64,033	(265)	528	(15,360)
Increase (decrease) in accounts payable and accrued expenses	(46,792)	(92,664)	20,949	38,504
Increase (decrease) in other liabilities	(12,564)	7,253	2,801	(662)
Net cash provided by (used in) operating activities – continuing operations	(6,594)	214,830	143,933	832,037
Net cash provided by operating activities – discontinued operations	—	16,191	8,781	43,269
Net cash provided by (used in) operating activities	(6,594)	231,021	152,714	875,306
Cash flow from investing activities:				
Development of oil and natural gas properties	(64,756)	(171,721)	(50,597)	(172,298)
Purchases of other property and equipment	(142,373)	(88,595)	(7,409)	(43,559)
Proceeds from sale of properties and equipment and other	368,291	1,172,025	(166)	(4,690)
Net cash provided by (used in) investing activities – continuing operations	161,162	911,709	(58,172)	(220,547)
Net cash provided by (used in) investing activities – discontinued operations	7,000	345,643	(584)	(9,891)
Net cash provided by (used in) investing activities	168,162	1,257,352	(58,756)	(230,438)

RIVIERA RESOURCES, INC.

CONSOLIDATED AND COMBINED STATEMENTS OF CASH FLOWS - Continued

	Successor		Predecessor	
(in thousands)	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
Cash flow from financing activities:				
Net transfers (to) from parent	(481,449)	(202,533)	636,000	(213,844)
Repurchases of shares	(153,314)	—	—	—
Proceeds from borrowings	44,500	190,000	—	978,500
Repayments of debt	(20,000)	(1,090,000)	(1,038,986)	(913,209)
Debt issuance costs paid	(2,892)	(7,729)	(151)	(752)
Payment to holders of claims under the Predecessor's second lien notes	—	—	(30,000)	—
Distributions to unitholders	(18,717)	(1,211)	—	—
Other	(841)	—	(4,593)	(14,845)
Net cash used in financing activities – continuing operations	(632,713)	(1,111,473)	(437,730)	(164,150)
Net cash used in financing activities – discontinued operations	—	—	—	—
Net cash used in financing activities	(632,713)	(1,111,473)	(437,730)	(164,150)
Net increase (decrease) in cash, cash equivalents and restricted cash	(471,145)	376,900	(343,772)	480,718
Cash, cash equivalents and restricted cash:				
Beginning	520,922	144,022	487,794	7,076
Ending	$ 49,777	$ 520,922	$ 144,022	$ 487,794

The accompanying notes are an integral part of these consolidated and combined financial statements.

NOTES TO CONSOLIDATED AND COMBINED FINANCIAL STATEMENTS

Note 1 – Basis of Presentation and Significant Accounting Policies

Unless otherwise indicated or the context otherwise requires, references herein to the "Company" refer (i) prior to the Spin-off (as defined below) to Linn Energy, Inc. ("Parent") and its consolidated subsidiaries, and (ii) after the Spin-off, to Riviera Resources, Inc. ("Riviera") and its consolidated subsidiaries. Unless otherwise indicated or the context otherwise requires, references herein to "LINN Energy" refer to Linn Energy, Inc. and its consolidated subsidiaries.

In April 2018, the Parent announced its intention to separate Riviera from LINN Energy. Following the Spin-off, Riviera is an independent oil and natural gas company with a strategic focus on efficiently operating its mature low-decline assets, developing its growth-oriented assets, and returning capital to shareholders.

To effect the separation, the Parent and certain of its then direct and indirect subsidiaries undertook an internal reorganization (including the conversion of Riviera Resources, LLC from a limited liability company to a corporation named Riviera Resources, Inc.), following which Riviera holds, directly or through its subsidiaries, substantially all of the assets of LINN Energy, other than LINN Energy's 50% equity interest in Roan Resources LLC ("Roan"). A subsidiary of the Company held the equity interest in Roan until the Parent's internal reorganization on July 25, 2018 (the "Reorganization Date"). Following the internal reorganization, the Parent distributed all of the outstanding shares of Riviera common stock to the Parent's shareholders on a pro rata basis (the "Spin-off"). The Spin-off was completed on August 7, 2018. Prior to the completion of the Spin-off, a then subsidiary of the Parent distributed $40 million to the Parent to pay the Parent's obligations during the transition period under the TSA (as defined below). Linn Energy, Inc. returned such $40 million to Riviera on September 24, 2018, which included approximately $7 million for the reimbursement of cash paid to settle the Parent's restricted stock units ("LINN RSUs") held by Riviera's employees and approximately $1 million for the payment of income taxes on shares withheld from participants upon vesting (see Note 13).

Following the Spin-off, Riviera is an independent reporting company quoted for trading on the OTCQX Market under the ticker "RVRA," and the Parent did not retain any ownership interest in Riviera.

On August 7, 2018, Riviera entered into a Transition Services Agreement (the "TSA") with the Parent to facilitate an orderly transition following the Spin-off. Pursuant to the TSA, Riviera agreed to provide the Parent with certain finance, financial reporting, information technology, investor relations, legal, payroll, tax and other services during the term of the TSA. Riviera reimbursed the Parent for, or paid on the Parent's behalf, all direct and indirect costs and expenses incurred by the Parent during the term of the TSA in connection with the fees for any such services. The TSA terminated in accordance with its terms on September 24, 2018.

Prior to the Spin-off, the accompanying consolidated and combined financial statements were prepared on a stand-alone basis and derived from Linn Energy, Inc.'s consolidated financial statements and accounting records for the periods presented as the Company was historically managed as a subsidiary of Linn Energy, Inc. After the Spin-off, Riviera is an independent company.

During the reporting period, the Parent was a successor issuer of Linn Energy, LLC pursuant to Rule 15d-5 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). As discussed further in Note 2, on May 11, 2016 (the "Petition Date"), Linn Energy, LLC, certain of its direct and indirect subsidiaries, and LinnCo, LLC (collectively, the "LINN Debtors") and Berry Petroleum Company, LLC ("Berry" and collectively with the LINN Debtors, the "Debtors"), filed voluntary petitions ("Bankruptcy Petitions") for relief under Chapter 11 of the U.S. Bankruptcy Code ("Bankruptcy Code") in the U.S. Bankruptcy Court for the Southern District of Texas ("Bankruptcy Court"). The Debtors' Chapter 11 cases were administered jointly under the caption In re Linn Energy, LLC, et al., Case No. 16-60040. During the pendency of the Chapter 11 proceedings, the Debtors operated their businesses as "debtors-in-possession" under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code.

Nature of Business

The Company's upstream reporting segment properties are currently located in six operating regions in the United States ("U.S."): the Hugoton Basin, East Texas, Michigan/Illinois, the Mid-Continent, North Louisiana and the Uinta Basin. The Blue Mountain reporting segment consists a cryogenic natural gas processing facility and a network of gathering pipelines and compressors located in the Merge/SCOOP/STACK play, each of which is owned by Blue Mountain Midstream LLC ("Blue Mountain Midstream"), a wholly owned subsidiary of the Company. During 2018, the Company divested all of its properties located in the previous Permian Basin operating region. During 2017, the Company divested all of its properties located in the previous California and South Texas operating regions. The Company has classified the results of operations and cash flows of its California properties as discontinued operations on its consolidated and combined financial statements. See Note 4 for additional information.

Historically, a subsidiary of the Company also owned a 50% equity interest in Roan. The Company's equity earnings (losses), consisting of its share of Roan's earnings or losses, are included in the consolidated financial statements through the Reorganization Date. However, on the Reorganization Date, the equity interest in Roan was distributed to the Parent and is no longer affiliated with Riviera. As such, the Company has classified the investment and equity earnings (losses) in Roan as discontinued operations on its consolidated financial statements. See Note 4 for additional information.

Principles of Consolidation and Combination

The Company presents its consolidated and combined financial statements in accordance with U.S. generally accepted accounting principles ("GAAP"). The consolidated and combined financial statements for Predecessor periods represent the results of operations of entities held by the Company after the Spin-off that were historically under common control of the Parent, which exclude Linn Acquisition Company, LLC ("LAC") and Berry. On February 28, 2017, LINN Energy and Berry emerged from bankruptcy as standalone unaffiliated entities. The consolidated financial statements for the Successor period represent the financial position and results of operations of entities held by the Company after the Spin-off that were historically under the control of the Parent. The consolidated and combined financial statements include the accounts of the Company and its subsidiaries. All significant intercompany transactions and balances have been eliminated. Prior to the Spin-off, the consolidated and combined financial statements were prepared on a carve-out basis and reflect significant assumptions and allocations. The consolidated and combined financial statements for previous periods include certain reclassifications that were made to conform to current presentation. Such reclassifications have no impact on previously reported net income (loss), stockholders' equity, or cash flows.

The consolidated and combined financial statements include an allocation of Linn Energy, LLC's third-party debt that was outstanding prior to its emergence from bankruptcy on February 28, 2017. As a result of this allocation, the Company's consolidated and combined statements of operations include interest expense, amortization of deferred financing fees and gains on debt extinguishment related to such debt. On the Effective Date of the Plan (as defined below), all outstanding obligations under Linn Energy, LLC's credit facility, second lien notes and senior notes were canceled pursuant to the terms of the Plan. Subsequent to LINN Energy's emergence from bankruptcy, Linn Energy Holdco II LLC, ("Holdco II" or the "Borrower") a newly formed wholly owned subsidiary of the Parent, was the borrower of all third-party debt. Such debt and related interest expense are also included in the consolidated financial statements.

Investments in noncontrolled entities over which the Company exercises significant influence are accounted for under the equity method.

Allocations

Cash and cash equivalents held by the Parent were not allocated to Riviera unless they were held in a legal entity that transferred to the Riviera. All intracompany transactions between the Parent and Riviera are considered to be effectively settled in the consolidated and combined financial statements at the time the transaction is recorded. The total net effect of the settlement of these intracompany transactions is reflected in the consolidated and combined statements of cash flows as a financing activity and in the consolidated balance sheets as net parent company investment. Net parent company investment is primarily impacted by contributions from the Parent which are the result of treasury activities and net funding provided by or distributed to the Parent.

Historically, the Parent had no assets or operations independent from its subsidiaries. Accordingly, the consolidated and combined financial statements include materially all of the Parent's historical general and administrative expenses, including 100% of its employee-related expenses, as its personnel were employed by Riviera Operating, LLC ("Riviera Operating" formerly known as Linn Operating, LLC), a former subsidiary of the Parent that became a subsidiary of Riviera as part of the Spin-off. The Company considers the methodology and results to be reasonable for all periods presented; however, these costs may not be indicative of the actual expenses that Riviera would have incurred as an independent public company or the costs it may incur in the future.

Bankruptcy Accounting

Upon LINN Energy's emergence from bankruptcy on February 28, 2017, the Parent adopted fresh start accounting which resulted in the Parent becoming a new entity for financial reporting purposes. As a result of the adoption of fresh start accounting and the effects of the implementation of the Plan (as defined in Note 2), the Company's consolidated financial statements subsequent to February 28, 2017, are not comparable to its consolidated and combined financial statements prior to February 28, 2017. References to "Successor" relate to the financial position and results of operations of the reorganized Company subsequent to February 28, 2017. References to "Predecessor" relate to the financial position of the Company prior to, and results of operations through and including, February 28, 2017. The Company's consolidated and combined financial statements and related footnotes are presented with a black line division, which delineates the lack of comparability between amounts presented after February 28, 2017, and amounts presented on or prior to February 28, 2017. See Note 2 for additional information.

Use of Estimates

The preparation of the accompanying consolidated and combined financial statements in conformity with GAAP requires management of the Company to make estimates and assumptions about future events. These estimates and the underlying assumptions affect the amount of assets and liabilities reported, disclosures about contingent assets and liabilities, and reported amounts of revenues and expenses. The estimates that are particularly significant to the financial statements include estimates of the Company's reserves of oil, natural gas and natural gas liquids ("NGL"), future cash flows from oil and natural gas properties, depreciation, depletion and amortization, asset retirement obligations, certain revenues and operating expenses, fair values of commodity derivatives and deferred taxes. In addition, as part of fresh start accounting, the Company made estimates and assumptions related to its reorganization value, the fair value of assets and liabilities recorded as a result of the adoption of fresh start accounting and income taxes.

As fair value is a market-based measurement, it is determined based on the assumptions that market participants would use. These estimates and assumptions are based on management's best estimates and judgment. Management evaluates its estimates and assumptions on an ongoing basis using historical experience and other factors, including the current economic environment, which management believes to be reasonable under the circumstances. Such estimates and assumptions are adjusted when facts and circumstances dictate. As future events and their effects cannot be determined with precision, actual results could differ from these estimates. Any changes in estimates resulting from continuing changes in the economic environment will be reflected in the financial statements in future periods.

Recently Adopted Accounting Standards

In November 2016, the Financial Accounting Standards Board ("FASB") issued an Accounting Standards Update ("ASU") that is intended to address diversity in the classification and presentation of changes in restricted cash on the statement of cash flows. The Company adopted this ASU on January 1, 2018, on a retrospective basis. The adoption of this ASU resulted in the inclusion of restricted cash in the beginning and ending balances of cash on the statements of cash flows and disclosure reconciling cash and cash equivalents presented on the balance sheets to cash, cash equivalents and restricted cash on the statement of cash flows (see Note 16).

In May 2014, the FASB issued an ASU that is intended to improve and converge the financial reporting requirements for revenue from contracts with customers ("ASC 606"). The Company adopted this ASU on January 1, 2018, using the modified retrospective transition method. Accordingly, the comparative information for the year ended December 31, 2017, has not been adjusted and continues to be reported under the previous revenue standard. The adoption of this ASU impacted the Company's gross revenues and expenses as reported on its consolidated statements of operations (see below), and resulted in increased disclosures regarding the Company's disaggregation of revenue (see Note 3).

Under ASC 606, the Company recognizes revenues based on a determination of when control of its commodities is transferred and whether it is acting as a principal or agent in certain transactions. All facts and circumstances of an arrangement are considered and judgment is often required in making this determination. For its natural gas contracts, the Company generally records its sales at the wellhead or inlet of the plant as revenues net of transportation, gathering and processing expenses if the processor is the customer and there is no redelivery of commodities to the Company. Conversely, the Company generally records its sales at the tailgate of the plant on a gross basis along with the associated transportation, gathering and processing expenses if the processor is a service provider and there is redelivery of commodities to the Company.

In its midstream operations, the Company recognizes service fees for processing of commodities purchased as a reduction to the purchase price of those commodities rather than as revenues. This recognition results in a decrease to revenues and expenses with no material impact on net income.

The items discussed above impacted the Company's reported "oil, natural gas and natural gas liquids sales," "marketing revenues," "other revenues," "transportation expenses," "marketing expenses" and "interest expense, net of amounts capitalized." The impact of adoption on the Company's current period results is as follows:

	Year Ended December 31, 2018		
	Under ASC 606	Under Prior Rule	Increase/ (Decrease)
		(in thousands)	
Revenues:			
Natural gas sales	$ 250,831	$ 251,810	$ (979)
Oil sales	74,696	74,696	—
NGL sales	94,575	93,728	847
Total oil, natural gas and NGL sales	420,102	420,234	(132)
Marketing revenues	245,081	270,101	(25,020)
Other revenues	23,880	22,669	1,211
	689,063	713,004	(23,941)
Expenses:			
Transportation expenses	83,562	83,694	(132)
Marketing expenses	220,971	245,991	(25,020)
Interest expense, net of amounts capitalized	2,417	2,088	329
Net income	$ 40,607	$ 39,725	$ 882

New Accounting Standards Issued But Not Yet Adopted

In February 2016, the FASB issued an ASU that is intended to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet. This ASU is effective for fiscal years beginning after December 15, 2018, and interim periods within those years (early adoption permitted). The Company is finalizing its assessment of the impact of the adoption of this ASU on its financial statements and related disclosures. The Company expects the adoption of this ASU to impact its balance sheet resulting from an increase in both assets and liabilities ranging from approximately $1 million to $4 million as of January 1, 2019, related to the Company's leasing activities with no material impact to the statement of operations. The Company will adopt this new standard effective January 1, 2019, using the modified retrospective effective date method and expects to apply practical expedients which, among other things, allows the Company to carryforward its historical lease classification and for the nonrecognition of short term leases.

Cash Equivalents

For purposes of the consolidated and combined statements of cash flows, the Company considers all highly liquid short-term investments with original maturities of three months or less to be cash equivalents. Outstanding checks in excess of funds on deposit are included in “accounts payable and accrued expenses” on the consolidated balance sheets and are classified as financing activities on the consolidated and combined statements of cash flows.

Accounts Receivable – Trade, Net

Trade accounts receivable are recorded at the invoiced amount and do not bear interest. The Company maintains an allowance for doubtful accounts for estimated losses inherent in its accounts receivable portfolio. In establishing the required allowance, management considers historical losses, current receivables aging, and existing industry and national economic data. The Company reviews its allowance for doubtful accounts monthly. Past due balances over 90 days and over a specified amount are reviewed individually for collectability. Account balances are charged off against the allowance after all means of collection have been exhausted and the potential recovery is remote. The balance in the Company’s allowance for doubtful accounts related to trade accounts receivable was approximately $397,000 and $1 million at December 31, 2018, and December 31, 2017, respectively.

Inventories

Materials, supplies and commodity inventories are valued at the lower of average cost and net realizable value and are included in “other current assets” on the consolidated balance sheets.

Oil and Natural Gas Properties

As a result of the application of fresh start accounting, the Company recorded its oil and natural gas properties at fair value as of the Effective Date (as defined in Note 2). See Note 2 for additional information.

Proved Properties

The Company accounts for oil and natural gas properties in accordance with the successful efforts method. In accordance with this method, all leasehold and development costs of proved properties are capitalized and amortized on a unit-of-production basis over the remaining life of the proved reserves and proved developed reserves, respectively. Costs of retired, sold or abandoned properties that constitute a part of an amortization base are charged or credited, net of proceeds, to accumulated depreciation, depletion and amortization unless doing so significantly affects the unit-of-production amortization rate, in which case a gain or loss is recognized currently. Gains or losses from the disposal of other properties are recognized currently. Expenditures for maintenance and repairs necessary to maintain properties in operating condition are expensed as incurred. Estimated dismantlement and abandonment costs are capitalized, net of salvage, at their estimated net present value and amortized on a unit-of-production basis over the remaining life of the related proved developed reserves. The Company capitalizes interest on borrowed funds related to its share of costs associated with the drilling and completion of new oil and natural gas wells. Interest is capitalized only during the periods in which these assets are brought to their intended use. The Company capitalized interest costs of approximately $158,000 and $257,000 for the ten months ended December 31, 2017, and the year ended December 31, 2016, respectively. The Company did not capitalize any interest costs during the year ended December 31, 2018, and two months ended February 28, 2017.

The Company evaluates the impairment of its proved oil and natural gas properties on a field-by-field basis whenever events or changes in circumstances indicate that the carrying value may not be recoverable. The carrying values of proved properties are reduced to fair value when the expected undiscounted future cash flows of proved and risk-adjusted probable and possible reserves are less than net book value. The fair values of proved properties are measured using valuation techniques consistent with the income approach, converting future cash flows to a single discounted amount. 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. These inputs require assumptions by the Company’s management at the time of the valuation and are the most sensitive and subject to change. The underlying commodity prices embedded in the Company’s estimated cash flows are the product of a process that begins with New York Mercantile Exchange (“NYMEX”) forward curve pricing, adjusted for estimated location and quality differentials, as well as other factors that Company management believes will impact realizable prices.

Based on the analysis described above, for the years ended December 31, 2018, and December 31, 2016, the Company recorded noncash impairment charges of approximately $16 million and $165 million, respectively, associated with proved oil and natural gas properties. The impairment charges recorded in 2018 were due to a decline in commodity prices and higher operating costs. The impairment charges recorded in 2016 were due to a decline in commodity prices, changes in expected capital development and a decline in the Company's estimates of proved reserves. The carrying values of the impaired proved properties were reduced to fair value, estimated using inputs characteristic of a Level 3 fair value measurement. The impairment charges are included in "impairment of long-lived assets" on the consolidated and combined statement of operations. The Company recorded no impairment charges associated with proved properties during the ten months ended December 31, 2017, or the two months ended February 28, 2017.

Unproved Properties
Costs related to unproved properties include costs incurred to acquire unproved reserves. Because these reserves do not meet the definition of proved reserves, the related costs are not classified as proved properties. Unproved leasehold costs are capitalized and amortized on a composite basis if individually insignificant, based on past success, experience and average lease-term lives. Individually significant leases are reclassified to proved properties if successful and expensed on a lease by lease basis if unsuccessful or the lease term expires. Unamortized leasehold costs related to successful exploratory drilling are reclassified to proved properties and depleted on a unit-of-production basis.

The Company evaluates the impairment of its unproved oil and natural gas properties whenever events or changes in circumstances indicate that the carrying value may not be recoverable. The carrying values of unproved properties are reduced to fair value based on management's experience in similar situations and other factors such as the lease terms of the properties and the relative proportion of such properties on which proved reserves have been found in the past.

The Company recorded no impairment charges associated with unproved properties for the year ended December 31, 2018, ten months ended December 31, 2017, the two months ended February 28, 2017, or the year ended December 31, 2016.

Exploration Costs
Exploratory geological and geophysical costs, delay rentals, amortization and impairment of unproved leasehold costs and costs to drill exploratory wells that do not find proved reserves are expensed as exploration costs. The costs of any exploratory wells are carried as an asset if the well finds a sufficient quantity of reserves to justify its capitalization as a producing well and as long as the Company is making sufficient progress towards assessing the reserves and the economic and operating viability of the project.

Other Property and Equipment

Other property and equipment includes natural gas gathering systems, pipelines, furniture and office equipment, buildings, vehicles, information technology equipment, software and other fixed assets. These assets are recorded at cost and are depreciated using the straight-line method based on expected lives ranging from one to 10 years for vehicles, equipment and other fixed assets, 20 to 39 years for buildings and five to 30 years for plants and pipelines.

Derivative Instruments

Historically, the Company has hedged a portion of its forecasted production to reduce exposure to fluctuations in oil and natural gas prices and provide long-term cash flow predictability to manage its business. The Company has also hedges its exposure to natural gas differentials in certain operating areas. In addition, the Company has hedged purchase costs and margins of its Blue Mountain Midstream Business.

The Company enters into commodity hedging transactions primarily in the form of fixed price swap contracts that are designed to provide a fixed price, collars, basis swaps, margin spreads and, from time to time, put options that are designed to provide a fixed price floor with the opportunity for upside. The Company enters into these transactions with respect to a portion of its projected production to provide an economic hedge of the risk related to the future commodity prices received or paid. The Company does not enter into derivative contracts for trading purposes.

A fixed price swap contract specifies a fixed price that the Company will receive from the counterparty as compared to floating market prices, and on the settlement date the Company will receive or pay the difference between the swap price and the market price. Collar contracts specify floor and ceiling prices to be received as compared to floating market prices. A basis swap specifies a fixed basis differential to the NYMEX Henry Hub natural gas price. A margin spread specifies a fixed basis spread between specified market hubs. A put option requires the Company to pay the counterparty a premium equal to the fair value of the option at the purchase date and receive from the counterparty the excess, if any, of the fixed price floor over the market price at the settlement date.

Derivative instruments are recorded at fair value and included on the consolidated balance sheets as assets or liabilities. The Company did not designate any of its contracts as cash flow hedges; therefore, the changes in fair value of these instruments are recorded in current earnings. The Company determines the fair value of its commodity derivatives utilizing pricing models that use a variety of techniques, including market quotes and pricing analysis. Inputs to the pricing models include publicly available prices and forward price curves generated from a compilation of data gathered from third parties. Company management 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 that those instruments trade in active markets. Assumed credit risk adjustments, based on published credit ratings and public bond yield spreads are applied to the Company's commodity derivatives. See Note 7 and Note 8 for additional details about the Company's derivative financial instruments.

Revenue from Contracts with Customers

Revenues representative of the Company's ownership interest in its properties are presented on a gross basis on the consolidated and combined statements of operations. The Company recognizes sales of oil, natural gas and NGL when it satisfies a performance obligation by transferring control of the product to a customer, in an amount that reflects the consideration to which the Company expects to be entitled in exchange for a product.

Natural Gas and NGL Sales
The Company's natural gas production is primarily sold under market-sensitive contracts that are typically priced at a differential to the published natural gas index price for the producing area due to the natural gas quality and the proximity to major consuming markets.

For its natural gas contracts, the Company generally records its wet gas sales at the wellhead or inlet of the plant as revenues net of transportation, gathering and processing expenses, and its residual natural gas and NGL sales at the tailgate of the plant on a gross basis along with the associated transportation, gathering and processing expenses. All facts and circumstances of an arrangement are considered and judgment is often required in making this determination.

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

Production Imbalances
Upon adoption of fresh start accounting on February 28, 2017, the Company elected the sales method to account for natural gas production imbalances. If the Company's sales volumes for a well exceed the Company's proportionate share of production from the well, a liability is recognized to the extent that the Company's share of estimated remaining recoverable reserves from the well is insufficient to satisfy this imbalance. No receivables are recorded for those wells on which the Company has taken less than its proportionate share of production. The Predecessor had applied the entitlements method to account for natural gas production imbalances in previous periods.

Marketing Revenues
The Company engages in the purchase, gathering and transportation of third-party natural gas and subsequently markets such natural gas to independent purchasers under separate arrangements. As such, the Company separately reports third-party marketing revenues and marketing expenses.

Share-Based Compensation

The Company recognizes expense for share-based compensation over the requisite service period in an amount equal to the fair value of share-based awards granted. The fair value of liability classified awards is remeasured at each reporting date through the settlement date with the change in fair value recognized as compensation expense over that period. The Company has made a policy decision to recognize compensation expense for service-based awards on a straight-line basis over the requisite service period for the entire award. Beginning in 2017, the Company accounts for forfeitures as they occur. See Note 13 for additional details about the Company's accounting for share-based compensation.

Deferred Financing Fees

The Company has incurred legal and bank fees related to the issuance of debt. At December 31, 2018, and December 31, 2017, net deferred financing fees of approximately \$5 million and \$4 million, respectively, were included in "other noncurrent assets" on the consolidated balance sheets. These debt issuance costs are amortized over the life of the debt agreement. Upon early retirement or amendment to the debt agreement, certain fees are written off to expense.

For the year ended December 31, 2018, the ten months ended December 31, 2017, the two months ended February 28, 2017, and the year ended December 31, 2016, amortization expense of approximately \$2 million, \$1 million, \$1 million and \$10 million, respectively, is included in "interest expense, net of amounts capitalized" on the consolidated and combined statements of operations. For the ten months ended December 31, 2017, and the year ended December 31, 2016, approximately \$3 million and \$1 million, respectively, were written off to expense and included in "other, net" on the consolidated and combined statements of operations related to amendments of the credit facilities. In addition, for the year ended December 31, 2016, approximately \$33 million was written off to expense and included in "reorganization items, net" on the consolidated and combined statement of operations in connection with the filing of the Bankruptcy Petitions. No fees were written off to expense for the year ended December 31, 2018, or the two months ended February 28, 2017.

Fair Value of Financial Instruments

The carrying values of the Company's receivables, payables and credit facilities are estimated to be substantially the same as their fair values at December 31, 2018, and December 31, 2017. As noted above, the Company carries its derivative financial instruments at fair value. See Note 8 for details about the fair value of the Company's derivative financial instruments.

Income Taxes

For periods prior to the Spin-off, income tax expense and deferred tax balances were calculated on a separate tax return basis although Riviera's operations have historically been included in the tax returns filed by the Parent, of which Riviera's business was a part. Beginning August 8, 2018, as a stand-alone entity, Riviera will file tax returns on its own behalf and its deferred taxes and effective tax rate may differ from those in the historical periods. Upon completion of the Spin-off, on August 8, 2018, the Company recorded a deferred tax asset, the calculation of which, relied on estimates and assumptions related to the value of the company and its oil and natural gas reserves. The Company believes that the assumptions and estimates used to determine these tax amounts are reasonable.

Effective February 28, 2017, upon LINN Energy's emergence from bankruptcy, LINN Energy became a C corporation subject to federal and state income taxes. Prior to February 28, 2017, the Predecessor to LINN Energy was a limited liability company treated as a partnership for federal and state income tax purposes, with the exception of the state of Texas, in which income tax liabilities and/or benefits were passed through to its unitholders. Limited liability companies are subject to Texas margin tax. In addition, certain of the Predecessor's subsidiaries were C corporations subject to federal and state income taxes. As such, with the exception of the state of Texas and certain subsidiaries prior to February 28, 2017, the Predecessor did not directly pay federal and state income taxes and recognition was not given to federal and state income taxes for the operations of the Predecessor.

Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis and tax carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. See Note 15 for additional details of the Company's accounting for income taxes.

Note 2 – Emergence From Voluntary Reorganization Under Chapter 11 and Fresh Start Accounting

On the Petition Date, the Debtors filed Bankruptcy Petitions for relief under Chapter 11 of the Bankruptcy Code in the Bankruptcy Court. The Debtors' Chapter 11 cases were administered jointly under the caption In re Linn Energy, LLC, et al., Case No. 16-60040.

On December 3, 2016, the LINN Debtors filed the Amended Joint Chapter 11 Plan of Reorganization of Linn Energy, LLC and Its Debtor Affiliates Other Than Linn Acquisition Company, LLC and Berry Petroleum Company, LLC (the "Plan"). The LINN Debtors subsequently filed amended versions of the Plan with the Bankruptcy Court.

On December 13, 2016, LAC and Berry filed the Amended Joint Chapter 11 Plan of Reorganization of Linn Acquisition Company, LLC and Berry Petroleum Company, LLC (the "Berry Plan" and together with the Plan, the "Plans"). LAC and Berry subsequently filed amended versions of the Berry Plan with the Bankruptcy Court.

On January 27, 2017, the Bankruptcy Court entered an order approving and confirming the Plans (the "Confirmation Order"). On February 28, 2017 (the "Effective Date"), the Debtors satisfied the conditions to effectiveness of the respective Plans, the Plans became effective in accordance with their respective terms and LINN Energy and Berry emerged from bankruptcy as stand-alone, unaffiliated entities.

Reorganization Items, Net

The Company incurred significant costs and recognized significant gains associated with the reorganization of the Company in connection with the Chapter 11 proceedings. Reorganization items represent costs and income directly associated with the Chapter 11 proceedings since the Petition Date, and also include adjustments to reflect the carrying value of certain liabilities subject to compromise at their estimated allowed claim amounts, as such adjustments were determined. The following table summarizes the components of reorganization items included on the consolidated and combined statements of operations:

	Successor		Predecessor	
(in thousands)	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
Gain on settlement of liabilities subject to compromise	$ —	$ —	$ 3,914,964	$ —
Recognition of an additional claim for the Predecessor's second lien notes settlement	—	—	(1,000,000)	—
Fresh start valuation adjustments	—	—	(591,525)	—
Income tax benefit related to implementation of the Plan	—	—	264,889	—
Legal and other professional fees	(5,055)	(8,584)	(46,961)	(56,656)
Unamortized deferred financing fees, discounts and premiums	—	—	—	(52,045)
Gains related to interest payable on Predecessor's second lien notes	—	—	—	551,000
Terminated contracts	—	—	(6,915)	(66,052)
Other	(104)	51	(13,315)	(40,127)
Reorganization items, net	$ (5,159)	$ (8,533)	$ 2,521,137	$ 336,120

Fresh Start Accounting

Upon LINN Energy's emergence from Chapter 11 bankruptcy, it adopted fresh start accounting in accordance with the provisions of ASC 852 which resulted in the Parent becoming a new entity for financial reporting purposes. In accordance with ASC 852, the Parent was required to adopt fresh start accounting upon its emergence from Chapter 11 because (i) the holders of existing voting ownership interests of the Predecessor of the Parent received less than 50% of the voting shares of the Successor of the Parent and (ii) the reorganization value of the Parent's assets immediately prior to confirmation of the Plan was less than the total of all postpetition liabilities and allowed claims.

Upon adoption of fresh start accounting, the reorganization value derived from the enterprise value as disclosed in the Plan was allocated to the Company's assets and liabilities based on their fair values (except for deferred income taxes) in accordance with ASC 805 "Business Combinations." The amount of deferred income taxes recorded was determined in accordance with ASC 740 "Income Taxes" ("ASC 740"). The Effective Date fair values of the Company's assets and liabilities differed materially from their recorded values as reflected on the historical balance sheet. The effects of the Plan and the application of fresh start accounting were reflected on the consolidated and combined balance sheet as of February 28, 2017, and the related adjustments thereto were recorded on the consolidated and combined statement of operations for the two months ended February 28, 2017.

As a result of the adoption of fresh start accounting and the effects of the implementation of the Plan, the Company's consolidated financial statements subsequent to February 28, 2017, are not comparable to its consolidated and combined financial statements prior to February 28, 2017. References to "Successor" relate to the financial position and results of operations of the reorganized Company as of and subsequent to February 28, 2017. References to "Predecessor" relate to the financial position of the Company prior to, and results of operations through and including, February 28, 2017.

The Company's consolidated and combined financial statements and related footnotes are presented with a black line division, which delineates the lack of comparability between amounts presented after February 28, 2017, and amounts presented on or prior to February 28, 2017. The Company's financial results for future periods following the application of fresh start accounting will be different from historical trends and the differences may be material.

Reorganization Value

Under ASC 852, the Parent determined a value to be assigned to the equity of the emerging entity as of the date of adoption of fresh start accounting. The Plan confirmed by the Bankruptcy Court estimated an enterprise value of $2.35 billion. The Plan enterprise value was prepared using an asset based methodology, as discussed further below. The enterprise value was then adjusted to determine the equity value of the Successor of approximately $2.07 billion. Adjustments to determine the equity value are presented below (in thousands):

Plan confirmed enterprise value	$	2,350,000
Fair value of debt		(900,000)
Fair value of subsequently determined tax attributes		621,486
Share-based payment liability		(7,155)
Value of Successor's equity	$	2,064,331

The subsequently determined tax attributes were primarily the result of the conversion from a limited liability company to a C corporation and differences in the accounting basis and tax basis of the Company's oil and natural gas properties as of the Effective Date.

The Company's principal assets are its oil and natural gas properties. The fair values of oil and natural gas properties were estimated using valuation techniques consistent with the income approach, converting future cash flows to a single discounted amount. Significant inputs used to determine the fair values of 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. These inputs require significant judgments and estimates by the Company's management at the time of the valuation and are the most sensitive and subject to change. The underlying commodity prices embedded in the Company's estimated cash flows are the product of a process that begins with NYMEX forward curve pricing, adjusted for estimated location and quality differentials, as well as other factors that Company management believes will impact realizable prices.

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

Consolidated Balance Sheet

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

	As of February 28, 2017						
	Predecessor	Reorganization Adjustments		Fresh Start Adjustments		Successor	
	(in thousands)						
ASSETS							
Current assets:							
Cash and cash equivalents	$ 575,803	$ (521,448)	(1)	$ —		$ 54,355	
Accounts receivable – trade, net	212,099	—		(7,808)	(13)	204,291	
Derivative instruments	15,391	—		—		15,391	
Restricted cash	1,602	80,164	(2)	—		81,766	
Other current assets	106,426	(15,983)	(3)	1,780	(14)	92,223	
Total current assets	911,321	(457,267)		(6,028)		448,026	
Noncurrent assets:							
Oil and natural gas properties (successful efforts method)	13,269,035	—		(11,082,258)	(15)	2,186,777	
Less accumulated depletion and amortization	(10,044,240)	—		10,044,240	(15)	—	
	3,224,795	—		(1,038,018)		2,186,777	
Other property and equipment	641,586	—		(197,653)	(16)	443,933	
Less accumulated depreciation	(230,952)	—		230,952	(16)	—	
	410,634	—		33,299		443,933	
Derivative instruments	4,492	—		—		4,492	
Deferred income taxes	—	264,889	(4)	356,597	(4)	621,486	
Other noncurrent assets	15,003	151	(5)	8,139	(17)	23,293	
	19,495	265,040		364,736		649,271	
Total noncurrent assets	3,654,924	265,040		(639,983)		3,279,981	
Total assets	$ 4,566,245	$ (192,227)		$ (646,011)		$ 3,728,007	
LIABILITIES AND EQUITY (DEFICIT)							
Current liabilities:							
Accounts payable and accrued expenses	$ 324,585	$ 41,266	(6)	$ (2,351)	(18)	$ 363,500	
Derivative instruments	7,361	—		—		7,361	
Current portion of long-term debt, net	1,937,822	(1,912,822)	(7)	—		25,000	
Other accrued liabilities	41,250	(1,025)	(8)	1,104	(19)	41,329	
Total current liabilities	2,311,018	(1,872,581)		(1,247)		437,190	
Derivative instruments	2,116	—		—		2,116	
Long-term debt	—	875,000	(9)	—		875,000	
Other noncurrent liabilities	402,776	(167)	(10)	(53,239)	(20)	349,370	
Liabilities subject to compromise	4,276,912	(4,276,912)	(11)	—		—	
Total equity (deficit):							
Net parent company investment	(2,426,577)	5,082,433	(12)	(591,525)	(12)	2,064,331	
Total equity (deficit)	(2,426,577)	5,082,433		(591,525)		2,064,331	
Total liabilities and equity (deficit)	$ 4,566,245	$ (192,227)		$ (646,011)		$ 3,728,007	

Reorganization Adjustments:

1) Changes in cash and cash equivalents included the following:

(in thousands)		
Net transfers to Parent (to pay holders of claims, as well as professional fees)	$	(499,684)
Payment of Berry Petroleum Company, LLC’s ad valorem taxes		(23,366)
Removal of restriction on cash balance		1,602
Changes in cash and cash equivalents	$	(521,448)

2) Primarily reflects the transfer to restricted cash to fund the Predecessor’s professional fees escrow account and general unsecured claims cash distribution pool.

3) Primarily reflects the write-off of the Predecessor’s deferred financing fees.

4) Reflects deferred tax assets recorded as of the Effective Date as determined in accordance with ASC 740. The deferred tax assets were primarily the result of the conversion from a limited liability company to a C corporation and differences in the accounting basis and tax basis of the Company’s oil and natural gas properties as of the Effective Date.

5) Reflects the capitalization of deferred financing fees related to the Successor’s revolving loan.

6) Net increase in accounts payable and accrued expenses reflects:

(in thousands)		
Recognition of payables for the professional fees escrow account	$	41,766
Recognition of payables for the general unsecured claims cash distribution pool		40,000
Payment of professional fees		(17,130)
Payment of Berry’s ad valorem taxes		(23,366)
Other		(4)
Net increase in accounts payable and accrued expenses	$	41,266

7) Reflects the settlement of the Predecessor Credit Facility through repayment of approximately $1.9 billion, net of the write-off of deferred financing fees and an increase of $25 million for the current portion of the Successor’s term loan.

8) Reflects a decrease of approximately $8 million for the payment of accrued interest on the Predecessor Credit Facility, partially offset by an increase of approximately $7 million related to noncash share-based compensation classified as a liability related to the incentive interest awards issued by Holdco to certain members of management (see Note 13).

9) Reflects borrowings of $900 million under the Emergence Credit Facility, which includes a $600 million revolving loan and a $300 million term loan, net of $25 million for the current portion of the Successor’s term loan.

10) Reflects a reduction in deferred tax liabilities as determined in accordance with ASC 740.

11) Reflects settlement of liabilities subject to compromise and the resulting net gain.

12) Net increase in equity reflects:

(in thousands)		
Cancellation of the Predecessor's equity	$	(2,426,577)
Net decrease in accumulated deficit		3,018,102
Fresh start valuation adjustments		(591,525)
Net transfers from Parent		2,064,331
Net increase in equity	$	2,064,331

Fresh Start Adjustments:

13) Reflects a change in accounting policy from the entitlements method to the sales method for natural gas production imbalances.

14) Reflects the recognition of intangible assets for the current portion of favorable leases, partially offset by decreases for well equipment inventory and the write-off of historical intangible assets.

15) Reflects a decrease of oil and natural gas properties, based on the methodology discussed above, and the elimination of accumulated depletion and amortization. The following table summarizes the components of oil and natural gas properties as of the Effective Date:

	Successor		Predecessor	
	Fair Value		Historical Book Value	
(in thousands)				
Proved properties	$	1,727,834	$	12,258,835
Unproved properties		458,943		1,010,200
		2,186,777		13,269,035
Less accumulated depletion and amortization		—		(10,044,240)
	$	2,186,777	$	3,224,795

16) Reflects a decrease of other property and equipment and the elimination of accumulated depreciation. The following table summarizes the components of other property and equipment as of the Effective Date:

	Successor		Predecessor	
	Fair Value		Historical Book Value	
(in thousands)				
Natural gas plants and pipelines	$	342,924	$	426,914
Office equipment and furniture		39,211		106,059
Buildings and leasehold improvements		32,817		66,023
Vehicles		16,980		30,760
Land		7,747		3,727
Drilling and other equipment		4,254		8,103
		443,933		641,586
Less accumulated depreciation		—		(230,952)
	$	443,933	$	410,634

In estimating the fair value of other property and equipment, the Company used a combination of cost and market approaches. A cost approach was used to value the Company's natural gas plants and pipelines and other operating assets, based on current replacement costs of the assets less depreciation based on the estimated economic useful lives of the assets and age of the assets. A market approach was used to value the Company's vehicles and land, using recent transactions of similar assets to determine the fair value from a market participant perspective.

17) Reflects the recognition of intangible assets for the noncurrent portion of favorable leases, as well as increases in equity method investments and carbon credit allowances. Assets and liabilities for out-of-market contracts were valued based on market terms as of February 28, 2017, and will be amortized over the remaining life of the respective lease. The Company's equity method investments were valued based on a market approach using a market EBITDA multiple. Carbon credit allowances were valued using a market approach based on trading prices for carbon credits on February 28, 2017.

18) Primarily reflects the write-off of deferred rent partially offset by an increase in carbon emissions liabilities.

19) Reflects an increase of the current portion of asset retirement obligations.

20) Primarily reflects a decrease of approximately $49 million for asset retirement obligations and approximately $5 million for deferred rent, partially offset by an increase of approximately $1 million for carbon emissions liabilities. The fair value of asset retirement obligations were 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. Carbon emissions liabilities were valued using a market approach based on trading prices for carbon credits on February 28, 2017.

Note 3 – Revenues

Disaggregation of Revenue

The following tables present the Company's disaggregated revenues by source and geographic area:

	Year Ended December 31, 2018						
	Natural Gas	Oil	NGL	Oil, Natural Gas and NGL Sales	Marketing Revenues	Other Revenues	Total
	(in thousands)						
Hugoton Basin	$ 86,995	$ 3,352	$ 70,619	$ 160,966	$ 100,331	$ 23,655	$ 284,952
Mid-Continent	36,336	26,765	14,046	77,147	—	58	77,205
East Texas	54,278	4,302	3,991	62,571	1,621	15	64,207
Michigan/Illinois	30,472	3,112	42	33,626	—	113	33,739
North Louisiana	25,253	4,997	985	31,235	1,111	6	32,352
Uinta Basin	15,171	11,480	2,702	29,353	—	—	29,353
Permian Basin	2,326	20,688	2,190	25,204	—	33	25,237
Blue Mountain	—	—	—	—	142,018	—	142,018
Total	$ 250,831	$ 74,696	$ 94,575	$ 420,102	$ 245,081	$ 23,880	$ 689,063

Contract Balances

Under the Company's product sales contracts, its customers are invoiced once the Company's performance obligations have been satisfied, at which point payment is unconditional. Accordingly, the Company's product sales contracts do not give rise to material contract assets or contract liabilities.

The Company had trade accounts receivable related to revenue from contracts with customers of approximately $107 million and $117 million as of December 31, 2018, and December 31, 2017, respectively.

Performance Obligations

The majority of the Company's sales are short-term in nature with a contract term of one year or less. For those contracts, the Company utilized the practical expedient in ASC 606-10-50-14 exempting the Company from disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less.

For the Company's product sales that have a contract term greater than one year, the Company utilized the practical expedient in ASC 606-10-50-14(A) which states the Company is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under these sales contracts, each unit of product generally represents a separate performance obligation; therefore future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required.

Note 4 – Divestitures and Discontinued Operations

Discontinued Operations

As discussed in Note 1, historically, a subsidiary of the Company owned the equity interest in Roan. However, on the Reorganization Date, the equity interest in Roan was distributed to the Parent and is no longer affiliated with Riviera. On August 31, 2017, the Parent, through certain of its then subsidiaries, completed the transaction in which the Company and Citizen Energy II, LLC ("Citizen") each contributed certain upstream assets located in Oklahoma to a newly formed company, Roan (such contribution, the "Roan Contribution"), which was focused on the accelerated development of the Merge/SCOOP/STACK play. In exchange for their respective contributions, a subsidiary of the Company and Citizen each received a 50% equity interest in Roan.

The Company used the equity method of accounting for its investment in Roan. The Company's equity earnings (losses) consisted of its share of Roan's earnings or losses and the amortization of the difference between the Company's investment in Roan and Roan's underlying net assets attributable to certain assets.

The carrying amount of the Company's investment in Roan of approximately $458 million at December 31, 2017, was classified as discontinued operations on the consolidated balance sheet. The Company's equity earnings (losses) in Roan were classified as discontinued operations on the consolidated statements of operations. No gain or loss was recognized for the distribution because the transaction was accounted for as an equity distribution to the Parent and is included in "net transfers to Parent" on the consolidated statement of equity.

The following are summarized statements of operations and balance sheet information for Roan.

Summarized Roan Resources LLC Statements of Operations Information

	January 1, 2018 through July 25, 2018	Four Months Ended December 31, 2017
	(in thousands)	
Revenues and other	$ 176,341	$ 75,461
Expenses	150,096	61,790
Other income and (expenses)	(4,260)	(1,180)
Net income	$ 21,985	$ 12,491

RIVIERA RESOURCES, INC.

NOTES TO CONSOLIDATED AND COMBINED FINANCIAL STATEMENTS - Continued

Summarized Roan Resources LLC Balance Sheet Information

	December 31, 2017
	(in thousands)
Current assets	$ 27,465
Noncurrent assets	1,826,741
	1,854,206
Current liabilities	149,409
Noncurrent liabilities	97,480
Members' equity	$ 1,607,317

For the period from January 1, 2018 through July 25, 2018, the Company recorded equity losses from its historical 50% interest in Roan of approximately $16 million (net of income tax expense of approximately $6 million). For the four months ended December 31, 2017, the Company's equity earnings from its historical 50% interest in Roan was approximately $7 million (net of income tax expense of approximately $4 million). The equity earnings and losses are included in "income (loss) from discontinued operations, net of income taxes" on the consolidated statements of operations.

On July 31, 2017, the Company completed the sale of its interest in properties located in the San Joaquin Basin in California to Berry Petroleum Company, LLC (the "San Joaquin Basin Sale"). Cash proceeds received from the sale of these properties were approximately $253 million, net of costs to sell of approximately $4 million, and the Company recognized a net gain of approximately $120 million. The gain is included in "income (loss) from discontinued operations, net of income taxes" on the consolidated statement of operations.

On July 21, 2017, the Company completed the sale of its interest in properties located in Los Angeles Basin in California to Bridge Energy LLC (the "Los Angeles Basin Sale"). Cash proceeds received from the sale of these properties were approximately $93 million, net of costs to sell of approximately $2 million, and the Company recognized a net gain of approximately $2 million. In addition, during August 2018, the company received an additional $7 million contingent payment related to the satisfaction of certain operational requirements resulting in a net gain of approximately $5 million. The gains are included in "income (loss) from discontinued operations, net of income taxes" on the consolidated statements of operations.

As a result of the Company's strategic exit from California in 2017 (completed by the San Joaquin Basin Sale and the Los Angeles Basin Sale), the Company classified the results of operations and cash flows of its California properties as discontinued operations on its consolidated and combined financial statements. The California properties were included in the upstream reporting segment.

The following table presents summarized financial results of the Company's California properties classified as discontinued operations on the consolidated and combined statements of operations:

	Successor	Predecessor	
	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
(in thousands)			
Revenues and other	$ 34,096	$ 14,891	$ 78,069
Expenses	19,479	13,758	88,431
Other income and (expenses)	(3,541)	(1,681)	(7,992)
Income (loss) from discontinued operations before income taxes	11,076	(548)	(18,354)
Income tax expense	4,165	—	—
Income (loss) from discontinued operations, net of income taxes	$ 6,911	$ (548)	$ (18,354)

Other income and (expenses) includes an allocation of interest expense for the California properties which represents interest on debt that was required to be repaid as a result of the sales. In addition, for the ten months ended December 31, 2017, the Company recognized a net gain on the sale of the California properties of approximately $76 million (net of income tax expense of approximately $46 million).

Other Divestitures – 2018

On April 10, 2018, the Company completed the sale of its conventional properties located in New Mexico. Cash proceeds received from the sale of these properties were approximately $14 million, and the Company recognized a net gain of approximately $12 million.

On April 4, 2018, the Company completed the sale of its interest in properties located in the Altamont Bluebell Field in Utah (the "Altamont Bluebell Assets Sale"). Cash proceeds received from the sale of these properties were approximately $129 million, net of costs to sell of approximately $2 million, and the Company recognized a net gain of approximately $83 million.

On March 29, 2018, the Company completed the sale of its interest in conventional properties located in west Texas. Cash proceeds received from the sale of these properties were approximately $105 million, net of costs to sell of approximately $2 million, and the Company recognized a net gain of approximately $54 million.

On February 28, 2018, the Company completed the sale of its Oklahoma waterflood and Texas Panhandle properties (the "Oklahoma and Texas Assets Sale"). Cash proceeds received from the sale of these properties were approximately $108 million (including a deposit of approximately $12 million received in 2017), net of costs to sell of approximately $1 million, and the Company recognized a net gain of approximately $46 million.

The divestitures discussed above are not presented as discontinued operations because they do not represent a strategic shift that will have a major effect on the Company's operations and financial results. The gains on these divestitures are included in "(gains) losses on sale of assets and other, net" on the consolidated statement of operations and were included in the upstream reporting segment.

Divestiture – Subsequent Event

On January 17, 2019, the Company completed the sale of its interest in properties located in the Arkoma Basin ("the Arkoma Assets Sale") in Oklahoma and received cash proceeds of approximately $65 million (including a deposit of approximately $5 million received in 2018).

The assets and liabilities associated with the Arkoma Assets Sale and the Oklahoma and Texas Assets Sale were classified as "held for sale" on the consolidated balance sheet at December 31, 2018, and December 31, 2017, respectively.

The following table presents carrying amounts of the assets and liabilities of the Company's properties classified as held for sale on the consolidated balance sheets:

	December 31,	
	2018	2017
	(in thousands)	
Assets:		
Oil and natural gas properties	$ 38,083	$ 92,245
Other property and equipment	152	12,983
Other	161	1,735
Total assets held for sale	$ 38,396	$ 106,963
Liabilities:		
Asset retirement obligations	$ 2,700	$ 42,001
Other	1,025	1,301
Total liabilities held for sale	$ 3,725	$ 43,302

Other assets primarily include inventories and other liabilities primarily include accounts payable.

Other Divestitures – 2017

On November 30, 2017, the Company completed the sale of its interest in properties located in the Williston Basin. Cash proceeds received from the sale of these properties were approximately $255 million, net of costs to sell of approximately $3 million, and the Company recognized a net gain of approximately $116 million.

On November 30, 2017, the Company completed the sale of its interest in properties located in Wyoming. Cash proceeds received from the sale of these properties were approximately $193 million, net of costs to sell of approximately $2 million, and the Company recognized a net gain of approximately $175 million.

On September 12, 2017, August 1, 2017, and July 31, 2017, the Company completed the sales of its interest in certain properties located in south Texas. Combined cash proceeds received from the sale of these properties were approximately $48 million, net of costs to sell of approximately $1 million, and the Company recognized a combined net gain of approximately $14 million.

On August 23, 2017, July 28, 2017, and May 9, 2017, the Company completed the sales of its interest in certain properties located in Texas and New Mexico. Combined cash proceeds received from the sale of these properties were approximately $31 million and the Company recognized a combined net gain of approximately $29 million.

On June 30, 2017, the Company completed the sale of its interest in properties located in the Salt Creek Field in Wyoming. Cash proceeds received from the sale of these properties were approximately $73 million, net of costs to sell of approximately $1 million, and the Company recognized a net gain of approximately $30 million.

On May 31, 2017, the Company completed the sale of its interest in properties located in western Wyoming. Cash proceeds received from the sale of these properties were approximately $559 million, net of costs to sell of approximately $6 million, and the Company recognized a net gain of approximately $277 million.

The divestitures discussed above are not presented as discontinued operations because they do not represent a strategic shift that will have a major effect on the Company's operations and financial results. The gains on these divestitures are included in "gains (losses) on sale of assets and other, net" on the consolidated statements of operations.

Note 5 – Other Property and Equipment

Other property and equipment consists of the following:

	December 31,	
	2018	2017
	(in thousands)	
Natural gas plant and pipeline	$ 523,253	$ 392,999
Furniture and office equipment	40,277	39,551
Buildings and leasehold improvements	24,974	27,301
Vehicles	9,011	10,811
Land	6,258	6,776
Drilling and other equipment	2,471	3,291
	606,244	480,729
Less accumulated depreciation	(62,368)	(28,658)
	$ 543,876	$ 452,071

Note 6 – Debt

Riviera Credit Facility

On August 4, 2017, the Parent entered into a credit agreement with Holdco II, as borrower, Royal Bank of Canada, as administrative agent, and the lenders and agents party thereto, providing for a new senior secured reserve-based revolving loan facility (the “Riviera Credit Facility”) with $500 million in borrowing commitments and an initial borrowing base of $500 million.

On April 30, 2018, the Parent entered into an amendment to the Riviera Credit Facility (the “Riviera Credit Facility Amendment”) which, among other things, modified the borrowing base and maximum borrowing commitment amount to $425 million. In January 2019, in connection with the closing of the Arkoma Assets Sale, the maximum borrowing commitment reduced to $385 million.

As of December 31, 2018, total borrowings outstanding under the Riviera Credit Facility were $20 million and there was approximately $371 million of available borrowing capacity (which includes a $34 million reduction for outstanding letters of credit). At February 28, 2019, there were no borrowings outstanding and approximately $351 million of available borrowing capacity under the Riviera Credit Facility (which includes a $34 million reduction for outstanding letters of credit). The maturity date is August 4, 2020. In connection with the Spin-off and as required by the Riviera Credit Facility Amendment, Riviera executed a Joinder Agreement on August 7, 2018, whereby it assumed the obligations of the Parent under the Riviera Credit Facility. Following the Spin-off, the Borrower is a subsidiary of Riviera.

Redetermination of the borrowing base under the Riviera Credit Facility, based primarily on reserve reports using lender commodity price expectations at such time, occurs semi-annually, in April and October. There was no change to the borrowing base as a result of the October 2018 redetermination. The interest rate under the Riviera Credit Facility is variable and was 5.0% at December 31, 2018. At the Company’s election, interest on borrowings under the Riviera Credit Facility is determined by reference to either the London Interbank Offered Rate (“LIBOR”) plus an applicable margin ranging from 2.50% to 3.50% per annum or the alternate base rate (“ABR”) plus an applicable margin ranging from 1.50% to 2.50% per annum, depending on utilization of the borrowing base. Interest is generally payable in arrears quarterly for loans bearing interest based at the ABR and at the end of the applicable interest period for loans bearing interest at the LIBOR, or if such interest period is longer than three months, at the end of the three month intervals during such interest period. The Company is required to pay a commitment fee to the lenders under the Riviera Credit Facility, which accrues at a rate per annum of 0.50% on the average daily unused amount of the available revolving loan commitments of the lenders.

The obligations under the Riviera Credit Facility are secured by mortgages covering approximately 85% of the total value of the proved reserves of the oil and natural gas properties of the Company and certain of its subsidiaries, along with liens on substantially all personal property of the Company and certain of its subsidiaries, and are guaranteed by the Company, and certain of its subsidiaries, subject to customary exceptions. Under the Riviera Credit Facility, the Company is required to maintain (i) a maximum total net debt to last twelve months EBITDA ratio of 4.0 to 1.0, and (ii) a minimum adjusted current ratio of 1.0 to 1.0.

The Riviera Credit Facility also contains affirmative and negative covenants, including as to compliance with laws (including environmental laws, ERISA and anti-corruption laws), maintenance of required insurance, delivery of quarterly and annual financial statements, oil and gas engineering reports and budgets, maintenance and operation of property (including oil and gas properties), restrictions on the incurrence of liens and indebtedness, mergers, consolidations and sales of assets, paying dividends or other distributions in respect of, or repurchasing or redeeming, the Company's capital stock, making certain investments and transactions with affiliates.

The Riviera Credit Facility contains events of default and remedies customary for credit facilities of this nature. Failure to comply with the financial and other covenants in the Riviera Credit Facility would allow the lenders, subject to customary cure rights, to require immediate payment of all amounts outstanding under the Riviera Credit Facility.

Blue Mountain Credit Facility

On August 10, 2018, Blue Mountain Midstream entered into a credit agreement with Royal Bank of Canada, as administrative agent, and the lenders and agents party thereto, providing for a new senior secured revolving loan facility (the "Blue Mountain Credit Facility" and together with the Riviera Credit Facility, the "Credit Facilities"), providing for an initial borrowing commitment of $200 million.

Before Blue Mountain Midstream completes certain operational milestones (such completion of the operational milestones, the "Covenant Changeover Date"), a condition to any borrowing is that Blue Mountain Midstream's consolidated total indebtedness to capitalization ratio (the "Debt/Cap Ratio") be not greater than 0.35 to 1.00 upon giving effect to such borrowing. As such, prior to the Covenant Changeover Date, the available borrowing capacity under the Blue Mountain Credit Facility may be less than the aggregate amount of the lenders' commitments at such time. On and after the Covenant Changeover Date, Blue Mountain Midstream will no longer have to comply with the Debt/Cap Ratio as a condition to drawing and may borrow up to the total amount of the lenders' aggregate commitments. The Blue Mountain Credit Facility also provides for the ability to increase the aggregate commitments of the lenders to up to $400 million after the Covenant Changeover Date, subject to obtaining commitments for any such increase, which may result in an increase in Blue Mountain Midstream's available borrowing capacity. As of December 31, 2018, total borrowings outstanding under the Blue Mountain Credit Facility were $4.5 million and there was approximately $72 million of available borrowing capacity (in addition, there was $12 million of outstanding letters of credit). The Covenant Changeover Date occurred February 8, 2019, which increased the current borrowing commitment to $200 million. At February 28, 2019, total borrowings outstanding under the Blue Mountain Credit Facility were approximately $19 million and there was approximately $169 million of available borrowing capacity (which includes a $12 million reduction for outstanding letters of credit). The Blue Mountain Credit Facility matures on August 10, 2023.

The interest under the Blue Mountain Credit Facility is variable and was 4.5% at December 31, 2018. At Blue Mountain Midstream's election, interest on borrowings under the Blue Mountain Credit Facility is determined by reference to either the LIBOR plus an applicable margin ranging from 2.00% to 3.00% per annum or the ABR plus an applicable margin ranging from 1.00% to 2.00% per annum, both depending on Blue Mountain Midstream's consolidated total leverage ratio. Interest is generally payable in arrears on the last day of March, June, September and December for loans bearing interest based at the ABR and at the end of the applicable interest period for loans bearing interest at the LIBOR, or if such interest period is longer than three months, at the end of three month intervals during such interest period. Blue Mountain Midstream is required under the Blue Mountain Credit Facility to pay a commitment fee to the lenders, which accrues at a rate per annum of 0.375% or 0.50% (depending on Blue Mountain Midstream's consolidated total leverage ratio) on the average daily unused amount of the available revolving loan commitments of the lenders.

The Blue Mountain Credit Facility is secured by a first priority lien on substantially all the assets of Blue Mountain Midstream. Under the Blue Mountain Credit Facility, Blue Mountain Midstream is required to maintain (i) for certain periods, a ratio of consolidated total debt (subject to certain carve-outs) to the sum of (a) total debt (subject to certain carve-outs) and (b) consolidated owners' equity interest in Blue Mountain Midstream and its potential future subsidiaries of no greater than 0.35 to 1.00, and (ii) subject to satisfaction of certain conditions and for certain periods (a) a ratio of consolidated EBITDA to consolidated interest expense no less than 2.50 to 1.00, (b) a ratio of consolidated net debt to consolidated EBITDA (the "consolidated total leverage ratio") no greater than 4.50 to 1.00 or 5.00 to 1.00, as applicable, and (c) in case certain other kinds of indebtedness are outstanding, a ratio of consolidated net debt secured by a lien on property of Blue Mountain Midstream to consolidated EBITDA no greater than 3.00 to 1.00.

The Blue Mountain Credit Facility also contains affirmative and negative covenants customary for credit facilities of this nature, including as to compliance with laws (including environmental laws, ERISA and anti-corruption laws), maintenance of required insurance, delivery of quarterly and annual financial statements, budgets, maintenance and operation of property, restrictions on the incurrence of liens and indebtedness, mergers, consolidations and sales of assets and transactions with affiliates.

The Blue Mountain Credit Facility contains events of default and remedies customary for credit facilities of this nature. If Blue Mountain Midstream does not comply with the covenants in the Blue Mountain Credit Facility, the lenders may, subject to customary cure rights, require immediate payment of all amounts outstanding under the Blue Mountain Credit Facility.

Emergence Credit Facility

On the Effective Date, pursuant to the terms of the Plan, the Parent entered into the emergence credit facility with Holdco II as borrower and Wells Fargo Bank, National Association, as administrative agent, providing for: 1) a reserve-based revolving loan with an initial borrowing base of $1.4 billion and 2) a term loan in an original principal amount of $300 million. In connection with the entry into the Riviera Credit Facility, the emergence credit facility was terminated and repaid in full.

Predecessor's Credit Facility, Second Lien Notes and Senior Notes

On the Effective Date, pursuant to the terms of the Plan, all outstanding obligations under the Predecessor's credit facility, second lien notes and senior notes were canceled. See Note 2 for additional information.

Predecessor Covenant Violations

The Company's filing of the Bankruptcy Petitions described in Note 2 constituted an event of default that accelerated the obligations under the Predecessor's credit facility, second lien notes and senior notes. For the two months ended February 28, 2017, contractual interest, which was not recorded, on the second lien notes and senior notes was approximately $57 million. Under the Bankruptcy Code, the creditors under these debt agreements were stayed from taking any action against the Company as a result of an event of default.

Fair Value

The Company's debt is recorded at the carrying amount on the consolidated balance sheet. The carrying amounts of the Credit Facilities approximate fair value because the interest rates are variable and reflective of market rates.

Note 7 – Derivatives

Commodity Derivatives

The following table presents derivative positions for the periods indicated as of December 31, 2018:

	2019	2020
Natural gas positions:		
Fixed price swaps (NYMEX Henry Hub):		
Hedged volume (MMMBtu)	55,115	10,980
Average price ($/MMBtu)	$ 2.90	$ 2.82
Collars (NYMEX Henry Hub):		
Hedged volume (MMMBtu)	7,300	—
Average floor price ($/MMBtu)	$ 2.75	$ —
Average ceiling price ($/MMBtu)	$ 3.00	$ —
Oil positions:		
Fixed price swaps (NYMEX WTI):		
Hedged volume (MBbls)	401	183
Average price ($/Bbl)	$ 64.52	$ 64.63
Natural gas basis differential positions: (1)		
PEPL basis swaps:		
Hedged volume (MMMBtu)	25,550	—
Hedge differential	$ (0.64)	$ —
MichCon basis swaps:		
Hedged volume (MMMBtu)	7,300	3,660
Hedge differential ($/MMBtu)	$ (0.19)	$ (0.19)
NWPL basis swaps:		
Hedged volume (MMMBtu)	3,650	—
Hedge differential ($/MMBtu)	$ (0.61)	$ —
Enable basis swaps:		
Hedged volume (MMMBtu)	1,825	—
Hedge differential ($/MMBtu)	$ (0.23)	$ —
Southern Star basis swaps:		
Hedged volume (MMMBtu)	1,825	—
Hedge differential ($/MMBtu)	$ (0.57)	$ —
NGL Positions:		
Fixed price swap (Mont Belvieu ethane):		
Hedged volume (gallons in thousands)	30,660	—
Average price ($/gallon)	$ 0.34	$ —
Fixed price swap (Mont Belvieu propane):		
Hedged volume (gallons in thousands)	15,330	—
Average price ($/gallon)	$ 0.68	$ —
Margin spread (Mont Belvieu propane and Conway propane):		
Hedged volume (gallons in thousands)	22,995	—
Average price ($/gallon)	$ (0.07)	$ —

(1) Settled or to be settled, as applicable, on the indicated pricing index to hedge basis differential to the NYMEX Henry Hub natural gas price.

During the year ended December 31, 2018, the Company entered into commodity derivative contracts consisting of natural gas basis swaps for March 2018 through December 2020, oil fixed price swaps for October 2018 through December 2020, natural gas fixed price swaps for 2019 and 2020, natural gas collars for 2019. In addition, the Company entered into NGL fixed price swaps for 2019 to hedge purchase costs and margins of its Blue Mountain Midstream Business. In April 2018, in connection with the closing of the Altamont Bluebell Assets Sale, the Company canceled its oil collars for 2018 and 2019. The Company paid net cash settlements of approximately $20 million for the cancellations.

During the ten months ended December 31, 2017, the Company entered into commodity derivative contracts consisting of oil fixed price swaps for 2018 and natural gas fixed price swaps for 2018 and 2019. The Company did not enter into any commodity derivative contracts during the two months ended February 28, 2017.

During the year ended December 31, 2016, the Company entered into commodity derivative contracts consisting of natural gas swaps for October 2016 through December 2019, oil swaps for November 2016 through December 2017, and oil collars for 2018 and 2019. In April 2016 and May 2016, the Company canceled (prior to the contract settlement dates) all of its then-outstanding derivative contracts for net proceeds of approximately $1.2 billion. The net proceeds were used to make permanent repayments of a portion of the borrowings outstanding under the Predecessor's credit facility.

The natural gas derivatives are settled based on the closing price of NYMEX Henry Hub natural gas on the last trading day for the delivery month, which occurs on the third business day preceding the delivery month, or the relevant index prices of natural gas published in Inside FERC's Gas Market Report on the first business day of the delivery month. The oil derivatives are settled based on the average closing price of NYMEX WTI crude oil for each day of the delivery month.

Balance Sheet Presentation

The Company's commodity derivatives are presented on a net basis in "derivative instruments" on the consolidated balance sheets. See Note 8 for fair value disclosures about oil and natural gas commodity derivatives. The following table summarizes the fair value of derivatives outstanding on a gross basis:

	December	
	2018	**2017**
	(in thousands)	
Assets:		
Commodity derivatives	$ 21,851	$ 22,589
Liabilities:		
Commodity derivatives	$ 11,209	$ 25,443

By using derivative instruments to economically hedge exposures to changes in commodity prices, the Company exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes the Company, which creates credit risk. The Company's counterparties are participants in its Credit Facilities. The Credit Facilities are secured by certain of the Company's and its subsidiaries' oil, natural gas and NGL reserves and personal property; therefore, the Company is not required to post any collateral. The Company does not receive collateral from its counterparties.

The maximum amount of loss due to credit risk that the Company would incur if its counterparties failed completely to perform according to the terms of the contracts, based on the gross fair value of financial instruments, was approximately $22 million at December 31, 2018. The Company minimizes the credit risk in derivative instruments by: (i) limiting its exposure to any single counterparty; (ii) entering into derivative instruments only with counterparties that meet the Company's minimum credit quality standard, or have a guarantee from an affiliate that meets the Company's minimum credit quality standard; and (iii) monitoring the creditworthiness of the Company's counterparties on an ongoing basis. In accordance with the Company's standard practice, its commodity derivatives are subject to counterparty netting under agreements governing such derivatives and therefore the risk of loss due to counterparty nonperformance is somewhat mitigated.

Gains and Losses on Derivatives

A summary of gains and losses on derivatives included on the consolidated and combined statements of operations is presented below:

	Successor		Predecessor	
	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
(in thousands)				
Gains (losses) on commodity derivatives	$ (23,404)	$ 13,533	$ 92,691	$ (164,330)
Marketing expenses	(1,839)	—	—	—
Total gains (losses) on commodity derivatives	$ (25,243)	$ 13,533	$ 92,691	$ (164,330)

The Company paid net cash settlements of approximately $39 million for the year ended December 31, 2018. The Company received net cash settlements of approximately $27 million for the ten months ended December 31, 2017, and paid net cash settlements of approximately $12 million for the two months ended February 28, 2017. The Company received net cash settlements of approximately $861 million the year ended December 31, 2016. In addition, during the year ended December 31, 2016, approximately $841 million in settlements (primarily in connection with the April 2016 and May 2016 commodity derivative cancellations) were paid directly by the counterparties to the lenders under the Predecessor's credit facility as repayments of a portion of the borrowings outstanding.

Note 8 – Fair Value Measurements on a Recurring Basis

The Company accounts for its commodity derivatives at fair value (see Note 7) on a recurring basis. The Company determines the fair value of its commodity derivatives utilizing pricing models that use a variety of techniques, including market quotes and pricing analysis. Inputs to the pricing models include publicly available prices and forward price curves generated from a compilation of data gathered from third parties. Company management 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 that those instruments trade in active markets. Assumed credit risk adjustments, based on published credit ratings and public bond yield spreads, are applied to the Company's commodity derivatives.

Fair Value Hierarchy

In accordance with applicable accounting standards, the Company has categorized its financial instruments into a three-level fair value hierarchy based on the priority of inputs to the valuation technique. The fair value hierarchy gives the highest priority to quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3).

Financial assets and liabilities recorded in the consolidated balance sheets are categorized based on the inputs to the valuation techniques as follows:

Level 1 Financial assets and liabilities for which values are based on unadjusted quoted prices for identical assets or liabilities in an active market that management has the ability to access.

Level 2 Financial assets and liabilities for which values are based on quoted prices in markets that are not active or model inputs that are observable either directly or indirectly for substantially the full term of the asset or liability (commodity derivatives).

Level 3 Financial assets and liabilities for which values are based on prices or valuation techniques that require inputs that are both unobservable and significant to the overall fair value measurement. These inputs reflect management's own assumptions about the assumptions a market participant would use in pricing the asset or liability.

When the inputs used to measure fair value fall within different levels of the hierarchy in a liquid environment, the level within which the fair value measurement is categorized is based on the lowest level input that is significant to the fair value measurement in its entirety. The Company conducts a review of fair value hierarchy classifications on a quarterly basis. Changes in the observability of valuation inputs may result in a reclassification for certain financial assets or liabilities.

The following presents the fair value hierarchy for assets and liabilities measured at fair value on a recurring basis:

	Successor		
	December 31, 2018		
	Level 2	Netting (1)	Total
		(in thousands)	
Assets:			
Commodity derivatives	$ 21,851	$ (6,490)	$ 15,361
Liabilities:			
Commodity derivatives	$ 11,209	$ (6,490)	$ 4,719

	Successor		
	December 31, 2017		
	Level 2	Netting (1)	Total
		(in thousands)	
Assets:			
Commodity derivatives	$ 22,589	$ (12,491)	$ 10,098
Liabilities:			
Commodity derivatives	$ 25,443	$ (12,491)	$ 12,952

(1) Represents counterparty netting under agreements governing such derivatives.

Note 9 – Asset Retirement Obligations

The Company has the obligation to plug and abandon oil and natural gas wells and related equipment at the end of production operations. Estimated asset retirement costs are recognized as liabilities with an increase to the carrying amounts of the related long-lived assets when the obligation is incurred. The liabilities are included in “other accrued liabilities” and “asset retirement obligations and other noncurrent liabilities” on the consolidated balance sheets. Accretion expense is included in “depreciation, depletion and amortization” on the consolidated and combined statements of operations. The fair value of additions to the asset retirement obligations 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 Company’s management at the time of the valuation and are the most sensitive and subject to change.

In addition, there is insufficient information to reasonably determine the timing and/or method of settlement for purposes of estimating the fair value of the asset retirement obligation of Blue Mountain Midstream’s assets. In such cases, asset retirement obligation cost is considered indeterminate because there is no data or information that can be derived from past practice, industry practice, management’s experience, or the asset’s estimated economic life. Indeterminate asset retirement obligation costs associated with Blue Mountain Midstream will be recognized in the period in which sufficient information exists to reasonably estimate potential settlement dates and methods.

The following table presents a reconciliation of the Company's asset retirement obligations:

(in thousands)	Successor: Year Ended December 31, 2018	Successor: Ten Months Ended December 31, 2017	Predecessor: Two Months Ended February 28, 2017
Asset retirement obligations at beginning of period	$ 164,553	$ 357,397	$ 402,162
Liabilities added from drilling	356	551	146
Liabilities associated with assets divested	(62,388)	(158,228)	—
Liabilities associated with assets held for sale	(2,700)	(42,001)	—
Current year accretion expense	7,235	14,995	4,024
Settlements	(2,824)	(8,189)	(618)
Revision of estimates	1,027	28	—
Fresh start adjustment (1)	—	—	(48,317)
	105,259	164,553	357,397
Less asset retirement obligations – discontinued operations	—	—	(26,978)
Asset retirement obligations at end of period	$ 105,259	$ 164,553	$ 330,419

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

Note 10 – Commitments and Contingencies

On May 11, 2016, the Debtors filed Bankruptcy Petitions for relief under Chapter 11 of the Bankruptcy Code in the Bankruptcy Court. The Debtors' Chapter 11 cases were administered jointly under the caption In re Linn Energy, LLC, et al., Case No. 16-60040. On January 27, 2017, the Bankruptcy Court entered the Confirmation Order. Consummation of the Plan was subject to certain conditions set forth in the Plan. On the Effective Date, all of the conditions were satisfied or waived and the Plan became effective and was implemented in accordance with its terms. On September 27, 2018, the Bankruptcy Court closed the LINN Debtors' Chapter 11 cases, but retained jurisdiction as provided in the Confirmation Order, including to potentially reopen the Chapter 11 cases if certain matters currently on appeal in the U.S. Court of Appeals for the Fifth Circuit are overturned, including the Default Interest Appeal (as defined below).

The commencement of the Chapter 11 proceedings automatically stayed certain actions against the Company, including actions to collect prepetition liabilities or to exercise control over the property of the Company's bankruptcy estates. However, the Company is, and will continue to be until the final resolution of all claims, subject to certain contested matters and adversary proceedings stemming from the Chapter 11 proceedings, which are not affected by the closure of the LINN Debtors' Chapter 11 cases.

On March 17, 2017, Wells Fargo Bank, National Association ("Wells Fargo"), the administrative agent under the Predecessor's credit facility, filed a motion in the Bankruptcy Court seeking payment of post-petition default interest of approximately $31 million. The Company has vigorously disputed that Wells Fargo is entitled to any default interest based on the plain language of the Plan and Confirmation Order. On November 13, 2017, the Bankruptcy Court ruled that the secured lenders are not entitled to payment of post-petition default interest. That ruling was appealed by Wells Fargo and on March 29, 2018, the U.S. District Court for the Southern District of Texas affirmed the Bankruptcy Court's ruling. On April 30, 2018, the Bankruptcy Court approved the substitution of UMB Bank, National Association ("UMB Bank") as successor to Wells Fargo as administrative agent under the Predecessor's credit facility. UMB Bank then immediately filed a notice of appeal to the U.S. Court of Appeals for the Fifth Circuit from the decision by the U.S. District Court for the Southern District of Texas, which affirmed the decision of the Bankruptcy Court. The Fifth Circuit heard oral arguments on February 6, 2019. That appeal ("the Default Interest Appeal") remains pending.

The Company is not currently a party to any litigation or pending claims that it believes would have a material adverse effect on its overall business, financial position, results of operations or liquidity; however, cash flow could be significantly impacted in the reporting periods in which such matters are resolved.

Except for in connection with its Chapter 11 proceedings, the Company made no significant payments to settle any legal, environmental or tax proceedings during the years ended December 31, 2018, or December 31, 2017. The Company regularly analyzes current information and accrues for probable liabilities on the disposition of certain matters as necessary. Liabilities for loss contingencies arising from claims, assessments, litigation or other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated.

Note 11 – Operating Leases

The Company leases office space and other property and equipment under lease agreements expiring on various dates through 2021. The Company recognized expense under operating leases of approximately $10 million, $6 million, $1 million and $9 million for the year ended December 31, 2018, the ten months ended December 31, 2017, the two months ended February 28, 2017, and the year ended December 31, 2016, respectively.

As of December 31, 2018, future minimum lease payments were as follows (in thousands):

2019	$ 4,054
2020	497
2021	56
2022	4
2023	—
Thereafter	—
	$ 4,611

Note 12 – Equity (Deficit)

For periods prior to the Spin-off, the Company’s equity consisted of net parent company investment. “Net transfers to parent” on the consolidated statements of equity is primarily related to cash distributed to the Parent, and for 2018, also includes the distribution of the investment in Roan of approximately $473 million on the Reorganization Date (see Note 1). During the Successor period, cash distributions to the Parent were used primarily for the purposes of repurchasing shares of the Parent’s Class A common stock. Upon completion of the Spin-off, net parent company investment was reclassified to “common stock” and “additional paid-in capital” on the consolidated balance sheet and consolidated statement of equity.

Shares Issued and Outstanding

On August 7, 2018, upon completion of the Spin-off, there were 76,190,908 shares of Riviera’s common stock, par value $0.01 per share issued and outstanding. As of December 31, 2018, there were 69,197,284 shares of common stock issued and outstanding.

Share Repurchase Program

On August 16, 2018, the Board authorized the repurchase of up to $100 million of the Company’s outstanding shares of common stock. During the period from August 2018 through December 31, 2018, the Company repurchased an aggregate of 945,979 shares of common stock at an average price of $19.21 per share for a total cost of approximately $18 million. For the period from January 1, 2019 through February 22, 2019, the Company repurchased 221,788 shares of common stock at an average price of $15.27 for a total cost of approximately $3 million. At February 22, 2019, approximately $78 million was available for share repurchase under the program.

In accordance with the SEC's regulations regarding issuer tender offers, the Company's share repurchase program was suspended concurrent with the September 24, 2018, announcement of the intent to commence a tender offer. The program was resumed in November 2018 following the expiration of the tender offer.

Any share repurchases are subject to restrictions in the Riviera Credit Facility.

Tender Offer

On September 24, 2018, the Company announced the intention to commence a tender offer to purchase $100 million of the Company's common stock. In October 2018, upon the terms and subject to the conditions described in the Offer to Purchase dated September 25, 2018, as amended, the Company repurchased an aggregate of 6,062,179 shares of common stock at a price of $22.00 per share for a total cost of approximately $133 million (excluding expenses of approximately $2 million related to the tender offer).

Dividends

The Company is not currently paying a cash dividend; however, the Board of Directors periodically reviews the Company's liquidity position to evaluate whether or not to pay a cash dividend. Any future payment of cash dividends would be subject to the restrictions in the Riviera Credit Facility.

Note 13 – Share-Based Compensation and Other Benefits

Riviera Omnibus Incentive Plan

In August 2018, the Company implemented the Riviera Resources, Inc. 2018 Omnibus Incentive Plan (the "Riviera Omnibus Incentive Plan") pursuant to which employees, consultants and non-employee directors of the Company and its affiliates are eligible to receive stock options, restricted stock, dividend equivalents, performance awards, other stock-based awards and other cash-based awards.

Pursuant to the Spin-off, on August 7, 2018, certain employees of the Company received 520,837 restricted stock units of the Company ("Riviera Legacy RSUs"). Such Riviera Legacy RSUs were originally granted as LINN RSUs pursuant to the Linn Energy, Inc. 2017 Omnibus Plan (the "LINN Incentive Plan"), and in connection with the Spin-off, the holders of such LINN RSUs were issued one Riviera RSU in respect of each such outstanding LINN RSU.

As of December 31, 2018, 2,869,130 shares were issuable under the Riviera Omnibus Incentive Plan pursuant to outstanding Riviera RSUs, including (i) the Riviera Legacy RSUs, (ii) 497,899 restricted stock units of the Company granted to certain employees of the Company (the "Restricted Shares" and together with Riviera Legacy RSUs, the "Riviera RSUs"), (iii) 1,899,156 restricted stock units of the Company granted as performance units to certain employees of the Company (the "Performance Shares") that, in the case of the Performance Shares, vest, if at all, based on the achievement of certain performance conditions specified in the award agreements.

The Committee (as defined in the Riviera Omnibus Incentive Plan) has broad authority under the Riviera Omnibus Incentive Plan to, among other things: (i) select participants; (ii) determine the types of awards that participants receive and the number of shares that are subject to such awards; and (iii) establish the terms and conditions of awards, including the price (if any) to be paid for the shares or the award. As of December 31, 2018, up to 1,086,698 shares of common stock were available for issuance under the Riviera Omnibus Incentive Plan within the share reserve established under the Riviera Omnibus Incentive Plan, 10,160 of which the Committee has designated for issuance as Restricted Shares and 38,752 of which the Committee has designated for issuance as Performance Shares. If any stock option or other stock-based award granted under the Riviera Omnibus Incentive Plan expires, terminates or is canceled for any reason without having been exercised in full, the number of shares of common stock underlying any unexercised award shall again be available for the purpose of awards under the Riviera Omnibus Incentive Plan. If any shares of restricted stock, performance awards or other stock-based awards denominated in shares of common stock awarded under the Riviera Omnibus Incentive Plan are forfeited for any reason, the number of forfeited shares shall again be available for purposes of awards under the Riviera Omnibus Incentive Plan. Any award under the Riviera Omnibus Incentive Plan settled in cash shall not be counted against the maximum share limitation.

As is customary in incentive plans of this nature, each share limit and the number and kind of shares available under the Riviera Omnibus Incentive Plan and any outstanding awards, as well as the exercise or purchase prices of awards, and performance targets under certain types of performance-based awards, are subject to adjustment in the event of certain reorganizations, mergers, combinations, recapitalizations, stock splits, stock dividends or other similar events that change the number or kind of shares outstanding, and extraordinary dividends or distributions of property to the Company's shareholders.

Blue Mountain Midstream Omnibus Incentive Plan

In July 2018, Blue Mountain Midstream adopted the Blue Mountain Midstream LLC 2018 Omnibus Incentive Plan (the "BMM Incentive Plan") pursuant to which employees, consultants and non-employee directors of Blue Mountain Midstream and its affiliates are eligible to receive unit options, restricted units, dividend equivalents, performance awards, other unit-based awards and other cash-based awards. No awards have been granted under the BMM Incentive Plan.

LINN Awards

In January 2018, the Parent's board of directors' compensation committee approved a then one-time liquidity program under which the Parent agreed, at the option of the participant, to 1) settle all or a portion of an eligible participant's LINN RSUs vesting on or before March 1, 2018, in cash, 2) repurchase all or a portion of any shares of LINN Class A common stock held by an eligible participant as a result of a prior vesting of restricted stock units, and/or 3) settle all or a portion of an eligible participant's LINN RSUs vesting after March 1, 2018, upon involuntary termination of employment, in each case at an agreed upon price (the "Liquidity Program"). For the period from January 1, 2018 through August 7, 2018, the Parent settled 1,028,875 LINN RSUs in cash and repurchased 120,829 shares of LINN Class A common stock for approximately $45 million pursuant to the Liquidity Program.

In April 2018, the Parent entered into agreements with each of its then serving executive officers, under which the Parent agreed, at the option of each officer, to repurchase certain of their LINN RSU awards and outstanding LINN Class A common stock. Pursuant to those agreements immediately prior to the Spin-off, on August 7, 2018, the Parent repurchased an aggregate of 2,477,834 shares of LINN Class A common stock for a total cost of approximately $102 million.

Under the LINN Incentive Plan, upon a participant's termination of employment and/or service (as applicable), the Parent had the right (but not the obligation) to repurchase all or any portion of the shares of Class A common stock, par value $0.001 per share of Linn Energy, Inc. ("LINN Class A common stock"), acquired pursuant to an award at a price equal to the fair market value (as determined under the LINN Incentive Plan) of the shares of LINN Class A common stock to be repurchased, measured as of the date of the Parent's repurchase notice. During May 2018, the Parent began exercising its right to repurchase vesting awards under the LINN Incentive Plan, which resulted in the modification of all awards then outstanding to liability classification. For the period from May 11, 2018 through August 7, 2018, the Parent repurchased 302,410 LINN RSUs for a total cost of approximately $12 million pursuant to its right to repurchase vesting awards.

In addition, for the period from January 1, 2018 through August 7, 2018, the Parent paid approximately $24 million for the payment of income taxes on 585,397 shares withheld from participants upon vesting of LINN RSUs.

On August 2, 2018, the Parent's board of directors authorized the termination of the LINN Incentive Plan following the settlement of all outstanding LINN RSUs and restricted common stock of the Parent. In addition, all remaining unvested LINN RSUs were vested upon the Spin-off, exclusive of the one Riviera Legacy RSU issued associated with each unvested LINN RSU, which Riviera Legacy RSUs remain outstanding and unvested under the Riviera Omnibus Incentive Plan. During August 2018 and September 2018, the Company settled 391,422 vested LINN RSUs in cash for approximately $7 million and approximately $1 million for the payment of income taxes on 50,537 shares withheld from participants upon vesting of LINN RSUs. The LINN Incentive Plan terminated on September 17, 2018, following the settlement of all outstanding LINN RSUs and restricted common stock of the Parent.

Accounting for Share-Based Compensation

The consolidated and combined financial statements include 100% of the Parent's employee-related expenses, as its personnel were employed by Riviera Operating, LLC, formerly known as Linn Operating, LLC, a subsidiary of the Parent that became a subsidiary of Riviera in connection with the Spin-off. Compensation cost related to the grant of share-based awards has been recorded at the subsidiary level with a corresponding credit to liability or equity, representing the Parent's capital contribution.

Upon completion of the Spin-off, at the option of the participant, Riviera continued settling Riviera RSUs for cash under the Liquidity Program. For the period from August 8, 2018 through December 31, 2018, Riviera has repurchased 27,623 Riviera RSUs for a total cost of approximately $570,000 pursuant to the Liquidity Program.

As a result of continuing the Liquidity Program and history of cash settling awards, all outstanding Riviera awards are liability classified at December 31, 2018. The Company has recognized a liability of approximately $4 million related to outstanding share based compensation awards included in "other accrued liabilities" on the consolidated balance sheet. All cash settlements of liability classified awards are classified as operating activities on the statement of cash flows. In addition, for the year ended December 31, 2018, the Company recorded incremental share-based compensation expense of approximately $28 million related to awards modified to liability classification in May 2018.

	Successor		Predecessor	
	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
(in thousands)				
General and administrative expenses (1)	$ 131,828	$ 41,285	$ 50,255	$ 34,268
Lease operating expenses	—	—	—	9,950
Total share-based compensation expenses	$ 131,828	$ 41,285	$ 50,255	$ 44,218
Income tax benefit	$ 8,846	$ 9,861	$ 5,170	$ 16,339

(1) The year ended December 31, 2018, includes approximately $123 million recorded by the Parent prior to the Spin-off.

Restricted Stock Units

The following summarizes the Company's restricted stock units activity:

	Number of Nonvested Units	Weighted Average Grant-Date Fair Value Per Unit
Riviera Legacy RSUs issued upon completion of the Spin-off	520,837	$ 15.18
Granted	497,899	$ 15.75
Vested	(27,623)	$ 15.14
Forfeited	(21,139)	$ 17.78
Nonvested units at December 31, 2018	969,974	$ 15.42

In December 2018, the Company granted to certain members of management 497,899 Restricted Shares with an aggregate grant date fair value of approximately $8 million. The Restricted Shares are set to vest over approximately 2.5 years.

The total fair value of Riviera RSUs that vested was approximately $570,000 for the period from August 7, 2018 through December 31, 2018. As of December 31, 2018, there was approximately $12 million of unrecognized compensation cost related to nonvested Riviera RSUs (inclusive of Restricted Shares). The cost is expected to be recognized over a weighted average period of approximately 2.0 years.

Performance Shares

In December 2018, the Company granted 1,899,156 (the maximum number of shares available to be earned) Performance Shares to certain members of management. The vesting of these awards is determined based on the Company's equity value (subject to adjustment for distributions to shareholders and certain other items) at a specified time. As of December 31, 2018, there was approximately $5 million of unrecognized compensation cost related to nonvested Performance Shares. The cost is expected to be recognized over a weighted average period of approximately 2.5 years. To date, no performance targets have been met.

The fair value of share-based compensation for Performance Shares was estimated on the balance sheet date using a Monte Carlo pricing model based on certain assumptions. The Company's determination of the fair value of share-based payment awards is affected by the Company's share price as well as assumptions regarding a number of complex and subjective variables. Expected volatility of 35% used in the estimation of fair value of the 2018 Performance Share grants was determined using available volatility data for the Company as well as an average of volatility computations of other identified peer companies in the oil and natural gas industry. The risk-free rate of 2.46% is based on the U.S. constant maturity treasury rate at the time of valuation with maturity corresponding to the expected vesting date.

Defined Contribution Plan

The Company sponsors a 401(k) defined contribution plan for eligible employees. For the years 2018 and 2017, Company contributions to the 401(k) plan consisted of a discretionary matching contribution equal to 100% of the first 4% of eligible compensation contributed by the employee on a before-tax basis. For 2016, Company contributions to the 401(k) plan consisted of a discretionary matching contribution equal to 100% of the first 6% of eligible compensation contributed by the employee on a before-tax basis. The Company contributed approximately $3 million, $3 million, $812,000 and $9 million during the ten months ended December 31, 2017, the two months ended February 28, 2017, and the year ended December 31, 2016, respectively, to the 401(k) plan's trustee account. The 401(k) plan funds are held in a trustee account on behalf of the plan participants.

Note 14 – Earnings Per Share

On August 7, 2018, the Parent distributed 76,190,908 shares of Riviera common stock to LINN Energy shareholders. The Parent did not retain any ownership in Riviera. Each shareholder of the Parent received one share of Riviera common stock for each share of LINN Class A common stock held by such shareholder of the Parent at the close of business on August 3, 2018, the record date.

Basic earnings per share is computed by dividing net income by the weighted average number of shares outstanding during the period. Diluted earnings per share is computed by adjusting the average number of shares outstanding for the dilutive effect, if any, of potential common shares. Basic and diluted earnings per share and the average number of shares outstanding were retrospectively restated for the number of shares of Riviera common stock outstanding immediately following the Spin-off and the same number of shares was used to calculate basic and diluted earnings per share in 2017 and 2016 since there were no Riviera equity awards outstanding prior to the Spin-off.

	Successor		Predecessor	
(in thousands, except per share amounts)	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
Income from continuing operations	$ 20,933	$ 345,131	$ 2,587,557	$ (343,733)
Income (loss) from discontinued operations, net of income taxes	19,674	90,064	(548)	(18,354)
Net income	$ 40,607	$ 435,195	$ 2,587,009	$ (362,087)
Income (loss) per share:				
Income from continuing operations per share – Basic	$ 0.28	$ 4.53	$ 33.96	$ (4.51)
Income from continuing operations per share – Diluted	$ 0.28	$ 4.53	$ 33.96	$ (4.51)
Income (loss) from discontinued operations per share – Basic	$ 0.26	$ 1.18	$ (0.01)	$ (0.24)
Income (loss) from discontinued operations per share – Diluted	$ 0.26	$ 1.18	$ (0.01)	$ (0.24)
Net income per share – Basic	$ 0.54	$ 5.71	$ 33.95	$ (4.75)
Net income per share – Diluted	$ 0.54	$ 5.71	$ 33.95	$ (4.75)
Weighted average shares outstanding – Basic	74,935	76,191	76,191	76,191
Dilutive effect of unit equivalents	425	—	—	—
Weighted average shares outstanding – Diluted	75,360	76,191	76,191	76,191

Note 15 – Income Taxes

For periods prior to the Spin-off, income tax expense and deferred tax balances were calculated on a separate tax return basis although Riviera's operations have historically been included in the tax returns filed by the Parent, of which Riviera's business was a part. Beginning August 8, 2018, as a stand-alone entity, Riviera will file tax returns on its own behalf and its deferred taxes and effective tax rate may differ from those in the historical periods. For federal income tax purposes, the Spin-off was treated as a sale of assets resulting in new deferred taxes being recorded.

Income tax expense (benefit) consisted of the following:

	Successor		Predecessor	
(in thousands)	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
Current taxes:				
Federal	$ 3	$ 7,140	$ —	$ (494)
State	(117)	2	—	427
Deferred taxes:				
Federal	25,816	363,027	—	11,582
State	3,885	15,485	(166)	(215)
	$ 29,587	$ 385,654	$ (166)	$ 11,300

The deferred tax effects of the Parent's change to a C corporation are included in income from continuing operations for the two months ended February 28, 2017. Amounts recognized as income taxes are included in "income tax expense (benefit)," as well as discontinued operations, on the consolidated and combined statements of operations.

As of December 31, 2018, the Company had approximately $10 million of net operating loss carryforwards for federal income tax purposes.

A reconciliation of the federal statutory tax rate to the effective tax rate is as follows:

	Successor		Predecessor	
	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
Federal statutory rate	21.0%	35.0%	35.0%	35.0%
Nondeductible compensation	40.6	0.8	—	—
Federal statutory rate change	—	13.8	—	—
State, net of federal tax benefit	3.2	2.6	—	0.7
Loss excluded from nontaxable entities	—	—	(35.0)	(23.4)
Share-based compensation	(8.0)	—	—	(1.4)
Other	1.8	0.6	—	(14.3)
Effective rate	58.6%	52.8%	—%	(3.4)%

On December 22, 2017, H.R. 1 (the "Tax Cuts and Jobs Act") was signed into law. The Company conducted an assessment of the impact of the Tax Cuts and Jobs Act and concluded that a noncash charge of approximately $101 million for the ten months ended December 31, 2017, against net deferred income taxes was necessary due to the decrease in the statutory federal income tax rate from 35% to 21%. This charge is included in "income tax expense (benefit)" on the consolidated statement of operations and resulted in a 13.8% increase in the Company's effective tax rate for the ten months ended December 31, 2017.

Significant components of the deferred tax assets and liabilities were as follows:

	December 31,	
	2018	2017
	(in thousands)	
Deferred tax assets:		
Net operating loss carryforwards	$ 2,503	$ 14,615
Share-based compensation	642	5,667
Oil and natural gas properties	125,021	171,425
Other	925	10,918
Total deferred tax assets	129,091	202,625
Deferred tax liabilities:		
Equity investment in Roan	—	(14,087)
Total deferred tax liabilities	—	(14,087)
Net deferred tax assets	$ 129,091	$ 188,538

The net deferred tax assets are recorded in "deferred income taxes" on the consolidated balance sheets at December 31, 2018, and December 31, 2017.

In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. At December 31, 2018, based upon the projections for future taxable income over the periods in which the deferred tax assets are deductible, management believes it is more likely than not that the Company will realize the benefits of these deductible differences.

In accordance with the applicable accounting standards, the Company recognizes only the impact of income tax positions that, based on their merits, are more likely than not to be sustained upon audit by a taxing authority. To evaluate its current tax positions in order to identify any material uncertain tax positions, the Company developed a policy of identifying and evaluating uncertain tax positions that considers support for each tax position, industry standards, tax return disclosures and schedules and the significance of each position. It is the Company's policy to recognize interest and penalties, if any, related to unrecognized tax benefits in income tax expense. The Company had no material uncertain tax positions at December 31, 2018, or December 31, 2017. The tax year 2018 remains open to examination for federal and state income tax purposes.

Note 16 – Supplemental Disclosures to the Consolidated Balance Sheets and Consolidated Statements of Cash Flows

"Other current assets" reported on the consolidated balance sheets include the following:

	December 31,	
	2018	2017
	(in thousands)	
Prepaids	$ 13,493	$ 43,150
Receivable from related party	8,300	23,163
Inventories	3,720	7,667
Other	1,208	2,703
Other current assets	$ 26,721	$ 76,683

"Other accrued liabilities" reported on the consolidated balance sheets include the following:

	December 31,	
	2018	2017
	(in thousands)	
Accrued compensation	$ 16,820	$ 29,089
Asset retirement obligations (current portion)	1,445	3,926
Deposits	10,060	15,349
Income taxes payable	—	7,009
Other	6,149	2,757
Other accrued liabilities	$ 34,474	$ 58,130

The following table provides a reconciliation of cash and cash equivalents on the consolidated balance sheets to cash, cash equivalents and restricted cash on the consolidated statements of cash flows:

	December 31,	
	2018	2017
	(in thousands)	
Cash and cash equivalents	$ 18,529	$ 464,477
Restricted cash	31,248	56,445
Cash, cash equivalents and restricted cash	$ 49,777	$ 520,922

Supplemental disclosures to the consolidated and combined statements of cash flows are presented below:

	Successor		Predecessor	
(in thousands)	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
Cash payments for interest, net of amounts capitalized	$ 132	$ 15,165	$ 17,651	$ 143,305
Cash payments for income taxes	$ —	$ 275	$ —	$ 4,060
Cash payments for reorganization items, net	$ 5,572	$ 11,889	$ 21,571	$ 37,748
Noncash investing activities:				
Accrued capital expenditures	$ 10,438	$ 31,447	$ 22,191	$ 31,128

For purposes of the consolidated and combined statements of cash flows, the Company considers all highly liquid short-term investments with original maturities of three months or less to be cash equivalents. At December 31, 2018, "restricted cash" on the consolidated balance sheet consists of approximately $21 million that will be used to settle certain claims in accordance with the Plan (which is the remainder of approximately $80 million transferred to restricted cash in February 2017 to fund such items) and approximately $10 million related to deposits. At December 31, 2017, "restricted cash" on the consolidated balance sheet consists of approximately $36 million that will be used to settle certain claims in accordance with the Plan, approximately $15 million related to deposits and approximately $5 million for other items.

During the year ended December 31, 2016, approximately $841 million in commodity derivative settlements (primarily in connection with the April 2016 and May 2016 commodity derivative cancellations) were paid directly by the counterparties to the lenders under the Parent's credit facility as repayments of a portion of the borrowings outstanding, and are reflected as noncash transactions by the Company.

Note 17 – Significant Customers

The Company has a concentration of customers who are engaged in oil and natural gas purchasing, transportation and/or refining within the U.S. This concentration of customers may impact the Company's overall exposure to credit risk, either positively or negatively, in that the customers may be similarly affected by changes in economic or other conditions. The Company's customers consist primarily of major oil and natural gas purchasers and the Company generally does not require collateral since it has not experienced significant credit losses on such sales. The Company routinely assesses the recoverability of all material trade and other receivables to determine collectibility (see Note 1).

For the year ended December 31, 2018, the Company's largest customer represented approximately 22% of the Company's sales. For the ten months ended December 31, 2017, the two months ended February 28, 2017, and the year ended December 31, 2016, no individual customer exceeded 10% of the Company's sales.

At December 31, 2018, trade accounts receivable from one customer represented approximately 18% of the Company's receivables. At December 31, 2017, no individual customer exceeded 10% of the Company's receivables.

Note 18 – Related Party Transactions

Roan Resources LLC

On August 31, 2017, the Company completed the Roan Contribution. In exchange for their respective contributions, a subsidiary of the Company and Citizen each received a 50% equity interest in Roan. Also on such date, Roan entered into a Master Services Agreement (the "MSA") with Riviera Operating, a subsidiary of Riviera, pursuant to which Riviera Operating provided certain operating, administrative and other services in respect of the assets contributed to Roan during a transitional period.

Under the MSA, Roan reimbursed Riviera Operating for certain costs and expenses incurred by Riviera Operating in connection with providing the services, and Roan paid to Riviera Operating a service fee of $1.25 million per month, prorated for partial months. For each of the years ended December 31, 2018, and December 31, 2017, the Company recognized service fees of approximately $5 million under the MSA, as a reduction to general and administrative expense. The MSA terminated according to its terms on April 30, 2018.

In addition, the Company's subsidiary, Blue Mountain Midstream has an agreement in place with Roan for the purchase and processing of natural gas from certain of Roan's properties. On January 31, 2019, Blue Mountain Midstream entered into an agreement with Roan to provide comprehensive water management services including pipeline gathering, disposal, treatment and redelivery of recycled water for re-use.

For the year ended December 31, 2018, the Company made natural gas purchases from Roan of approximately $102 million, included in "marketing expenses" on the consolidated statements of operations. At December 31, 2018, the Company had approximately $9 million due from Roan, primarily associated with amounts due to Riviera under the agreements related to the Spin-off, included in "other current assets" and approximately $14 million due to Roan, associated with natural gas purchases included in "accounts payable and accrued expenses" on the consolidated balance sheet. At December 31, 2017, the Company had approximately $23 million due from Roan, primarily associated with capital spending, included in "other current assets" and approximately $18 million due to Roan, primarily associated with joint interest billings and natural gas purchases, included in "accounts payable and accrued expenses" on the consolidated balance sheet.

Note 19 – Segments

At December 31, 2018, the Company had two reporting segments: Upstream and Blue Mountain. The upstream reporting segment was engaged in the exploration, development, production, and sale of oil, natural gas, and NGLs and consists of the Company's properties in the Hugoton Basin, (including the Jayhawk natural gas processing plant, located in Kansas), East Texas, Michigan/Illinois, the Mid-Continent, North Louisiana and the Uinta Basin. The Blue Mountain reporting segment was new for the second quarter of 2018 as a result of a change in the way the chief operating decision maker ("CODM") assesses the Company's results of operations following the hiring of a segment manager to lead the Blue Mountain reporting segment and the commissioning of the cryogenic natural gas processing facility during the second quarter of 2018. The Blue Mountain reporting segment consists of a cryogenic natural gas processing facility and a network of gathering pipelines and compressors located in the Merge/SCOOP/STACK play. To assess the performance of the Company's reporting segments, the CODM analyzes field level cash flow. The Company defines field level cash flow as revenues less direct operating expenses. Other indirect income (expenses) include "general and administrative expenses," "exploration costs," "depreciation, depletion and amortization," "(gains) on sale of assets and other, net," "other income and (expenses)" and "reorganization items, net." Prior period amounts are presented on a comparable basis. In addition, information regarding total assets by reporting segment is not presented because it is not reviewed by the CODM. The following tables present the Company's financial information by reporting segment:

The following tables present the Company's financial information by reporting segment:

	Successor			
	Year Ended December 31, 2018			
	Upstream	Blue Mountain	Not Allocated to Segments	Consolidated
	(in thousands)			
Oil, natural gas and natural gas liquids sales	$ 420,102	$ —	$ —	$ 420,102
Marketing revenues	103,063	142,018	—	245,081
Other revenues	23,880	—	—	23,880
	547,045	142,018	—	689,063
Lease operating expenses	120,097	—	—	120,097
Transportation expenses	83,562	—	—	83,562
Marketing expenses	91,869	127,263	1,839	220,971
Taxes other than income taxes	28,598	883	249	29,730
Total direct operating expenses	324,126	128,146	2,088	454,360
Field level cash flow	$ 222,919	$ 13,872	(2,088)	234,703
Losses on commodity derivatives			(23,404)	(23,404)
Other indirect income (expenses)			(160,779)	(160,779)
Income from continuing operations before income taxes				$ 50,520

	Successor			
	Ten Months Ended December 31, 2017			
	Upstream	Blue Mountain	Not Allocated to Segments	Consolidated
	(in thousands)			
Oil, natural gas and natural gas liquids sales	$ 709,363	$ —	$ —	$ 709,363
Marketing revenues	75,756	7,187	—	82,943
Other revenues	20,839	—	—	20,839
	805,958	7,187	—	813,145
Lease operating expenses	208,446	—	—	208,446
Transportation expenses	113,128	—	—	113,128
Marketing expenses	64,225	4,783	—	69,008
Taxes other than income taxes	47,290	121	142	47,553
Total direct operating expenses	433,089	4,904	142	438,135
Field level cash flow	$ 372,869	$ 2,283	(142)	375,010
Gains on commodity derivatives			13,533	13,533
Other indirect income (expenses)			342,242	342,242
Income from continuing operations before income taxes				$ 730,785

	Predecessor			
	Two Months Ended February 28, 2017			
	Upstream	Blue Mountain	Not Allocated to Segments	Consolidated
	(in thousands)			
Oil, natural gas and natural gas liquids sales	$ 188,885	$ —	$ —	$ 188,885
Marketing revenues	5,999	637	—	6,636
Other revenues	9,915	—	—	9,915
	204,799	637	—	205,436
Lease operating expenses	49,665	—	—	49,665
Transportation expenses	25,972	—	—	25,972
Marketing expenses	4,602	218	—	4,820
Taxes other than income taxes	14,773	78	26	14,877
Total direct operating expenses	95,012	296	26	95,334
Field level cash flow	$ 109,787	$ 341	(26)	110,102
Gains on commodity derivatives			92,691	92,691
Other indirect income (expenses)			2,384,598	2,384,598
Income from continuing operations before income taxes				$ 2,587,391

	Predecessor			
	Year Ended December 31, 2016			
	Upstream	Blue Mountain	Not Allocated to Segments	Consolidated
	(in thousands)			
Oil, natural gas and natural gas liquids sales	$ 874,161	$ —	$ —	$ 874,161
Marketing revenues	36,340	165	—	36,505
Other revenues	93,308	—	—	93,308
	1,003,809	165	—	1,003,974
Lease operating expenses	296,891	—	—	296,891
Transportation expenses	161,574	—	—	161,574
Marketing expenses	28,510	1,226	—	29,736
Taxes other than income taxes	66,616	—	1,028	67,644
Total direct operating expenses	553,591	1,226	1,028	555,845
Field level cash flow	$ 450,218	$ (1,061)	(1,028)	448,129
Losses on commodity derivatives			(164,330)	(164,330)
Other indirect income (expenses)			(616,232)	(616,232)
Loss from continuing operations before income taxes				$ (332,433)

RIVIERA RESOURCES, INC.

SUPPLEMENTAL OIL AND NATURAL GAS DATA (Unaudited)

The following discussion and analysis should be read in conjunction with the "Consolidated and Combined Financial Statements" and "Notes to Consolidated and Combined Financial Statements," which are included in this Annual Report on Form 10-K in Item 8. "Financial Statements and Supplementary Data."

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

Costs incurred in oil and natural gas property acquisition, exploration and development, whether capitalized or expensed, are presented below:

	Successor		Predecessor	
	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
(in thousands)				
Property acquisition costs:				
Proved	$ —	$ —	$ —	$ —
Unproved	—	—	—	—
Exploration costs	17,017	103,689	15,153	40,074
Development costs	19,271	96,178	24,256	86,053
Asset retirement costs	(131)	376	312	112
Total costs incurred – continuing operations	$ 36,157	$ 200,243	$ 39,721	$ 126,239
Total costs incurred – discontinued operations	$ —	$ 1,313	$ 269	$ 307

Oil and Natural Gas Capitalized Costs

Aggregate capitalized costs related to oil, natural gas and NGL production activities with applicable accumulated depletion and amortization are presented below:

	December 31,	
	2018	2017
	(in thousands)	
Proved properties	$ 709,053	$ 904,390
Unproved properties	47,499	45,693
	756,552	950,083
Less accumulated depletion and amortization	(93,507)	(49,619)
	$ 663,045	$ 900,464

RIVIERA RESOURCES, INC.

SUPPLEMENTAL OIL AND NATURAL GAS DATA (Unaudited) - Continued

Results of Oil and Natural Gas Producing Activities

The results of operations for oil, natural gas and NGL producing activities (excluding corporate overhead and interest costs):

	Successor		Predecessor	
(in thousands)	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017	Year Ended December 31, 2016
Revenues and other:				
Oil, natural gas and natural gas liquids sales	$ 420,102	$ 709,363	$ 188,885	$ 874,161
Gains (losses) on commodity derivatives	(25,109)	13,533	92,691	(164,330)
	394,993	722,896	281,576	709,831
Production costs:				
Lease operating expenses	120,097	208,446	49,665	296,891
Transportation expenses	83,562	113,128	25,972	161,574
Severance taxes, ad valorem taxes	28,598	47,411	14,851	66,616
	232,257	368,985	90,488	525,081
Other costs:				
Exploration costs	5,178	3,137	93	4,080
Depletion and amortization	58,347	101,360	39,689	295,889
Impairment of long-lived assets	15,697	—	—	165,044
(Gains) losses on sale of assets and other, net	(219,237)	(678,200)	18	417
Income tax benefit	(54,588)	(4,640)	(166)	(649)
	(194,603)	(578,343)	39,634	464,781
Results of operations – continuing operations	$ 357,339	$ 932,254	$ 151,454	$ (280,031)
Results of operations – discontinued operations	$ —	$ 142,175	$ 1,246	$ (9,773)

There is no federal tax provision included in the Predecessor's results above because the Predecessor's subsidiaries subject to federal income taxes did not own any of the Predecessor's oil and natural gas interests. Limited liability companies are subject to Texas margin tax. See Note 15 for additional information about income taxes.

RIVIERA RESOURCES, INC.

SUPPLEMENTAL OIL AND NATURAL GAS DATA (Unaudited) - Continued

Proved Oil, Natural Gas and NGL Reserves

The proved reserves of oil, natural gas and NGL of the Company have been prepared by the independent engineering firm, DeGolyer and MacNaughton. In accordance with Securities and Exchange Commission ("SEC") regulations, reserves at December 31, 2018, December 31, 2017, and December 31, 2016, were estimated using the average price during the 12-month period, determined as an unweighted average of the first-day-of-the-month price for each month, excluding escalations based upon future conditions. An analysis of the change in estimated quantities of oil, natural gas and NGL reserves, all of which are located within the U.S., is shown below:

	Successor			
	Year Ended December 31, 2018			
	Natural Gas (Bcf)	Oil (MMBbls)	NGL (MMBbls)	Total (Bcfe)
Proved developed and undeveloped reserves:				
Beginning of year	1,377	27.1	71.5	1,968
Revisions of previous estimates	24	(0.9)	(2.1)	7
Sales of minerals in place	(52)	(21.3)	(9.8)	(239)
Extensions and discoveries	1	0.1	0.1	2
Production	(90)	(1.2)	(3.8)	(120)
End of year	1,260	3.8	55.9	1,618
Proved developed reserves:				
Beginning of year	1,323	27.0	70.5	1,908
End of year	1,203	3.7	54.7	1,553
Proved undeveloped reserves:				
Beginning of year	54	0.1	1.0	60
End of year	57	0.1	1.2	65

	Successor					
	Year Ended December 31, 2017					
	Natural Gas (Bcf)	Oil (MMBbls)	NGL (MMBbls)	Total Continuing Operations (Bcfe)	Total Discontinued Operations (Bcfe)	Total (Bcfe)
Proved developed and undeveloped reserves:						
Beginning of year	2,290	72.6	104.1	3,350	170	3,520
Revisions of previous estimates	(102)	(5.6)	9.7	(78)	—	(78)
Sales of minerals in place	(754)	(37.0)	(39.6)	(1,213)	(164)	(1,377)
Extensions and discoveries	90	3.7	4.9	142	—	142
Production	(147)	(6.6)	(7.6)	(233)	(6)	(239)
End of year	1,377	27.1	71.5	1,968	—	1,968
Proved developed reserves:						
Beginning of year	2,118	66.7	94.4	3,084	170	3,254
End of year	1,323	27.0	70.5	1,908	—	1,908
Proved undeveloped reserves:						
Beginning of year	172	5.9	9.7	266	—	266
End of year	54	0.1	1.0	60	—	60

RIVIERA RESOURCES, INC.

SUPPLEMENTAL OIL AND NATURAL GAS DATA (Unaudited) - Continued

	Predecessor					
	Year Ended December 31, 2016					
	Natural Gas (Bcf)	Oil (MMBbls)	NGL (MMBbls)	Total Continuing Operations (Bcfe)	Total Discontinued Operations (Bcfe)	Total (Bcfe)
Proved developed and undeveloped reserves:						
Beginning of year	2,212	74.3	97.0	3,240	195	3,435
Revisions of previous estimates	—	(3.8)	1.2	(16)	(13)	(29)
Extensions and discoveries	265	10.1	15.2	417	—	417
Production	(187)	(8.0)	(9.3)	(291)	(12)	(303)
End of year	2,290	72.6	104.1	3,350	170	3,520
Proved developed reserves:						
Beginning of year	2,212	74.3	97.0	3,240	195	3,435
End of year	2,118	66.7	94.4	3,084	170	3,254
Proved undeveloped reserves:						
Beginning of year	—	—	—	—	—	—
End of year	172	5.9	9.7	266	—	266

The tables above include changes in estimated quantities of oil and NGL reserves shown in Mcf equivalents using the ratio of one barrel to six Mcf. Reserves for the Company’s California properties are reported as discontinued operations for all periods presented.

Proved reserves from continuing operations decreased by approximately 350 Bcfe to approximately 1,618 Bcfe for the year ended December 31, 2018, from 1,968 Bcfe for the year ended December 31, 2017. The year ended December 31, 2018, includes approximately 7 Bcfe of positive revisions of previous estimates (87 Bcfe of positive revisions due to higher commodity prices partially offset by 80 Bcfe of negative revisions due to asset performance). During the year ended December 31, 2018, several divestitures decreased reserves by approximately 239 Bcfe (see Note 4 for additional information of divestitures). In addition, extensions and discoveries, primarily from 52 productive wells drilled during the year, contributed approximately 2 Bcfe to the increase in proved reserves.

Proved reserves from continuing operations decreased by approximately 1,382 Bcfe to approximately 1,968 Bcfe for the year ended December 31, 2017, from 3,350 Bcfe for the year ended December 31, 2016. The year ended December 31, 2017, includes approximately 78 Bcfe of negative revisions of previous estimates (264 Bcfe of negative revisions due to asset performance partially offset by 186 Bcfe of positive revisions due to higher commodity prices). During the year ended December 31, 2017, several divestitures decreased reserves by approximately 1,213 Bcfe (see Note 4 for additional information of divestitures). In addition, extensions and discoveries, primarily from 90 productive wells drilled during the year, contributed approximately 142 Bcfe to the increase in proved reserves.

Proved reserves from continuing operations increased by approximately 110 Bcfe to approximately 3,350 Bcfe for the year ended December 31, 2016, from 3,240 Bcfe for the year ended December 31, 2015. The year ended December 31, 2016, includes approximately 16 Bcfe of negative revisions of previous estimates (97 Bcfe of negative revisions due to lower commodity prices partially offset by 81 Bcfe of positive revisions due to asset performance). In addition, extensions and discoveries, primarily from 211 productive wells drilled during the year, contributed approximately 417 Bcfe to the increase in proved reserves.

RIVIERA RESOURCES, INC.

SUPPLEMENTAL OIL AND NATURAL GAS DATA (Unaudited) - Continued

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

Information with respect to the standardized measure of discounted future net cash flows relating to proved reserves is summarized below. Future cash inflows are computed by applying applicable prices relating to the Company's proved reserves to the year-end quantities of those reserves. Future production, development, site restoration and abandonment costs are derived based on current costs assuming continuation of existing economic conditions. Future income tax expenses are calculated by applying the year-end statutory tax rates (with consideration of any known future changes) to the pretax net cash flows, reduced by the applicable tax basis and giving effect to any tax deductions, tax credits and allowances relating to the proved oil and natural gas reserves. There are no future income tax expenses at December 31, 2016, because the Predecessor was not subject to federal income taxes. Limited liability companies are subject to Texas margin tax; however, these amounts were not material. See Note 15 for additional information about income taxes.

	December 31,		
	2018	2017	2016
	(in thousands)		
Future cash inflows	$ 5,167,664	$ 6,730,186	$ 9,856,698
Future production costs	(3,139,932)	(3,810,932)	(5,755,460)
Future development costs	(337,808)	(486,989)	(917,262)
Future income tax expenses	(226,425)	(303,803)	—
Future net cash flows	1,463,499	2,128,462	3,183,976
10% annual discount for estimated timing of cash flows	(716,210)	(1,083,331)	(1,488,219)
Standardized measure of discounted future net cash flows – continuing operations	$ 747,289	$ 1,045,131	$ 1,695,757
Standardized measure of discounted future net cash flows – discontinued operations	$ —	$ —	$ 232,941
Representative NYMEX prices: (1)			
Natural gas (MMBtu)	$ 3.10	$ 2.98	$ 2.48
Oil (Bbl)	$ 65.66	$ 51.34	$ 42.64

(1) In accordance with SEC regulations, reserves were estimated using the average price during the 12-month period, determined as an unweighted average of the first-day-of-the-month price for each month, excluding escalations based upon future conditions. The average price used to estimate reserves is held constant over the life of the reserves.

SUPPLEMENTAL OIL AND NATURAL GAS DATA (Unaudited) - Continued

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

	Year Ended December 31,		
	2018	2017	2016
	(in thousands)		
Sales and transfers of oil, natural gas and NGL produced during the period	$ (187,845)	$ (438,775)	$ (349,080)
Changes in estimated future development costs	3,835	(5,276)	19,460
Net change in sales and transfer prices and production costs related to future production	(89,459)	400,411	(92,236)
Sales of minerals in place	(206,636)	(685,050)	—
Extensions, discoveries and improved recovery	2,683	187,223	221,765
Previously estimated development costs incurred during the period	—	9,704	—
Net change due to revisions in quantity estimates	(10,022)	(65,935)	10,387
Net change in income taxes	30,637	(155,257)	—
Accretion of discount	120,039	169,576	169,318
Changes in production rates and other	38,926	(67,247)	22,958
Change – continuing operations	$ (297,842)	$ (650,626)	$ 2,572
Change – discontinued operations	$ —	$ (232,941)	$ (112,047)

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 assumptions. The required projection of production and related expenditures over time requires further estimates with respect to pipeline availability, rates of demand and governmental control. Actual future prices and costs are likely to be substantially different from the current prices and costs utilized in the computation of reported amounts. Any analysis or evaluation of the reported amounts should give specific recognition to the computational methods utilized and the limitations inherent therein.

RIVIERA RESOURCES, INC.

SUPPLEMENTAL QUARTERLY DATA (Unaudited)

The following discussion and analysis should be read in conjunction with the “Consolidated and Combined Financial Statements” and “Notes to Consolidated and Combined Financial Statements,” which are included in this Annual Report on Form 10-K in Item 8. “Financial Statements and Supplementary Data.”

Quarterly Financial Data

	Successor			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per share amounts)			
2018:				
Oil, natural gas and natural gas liquids sales	$ 136,876	$ 87,004	$ 89,653	$ 106,569
Gains (losses) on commodity derivatives	(15,030)	(7,525)	(3,175)	2,326
Total revenues and other	174,007	128,833	159,601	203,218
Total expenses (1)	191,631	207,171	230,478	186,204
(Gains) Losses on sale of assets and other, net	(106,296)	(101,934)	221	(589)
Reorganization items, net	(1,951)	(1,259)	(1,277)	(672)
Income (loss) from continuing operations	34,608	8,955	(33,236)	10,606
Income (loss) from discontinued operations, net of income taxes	36,331	(1,758)	(14,899)	—
Net income (loss)	70,939	7,197	(48,135)	10,606
Income (loss) per share – continuing operations:				
Basic	$ 0.45	$ 0.11	$ (0.43)	$ 0.15
Diluted	$ 0.45	$ 0.11	$ (0.43)	$ 0.15
Income (loss) per share – discontinued operations:				
Basic	$ 0.48	$ (0.02)	$ (0.20)	$ —
Diluted	$ 0.48	$ (0.02)	$ (0.20)	$ —
Net income (loss) per share:				
Basic	$ 0.93	$ 0.09	$ (0.63)	$ 0.15
Diluted	$ 0.93	$ 0.09	$ (0.63)	$ 0.15

(1) Includes the following expenses: lease operating, transportation, marketing, general and administrative, exploration, depreciation, depletion and amortization, impairment of long-lived assets and taxes, other than income taxes.

RIVIERA RESOURCES, INC.

SUPPLEMENTAL QUARTERLY DATA (Unaudited) - Continued

	Predecessor	Successor			
(in thousands, except per share amounts)	January 1, 2017 to February 28, 2017	March 1, 2017 to March 31, 2017	Second Quarter	Third Quarter	Fourth Quarter
2017:					
Oil, natural gas and natural gas liquids sales	$ 188,885	$ 80,325	$ 243,167	$ 206,318	$ 179,553
Gains (losses) on commodity derivatives	92,691	(11,959)	45,714	(14,497)	(5,725)
Total revenues and other	298,127	73,308	307,819	236,682	208,869
Total expenses (1)	214,327	76,279	214,308	210,252	191,491
(Gains) losses on sale of assets and other, net	672	445	(308,269)	(25,896)	(289,863)
Reorganization items, net	2,521,137	(2,565)	(3,059)	(2,605)	(304)
Income (loss) from continuing operations	2,587,557	(6,123)	228,460	43,606	79,188
Income (loss) from discontinued operations, net of income taxes	(548)	457	5,302	78,556	5,749
Net income (loss)	2,587,009	(5,666)	233,762	122,162	84,937
Income (loss) per share – continuing operations:					
Basic	$ 33.96	$ (0.08)	$ 3.00	$ 0.57	$ 1.03
Diluted	$ 33.96	$ (0.08)	$ 3.00	$ 0.57	$ 1.03
Income (loss) per share – discontinued operations:					
Basic	$ (0.01)	$ 0.01	$ 0.07	$ 1.03	$ 0.08
Diluted	$ (0.01)	$ 0.01	$ 0.07	$ 1.03	$ 0.08
Net income (loss) per share:					
Basic	$ 33.95	$ (0.07)	$ 3.07	$ 1.60	$ 1.11
Diluted	$ 33.95	$ (0.07)	$ 3.07	$ 1.60	$ 1.11

(1) Includes the following expenses: lease operating, transportation, marketing, general and administrative, exploration, depreciation, depletion and amortization, impairment of long-lived assets and taxes, other than income taxes.

Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

None

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

The Company maintains disclosure controls and procedures that are designed to ensure that information required to be disclosed in the Company's reports under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to management, including the Company's Chief Executive Officer and Chief Financial Officer, and the Company's Audit Committee of the Board of Directors, as appropriate, to allow timely decisions regarding required disclosure. In designing and evaluating the disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and management is required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures.

The Company carried out an evaluation under the supervision and with the participation of its management, including its Chief Executive Officer and Chief Financial Officer, of the effectiveness of its disclosure controls and procedures as of the end of the period covered by this report. Based on this evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company's disclosure controls and procedures were effective as of December 31, 2018.

Management's Annual Report on Internal Control Over Financial Reporting

See "Management's Report on Internal Control Over Financial Reporting" in Item 8. "Financial Statements and Supplementary Data."

Changes in the Company's Internal Control Over Financial Reporting

The Company's management is also responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act. The Company's internal controls were designed to provide reasonable assurance as to the reliability of its financial reporting and the preparation and presentation of the consolidated financial statements for external purposes in accordance with accounting principles generally accepted in the United States.

Because of its inherent limitations, internal control over financial reporting may not detect or prevent misstatements. Projections of any evaluation of the 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.

There were no changes in the Company's internal control over financial reporting during the fourth quarter of 2018 that materially affected, or were reasonably likely to materially affect, the Company's internal control over financial reporting.

Item 9B. Other Information

None

Part III

Item 10. Directors, Executive Officers and Corporate Governance

A list of the Company's executive officers and biographical information appears below under the caption "Executive Officers of the Company." Additional information required by this item is incorporated by reference to the Proxy Statement for the Annual Meeting of Stockholders to be held on June 5, 2019 (the "2019 Proxy Statement").

Each of the Company's executive officers, with the exception of Daniel Furbee and C. Gregory Harper, served as an officer of LINN Energy prior to and during its Chapter 11 proceedings.

Executive Officers of the Company

Name	Age	Position with the Company
David B. Rottino	52	President, Chief Executive Officer and Director of Riviera Resources, Inc.
Daniel Furbee	36	Executive Vice President and Chief Operating Officer of Riviera Resources, Inc.
James G. Frew	41	Executive Vice President and Chief Financial Officer of Riviera Resources, Inc.
Darren Schluter	49	Executive Vice President, Finance, Administration and Chief Accounting Officer of Riviera Resources, Inc.
Holly Anderson	41	Executive Vice President and General Counsel of Riviera Resources, Inc.
C. Gregory Harper	54	President and Chief Executive Officer of Blue Mountain Midstream LLC, and Director of Riviera Resources, Inc.

David B. Rottino is the President and Chief Executive Officer in addition to serving on Riviera Resources, Inc.'s board of directors and has served in such capacity since August 2018. He previously served as Linn Energy, Inc.'s Executive Vice President and Chief Financial Officer and as a member of the LINN Energy board of directors from February 2017 to August 2018, as Linn Energy, LLC's Executive Vice President and Chief Financial Officer from August 2015 to February 2017, as Executive Vice President, Business Development and Chief Accounting Officer from January 2014 to August 2015, as Senior Vice President of Finance, Business Development and Chief Accounting Officer from July 2010 to January 2014, and as Senior Vice President and Chief Accounting Officer from June 2008 to July 2010.

Daniel Furbee is the Executive Vice President and Chief Operating Officer and has served in such capacity since August 2018. He previously served as Linn Energy Inc.'s Vice President of Asset and Business Development from March 2018 to August 2018 and as Vice President of Business Development and Asset Development for Sanchez Energy Corporation from August 2013 to April 2018. From 2005 to August 2013, Mr. Furbee served in various engineering positions, including most recently as a Senior Staff Engineer-Business Development, at Linn Energy, LLC.

James G. Frew is the Executive Vice President and Chief Financial Officer and has served in such capacity since August 2018. He previously served as Linn Energy, Inc.'s Vice President, Marketing and Midstream from February 2017 to August 2018, as Linn Energy, LLC's Vice President, Marketing and Midstream from 2014 to February 2017 and Director, Strategy, Planning and Business Development from 2011 to 2014.

Darren Schluter is the Executive Vice President, Finance, Administration and Chief Accounting Officer, and as served in such capacity since August 2018. He previously served as Linn Energy, Inc.'s Vice President and Controller from February 2017 to August 2018, as Linn Energy, LLC's Vice President and Controller from July 2010 to February 2017 and as Controller from February 2007 to July 2010.

Holly Anderson is the Executive Vice President and General Counsel and as served in such capacity since August 2018. She previously served as Linn Energy, Inc.'s Vice President and Assistant General Counsel from March 2017 to August 2018, as Linn Energy, LLC's Assistant General Counsel from March 2014 to March 2017 and Senior Counsel from June 2010 to March 2014.

Item 10. Directors, Executive Officers and Corporate Governance - Continued

C. Gregory Harper is the President and Chief Executive Officer of Blue Mountain Midstream LLC, Riviera Resources, Inc.'s wholly owned subsidiary, and has served in such capacity since April 2018, in addition to serving on Riviera Resources, Inc.'s board of directors since August 2018. From May 2017 until March 2018, Mr. Harper managed his personal investments. Mr. Harper retired from Enbridge Inc. in April 2017 where he served as President, Gas Pipelines and Processing and as the Principal Executive Officer of Midcoast Holdings L.L.C. since January 2014. Before joining Enbridge, Mr. Harper served as Senior Vice President of Midstream with Southwestern Energy Company, from August 2013 to January 2014. Before joining Southwestern Energy, Mr. Harper served as Senior Vice President and Group President of CenterPoint Energy Pipelines and Field Services from December 2008 to June 2013. Before joining CenterPoint Energy in 2008, Mr. Harper served as President, Chief Executive Officer and as a Director of Spectra Energy Partners, LP from March 2007 to December 2008. From January 2007 to March 2007, Mr. Harper was Group Vice President of Spectra Energy Corp., and he was Group Vice President of Duke Energy from January 2004 to December 2006. Mr. Harper served as Senior Vice President of Energy Marketing and Management for Duke Energy North America from January 2003 until January 2004 and Vice President of Business Development for Duke Energy Gas Transmission and Vice President of East Tennessee Natural Gas, LLC from March 2002 until January 2003. Mr. Harper currently serves on the board of Sprague Resources where he has served as the chair of the audit committee since Sprague's initial public offering in 2013, and previously served on the boards of Midcoast Holdings, L.L.C., Enbridge Energy Company, Inc. and Enbridge Energy Management, L.L.C. Mr. Harper received his Bachelor's degree in Mechanical Engineering from the University of Kentucky and his Master's degree in Business Administration from the University of Houston.

Item 11. Executive Compensation

Information required by this item is incorporated by reference to the 2019 Proxy Statement.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information required by this item is incorporated by reference to the 2019 Proxy Statement.

Securities Authorized for Issuance Under Equity Compensation Plans

The following summarizes information regarding the number of shares of common stock that are available for issuance under all of the Company's equity compensation plans as of December 31, 2018:

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Unit Options, Warrants and Rights	Weighted Average Exercise Price of Outstanding Unit Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders	—	—	1,086,698
Equity compensation plans not approved by security holders	—	—	—
	—	—	1,086,698

Item 13. Certain Relationships and Related Transactions, and Director Independence

Information required by this item is incorporated by reference to the 2019 Proxy Statement.

Item 14. Principal Accounting Fees and Services

Information required by this item is incorporated by reference to the 2019 Proxy Statement.

Part IV

Item 15. Exhibits and Financial Statement Schedules

(a) - 1. Financial Statements:

All financial statements are omitted for the reason that they are not required or the information is otherwise supplied in Item 8. “Financial Statements and Supplementary Data” in this Annual Report on Form 10-K.

(a) - 2. Financial Statement Schedules:

All schedules are omitted for the reason that they are not required or the information is otherwise supplied in Item 8. “Financial Statements and Supplementary Data” in this Annual Report on Form 10-K.

(a) - 3. Exhibits:

The exhibits required to be filed by this Item 15 are set forth in the “Index to Exhibits” accompanying this report.

Index to Exhibits

Exhibit Number		Description
2.1#	—	Amended Joint Chapter 11 Plan of Reorganization of Linn Energy, LLC and Its Debtor Affiliates Other Than Linn Acquisition Company, LLC and Berry Petroleum Company, LLC, dated January 25, 2017 (incorporated by reference to Exhibit 2.1 of the Company's Registration Statement on Form S-1 filed on June 27, 2018)
2.2#	—	Purchase and Sale Agreement, dated April 30, 2017, by and between Linn Energy Holdings, LLC, Linn Operating, LLC and Jonah Energy LLC (incorporated by reference to Exhibit 2.2 of the Company's Registration Statement on Form S-1 filed on June 27, 2018)
2.3#	—	Purchase and Sale Agreement, dated May 23, 2017, by and among Linn Energy Holdings, LLC, Linn Operating, LLC, Linn Midstream, LLC and Berry Petroleum Company, LLC (incorporated by reference to Exhibit 2.3 of the Company's Registration Statement on Form S-1 filed on June 27, 2018)
2.4#	—	Purchase and Sale Agreement, dated May 25, 2017, by and between Linn Energy Holdings, LLC, Linn Operating, LLC and Denbury Onshore, LLC (incorporated by reference to Exhibit 2.4 of the Company's Registration Statement on Form S-1 filed on June 27, 2018)
2.5#	—	First Amendment, dated June 30, 2017, to Purchase and Sale Agreement, dated May 25, 2017, by and between Linn Energy Holdings, LLC, Linn Operating, LLC and Denbury Onshore, LLC (incorporated by reference to Exhibit 2.5 of the Company's Registration Statement on Form S-1 filed on June 27, 2018)
2.6#	—	Purchase and Sale Agreement, dated June 1, 2017, by and between Linn Energy Holdings, LLC, Linn Operating, LLC, Linn Midstream, LLC and Bridge Energy LLC (incorporated by reference to Exhibit 2.6 of the Company's Registration Statement on Form S-1 filed on June 27, 2018)
2.7	—	First Amendment, dated July 10, 2017, to Purchase and Sale Agreement, dated June 1, 2017, by and between Linn Energy Holdings, LLC, Linn Operating, LLC, Linn Midstream, LLC and Bridge Energy LLC (incorporated by reference to Exhibit 2.7 of the Company's Registration Statement on Form S-1 filed on June 27, 2018)
2.8#	—	Purchase and Sale Agreement, dated October 3, 2017, by and between Linn Energy Holdings, LLC, Linn Operating, LLC and Washakie Exaro Opportunities, LLC (incorporated by reference to Exhibit 2.8 of the Company's Registration Statement on Form S-1 filed on June 27, 2018)
2.9#	—	First Amendment, dated October 12, 2017, to Purchase and Sale Agreement, dated October 3, 2017, by and between Linn Energy Holdings, LLC, Linn Operating, LLC and Washakie Exaro Opportunities, LLC (incorporated by reference to Exhibit 2.9 of the Company's Registration Statement on Form S-1 filed on June 27, 2018)
2.10#	—	Purchase and Sale Agreement, dated October 20, 2017, by and between Linn Energy Holdings, LLC, Linn Operating, LLC and Valorem Energy Operating, LLC (incorporated by reference to Exhibit 2.10 of the Company's Registration Statement on Form S-1 filed on June 27, 2018)
2.11#	—	Purchase and Sale Agreement, dated December 18, 2017, by and between Linn Energy Holdings, LLC, Linn Operating, LLC and Scout Energy Group IV, LP (incorporated by reference to Exhibit 2.11 of the Company's Registration Statement on Form S-1 filed on June 27, 2018)
2.12#	—	Amendment, dated January 11, 2018, to Purchase and Sale Agreement, dated December 18, 2017, by and between Linn Energy Holdings, LLC, Linn Operating, LLC and Scout Energy Group IV, LP incorporated by reference to Exhibit 2.12 of the Company's Registration Statement on Form S-1 filed on June 27, 2018)
2.13#	—	Purchase and Sale Agreement, dated January 15, 2018, by and between Linn Energy Holdings, LLC, Linn Operating, LLC and Altamont Energy LLC (f/k/a Wasatch Energy LLC) (incorporated by reference to Exhibit 2.13 of the Company's Registration Statement on Form S-1 filed on June 27, 2018)
2.14#	—	Purchase and Sale Agreement, dated February 13, 2018, by and among Linn Energy Holdings, LLC, Linn Operating, LLC and Scout Energy Group IV, LP (incorporated by reference to Exhibit 2.14 of the Company's Registration Statement on Form S-1 filed on June 27, 2018)
2.15#	—	Fourth Amendment to Contribution Agreement, dated February 27, 2018, to Contribution Agreement, dated June 27, 2017, by and among Linn Energy Holdings, LLC, Linn Operating, LLC, Citizen Energy II, LLC and Roan Resources LLC (incorporated by reference to Exhibit 2.15 of the Company's Registration Statement on Form S-1 filed on June 27, 2018)

Index to Exhibits - Continued

Exhibit Number		Description
2.16#	—	First Amendment, dated February 27, 2018, to Purchase and Sale Agreement, dated January 15, 2018, by and among Linn Energy Holdings, LLC, Linn Operating, LLC and Altamont Energy LLC (f/k/a Wasatch Energy LLC) (incorporated by reference to Exhibit 2.16 of the Company's Registration Statement on Form S-1 filed on June 27, 2018)
2.17	—	Second Amendment, dated February 28, 2018, to Purchase and Sale Agreement, dated January 15, 2018, by and among Linn Energy Holdings, LLC, Linn Operating, LLC and Altamont Energy LLC (f/k/a Wasatch Energy LLC) (incorporated by reference to Exhibit 2.17 of the Company's Registration Statement on Form S-1 filed on June 27, 2018)
2.18#	—	Separation and Distribution Agreement, dated August 7, 2018, between Linn Energy, Inc. and Riviera Resources, Inc. (incorporated by reference to Exhibit 2.1 to Form 8-K filed August 10, 2018)
3.1	—	Certificate of Conversion of Riviera Resources, LLC (incorporated by reference to Exhibit 3.1 to Form 8-K filed on August 10, 2018)
3.2	—	Certificate of Incorporation of Riviera Resources, Inc. (incorporated by reference to Exhibit 4.1 to Registration Statement on Form S-8 filed on August 7, 2018)
3.3	—	Bylaws of Riviera Resources, Inc. (incorporated by reference to Exhibit 4.2 to Registration Statement on Form S-8 filed on August 7, 2018)
10.1*	—	Riviera Resources, Inc. 2018 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.1 to Form S-8 filed August 7, 2018)
10.2*	—	Form of Performance-Vesting Stock Unit Agreement pursuant to the Riviera Resources, Inc. 2018 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.2 to Form S-8 filed August 7, 2018)
10.3*	—	Form of Restricted Stock Unit Agreement pursuant to the Riviera Resources, Inc. 2018 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.3 to Form S-8 filed August 7, 2018)
10.4*	—	Form of Indemnity Agreement between Riviera Resources, Inc. and the directors and officers of Riviera Resources, Inc. (incorporated by reference to Exhibit 10.4 to Form S-8 filed August 7, 2018)
10.5	—	Tax Matters Agreement, dated August 7, 2018, between Linn Energy, Inc., Riviera Resources, Inc. and the subsidiaries of Riviera Resources, Inc. party thereto (incorporated by reference to Exhibit 10.1 to Form 8-K filed August 10, 2018)
10.6	—	Transition Services Agreement, dated August 7, 2018, between Linn Energy, Inc. and Riviera Resources, Inc. (incorporated by reference to Exhibit 10.2 to Form 8-K filed August 10, 2018)
10.7	—	Registration Rights Agreement, dated as of August 7, 2018, among Riviera Resources, Inc. and the holders party thereto (incorporated by reference to Exhibit 10.3 to Form 8-K filed August 10, 2018)
10.8	—	Credit Agreement, dated as of August 4, 2017, among Linn Energy Holdco II LLC, as borrower, Linn Energy Holdco LLC, as parent, Linn Energy, Inc., as holdings, Royal Bank of Canada, as administrative agent, Citibank, N.A., as syndication agent, Barclays Bank PLC, JPMorgan Chase Bank, N.A., Morgan Stanley Senior Funding, Inc. and PNC Bank National Association, as co-documentation agents, and the lenders party thereto (incorporated by reference to Exhibit 10.19 of the Company's Registration Statement on Form S-1 filed on June 27, 2018)
10.9	—	First Amendment to Credit Agreement, dated as of September 29, 2017, to the Credit Agreement, dated as of August 4, 2017, among Linn Energy Holdco II LLC, as borrower, Linn Energy Holdco LLC, as parent, Linn Energy, Inc., as holdings, Royal Bank of Canada, as administrative agent, Citibank, N.A., as syndication agent, Barclays Bank PLC, JPMorgan Chase Bank, N.A., Morgan Stanley Senior Funding, Inc. and PNC Bank National Association, as co-documentation agents, and the lenders party thereto (incorporated by reference to Exhibit 10.20 of the Company's Registration Statement on Form S-1 filed on June 27, 2018)
10.10	—	Second Amendment to Credit Agreement, dated as of April 30, 2018, to Credit Agreement dated as of August 4, 2017, among Linn Energy Holdco II LLC, as borrower, Linn Energy Holdco LLC, as parent, Linn Energy, Inc. as holdings, Royal Bank of Canada, as administrative agent, Citibank, N.A., as syndication agent, Barclays Bank PLC, JPMorgan Chase Bank, N.A., Morgan Stanley Senior Funding, Inc. and PNC Bank National Association, as co-documentation agents, and the lenders party thereto (incorporated by reference to Exhibit 10.21 of the Company's Registration Statement on Form S-1 filed on June 27, 2018)

Index to Exhibits - Continued

Exhibit Number		Description
10.11	—	Credit Agreement, dated as of August 10, 2018, among Blue Mountain Midstream LLC, as borrower, Royal Bank of Canada, as administrative agent and issuing bank, Citibank, N.A. and Capital One, National Association, as co-syndication agents, ABN AMRO Capital USA LLC and PNC Bank National Association, as co-documentation agents, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to Form 8-K filed August 15, 2018)
10.12	—	Second Amended and Restated Limited Liability Company Operating Agreement of Blue Mountain Midstream LLC, dated as of July 1, 2018 (incorporated by reference to Exhibit 10.9 to Quarterly Report on Form 10-Q filed November 8, 2018)
10.13	—	Blue Mountain Midstream LLC 2018 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.10 to Quarterly Report on Form 10-Q filed November 8, 2018)
10.14	—	Form of Performance-Vesting Security Unit Agreement pursuant to the Blue Mountain Midstream LLC 2018 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.30 to Form S-1 filed on June 27, 2018)
10.15	—	Form of Restricted Security Unit Agreement pursuant to the Blue Mountain Midstream LLC 2018 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.31 to Form S-1 filed on June 27, 2018)
10.16*	—	Third Amended and Restated Employment Agreement of David B. Rottino, dated February 28, 2017 (incorporated by reference to Exhibit 10.22 to Registration Statement on Form S-1 filed on June 27, 2018)
10.17*	—	Letter Agreement, dated April 19, 2018, between David B. Rottino and Linn Energy, Inc. (incorporated by reference to Exhibit 10.23 to Registration Statement on Form S-1 filed on June 27, 2018)
10.18*	—	Offer Letter to Daniel Furbee, dated March 19, 2018 (incorporated by reference to Exhibit 10.24 to Registration Statement on Form S-1 filed on June 27, 2018)
10.19*	—	Employment Agreement of Greg Harper, dated March 29, 2018 (incorporated by reference to Exhibit 10.26 to Registration Statement on Form S-1 filed on June 27, 2018)
10.20*	—	Amendment No. 1 to Employment Agreement of Greg Harper, dated July 17, 2018 (incorporated by reference to Exhibit 10.27 to Amendment No. 1 to Registration Statement on Form S-1/A filed on July 19, 2018)
10.21	—	Transition Services and Separation Agreement, dated as of February 28, 2017, by and between Linn Energy, LLC, LinnCo, LLC, and certain subsidiaries of Linn Energy, Inc. party thereto and Berry Petroleum Company, LLC (incorporated by reference to Exhibit 10.7 to Form S-1 filed on June 27, 2018)
10.22	—	Joint Operating Agreement, dated February 28, 2017, between Linn Operating, Inc., as operator, and Berry Petroleum Company, LLC, as non-operator (Hugoton) (incorporated by reference to Exhibit 10.8 to Form S-1 filed on June 27, 2018)
10.23	—	Joint Operating Agreement, dated February 28, 2017, between Berry Petroleum Company, LLC, as operator, and Linn Energy Holdings, LLC, as non-operator (Hill) (incorporated by reference to Exhibit 10.9 to Form S-1 filed on June 27, 2018)
10.24	—	Engineering and Construction Agreement, dated June 13, 2017, between Blue Mountain Midstream LLC (f/k/a LINN Midstream, LLC) and BCCK Engineering Incorporated (incorporated by reference to Exhibit 10.10 to Form S-1 filed on June 27, 2018)
10.25	—	Equipment Supply Agreement, dated June 13, 2017, between Blue Mountain Midstream LLC (f/k/a LINN Midstream, LLC) and BCCK Engineering Incorporated (incorporated by reference to Exhibit 10.11 to Form S-1 filed on June 27, 2018)
10.26	—	Contribution Agreement, dated June 27, 2017, by and among Linn Energy Holdings, LLC, Linn Operating, LLC, Citizen Energy II, LLC and Roan Resources LLC (incorporated by reference to Exhibit 10.12 to Form S-1 filed on June 27, 2018)
10.27	—	First Amendment to Contribution Agreement, dated August 31, 2017, to Contribution Agreement, dated June 27, 2017, by and among Linn Energy Holdings, LLC, Linn Operating, LLC, Citizen Energy II, LLC and Roan Resources LLC (incorporated by reference to Exhibit 10.13 to Form S-1 filed on June 27, 2018)
10.28	—	Second Amendment to Contribution Agreement, dated October 31, 2017, to Contribution Agreement, dated June 27, 2017, by and among Roan Holdco LLC, Linn Operating, LLC, Roan Holdings, LLC and Roan Resources LLC (incorporated by reference to Exhibit 10.14 to Form S-1 filed on June 27, 2018)

Index to Exhibits - Continued

Exhibit Number		Description
10.29	—	Third Amendment to Contribution Agreement, dated November 29, 2017, to Contribution Agreement, dated June 27, 2017, by and among Linn Energy Holdings, LLC, Linn Operating, LLC, Citizen Energy II, LLC and Roan Resources LLC (incorporated by reference to Exhibit 10.15 to Form S-1 filed on June 27, 2018)
21.1**	—	List of Significant Subsidiaries
23.1**	—	Consent of KPMG LLP
23.2**	—	Consent of DeGolyer and MacNaughton – Riviera
31.1**	—	Rule 13a-14(a)/15d-14(a) Certification of Chief Executive Officer
31.2**	—	Rule 13a-14(a)/15d-14(a) Certification of Chief Financial Officer
32.1**	—	Section 1350 Certification of Chief Executive Officer
32.2**	—	Section 1350 Certification of Chief Financial Officer
99.1**	—	2018 Report of DeGolyer and MacNaughton
101.INS**	—	XBRL Instance Document
101.SCH**	—	XBRL Taxonomy Extension Schema Document
101.CAL**	—	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF**	—	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB**	—	XBRL Taxonomy Extension Label Linkbase Document
101.PRE**	—	XBRL Taxonomy Extension Presentation Linkbase Document

* Management Contract or Compensatory Plan or Arrangement required to be filed as an Exhibit hereto pursuant to Item 601 of Regulation S-K.

** Filed herewith.

\# Pursuant to Item 601(b)(2) of Regulation S-K, the registrant agrees to furnish supplementally a copy of any omitted Exhibit or schedule to the SEC upon request.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

RIVIERA RESOURCES, INC.

Date: February 28, 2019	By: /s/ David B. Rottino David B. Rottino President and Chief Executive Officer
Date: February 28, 2019	By: /s/ James G. Frew James G. Frew Executive Vice President and Chief Financial Officer
Date: February 28, 2019	By: /s/ Darren R. Schluter Darren R. Schluter Executive Vice President, Finance, Administration and Chief Accounting Officer (Principal Accounting Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ David B. Rottino David B. Rottino	President, Chief Executive Officer and Director (Principal Executive Officer)	February 28, 2019
/s/ James G. Frew James G. Frew	Executive Vice President, Chief Financial Officer (Principal Financial Officer)	February 28, 2019
/s/ Darren R. Schluter Darren R. Schluter	Executive Vice President, Finance, Administration and Chief Accounting Officer (Principal Accounting Officer)	February 28, 2019
/s/ Matthew Bonanno Matthew Bonanno	Director	February 28, 2019
/s/ Philip Brown Philip Brown	Director	February 28, 2019
/s/ C. Gregory Harper C. Gregory Harper	Director	February 28, 2019
/s/ Evan Lederman Evan Lederman	Director	February 28, 2019
/s/ Andrew Taylor Andrew Taylor	Director	February 28, 2019

LIST OF SIGNIFICANT SUBSIDIARIES
As of December 31, 2018

Name of Subsidiary	Jurisdiction of Incorporation or Organization
Linn Merger Sub #1, LLC	Delaware
Linn Energy Holdco, LLC	Delaware
Linn Energy Holdco II, LLC	Delaware
Riviera Upstream, LLC	Delaware
Blue Mountain Midstream LLC	Delaware

The names of certain subsidiaries have been omitted since, considered in the aggregate as a single subsidiary, they would not constitute a significant subsidiary, as defined in Rule 1−02(w) of Regulation S-X, as of the end of the year covered by this report.

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

The Board of Directors
Riviera Resources, Inc.:

We consent to the incorporation by reference in the registration statements on Form S-3 (No. 333-227895) and on Form S-8 (No. 333-226637) of Riviera Resources, Inc. and subsidiaries of our report dated February 28, 2019, with respect to the consolidated balance sheets of Riviera Resources, Inc. as of December 31, 2018 and 2017 (Successor), the related consolidated and combined statements of operations, equity (deficit), and cash flows for the year ended December 31, 2018 (Successor), for the ten months ended December 31, 2017 (Successor), the two months ended February 28, 2017 and for the year ended December 31, 2016 (Predecessor) and the related notes (collectively, the consolidated and combined financial statements), and the effectiveness of internal control over financial reporting as of December 31, 2018, which reports appear in the December 31, 2018 annual Form 10-K of Riviera Resources, Inc..

Our report on the consolidated and combined financial statements refers to Riviera Resources, Inc.’s 2018 change in the method of accounting due to the adoption of Accounting Standards Codification (ASC) 606, *Revenue from Contracts with Customers*, preparation of the consolidated and combined financial statements on a carve-out basis prior to its spin-off from Linn Energy, Inc. (the former parent of Riviera Resources), and a change in the basis of presentation for preparation on a combined basis of accounting prior to the former parent’s emergence from bankruptcy.

/s/ KPMG LLP

Houston, Texas
February 28, 2019

Exhibit 23.2

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

February 28, 2019

Riviera Resources, Inc.
600 Travis
Houston, Texas 77002

Ladies and Gentlemen:

We hereby consent to the use of the name DeGolyer and MacNaughton, to references to DeGolyer and MacNaughton as independent petroleum engineers, and to the inclusion of information taken from the reports listed below in the Riviera Resources, Inc. Annual Report on Form 10-K for the year ended December 31, 2018 (the “10-K”), to be filed with the United States Securities and Exchange Commission on or about February 28, 2019, and in the registration statements on Form S-3 (No. 333-227895) and Form S-8 (No. 333-226637):

- Report as of December 31, 2018 on Reserves and Revenue of Certain Properties with interests attributable to Riviera Operating, LLC;
- Report as of December 31, 2017 on Reserves and Revenue of Certain Properties owned by Linn Operating, Inc.; and
- Report as of December 31, 2016 on Reserves and Revenue of Certain Properties owned by Linn Energy, LLC.

We further consent to the inclusion of our report of third-party dated February 22, 2019, as Exhibit 99.1 in the 10-K.

Very truly yours,

/s/ DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

Exhibit 31.1

CERTIFICATION

I, David B. Rottino, certify that:

1. I have reviewed this Annual Report on Form 10-K of Riviera Resources, Inc. (the "registrant");

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

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

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

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

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

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

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

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

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

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

Date: February 28, 2019

/s/ David B. Rottino

David B. Rottino
President and Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, James G. Frew, certify that:

1. I have reviewed this Annual Report on Form 10-K of Riviera Resources, Inc. (the “registrant”);

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

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

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

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

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

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

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

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

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

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

Date: February 28, 2019

/s/ James G. Frew

James G. Frew
Executive Vice President and Chief Financial Officer

Exhibit 32.1

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

In connection with the Annual Report of Riviera Resources, Inc. (the “Company”) on Form 10-K for the year ended December 31, 2018, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, David B. Rottino, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

Date: February 28, 2019

/s/ David B. Rottino
David B. Rottino
President and Chief Executive Officer

Exhibit 32.2

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

In connection with the Annual Report of Riviera Resources, Inc. (the “Company”) on Form 10-K for the year ended December 31, 2018, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, James G. Frew, Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

Date: February 28, 2019

/s/ James G. Frew
James G. Frew
Executive Vice President and Chief Financial Officer

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244
February 22, 2019

Riviera Operating, LLC
600 Travis
Suite 1700
Houston, Texas 77002

Ladies and Gentlemen:

Pursuant to your request, this report of third party presents an independent evaluation, as of December 31, 2018, of the extent and value of the estimated net proved oil, condensate, natural gas liquids (NGL), and gas reserves of certain properties in which Riviera Operating, LLC (Riviera) has represented it holds an interest. This evaluation was completed on February 22, 2019. The properties evaluated herein consist of working and royalty interests located in Illinois, Kansas, Louisiana, Michigan, New Mexico, Oklahoma, Texas, and Utah. Riviera has represented that these properties account for 100 percent on a net gas equivalent basis of Riviera's net proved reserves as of December 31, 2018. The net proved reserves estimates have been prepared in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the Securities and Exchange Commission (SEC) of the United States. This report was prepared in accordance with guidelines specified in Item 1202 (a)(8) of Regulation S–K and is to be used for inclusion in certain SEC filings by Riviera.

Reserves estimates included herein are expressed as net reserves. Gross reserves are defined as the total estimated petroleum remaining to be produced from these properties after December 31, 2018. Net reserves are defined as that portion of the gross reserves attributable to the interests held by Riviera after deducting all interests held by others.

Values for proved reserves in this report are expressed in terms of future gross revenue, future net revenue, and present worth. Future gross revenue is defined as that revenue which will accrue to the evaluated interests from the production and sale of the estimated net reserves. Future net revenue is calculated by deducting production taxes, ad valorem taxes, operating expenses, net profits interest expenses, capital costs, and abandonment costs from future gross revenue. Operating expenses include field operating expenses, transportation and processing expenses, and an allocation of overhead that directly relates to production activities. Capital costs include drilling and completion costs, facilities costs, and field maintenance costs. Abandonment costs are represented by Riviera to be inclusive of those costs associated with the removal of equipment, plugging of wells, and reclamation and restoration associated with the abandonment. At the request of Riviera, future income taxes were not taken into account in the preparation of these estimates. Present worth is defined as future net revenue discounted at a specified arbitrary nominal discount rate of 10 percent compounded monthly over the expected period of realization. Present worth should not be construed as fair market value because no consideration was given to additional factors that influence the prices at which properties are bought and sold.

Estimates of reserves and revenue should be regarded only as estimates that may change as production history and additional information become available. Not only are such estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

Information used in the preparation of this report was obtained from Riviera and from public sources. In the preparation of this report we have relied, without independent verification, upon information furnished by Riviera with respect to the property interests being evaluated, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, and various other information and data that were accepted as represented. A field examination of the properties was not considered necessary for the purposes of this report.

Definition of Reserves

Petroleum reserves included in this report are classified as proved. Only proved reserves have been evaluated for this report. Reserves classifications used in this report are in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the SEC. Reserves are judged to be economically producible in future years from known reservoirs under existing economic and operating conditions and assuming continuation of current regulatory practices using conventional production methods and equipment. In the analyses of production-decline curves, reserves were estimated only to the limit of economic rates of production under existing economic and operating conditions using prices and costs consistent with the effective date of this report, including consideration of changes in existing prices provided only by contractual arrangements but not including escalations based upon future conditions. The petroleum reserves are classified as follows:

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

(i) The area of the reservoir considered as proved includes:
(A) The area identified by drilling and limited by fluid contacts, if any, and (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Developed oil and gas reserves – Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; 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.

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

(i) 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) 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 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, as defined in [section 210.4–10 (a) Definitions], or by other evidence using reliable technology establishing reasonable certainty.

Methodology and Procedures

Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the SEC and with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (Revision as of February 19, 2007).” The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

Based on the current stage of field development, production performance, the development plans provided by Riviera, and analyses of areas offsetting existing wells with test or production data, reserves were classified as proved.

Riviera has represented that its senior management is committed to the development plan provided by Riviera and that Riviera has the financial capability to execute the development plan, including the drilling and completion of wells and the installation of equipment and facilities.

For depletion-type reservoirs or those whose performance disclosed a reliable decline in producing-rate trends or other diagnostic characteristics, reserves were estimated by the application of appropriate decline curves or other performance relationships. In the analyses of production-decline curves, reserves were estimated only to the limits of economic production as defined under the Definition of Reserves heading of this report.

In certain cases, reserves were estimated by incorporating elements of analogy with similar wells or reservoirs for which more complete data were available.

Data provided by Riviera from wells drilled through December 31, 2018, and made available for this evaluation were used to prepare the reserves estimates herein. These reserves estimates were based on consideration of monthly production data available for certain properties only through February 2018. Estimated cumulative production, as of December 31, 2018, was deducted from the estimated gross ultimate recovery to estimate gross reserves. This required that production be estimated for up to 10 months. Riviera has represented that properties with monthly production data only through February 2018 were producing as of December 31, 2018.

Oil and condensate reserves estimated herein are those to be recovered by normal field separation. NGL reserves estimated herein include C5+ and liquefied petroleum gas (LPG), which consists primarily of propane and butane fractions. NGL reserves are the result of low-temperature plant processing. Oil, condensate, and NGL reserves included in this report are expressed in thousands of barrels (Mbbl) representing 42 United States gallons per barrel. For reporting purposes, oil and condensate reserves have been estimated separately and are presented herein as a summed quantity.

Gas quantities estimated herein are expressed as sales gas. Sales gas is defined as the total gas to be produced from the reservoirs, measured at the point of delivery, after reduction for fuel use and shrinkage resulting from field separation and processing. Gas reserves estimated herein are reported as sales gas. All gas reserves are expressed at a temperature base of 60 degrees Fahrenheit (°F) and at the pressure base of the state in which the reserves are located. Gas reserves included in this report are expressed in millions of cubic feet (MMcf).

Gas quantities are identified by the type of reservoir from which the gas will be produced. Nonassociated gas is gas at initial reservoir conditions with no oil present in the reservoir. Associated gas is both gas-cap gas and solution gas. Gas-cap gas is gas at initial reservoir conditions and is in communication with an underlying oil zone. Solution gas is gas dissolved in oil at initial reservoir conditions. Gas quantities estimated herein include both associated and nonassociated gas.

At the request of Riviera, liquid reserves estimated herein were converted to gas equivalent using an energy equivalent factor of 1 barrel of liquids per 6,000 cubic feet of gas equivalent. This conversion factor was provided by Riviera.

Primary Economic Assumptions

Revenue values in this report were estimated using initial prices, expenses, and costs provided by Riviera. Future prices were estimated using guidelines established by the SEC and the Financial Accounting Standards Board (FASB). The following economic assumptions were used for estimating the revenue values reported herein:

Oil, Condensate, and NGL Prices

Riviera has represented that the oil, condensate, and NGL prices were based on West Texas Intermediate (WTI) pricing, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual agreements. The oil, condensate, and NGL prices were calculated using differentials furnished by Riviera to the reference price of $65.66 per barrel and held constant thereafter. The volume-weighted average prices attributable to the estimated proved reserves over the lives of the properties were $63.52 per barrel of oil and condensate and $24.44 per barrel of NGL.

Gas Prices

Riviera has represented that the gas prices were based on Henry Hub pricing, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual agreements. The gas prices were calculated for each property using differentials furnished by Riviera to the reference price of $3.10 per million British thermal units ($/MMBtu) and held constant thereafter. British thermal unit factors provided by Riviera were used to convert prices from $/MMBtu to dollars per thousand cubic feet. The volume-weighted average price attributable to the estimated proved reserves over the lives of the properties was $2.827 per thousand cubic feet of gas.

Production and Ad Valorem Taxes

Production taxes were calculated using the tax rates for the state in which the reserves are located, including, where appropriate, abatements for enhanced recovery programs. Ad valorem taxes were calculated using rates provided by Riviera based on recent payments.

Operating Expenses, Capital Costs, and Abandonment Costs

Estimates of operating expenses, provided by Riviera and based on current expenses, were held constant for the lives of the properties. Future capital expenditures were estimated using 2018 values, provided by Riviera, and were not adjusted for inflation. In certain cases, future expenditures, either higher or lower than current expenditures, may have been used because of anticipated changes in operating conditions, but no general escalation that might result from inflation was applied. Abandonment costs, which are those costs associated with the removal of equipment, plugging of wells, and reclamation and restoration associated with the abandonment, were provided by Riviera for all properties and were not adjusted for inflation. Operating expenses, capital costs, and abandonment costs were considered, as appropriate, in determining the economic viability of non-producing and undeveloped reserves estimated herein.

In our opinion, the information relating to estimated proved reserves, estimated future net revenue from proved reserves, and present worth of estimated future net revenue from proved reserves of oil, condensate, natural gas liquids, and gas of the properties evaluated by us contained in this report has been prepared in accordance with Paragraphs 932-235-50-4, 932-235-

50-6, 932-235-50-7, 932-235-50-9, 932-235-50-30, and 932-235-50-31(a), (b), and (e) of the Accounting Standards Update 932-235-50, Extractive Industries – Oil and Gas (Topic 932): Oil and Gas Reserve Estimation and Disclosures (January 2010) of the Financial Accounting Standards Board and Rules 4–10(a) (1)–(32) of Regulation S–X and Rules 302(b), 1201, 1202(a) (1), (2), (3), (4), (8), and 1203(a) of Regulation S–K of the SEC; provided, however, that (i) future income tax expenses have not been taken into account in estimating the future net revenue and present worth values set forth herein and (ii) estimates of the proved developed and proved undeveloped reserves are not presented at the beginning of the year.

To the extent the above-enumerated rules, regulations, and statements require determinations of an accounting or legal nature, we, as engineers, are necessarily unable to express an opinion as to whether the above-described information is in accordance therewith or sufficient therefor.

Summary of Conclusions

The estimated net proved reserves, as of December 31, 2018, of the properties evaluated herein were based on the definition of proved reserves of the SEC and are summarized as follows, expressed in thousands of barrels (Mbbl), millions of cubic feet (MMcf), and millions of cubic feet of gas equivalent (MMcfe):

	Estimated by DeGolyer and MacNaughton Net Proved Reserves as of December 31, 2018			
	Oil and Condensate (Mbbl)	**NGL (Mbbl)**	**Sales Gas (MMcf)**	**Gas Equivalent (MMcfe)**
Proved Developed	3,648	54,725	1,202,562	1,552,800
Proved Undeveloped	119	1,210	57,330	65,304
Total Proved	**3,767**	**55,935**	**1,259,892**	**1,618,104**

Note: Liquid reserves estimated herein were converted to gas equivalent using an energy equivalent factor of 1 barrel of liquids per 6,000 cubic feet of gas equivalent.

The estimated future revenue to be derived from the production and sale of the net proved reserves, as of December 31, 2018, of the properties evaluated using the guidelines established by the SEC is summarized as follows, expressed in thousands of dollars (M$):

	Proved Developed (M$)	**Total Proved (M$)**
Future Gross Revenue	4,940,147	5,167,949
Production and Ad Valorem Taxes	319,195	329,135
Operating Expenses	2,773,844	2,810,797
Net Profits Interest Expenses	285	285
Capital Costs	28,409	78,534
Abandonment Costs	258,768	259,274
Future Net Revenue	1,559,646	1,689,924
Present Worth at 10 Percent	824,194	871,910

Note: Future income taxes have not been taken into account in the preparation of these estimates.

While the oil and gas industry may be subject to regulatory changes from time to time that could affect an industry participant's ability to recover its reserves, we are not aware of any such governmental actions which would restrict the recovery of the December 31, 2018, estimated reserves.

DeGolyer and MacNaughton is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1936. DeGolyer and MacNaughton does not have any financial interest, including stock ownership, in Riviera. Our fees were not contingent on the results of our evaluation. This report has been prepared at the request of Riviera. DeGolyer and MacNaughton has used all data, assumptions, procedures, and methods that it considers necessary to prepare this report.

Submitted,

/s/ DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

/s/ Gregory K. Graves, P.E.
Gregory K. Graves, P.E.
Senior Vice President
DeGolyer and MacNaughton

CERTIFICATE of QUALIFICATION

I, Gregory K. Graves, Petroleum Engineer with DeGolyer and MacNaughton, 5001 Spring Valley Road, Suite 800 East, Dallas, Texas, 75244 U.S.A., hereby certify:

1. That I am a Senior Vice President with DeGolyer and MacNaughton, which firm did prepare the report of third party addressed to Riviera dated February 22, 2019, and that I, as Senior Vice President, was responsible for the preparation of this report of third party.

2. That I attended the University of Texas at Austin, and that I graduated with a Bachelor of Science degree in Petroleum Engineering in the year 1984; that I am a Registered Professional Engineer in the State of Texas; that I am a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers; and that I have in excess of 34 years of experience in oil and gas reservoir studies and reserves evaluations.

/s/ Gregory K. Graves, P.E.
Gregory K. Graves, P.E.
Senior Vice President
DeGolyer and MacNaughton