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, 2019

☐ **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:

Title of each class	Trading symbols(s)	Name of exchange on which registered
None	**None**	**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 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 ☒

Aggregate market value of the Company's common stock held by non-affiliates of the registrant as of June 28, 2019, was $293,404,582 based on the closing price on the OTCQX Market.

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, 2020, there were 58,037,642 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 2020 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days after December 31, 2019, are incorporated by reference to the extent set forth in Part III, Items 10-14 of this Annual Report on Form 10-K.

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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, 2017. 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

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. Riviera is quoted for trading on the OTCQX Market under the ticker "RVRA." The Company has two operating segments: upstream and Blue Mountain.

The Company's upstream reporting segment properties are currently primarily located in two operating regions in the United States ("U.S."): the Mid-Continent and North Louisiana. Proved reserves at December 31, 2019, were approximately 316 Bcfe, of which approximately 89% were natural gas, 6% were natural gas liquids ("NGL") and 5% were oil. Approximately 90% were classified as proved developed, with a total standardized measure of discounted future net cash flows of approximately $159 million. At December 31, 2019, the Company operated 1,446 or approximately 55% of its 2,635 gross productive wells.

In the first quarter of 2020, the Company completed the sale of its interests in non-operated properties located in the Drunkards Wash field in the Uinta Basin, the Overton field in East Texas and the Personville field in East Texas. These properties are included in "assets held for sale" on the consolidated balance sheet as of December 31, 2019. Reserve information as of December 31, 2019, includes amounts associated with these properties. See Note 4 for additional information.

The Blue Mountain reporting segment consists of a state of the art cryogenic natural gas processing facility, a network of gathering pipelines and compressors and produced water services and a crude oil gathering system 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.

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.

Item 1. Business - Continued

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.

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 and combined 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 and combined financial statements. See Note 4 for additional information. In December 2019, stockholders of Roan Resources, Inc. approved an Agreement and Plan of Merger ("Merger") between Roan Resources, Inc. and a subsidiary of Citizen Energy Operating, LLC ("Citizen Operating") under which Roan Resources, Inc., including its subsidiary Roan Resources LLC, became wholly owned subsidiaries of Citizen Operating. The effective date of the Merger was December 6, 2019, and as a result of the Merger, the Company and Roan Resources, Inc. no longer share certain mutual directors and significant stockholders.

Strategy

Riviera is strategically focused on efficiently operating its mature low-decline assets, developing its growth-oriented assets, and returning capital to shareholders. The Company has producing properties currently located primarily in Oklahoma and Louisiana. The Company's wholly owned subsidiary, 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 and oil 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 2019:

On November 22, 2019, the Company completed the sale of its interest in the remaining properties located in the Hugoton Basin (the "Hugoton Basin Assets Sale"). Cash proceeds received from the sale of these properties were approximately $286 million. During the year ended December 31, 2019, the Company recorded a noncash impairment charge of approximately $100 million to reduce the carrying value of these assets to fair value. In connection with the Hugoton Basin Assets Sale, the buyer also acquired the Company's interests in Mayzure, LLC, a wholly owned subsidiary of the Company, which was the counterparty to the volumetric production payment agreements based on helium produced from certain oil and natural gas properties in the Hugoton Basin.

Blue Mountain Midstream entered into an agreement with a potential customer to construct a gathering system, as well as gather and process gas. During the third quarter of 2019, a decision was made not to proceed with the gas gathering and processing contract, and as a result, the customer reimbursed Blue Mountain Midstream for capital deployed and operating expenses incurred, in addition to paying a success fee for constructing the assets. During the year ended December 31, 2019, Blue Mountain Midstream received a capital reimbursement of approximately $20 million. Blue Mountain Midstream also received approximately $4 million for the success fee and the expense reimbursement, which is included in "(gains) losses on sale of assets and other, net" on the consolidated and combined statement of operations.

On September 5, 2019, the Company completed the sale of its interest in properties located in Illinois. Cash proceeds from the sale of these properties were approximately $4 million and the Company recorded a net gain of approximately $4 million.

On August 30, 2019, the Company completed the sale of its interest in non-core assets located in North Louisiana. Cash proceeds from the sale were approximately $2 million and the Company recorded a net gain of approximately $376,000.

On July 3, 2019, the Company completed the sale of its interest in properties located in Michigan (the "Michigan Assets Sale"). Cash proceeds from the sale of these properties were approximately $39 million. The Company recorded a noncash impairment charge to reduce the carrying value of these assets to fair value of approximately $18 million for the year ended December 31, 2019.

On May 31, 2019, the Company completed the sale of its interest in non-operated properties located in the Hugoton Basin in Kansas. Cash proceeds received from the sale of these properties were approximately $29 million and the Company recognized a net loss of approximately $10 million.

On January 17, 2019, the Company completed the sale of its interest in properties located in the Arkoma Basin in Oklahoma. Cash proceeds received from the sale of these properties were approximately $64 million (including a deposit of approximately $5 million received in 2018), and the Company recognized a net gain of approximately $28 million.

Divestitures – Subsequent Events

On January 15, 2020, the Company completed the sale of its interests in non-operated properties located in the Drunkards Wash field in the Uinta Basin (the “Drunkards Wash Asset Sale”). Cash proceeds from the sale of these properties were approximately $4 million (including a deposit of approximately $450,000 received in 2019).

On January 31, 2020, the Company completed the sale of its interest in properties located in the Overton field in East Texas (the “Overton Assets Sale”). Cash proceeds from the sale of these properties were approximately $17 million (including a deposit of approximately $2 million received in 2019). During the year ended December 31, 2019, the Company recorded a noncash impairment charge of approximately $13 million to reduce the carrying value of these assets to fair value.

On February 14, 2020, the Company completed the sale of its interest in properties located in the Personville field in East Texas (the “Personville Assets Sale”). Cash proceeds from the sale of these properties were approximately $29 million (including a deposit of approximately $3 million received in 2019). During the year ended December 31, 2019, the Company recorded a noncash impairment charge of approximately $72 million to reduce the carrying value of these assets to fair value.

On November 20, 2019, the Company signed an agreement to sell its building located in Oklahoma City, Oklahoma for an amended contract price of $21 million. The sale is expected to close in the first quarter of 2020. During the year ended December 31, 2019, the Company recorded a noncash impairment charge of approximately $5 million to reduce the carrying value of this asset to fair value.

The assets and liabilities associated with the sale of the Oklahoma office building, the Drunkards Wash Asset Sale, the Overton Assets Sale and the Personville Assets Sale are classified as held for sale on the consolidated balance sheet at December 31, 2019.

2019 Oil and Natural Gas and Midstream Capital Expenditures

During the year ended December 31, 2019, the Company had total capital expenditures, excluding acquisitions, of approximately $172 million, including approximately $63 million related to its oil and natural gas capital program and approximately $105 million related to Blue Mountain Midstream.

2020 Oil and Natural Gas and Midstream Capital Budget

For 2020, the Company estimates its total capital expenditures, excluding acquisitions, will be approximately $52 million, including approximately $25 million related to its oil and natural gas capital program and approximately $27 million related to Blue Mountain Midstream. This estimate is under continuous review and subject to ongoing adjustments.

Financing Activities

Riviera Credit Facility
Riviera’s credit agreement provides for a senior secured reserve-based revolving loan facility (the “Riviera Credit Facility”). On September 27, 2019, the Company entered into an amendment to the Riviera Credit Facility to, among other things, extend its maturity date to August 4, 2021. The amendment resulted in a borrowing commitment reduction from $230 million to $90 million, primarily due to asset sales, with the next scheduled borrowing base redetermination to occur on April 1, 2020.

Item 1. Business - Continued

Blue Mountain Midstream Credit Facility
Blue Mountain Midstream's credit agreement provides for a senior secured revolving loan facility (the "Blue Mountain Midstream Credit Facility"). On February 8, 2019, the borrowing commitment under the Blue Mountain Midstream Credit Facility was increased to $200 million. The Blue Mountain Credit Facility together with the Riviera Credit Facility, are referred to as the "Credit Facilities."

Cash Distributions
On November 21, 2019, the Board of Directors of the Company declared a cash distribution of $4.25 per share. A cash distribution totaling approximately $249 million was paid on December 12, 2019, to shareholders of record as of the close of business on December 5, 2019. In addition, approximately $11 million for potential future distributions was recorded in restricted cash at December 31, 2019. In December 2019, distributions payable of approximately $2 million related to outstanding share-based compensation awards was also recorded. These amounts are included in "other accrued liabilities" and "asset retirement obligations and other noncurrent liabilities" on the consolidated balance sheet at December 31, 2019.

Share Repurchase Program
On July 18, 2019, the Company's Board of Directors increased the share repurchase authorization to $150 million of the Company's outstanding shares of common stock. During the year ended December 31, 2019, the Company repurchased an aggregate of 8,475,514 shares of common stock at an average price of $12.72 per share for a total cost of approximately $108 million. Included in this number are private purchases of 2,380,425 shares of common stock purchased at a discount to market, at an average price of $10.91 for a total cost of approximately $26 million. See Note 12 for additional information. For the period from January 1, 2020 through February 21, 2020, the Company repurchased 171,107 shares of common stock at an average price of $7.84 for a total cost of approximately $1 million. At February 21, 2020, approximately $23 million was available for share repurchases under the program. Any share repurchases are subject to restrictions in the Riviera Credit Facility.

Tender Offer
On June 13, 2019, the Company's Board of Directors announced the intention to commence a tender offer to purchase $40 million of the Company's common stock. In July 2019, upon the terms and subject to the conditions described in the Offer to Purchase dated June 18, 2019, the Company repurchased an aggregate of 2,666,666 shares of common stock at a price of $15.00 per share for a total cost of approximately $40 million (excluding expenses of approximately $440,000 related to the tender offer).

Commodity Derivatives

During the year ended December 31, 2019, the Company entered into commodity derivative contracts consisting of natural gas fixed price swaps and NGL fixed price swaps for 2019 and oil fixed price swaps and natural gas basis swaps for 2020. In July 2019, in connection with the closing of the Michigan Assets Sale, the Company canceled its MichCon natural gas basis swaps for 2019 and 2020.

Oil Services Agreement

On July 17, 2019, a subsidiary of Blue Mountain Midstream entered into an agreement with Roan to gather Roan's oil in the Merge/SCOOP/STACK play. The agreement provides for a 10-year term covering an 89,000 net acre dedicated area in nine Townships in central Oklahoma. Blue Mountain plans to construct an initial crude system consisting of approximately 28 miles of gathering pipelines with two downstream interconnections providing Roan with direct access to the Cushing market. The Blue Mountain system will initially be capable of transporting up to 60,000 barrels per day of crude oil. Services will commence in the first half of 2020. On December 6, 2019, Roan became a wholly owned indirect subsidiary of Citizen Operating.

Water Services Agreement

On January 31, 2019, a subsidiary of Blue Mountain Midstream 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 provides 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. On December 6, 2019, Roan became a wholly owned indirect subsidiary of Citizen Operating.

Item 1. Business - Continued

Upstream Reporting Segment Operating Regions

The Company's upstream reporting segment properties are currently primarily located in two operating regions in the U.S.:

- Mid-Continent, which includes properties in the Northwest STACK in northwestern Oklahoma and various other oil and natural gas producing properties throughout Oklahoma; and
- North Louisiana, which includes oil and natural gas properties producing primarily from the Hosston, Cotton Valley Bossier and Smackover formations.

In the first quarter of 2020, the Company completed the sale of its interests in non-operated properties located in the Drunkards Wash field in the Uinta Basin, the Overton field in East Texas and the Personville field in East Texas. These properties are included in "assets held for sale" on the consolidated balance sheet as of December 31, 2019. Reserve information as of December 31, 2019, includes amounts associated with these properties. See Note 4 for details of the Company's divestitures.

During 2019, the Company divested all of its properties located in the Hugoton Basin and Michigan/Illinois operating regions. During 2018, the Company divested all of its properties located in the Permian Basin operating region. During 2017, the Company divested all of its properties located in the 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.

East Texas

At December 31, 2019, the East Texas region consisted 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 40% of total proved reserves at December 31, 2019, all of which were classified as proved developed. This region produced approximately 42 MMcfe/d of the Company's 2019 average daily production. During 2019, the Company invested approximately $1 million to develop the properties in this region. As noted above, the majority of the Company's properties located in East Texas are included in "assets held for sale" on the consolidated balance sheet as of December 31, 2019.

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 22% of total proved reserves at December 31, 2019, all of which were classified as proved developed. This region produced approximately 36 MMcfe/d of the Company's 2019 average daily production. During 2019, the Company invested approximately $9 million to develop the properties in this region and approximately $43 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 25% of total proved reserves at December 31, 2019, of which 61% were classified as proved developed. This region produced approximately 31 MMcfe/d of the Company's 2019 average daily production. During 2019, the Company invested approximately $10 million to develop the properties in this region.

Uinta Basin

Uinta Basin proved reserves represented approximately 13% of total proved reserves at December 31, 2019, all of which were classified as proved developed. The Uinta Basin region produced approximately 18 MMcfe/d of the Company's 2019 average daily production. During 2019, the Company invested approximately $1 million to develop the properties in the Uinta Basin region. As noted above, these properties are included in "assets held for sale" on the consolidated balance sheet as of December 31, 2019.

Blue Mountain Segment

Blue Mountain Midstream currently provides natural gas and oil gathering, compression and processing and produced water 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 and produced water services (collectively, the "Blue Mountain System"). 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 producers that 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 2019, Blue Mountain Midstream invested approximately $102 million for plant and pipeline construction activities primarily associated with the Blue Mountain System.

Drilling and Acreage

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

	Year Ended December 31,		
	2019	**2018**	**2017**
Gross wells:			
Productive	61	52	90
Dry	—	—	—
	61	52	90
Net development wells:			
Productive	3	1	12
Dry	—	—	—
	3	1	12
Net exploratory wells:			
Productive	6	2	9
Dry	—	—	—
	6	2	9

There were no lateral segments added to existing vertical wellbores during the years ended December 31, 2019, December 31, 2018, or December 31, 2017. As of December 31, 2019, the Company had 14 gross (no 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, 2019. Productive wells consist of producing wells and wells capable of production, including wells awaiting pipeline or other connections to commence deliveries. The number of wells below does not include approximately 2,331 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)	1,318	1,114	128	95	1,446	1,209
Nonoperated (3)	1,027	305	162	18	1,189	323
	2,345	1,419	290	113	2,635	1,532

(1) Includes 1,544 gross and 1,016 net wells divested in 2020.

(2) The Company had 4 operated wells with multiple completions at December 31, 2019.

(3) The Company had 1 nonoperated well with multiple completions at December 31, 2019.

Developed and Undeveloped Acreage

The following table sets forth information relating to leasehold acreage as of December 31, 2019:

	Developed Acreage		Undeveloped Acreage		Total Acreage (1)	
	Gross	Net	Gross	Net	Gross	Net
			(in thousands)			
Leasehold acreage	677	377	23	6	700	383

(1) Includes approximately 264 gross and 156 net acres divested in 2020.

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 the published natural gas index for the producing area plus or minus a differential attributable 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, 2019, the Company had no natural gas or NGL delivery commitments under 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 percentage of the published index price for the producing area for its residue natural gas and NGL. 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.

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, 2019, 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,		Ten Months Ended December 31,	Two Months Ended February 28,
	2019	2018	2017	2017
Total production:				
Natural gas (MMcf)	71,968	90,091	118,110	29,223
Oil (MBbls)	617	1,186	5,442	1,191
NGL (MBbls)	2,133	3,762	6,287	1,263
Total (MMcfe)	88,466	119,781	188,481	43,945
Average daily production:				
Natural gas (MMcf/d)	197	247	386	495
Oil (MBbls/d)	1.7	3.2	17.8	20.2
NGL (MBbls/d)	5.8	10.3	20.5	21.4
Total (MMcfe/d)	242	328	616	745
Weighted average prices (unhedged): (1)				
Natural gas (Mcf)	$ 2.28	$ 2.78	$ 2.69	$ 3.41
Oil (Bbl)	$ 57.15	$ 62.99	$ 47.42	$ 49.16
NGL (Bbl)	$ 17.36	$ 25.14	$ 21.28	$ 24.37
Average NYMEX prices:				
Natural gas (MMBtu)	$ 2.63	$ 3.09	$ 3.00	$ 3.66
Oil (Bbl)	$ 57.03	$ 64.77	$ 50.53	$ 53.04
Costs per Mcfe of production:				
Lease operating expenses	$ 0.88	$ 1.00	$ 1.11	$ 1.13
Transportation expenses	$ 0.73	$ 0.70	$ 0.60	$ 0.59
General and administrative expenses (2)	$ 0.70	$ 2.05	$ 0.62	$ 1.63
Depreciation, depletion and amortization	$ 0.87	$ 0.79	$ 0.71	$ 1.07
Taxes, other than income taxes	$ 0.17	$ 0.25	$ 0.25	$ 0.34
Total production – discontinued operations:				
Equity method investment – Total (MMcfe) (3)	—	23,355	9,235	—
California – Total (MMcfe) (4)	—	—	4,326	1,755

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

(2) General and administrative expenses for the years ended December 31, 2019, and December 31, 2018, the ten months ended December 31, 2017, and the two months ended February 28, 2017, include approximately $11 million, $132 million, $41 million and $50 million, respectively, of share-based compensation expenses and approximately $5 million, $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 Petroleum Company, LLC ("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,		
	2019	2018	2017
Total production:			
Hugoton Basin Field:			
Natural gas (MMcf)	*	33,510	34,363
Oil (MBbls)	*	24	45
NGL (MBbls)	*	2,581	2,968
Total (MMcfe)	*	49,137	52,437
East Texas Basin Field:			
Natural gas (MMcf)	14,253	17,355	*
Oil (MBbls)	60	66	*
NGL (MBbls)	130	113	*
Total (MMcfe)	15,393	18,432	*
Sabine Uplift Field: (1)			
Natural gas (MMcf)	10,584	*	*
Oil (MBbls)	35	*	*
NGL (MBbls)	42	*	*
Total (MMcfe)	11,047	*	*
Anadarko Basin Field: (2)			
Natural gas (MMcf)	7,144	*	*
Oil (MBbls)	416	*	*
NGL (MBbls)	353	*	*
Total (MMcfe)	11,759	*	*

* Represented less than 15% of the Company's total proved reserves for the year indicated. The Company sold its properties in the Hugoton Basin Field in November 2019.

(1) North Louisiana.

(2) Excludes royalties.

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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, 2019, 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	250	2	3	284
Proved undeveloped reserves	31	—	—	32
Total proved reserves	281	2	3	316
Standardized measure of discounted future net cash flows (in millions) (1)				$ 159
Representative NYMEX prices: (2)				
Natural gas (MMBtu)				$ 2.58
Oil (Bbl)				$ 55.69

(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, 2019, the Company's PUDs decreased to 32 Bcfe from 65 Bcfe at December 31, 2018, representing a decrease of approximately 33 Bcfe. The decrease was primarily due to divestitures. Reserves classified as PUDs at December 31, 2018, that were converted to proved developed reserves during the year ended December 31, 2019, were not material.

Based on the December 31, 2019, reserve reports, the amounts of capital expenditures estimated to be incurred in 2020, 2021 and 2022 to develop the Company's PUDs are approximately $5 million, $5 million and $5 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 32 Bcfe of PUDs at December 31, 2019, 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, 2019, sales to ONEOK Hydrocarbon, L.P. accounted for approximately 19% 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 strictly 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.

Item 1. Business - Continued

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.

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 the same stringent federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection 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;
- require, with little to no notice, the cessation of fluid disposal operations into disposal wells owned or controlled by the Company, or other disposal wells that the Company utilizes, which could in turn cause an unexpected, significant increase in the price to dispose of such fluids and/or cause the Company to shut in proximate producing wells while awaiting disposal capacity;
- 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

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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 requires federal agencies to consider the potential environmental effects of federal actions, including oil and natural gas production activities on federal lands;
- Resource Conservation and Recovery Act ("RCRA"), which governs the management of solid waste;
- 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 requiring 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. For example, there is currently pending before the Oklahoma Corporation Commission a proposal to reduce the statewide proration formula for unallocated gas wells that, alone or together in a single unit, have a flow rate of 2,000 mcf per day or greater. If this proposal is approved, it could reduce the volumes of natural gas that our upstream segment is entitled to recover and reduce the volumes flowing to Blue Mountain's gathering and processing system from producer customers. 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, including those related 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, and results of operations or cash flows. Future regulatory issues that could impact the Company or its operations include 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 adopted and implemented regulations to restrict emissions of GHGs under existing provisions of the Clean Air Act, but the future of these regulations is not clear. For example, in May 2016, the EPA finalized rules that set additional emissions limits for volatile organic compounds ("VOCs") 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 included 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 2019, under a new administration, the EPA proposed to remove transmission and storage activities from the purview of the rules, thereby rescinding the VOC and methane emissions limits applicable to those activities. The proposed rule would also rescind the methane limit emissions for production and processing sources, but would maintain emissions limits for VOCs. In the alternative, the EPA also proposed to simply rescind the methane requirements for all oil and natural gas sources, without removing any activities from the source category. A lawsuit filed in April 2018 by a coalition of states 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 is pending (as of October 2019, the EPA had requested a stay of the litigation pending the outcome of its proposed overhaul of the 2016 methane requirements). 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, and on November 4, 2019, the U.S. submitted formal notification of its withdrawal to the United Nations. The withdrawal will take effect one year from delivery of the notification, although there is a possibility that a new administration could choose to rejoin the Paris 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, various corporations, and numerous investors 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 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 (oral arguments were heard in the case in January 2020 after a long hiatus). 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 or ban 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.

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 required the EPA to propose a rulemaking for revision of certain regulations pertaining to oil and gas wastes or to sign a determination that revision of the regulations is not necessary, and in April of 2019 the EPA made the determination that revisions to the regulations were not necessary at that time, concluding that any adverse effects related to oil and gas waste were more appropriately and readily addressed within the framework of existing state regulatory programs. 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 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 VOC emissions from new, modified or reconstructed sources in the oil and natural gas sector; however, in September 2019, under a new administration, the EPA published proposed amendments that would rescind the methane standards and roll back other 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 but may be stayed pending the outcome of the EPA's proposed overhaul of the 2016 rules. 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 June 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"). 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. The EPA and the Army Corps of Engineers published a rule to revise the definition of WOTUS for all CWA programs, which went into effect in August 2015, which was stayed nationwide in October 2015 pending several legal challenges to the rule. 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 October 2019, the EPA published a final rule repealing the rule revising the WOTUS definition, which became effective on December 23, 2019 and has already been challenged in federal district courts in New Mexico, New York, and South Carolina. In January 2020, the EPA announced a final rule redefining WOTUS. Several groups have already announced their intentions to challenge this rule as well. To the extent the repeal and revision rules are successfully challenged or the August 2015 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. This 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 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 FERC accounting and reporting requirements. As such, the Blue Mountain Delivery Line is not currently subject to conventional FERC 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 Blue Mountain Delivery Line 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.

Item 1. Business - Continued

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, however, 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, the Commodities Futures Trading Commission ("CFTC"), and/or the Federal Trade Commission ("FTC"). See "−Other Federal Laws and Regulations Affecting the Company's Industry−*EP Act 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 2005 amended 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 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"), each subject to annual adjustment to account for inflation. 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 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 their 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. In October 2019, PHMSA finalized rules addressing integrity management requirements and applying new safety regulations to hazardous liquid pipelines, including a requirement that operators inspect affected pipelines following extreme weather events or natural disasters, that all hazardous liquid pipelines have a system for detecting leaks and that pipelines in high consequence areas be capable of accommodating in-line inspection tools within 20 years. 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 $218,647 per violation per day, with a maximum of $2,186,465 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. PHMSA finalized a rulemaking implementing this new authority in October 2019. In April 2016, PHMSA published a notice of proposed rulemaking, addressing natural gas transmission and gathering lines, and PHMSA issued a final rule with respect to natural gas transmission lines in October 2019. PHMSA has yet to finalize this rulemaking with respect to gathering lines, although it expects to do so later in 2020. With respect to transmission pipelines, the final rule changes integrity management requirements, expands assessment and repair requirements to pipelines in "moderate-consequence areas," including areas of medium population density, and increases requirements for monitoring and inspection of pipeline segments not located in HCAs. The final rule also requires that records or other data relied on to determine operating pressures must be traceable, verifiable and complete. If the pending gathering pipeline portion of the rulemaking leads to a final rule that applies similar requirements to our gathering lines, then 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. As PHMSA has yet to finalize this rulemaking as applied to gathering lines, however, the contents and timing of any final rule, as well as their effects on the Company, 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. While many rules implementing the Dodd-Frank Act have been finalized, some have not, and as a result, the final form of the regulatory regime for commodity derivatives remains uncertain.

Position limits for certain energy commodity futures and options contracts, as well as economically equivalent swaps, futures and options, are subject to ongoing rulemaking activities. The CFTC's original position-limits rule was vacated and remanded by a federal district court in 2012. The CFTC subsequently proposed new rules in November 2013, which it supplemented in June 2016, and then reproposed in revised form in December 2016. In January 2020, the CFTC withdrew the 2013 proposal, the 2016 supplement, and the 2016 reproposal, and issued a new proposed rule, which includes limits on positions in (1) certain "Core Referenced Futures Contracts," including contracts for several energy commodities; (2) futures and options on futures that are directly or indirectly linked to the price of a Core Referenced Futures Contract, or to the same commodity for delivery at the same location as specified in that Core Referenced Futures Contract; and (3) economically equivalent swaps. The proposal also includes exemptions from position limits for bona fide hedging activities, which we expect we will qualify for if the exemptions are finalized as currently proposed. As the proposal is not yet final, the impact of the proposed rule on the Company and its counterparties is uncertain at this time.

The CFTC requires that market participants must clear certain interest rate swaps and credit default swaps, but clearing is not required for physical commodity swaps. The CFTC also requires certain market participants to maintain minimum margin requirements for uncleared swaps. The Company qualifies for end-user exceptions from both the clearing and margin requirements, although the application of these rules to other market participants, such as swap dealers, may affect the cost and availability of the swaps the Company uses for hedging. In addition, if any of the Company's swaps do not qualify for the end-user exceptions in the future, then the Company may be required to clear such transactions or execute them on a derivatives contract market or swap execution facility and post collateral, which could impact the Company's liquidity.

Although the Company cannot predict the ultimate outcome of remaining Dodd-Frank Act rulemakings, or of any new rules that may be proposed pursuant to the Dodd-Frank Act, to the extent they are applicable to the Company or its derivative counterparties, they 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.

The Company's derivatives activities and 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. It also prohibits knowingly delivering or causing to be delivered false, misleading or inaccurate reports concerning market information or conditions that affect or tend to affect the price of any commodity. The FTC's Petroleum Market Manipulation Rule, issued pursuant to the EISA, prohibits fraudulent or deceptive conduct in connection with wholesale purchases or sales of crude oil or refined petroleum products. Fines for violations of the CEA and the EISA can be up to $1 million per day per violation, subject to adjustment for inflation, and certain knowing or willful violations may also lead to a felony conviction.

Item 1. Business - Continued

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, 2019, 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 2020 or that will otherwise have a material impact on its financial position, results of operations or cash flows.

Employees

As of December 31, 2019, the Company employed approximately 250 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.

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 Exchange Act, 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;
- midstream asset construction;
- key relationships with third parties relating to its midstream business;
- commitments under its midstream operations;
- 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.

Item 1. Business - Continued

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.

The Riviera Credit Facility provides for a senior secured reserve-based revolving loan facility with a borrowing base of $90 million at December 31, 2019. The maximum commitment amount was $500 million at December 31, 2019. As of December 31, 2019, there were no borrowings outstanding under the Riviera Credit Facility and there was approximately $89 million of available borrowing capacity (which includes a reduction of approximately $701,000 for outstanding letters of credit). As of January 31, 2020, these amounts were unchanged.

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. The next scheduled borrowing base redetermination will take place on April 1, 2020. 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, Blue Mountain Midstream has a senior secured revolving loan facility (the "Blue Mountain Credit Facility") with a borrowing base of $200 million at December 31, 2019. The maximum commitment amount was $200 million at December 31, 2019. The Blue Mountain Credit Facility also provides for the ability to increase the aggregate commitments of the lenders to up to $400 million, 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, 2019, total borrowings outstanding under the Blue Mountain Credit Facility were approximately $70 million and there was approximately $117 million of available borrowing capacity (which includes a $13 million reduction for outstanding letters of credit). As of January 31, 2020, there were $73 million borrowings outstanding under the Blue Mountain Credit Facility, and there was approximately $115 million of available borrowing capacity (which includes a $12 million reduction for outstanding letters of credit). The Blue Mountain Credit Facility together with the Riviera Credit Facility, are referred to as the "Credit Facilities").

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) a ratio of consolidated EBITDA to consolidated interest expense no less than 2.50 to 1.00, (ii) 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 (iii) in case certain other kinds of debt are outstanding, a ratio of consolidated net debt secured by a lien on property of Blue

Item 1A. Risk Factors - Continued

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 2018 and 2019, 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. Various factors could materially affect our ability to divest of such assets, including the availability of buyers willing to acquire assets on terms we find acceptable and the approvals of third parties and governmental agencies.

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

Electricity prices are volatile and we may be unable to maintain stable and favorable prices and may not be able to obtain stable or favorable prices in the future, which may have a significant impact on our financial condition and results of operations.

Because our Blue Mountain segment relies on electricity for many of its operations, electricity prices are an important driver of its operating expenses. Recent dispositions of assets in our upstream reporting segment have caused our Blue Mountain reporting segment to comprise a larger portion of our portfolio. As a result, the prices at which our Blue Mountain segment is able to obtain electricity continues to have an increasingly significant impact on our consolidated operating costs and profitability. Although we enter into long-term contracts for electricity and although our electric service is subject to approved tariffs, regulatory changes, changes in interpretation of laws or other events may make it difficult for us to maintain favorable or stable electricity prices for our Blue Mountain segment and have an adverse effect on our results of operations. Additionally, the provider of electricity to the Cryo Plant may be changed based on claims pending before the Oklahoma Corporation Commission, which could result in significant increases in electrical costs based on the new providers then prevailing rates.

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, 2018 and 2019, 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 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.

Item 1A. Risk Factors - Continued

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.

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.

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;
- lack of availability or sufficient capacity of fluid disposal facilities to allow oil and gas productive wells to produce at economic rates, potential as a result of unexpected, sudden regulatory intervention;
- blowouts, craterings and explosions; and
- uncontrollable flows of oil, natural gas and NGL or well fluids.

Item 1A. Risk Factors - Continued

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 midstream gathering and transportation facilities 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. 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.

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 or our oil gathering 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 and our oil gathering system 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 oil, 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.

Item 1A. Risk Factors - Continued

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, 2019, non-operated wells represented approximately 45% of our owned gross wells, or approximately 21% 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.

Our assets are located in limited geographical areas.

Following the anticipated consummation of announced divestitures, which are expected to close in the first quarter of 2020, approximately 96% of our total proved reserves will be located in either Oklahoma or Louisiana. Furthermore all of the midstream assets owned by Blue Mountain Midstream, including the Cryo Plant, are located in Oklahoma.

Because of this concentration in a limited geographical area, the success and profitability of our operations may be disproportionately affected by regional factors relative to our competitors that have more geographically dispersed operations. These factors include, among others: (i) severe weather events, (ii) regional prices and regional supply and demand for oil, natural gas, and natural gas liquids, (iii) the costs for and availability of oil and field services and drilling rigs in the region, (iv) infrastructure capacity and the availability and cost of gathering, processing and treating facilities, and (v) local laws and regulations affecting oil and gas development, production, transportation and sales. Any of these events have the potential to shut-in, curtail, or delay development and production, increase the cost of development and production, or decrease the profitability of our operations. Any of the risks described above could have a material adverse effect on our financial condition, results of operations, and cash flows.

Concerns over general economic, business or industry conditions may have a material adverse effect on our results of operations, financial condition and cash available for distribution.

Concerns over global economic conditions, energy costs, geopolitical issues, inflation, the availability and cost of credit in the European, Asian and the U.S. markets contribute to economic uncertainty and diminished expectations for the global economy. These factors, combined with volatile prices of oil, NGL and natural gas, volatility in consumer confidence and job markets, may result in an economic slowdown or recession. In addition, continued hostilities in the Middle East and the occurrence or threat of terrorist attacks in the U.S. or other countries could adversely affect the economies of the U.S. and other countries. Concerns about global economic growth have had a significant adverse impact on global financial markets and commodity prices. If the economic climate in the U.S. or abroad deteriorates, worldwide demand for petroleum products could diminish, which could impact the price at which oil, NGL and natural gas from our properties are sold, affect the ability of vendors, suppliers and customers associated with our properties to continue operations and ultimately adversely impact our results of operations, financial condition and cash available for distribution.

Conservation measures and technological advances could reduce demand for oil and natural gas.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, technological advances in fuel economy and energy generation devices could reduce demand for oil and natural gas. The impact of the changing demand for oil and natural gas services and products may have a material adverse effect on our business, financial condition, results of operations and cash available for distribution.

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, compressors, 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 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 and have similarly impacted gathering systems, processing facilities, compressors, pipelines and other facilities. 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, pipeline, disposal and other 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 and midstream operations. 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. We are also required to obtain permits and authorizations for the development and operation of natural gas gathering pipelines, compressors and processing facilities and in connection with the gathering, treatment and disposal of produced water and other wastes. Delays in obtaining or the failure to obtain such permits and authorizations, or the imposition of more stringent or burdensome restrictions or obligations on our operations in connection with the renewal or amendment of such permits and authorizations, could have a material adverse effect on our midstream operations. Similarly, the disposal of some fluids from producing wells is a necessary part of the Company’s upstream model. Fluid disposal may be subject to state or federal regulation depending on the jurisdiction. The regulatory authority could delay or refuse the permitting of a new disposal well. Such authority could unexpectedly cause the cessation of disposal of fluids into an existing disposal well, or into all disposal wells within a general area. The lack of adequate disposal availability or capacity could cause in increase in the cost to operate producing wells or negatively affect the Company’s ability to operate producing oil and gas wells at the most economic rates. 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.

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 and could result in reductions or delays in crude oil and natural gas production.

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 1. “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. Similar restrictions may also be applied due to other events such as saltwater purges or other pollution events.

At the federal level, several agencies have asserted jurisdiction over certain aspects of the hydraulic fracturing process. For example, the EPA has moved forward with various regulatory actions, including the issuance of new regulations requiring reduced emission completions, i.e., “green completions” for hydraulically fractured wells, and emission requirements for certain midstream equipment. Also, in June 2016, the EPA finalized rules which prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants. Certain environmental groups have also suggested that additional laws may be needed to more closely and uniformly regulate the hydraulic fracturing process. We cannot predict whether any such legislation will be enacted and if so, what its provisions would be. Additional levels of regulation and permits required through the adoption of new laws and regulations at the federal, state or local level could lead to delays, increased operating costs and process prohibitions that could reduce the volumes of crude oil and natural gas that move through our gathering systems and decrease demand for our water services, which in turn could materially adversely impact our revenues.

A change in the jurisdictional characterization of some of our assets by federal or state 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, in certain cases, 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 2005, FERC has civil penalty authority under the NGA and NGPA to impose penalties for violations of up to $1 million per day for each violation, subject to annual adjustment for inflation, 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 affect 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, construction and abandonment of interstate natural gas pipeline facilities, 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 natural gas gathering services.

Our business is also exposed to state-level regulation. Our non-proprietary gathering lines are typically subject to state-level ratable take and common purchaser statutes. Ratable take statutes generally require gatherers to take, without undue discrimination, oil or natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes restrict our right as an owner of gathering facilities to decide with whom we contract to purchase or transport oil or natural gas.

Item 1A. Risk Factors - Continued

Federal law leaves economic regulation of natural gas gathering to the states. The states in which we operate have adopted complaint-based regulation of oil and natural gas gathering activities, which allows oil and natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to oil and natural-gas gathering access and rate discrimination. Other state regulations may not directly regulate our business, but may nonetheless affect the availability of natural gas for purchase, processing and sale, including state regulation of production rates and maximum daily production allowable from gas wells.

While our proprietary gathering lines are currently subject only to limited state regulation, there is a risk that state laws will change, which may give producers a stronger basis to challenge the proprietary status of a line, or the rates, terms and conditions of a gathering line providing transportation service. 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.

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) and 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 and could impose additional increased operating costs or necessitate new capital expenditures.

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.

In addition, states have adopted regulations similar to—and, in some cases, more stringent than—existing PHMSA regulations for certain intrastate gas and hazardous liquid pipelines.

Item 1A. Risk Factors - Continued

At this time, we cannot predict the ultimate cost of compliance with applicable pipeline integrity management regulations, as the cost will vary significantly depending on the number and extent of any repairs or upgrades found to be necessary as a result of pipeline integrity testing, but the results of these tests could cause us to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the safe and reliable operation of our pipelines.

Changes to pipeline safety laws by Congress and promulgation of regulations by PHMSA or states that result in more stringent or costly safety standards could have a significant adverse effect on us and similarly situated midstream operators. For example, in October 2019, PHMSA published three final rules, including regulations relating to the transportation of hazardous liquids and transmission of natural gas. These rules include increased owner/operator requirements related to reporting, inspection, and integrity management for both hazardous liquid and gas transmission pipelines, which may impose costs on us and our operations either directly or when costs imposed on others are passed along to us in the form of higher rates or fees for transportation. In addition, a related rulemaking to address safety regulations for gas-gathering pipelines remains pending. The contents and timing of a final rule in that proceeding remains uncertain, although PHMSA expects to act later in 2020. That rulemaking, along with remaining safety enhancement requirements and other provisions of the 2011 Pipeline Safety Act, as well as any future implementation of PHMSA rules thereunder, could require us to install new or modified safety controls, pursue additional capital projects, or conduct maintenance or compliance programs on an accelerated basis, any or all of which tasks could result in our incurring increased costs that could have a material adverse effect on our results of operations or financial position.

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. However, in September 2019, under a new administration, the EPA published proposed amendments that would rescind the methane standards and roll back other 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 but may be stayed pending the outcome of the EPA's proposed overhaul of the 2016 rules. 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 and on November 4, 2019, the U.S. submitted formal notification of its withdrawal to the United Nations. The withdrawal will take effect one year from delivery of the notification, although there is a possibility that a new administration could choose to rejoin the Paris 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, various corporations, and numerous investors 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 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.

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.

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 and York Capital Management, L.P. collectively owned approximately 65% of our common stock as of December 31, 2019. 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, 2019, approximately 65% of our common stock was beneficially owned by three 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.

Although we paid a one-time cash distribution on December 12, 2019, we are not currently paying a regular 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 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.

Risks Relating to Our Midstream Business

Because substantially all revenue in the Blue Mountain segment is derived from selling volumes purchased from Roan Resources LLC ("Roan"), a wholly owned indirect subsidiary of Citizen Operating, LLC ("Citizen Operating" and together with Roan, "Citizen"), any development that materially and adversely affects the operations, financial condition or market reputation of Citizen could have a material and adverse impact on us.

Citizen is the most significant counterparty for our wholly owned subsidiary, Blue Mountain Midstream, and selling volumes purchased from Citizen accounted for substantially all the revenues for the Blue Mountain segment in 2019. We expect Blue Mountain Midstream to derive a material portion of its revenues from selling volumes purchased from Citizen for the foreseeable future. As a result, any event, whether in our area of operations or otherwise, that adversely affects Citizen'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 Citizen cover midstream and water management services in a number of areas that are at the early stages of development and in areas that Citizen is still determining whether to develop. In addition, Citizen owns acreage in areas that are not dedicated to Blue Mountain Midstream. We cannot predict which of these areas Citizen will determine to develop and at what time. Citizen 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. Citizen'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 Citizen, with respect to our natural gas gathering, processing and compression, oil gathering, and water management services agreements. We cannot predict the extent to which Citizen's business would be impacted if conditions in the energy industry deteriorate, nor can we estimate the impact such conditions would have on Citizen's ability to execute its drilling and development program or perform under our natural gas gathering, processing and compression, oil gathering, and water management services agreements. Any material non-performance by Citizen could adversely affect the Blue Mountain segment's business, results of operations and cash flows.

Our construction of Blue Mountain Midstream's natural gas gathering, processing and compression, oil gathering, 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.

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, oil gathering, 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 our assets, or additions to our existing assets, may require us to obtain rights-of-way prior to constructing pipelines or facilities. We may be unable to timely obtain such rights-of-way or capitalize on other attractive expansion opportunities. Additionally, it may become more expensive for us to obtain rights-of-way or to expand or renew existing rights-of-way. If the cost of renewing or obtaining rights-of-way increases, our cash flows could be adversely affected.

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

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

Blue Mountain Midstream's dedication from Citizen under its natural gas gathering, processing and compression agreement is not the only dedication in Citizen's area of operations.

Blue Mountain Midstream's natural gas gathering, processing and compression agreement with Citizen contains an acreage dedication through November 2030. However, Citizen has multiple dedications in certain of its area of operations that Blue Mountain Midstream services. If Citizen is unable to effectively manage these split dedications within a section with multiple dedications, or if competition from other midstream providers results in Citizen focusing on acreage that is not dedicated to Blue Mountain, it could have an adverse effect on our business and financial condition.

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

Under Blue Mountain Midstream's agreements with Citizen, Citizen is required to deliver its natural gas production, produced water and oil from the contract areas (the "dedicated acreage"). If Citizen sells any of the dedicated acreage to a third party, the third party's financial condition could be materially worse than Citizen'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 and natural gas liquids into market areas. Changes in this basis spread could significantly affect our margins or even result in losses.

Our contracts are subject to renewal risks.

We are a party to certain long term, fixed fee contracts with terms of various durations. As these contracts expire, we will have to negotiate extensions or renewals with existing suppliers and customers or enter into new contracts with other suppliers and customers. We may not be able to obtain new contracts on favorable commercial terms, if at all. We also may be unable to maintain the economic structure of a particular contract with an existing customer or maintain the overall mix of our contract portfolio. The extension or replacement of existing contracts depends on a number of factors beyond our control, including:

- the level of existing and new competition to provide services to our markets;
- the macroeconomic factors affecting our current and potential customers;
- the balance of supply and demand, on a short-term, seasonal and long-term basis, in our markets;
- the extent to which the customers in our markets are willing to contract on a long-term basis; and
- the effects of federal, state or local regulations on the contracting practices of our customers.

Our inability to renew our existing contracts on terms that are favorable or to successfully manage our overall contract mix over time may have a material adverse effect on our business, results of operations and financial condition.

Mergers among our customers and competitors could result in lower volumes being shipped on our pipelines or products stored in or distributed through our terminals, thereby reducing the amount of cash we generate.

Mergers among our existing customers and our competitors could provide strong economic incentives for the combined entities to utilize their existing systems instead of ours in those markets where our systems compete. As a result, we could lose some or all of the volumes and associated revenue from these customers. As a significant portion of our operating costs are fixed, a reduction in volumes would result not only in less revenue, but also a decline in cash flow of a similar magnitude, which could materially adversely affect our results of operations, financial position or cash flows.

We do not own all of the land on which our pipelines and facilities are located, which could result in disruptions to our operations.

We do not own all of the land on which our pipelines and facilities have been constructed, and we are, therefore, subject to the possibility of more onerous terms and/or increased costs to retain necessary land use if we do not have valid rights-of-way or if such rights-of-way lapse or terminate or if our pipelines are not properly located within the boundaries of such rights-of-way. We obtain the rights to construct and operate our pipelines on land owned by third parties and governmental agencies for a specific period of time. If we were to be unsuccessful in renegotiating rights-of-way, we might have to relocate our facilities. Our loss of these rights, through our inability to renew right-of-way contracts or otherwise, could have a material adverse effect on our business, results of operations and financial condition.

Item 1A. Risk Factors - Continued

Our assets may not be adequately insured, and we could experience losses that exceed our insurance coverage.

We are not fully insured against all hazards or operational risks related to our businesses, and the insurance we carry requires that we meet certain deductibles before we can collect for any losses we sustain. If a significant accident or event occurs that is not fully insured, it could materially adversely affect our results of operations, financial position or cash flows and our ability to pay cash distributions.

In addition to the foregoing risks affecting our midstream business, many of the risks that apply to our upstream business also apply to our midstream business.

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 Louisiana and Oklahoma.

Item 3. Legal Proceedings

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 Bankruptcy Code in the U.S. Bankruptcy Court for the Southern District of Texas (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 an order approving and confirming the plan (the "Plan") of reorganization of the Debtors (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.

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.

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, 2020, there were approximately 14 stockholders of record based on information provided by the Company's transfer agent.

Dividends

Although the Company paid a one-time cash distribution on December 12, 2019, the Company is not currently paying a regular 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. See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" in this Annual Report on Form 10-K.

Cash Distributions

On November 21, 2019, the Board of Directors of the Company declared a cash distribution of $4.25 per share. A cash distribution totaling approximately $249 million was paid on December 12, 2019, to shareholders of record as of the close of business on December 5, 2019. In addition, approximately $11 million for potential future distributions was recorded in restricted cash at December 31, 2019. In December 2019, distributions payable of approximately $2 million related to outstanding share-based compensation awards was also recorded. These amounts are included in "other accrued liabilities" and "asset retirement obligations and other noncurrent liabilities" on the consolidated balance sheet at December 31, 2019.

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 Exchange Act, 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 $150 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.

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

The following sets forth information with respect to the Company's repurchases of shares of its common stock during the fourth quarter of 2019.

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	94,374	$ 13.22	94,374	$ 27,926
November 1– 30	44,551	$ 12.85	44,551	$ 27,354
December 1 – 31	366,042	$ 9.11	366,042	$ 24,020
Total	504,967	$ 10.21	504,967	

(1) On July 18, 2019, the Board authorized the repurchase of up to $150 million of the Company's outstanding shares of common stock. On June 13, 2019, the Company announced the intention to commence a tender offer to purchase $40 million of the Company's common stock. In July 2019, upon the terms and subject to the conditions described in the Offer to Purchase dated June 18, 2019, the Company repurchased an aggregate of 2,666,666 shares of common stock at a price of $15.00 per share for a total cost of approximately $40 million (excluding expenses of approximately $440,000 related to the tender offer).

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, and December 31, 2015 (see Note 4).

	Successor			Predecessor		
	Year Ended December 31,		Ten Months Ended December 31,	Two Months Ended February 28,	Year Ended December 31,	
(in thousands, except per share amounts)	2019	2018	2017	2017	2016	2015
Statement of operations data:						
Oil, natural gas and natural gas liquids sales	$ 236,053	$ 420,102	$ 709,363	$ 188,885	$ 874,161	$ 1,065,795
Gains (losses) on commodity derivatives	10,091	(23,404)	13,533	92,691	(164,330)	1,027,014
Depreciation, depletion and amortization	77,089	94,958	133,711	47,155	342,614	513,508
Interest expense, net of amounts capitalized	6,997	2,417	12,380	16,725	184,870	456,749
Income tax expense (benefit)	127,859	29,587	385,654	(166)	11,300	(6,307)
(Loss) income from continuing operations	(297,570)	20,933	345,131	2,587,557	(343,733)	(3,812,416)
Income (loss) from discontinued operations	3,824	19,674	90,064	(548)	(18,354)	9,586
Net (loss) income	(293,746)	40,607	435,195	2,587,009	(362,087)	(3,802,830)
(Loss) income from continuing operations per share – basic and diluted	(4.71)	0.28	4.53	33.96	(4.51)	(50.04)
Income (loss) from discontinued operations per share – basic and diluted	0.06	0.26	1.18	(0.01)	(0.24)	0.13
Net (loss) income per share – basic and diluted	(4.65)	0.54	5.71	33.95	(4.75)	(49.91)
Weighted average shares outstanding –						
basic	63,118	74,935	76,191	76,191	76,191	76,191
diluted	63,118	75,360	76,191	76,191	76,191	76,191
Distributions declared per share	$ 4.25	$ —	$ —	$ —	$ —	$ —

Item 6. Selected Financial Data - Continued

	Successor			Predecessor		
	At or for the Year Ended December 31,		At or for the Ten Months Ended December 31,	Two Months Ended February 28,	At or for the Year Ended December 31,	
(in thousands)	2019	2018	2017	2017	2016	2015
Cash flow data:						
Net cash provided by (used in):						
Operating activities	$ 114,441	$ (6,594)	$ 231,021	$ 152,714	$ 875,306	$ 1,127,700
Investing activities	265,336	168,162	1,257,352	(58,756)	(230,438)	(276,023)
Financing activities	(280,385)	(632,713)	(1,111,473)	(437,730)	(164,150)	(850,886)
Balance sheet data:						
Total assets	$ 816,259	$ 1,592,834	$ 2,868,125		$ 4,444,151	$ 6,018,375
Current portion of long-term debt, net	—	—	—		1,937,729	2,841,518
Long-term debt, net	69,800	24,500	—		—	4,447,308
Liabilities subject to compromise	—	—	—		4,280,005	—
Total equity (deficit)	573,551	1,262,374	2,339,046		(2,587,009)	(2,110,804)

Item 6. Selected Financial Data - Continued

	Successor			Predecessor		
	At or for the Year Ended December 31,		At or for the Ten Months Ended December 31,	Two Months Ended February 28,	At or for the Year Ended December 31,	
	2019	2018	2017	2017	2016	2015
Production data:						
Average daily production – continuing operations:						
Natural gas (MMcf/d)	197	247	386	495	511	549
Oil (MBbls/d)	1.7	3.2	17.8	20.2	22.1	27.4
NGL (MBbls/d)	5.8	10.3	20.5	21.4	25.4	25.6
Total (MMcfe/d)	242	328	616	745	796	867
Average daily production – discontinued operations:						
Equity method investments – Total (MMcfe/d) (1)	—	64	30	—	—	—
California - Total (MMcfe/d) (2)	—	—	14	30	32	30
Reserves data: (3)						
Proved reserves – continuing operations:						
Natural gas (Bcf)	281	1,260	1,377		2,290	2,212
Oil (MMBbls)	2	4	27		73	74
NGL (MMBbls)	3	56	72		104	97
Total (Bcfe)	316	1,618	1,968		3,350	3,240
Proved reserves – discontinued operations:						
Equity method investments – Total (Bcfe) (1)	—	—	694		—	—
California - Total (Bcfe) (2)	—	—	—		170	195

(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 natural gas liquids ("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."

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."

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, 2017.

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.

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.

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 and combined 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 and combined financial statements. See Note 4 for additional information. In December 2019, stockholders of Roan Resources, Inc. approved an Agreement and Plan of Merger ("Merger") between Roan Resources, Inc. and a subsidiary of Citizen Energy Operating, LLC ("Citizen Operating") under which Roan Resources, Inc., including its subsidiary Roan Resources LLC, became wholly owned subsidiaries of Citizen Operating. The effective date of the Merger was December 6, 2019, and as a result of the Merger, the Company and Roan no longer share certain mutual directors and significant stockholders.

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. Riviera is quoted for trading on the OTCQX Market under the ticker "RVRA," and the Parent did not retain any ownership interest in the Company.

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. 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). 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 primarily located in two operating regions in the United States ("U.S."):

- Mid-Continent, which includes properties in the Northwest STACK in northwestern Oklahoma and various other oil and natural gas producing properties throughout Oklahoma; and
- North Louisiana, which includes oil and natural gas properties producing primarily from the Hosston, Cotton Valley Bossier and Smackover formations.

In the first quarter of 2020, the Company completed the sale of its interests in non-operated properties located in the Drunkards Wash field in the Uinta Basin, the Overton field in East Texas and the Personville field in East Texas. These properties are included in "assets held for sale" on the consolidated balance sheet as of December 31, 2019. Reserve information as of December 31, 2019, includes amounts associated with these properties. See Note 4 for additional information.

During 2019, the Company divested all of its properties located in the Hugoton Basin and Michigan/Illinois operating regions. During 2018, the Company divested all of its properties located in the Permian Basin operating region. During 2017, the Company divested all of its properties located in the 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 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, a network of gathering pipelines and compressors and produced water services and a crude oil gathering system 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.

In addition to the activities described above, the Company has also engaged an investment bank to explore a potential sale or merger of Riviera or Blue Mountain Midstream.

For the year ended December 31, 2019, the Company's results included the following:

- oil, natural gas and NGL sales of approximately $236 million compared to $420 million for the year ended December 31, 2018;
- average daily production of approximately 242 MMcfe/d compared to 328 MMcfe/d for the year ended December 31, 2018;

- net loss of approximately $294 million compared to net income of $41 million for the year ended December 31, 2018;
- net cash provided by operating activities of approximately $114 million compared to net cash used in operating activities of approximately $7 million for the for the year ended December 31, 2018;
- capital expenditures of approximately $172 million compared to $170 million for the year ended December 31, 2018; and
- 61 wells drilled (all successful) compared to 52 wells drilled (all successful) for 2018.

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 2019:

On November 22, 2019, the Company completed the sale of its interest in the remaining properties located in the Hugoton Basin (the "Hugoton Basin Assets Sale"). Cash proceeds received from the sale of these properties were approximately $286 million. During the year ended December 31, 2019, the Company recorded a noncash impairment charge of approximately $100 million to reduce the carrying value of these assets to fair value. In connection with the Hugoton Basin Assets Sale, the buyer also acquired the Company's interests in Mayzure, LLC, a wholly owned subsidiary of the Company, which was the counterparty to the volumetric production payment agreements based on helium produced from certain oil and natural gas properties in the Hugoton Basin.

Blue Mountain Midstream entered into an agreement with a potential customer to construct a gathering system, as well as gather and process gas. During the third quarter of 2019, a decision was made not to proceed with the gas gathering and processing contract, and as a result, the customer reimbursed Blue Mountain Midstream for capital deployed and operating expenses incurred, in addition to paying a success fee for constructing the assets. During the year ended December 31, 2019, Blue Mountain Midstream received a capital reimbursement of approximately $20 million. Blue Mountain Midstream also received approximately $4 million for the success fee and the expense reimbursement, which is included in "(gains) losses on sale of assets and other, net" on the consolidated and combined statement of operations.

On September 5, 2019, the Company completed the sale of its interest in properties located in Illinois. Cash proceeds from the sale of these properties were approximately $4 million and the Company recorded a net gain of approximately $4 million.

On August 30, 2019, the Company completed the sale of its interest in non-core assets located in North Louisiana. Cash proceeds from the sale were approximately $2 million and the Company recorded a net gain of approximately $376,000.

On July 3, 2019, the Company completed the sale of its interest in properties located in Michigan (the "Michigan Assets Sale"). Cash proceeds from the sale of these properties were approximately $39 million. The Company recorded a noncash impairment charge to reduce the carrying value of these assets to fair value of approximately $18 million for the year ended December 31, 2019.

On May 31, 2019, the Company completed the sale of its interest in non-operated properties located in the Hugoton Basin in Kansas. Cash proceeds received from the sale of these properties were approximately $29 million and the Company recognized a net loss of approximately $10 million.

On January 17, 2019, the Company completed the sale of its interest in properties located in the Arkoma Basin in Oklahoma (the "Arkoma Assets Sale"). Cash proceeds received from the sale of these properties were approximately $64 million (including a deposit of approximately $5 million received in 2018), and the Company recognized a net gain of approximately $28 million.

Divestitures – Subsequent Events

On January 15, 2020, the Company completed the sale of its interests in non-operated properties located in the Drunkards Wash field in the Uinta Basin (the "Drunkards Wash Asset Sale"). Cash proceeds from the sale of these properties were approximately $4 million (including a deposit of approximately $450,000 received in 2019).

On January 31, 2020, the Company completed the sale of its interest in properties located in the Overton field in East Texas (the "Overton Assets Sale"). Cash proceeds from the sale of these properties were approximately $17 million (including a deposit of approximately $2 million received in 2019). During the year ended December 31, 2019, the Company recorded a noncash impairment charge of approximately $13 million to reduce the carrying value of these assets to fair value.

On February 14, 2020, the Company completed the sale of its interest in properties located in the Personville field in East Texas (the "Personville Assets Sale"). Cash proceeds from the sale of these properties were approximately $29 million (including a deposit of approximately $3 million received in 2019). During the year ended December 31, 2019, the Company recorded a noncash impairment charge of approximately $72 million to reduce the carrying value of these assets to fair value.

On November 20, 2019, the Company signed an agreement to sell its building located in Oklahoma City, Oklahoma for an amended contract price of $21 million. The sale is expected to close in the first quarter of 2020. During the year ended December 31, 2019, the Company recorded a noncash impairment charge of approximately $5 million to reduce the carrying value of this asset to fair value.

The assets and liabilities associated with the sale of the Oklahoma office building, the Drunkards Wash Asset Sale, the Overton Assets Sale and the Personville Assets Sale are classified as held for sale on the consolidated balance sheet at December 31, 2019.

Oil Services Agreement

On July 17, 2019, a subsidiary of Blue Mountain Midstream entered into an agreement with Roan to gather Roan's oil in the Merge/SCOOP/STACK play. The agreement provides for a 10-year term covering an 89,000 net acre dedicated area in nine Townships in central Oklahoma. Blue Mountain plans to construct an initial crude system consisting of approximately 28 miles of gathering pipelines with two downstream interconnections providing Roan with direct access to the Cushing market. The Blue Mountain system will initially be capable of transporting up to 60,000 barrels per day of crude oil. Services will commence in the first half of 2020. On December 6, 2019, Roan became a wholly owned indirect subsidiary of Citizen Operating.

Water Services Agreement

On January 31, 2019, a subsidiary of Blue Mountain Midstream 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 provides 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. On December 6, 2019, Roan became a wholly owned indirect subsidiary of Citizen Operating.

2019 Oil and Natural Gas and Midstream Capital Expenditures

During the year ended December 31, 2019, the Company had total capital expenditures, excluding acquisitions, of approximately $172 million, including approximately $63 million related to its oil and natural gas capital program and approximately $105 million related to Blue Mountain Midstream.

2020 Oil and Natural Gas and Midstream Capital Budget

For 2020, the Company estimates its total capital expenditures, excluding acquisitions, will be approximately $52 million, including approximately $25 million related to its oil and natural gas capital program and approximately $27 million related to Blue Mountain Midstream. This estimate is under continuous review and subject to ongoing adjustments.

Financing Activities

Riviera Credit Facility
Riviera's credit agreement provides for a senior secured reserve-based revolving loan facility (the "Riviera Credit Facility"). On September 27, 2019, the Company entered into an amendment to the Riviera Credit Facility to, among other things, extend its maturity date to August 4, 2021. The amendment resulted in a borrowing commitment reduction from $230 million to $90 million, primarily due to asset sales, with the next scheduled borrowing base redetermination to occur on April 1, 2020.

Blue Mountain Midstream Credit Facility
Blue Mountain Midstream's credit agreement provides for a senior secured revolving loan facility (the "Blue Mountain Midstream Credit Facility"). On February 8, 2019, the borrowing commitment under the Blue Mountain Midstream Credit Facility was increased to $200 million. The Blue Mountain Credit Facility together with the Riviera Credit Facility, are referred to as the "Credit Facilities."

Cash Distributions
On November 21, 2019, the Board of Directors of the Company declared a cash distribution of $4.25 per share. A cash distribution totaling approximately $249 million was paid on December 12, 2019, to shareholders of record as of the close of business on December 5, 2019. In addition, approximately $11 million for potential future distributions was recorded in restricted cash at December 31, 2019. In December 2019, distributions payable of approximately $2 million related to outstanding share-based compensation awards was also recorded. These amounts are included in "other accrued liabilities" and "asset retirement obligations and other noncurrent liabilities" on the consolidated balance sheet at December 31, 2019.

Share Repurchase Program
On July 18, 2019, the Company's Board of Directors increased the share repurchase authorization to $150 million of the Company's outstanding shares of common stock. During the year ended December 31, 2019, the Company repurchased an aggregate of 8,475,514 shares of common stock at an average price of $12.72 per share for a total cost of approximately $108 million. Included in this number are private purchases of 2,380,425 shares of common stock purchased at a discount to market, at an average price of $10.91 for a total cost of approximately $26 million. See Note 12 for additional information. For the period from January 1, 2020 through February 21, 2020, the Company repurchased 171,107 shares of common stock at an average price of $7.84 for a total cost of approximately $1 million. At February 21, 2020, approximately $23 million was available for share repurchases under the program. Any share repurchases are subject to restrictions in the Riviera Credit Facility.

Tender Offer
On June 13, 2019, the Company's Board of Directors announced the intention to commence a tender offer to purchase $40 million of the Company's common stock. In July 2019, upon the terms and subject to the conditions described in the Offer to Purchase dated June 18, 2019, the Company repurchased an aggregate of 2,666,666 shares of common stock at a price of $15.00 per share for a total cost of approximately $40 million (excluding expenses of approximately $440,000 related to the tender offer).

Commodity Derivatives

During the year ended December 31, 2019, the Company entered into commodity derivative contracts consisting of natural gas fixed price swaps and NGL fixed price swaps for 2019 and oil fixed price swaps and natural gas basis swaps for 2020. In July 2019, in connection with the closing of the Michigan Assets Sale, the Company canceled its MichCon natural gas basis swaps for 2019 and 2020.

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

Results of Operations

Comparison of the Years Ended December 31, 2019, and December 31, 2018

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

	Year Ended December 31, 2019	Year Ended December 31, 2018	Variance
	(in thousands)		
Revenues and other:			
Natural gas sales	$ 163,778	$ 250,831	$ (87,053)
Oil sales	35,253	74,696	(39,443)
NGL sales	37,022	94,575	(57,553)
Total oil, natural gas and NGL sales	236,053	420,102	(184,049)
Gains (losses) on commodity derivatives	10,091	(23,404)	33,495
Marketing and other revenues	233,635	268,961	(35,326)
	479,779	665,659	(185,880)
Expenses:			
Lease operating expenses	77,719	120,097	(42,378)
Transportation expenses	64,149	83,562	(19,413)
Marketing expenses	166,651	220,971	(54,320)
General and administrative expenses [1]	61,671	245,291	(183,620)
Exploration costs	5,122	5,178	(56)
Depreciation, depletion and amortization	77,089	94,958	(17,869)
Impairment of assets held for sale and long-lived assets	208,376	15,697	192,679
Taxes, other than income taxes	15,374	29,730	(14,356)
(Gains) losses on sale of assets and other, net	(20,743)	(208,598)	187,855
	655,408	606,886	48,522
Other income and (expenses)	(7,441)	(3,094)	(4,347)
Reorganization items, net	13,359	(5,159)	18,518
(Loss) income from continuing operations before income taxes	(169,711)	50,520	(220,231)
Income tax expense	127,859	29,587	98,272
(Loss) income from continuing operations	(297,570)	20,933	(318,503)
Income from discontinued operations, net of income taxes	3,824	19,674	(15,850)
Net (loss) income	$ (293,746)	$ 40,607	$ (334,353)

(1) General and administrative expenses for the years ended December 31, 2019, and December 31, 2018, include approximately $11 million and $132 million, respectively, of share-based compensation expenses and approximately $5 million and $27 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.

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

	Year Ended December 31, 2019	2018	Variance
Average daily production:			
Natural gas (MMcf/d)	197	247	(20%)
Oil (MBbls/d)	1.7	3.2	(47%)
NGL (MBbls/d)	5.8	10.3	(44%)
Total (MMcfe/d)	242	328	(26%)
Weighted average prices: (1)			
Natural gas (Mcf)	$ 2.28	$ 2.78	(18%)
Oil (Bbl)	$ 57.15	$ 62.99	(9%)
NGL (Bbl)	$ 17.36	$ 25.14	(31%)
Average NYMEX prices:			
Natural gas (MMBtu)	$ 2.63	$ 3.09	(15%)
Oil (Bbl)	$ 57.03	$ 64.77	(12%)
Costs per Mcfe of production:			
Lease operating expenses	$ 0.88	$ 1.00	(12%)
Transportation expenses	$ 0.73	$ 0.70	4%
General and administrative expenses (2)	$ 0.70	$ 2.05	(66%)
Depreciation, depletion and amortization	$ 0.87	$ 0.79	10%
Taxes, other than income taxes	$ 0.17	$ 0.25	(30%)
Average daily production – discontinued operations:			
Equity method investments – Total (MMcfe/d) (3)	—	64	(100%)

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

(2) General and administrative expenses for the years ended December 31, 2019, and December 31, 2018, include approximately $11 million and $132 million, respectively, of share-based compensation expenses and approximately $5 million and $27 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.

(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.

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

Upstream Reporting Segment

	Year Ended December 31, 2019	Year Ended December 31, 2018	Variance
	(in thousands)		
Oil, natural gas and NGL sales	$ 236,053	$ 420,102	$ (184,049)
Marketing and other revenues	73,929	126,943	(53,014)
	309,982	547,045	(237,063)
Lease operating expenses	77,719	120,097	(42,378)
Transportation expenses	64,149	83,562	(19,413)
Marketing expenses	40,389	91,869	(51,480)
Severance taxes and ad valorem taxes	17,930	28,598	(10,668)
Total direct operating expenses	200,187	324,126	(123,939)
Field level cash flow (1)	$ 109,795	$ 222,919	$ (113,124)

(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 $184 million or 44% to approximately $236 million for the year ended December 31, 2019, from approximately $420 million for the year ended December 31, 2018, due to lower production volumes as a result of divestitures completed in 2018 and 2019, as well as lower commodity prices. Lower oil and NGL prices resulted in a decrease in revenues of approximately $4 million and $16 million, respectively. Lower natural gas prices resulted in a decrease in revenues of approximately $37 million.

Average daily production volumes decreased to approximately 242 MMcfe/d for the year ended December 31, 2019, from approximately 328 MMcfe/d for the year ended December 31, 2018. Lower oil, natural gas and NGL production volumes resulted in a decrease in revenues of approximately $36 million, $50 million and $41 million, respectively.

The following table sets forth average daily production by region:

	Year Ended December 31, 2019	Year Ended December 31, 2018	Variance	
Average daily production (MMcfe/d):				
Hugoton Basin	101	138	(37)	(27%)
Mid-Continent	36	53	(17)	(32%)
East Texas	42	50	(8)	(16%)
Michigan/Illinois	14	28	(14)	(50%)
North Louisiana	31	26	5	19%
Uinta Basin	18	23	(5)	(22%)
Permian Basin	—	10	(10)	(100%)
	242	328	(86)	(26%)

The decreases in average daily production volumes in the Hugoton Basin and Mid-Continent regions primarily reflect lower production volumes as a result of divestitures completed during 2018 and 2019, partially offset by increased development capital spending in the Mid-Continent region. Additionally, Hugoton Basin volumes were impacted by the election to reject ethane prior to its sale in November 2019. The decreases in average daily production volumes in the Uinta Basin and Permian Basin regions primarily reflect lower production volumes as a result of divestitures completed during 2018. The decrease in average daily production in the Michigan/Illinois region reflect lower production volumes, as a result of the Michigan and Illinois Assets Sales in the third quarter of 2019. See Note 4 for additional information about divestitures. The decreases in average daily production volumes in the East Texas region reflect lower production volumes as a result of reduced development capital spending and natural declines. The increase in production volumes in North Louisiana is due to new wells drilled in 2019.

Marketing and Other Revenues

	Year Ended December 31, 2019	Year Ended December 31, 2018	Variance
	(in thousands)		
Jayhawk Plant	$ 48,861	$ 99,361	$ (50,500)
Helium	18,072	22,135	(4,063)
Other	6,996	5,447	1,549
	$ 73,929	$ 126,943	$ (53,014)

Marketing and other revenues decreased by approximately $53 million or 42% to approximately $74 million for the year ended December 31, 2019, from approximately $127 million for the year ended December 31, 2018. The decrease was primarily due to third party take-in-kind elections. Other primarily includes revenues from other midstream systems in the East Texas and North Louisiana regions.

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 $42 million or 35% to approximately $78 million for the year ended December 31, 2019, from approximately $120 million for the year ended December 31, 2018. The decrease was primarily due to the divestitures completed in 2018 and 2019. Lease operating expenses per Mcfe decreased to $0.88 per Mcfe for the year ended December 31, 2019, from $1.00 per Mcfe for the year ended December 31, 2018.

Transportation Expenses
Transportation expenses decreased by approximately $20 million or 23% to approximately $64 million for the year ended December 31, 2019, from approximately $84 million for the year ended December 31, 2018. The decrease was due to reduced costs as a result of lower production volumes primarily as a result of the divestitures completed in 2018 and 2019. Transportation expenses per Mcfe increased to $0.73 per Mcfe for the year ended December 31, 2019, from $0.70 per Mcfe for the year ended December 31, 2018. The increase in the rate per Mcfe is primarily driven by increased expenses in the Hugoton Basin prior to its sale in November 2019.

Marketing Expenses

	Year Ended December 31, 2019	Year Ended December 31, 2018	Variance
	(in thousands)		
Jayhawk Plant	$ 37,600	$ 88,109	$ (50,509)
Other	2,789	3,760	(971)
	$ 40,389	$ 91,869	$ (51,480)

Marketing expenses represent third-party activities associated with company-owned gathering systems, plants and facilities. Marketing expenses decreased by approximately $52 million or 56% to approximately $40 million for the year ended December 31, 2019, from approximately $92 million for the year ended December 31, 2018. The decrease was primarily due to third party take-in-kind elections.

Severance and Ad Valorem Taxes

	Year Ended December 31, 2019	Year Ended December 31, 2018	Variance
	(in thousands)		
Severance taxes	$ 6,925	$ 14,447	$ (7,522)
Ad valorem taxes	11,005	14,151	(3,146)
	$ 17,930	$ 28,598	$ (10,668)

Severance taxes, which are a function of revenues generated from production, decreased primarily due to lower production volumes due to divestitures completed in 2018 and 2019. 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 2018 and 2019.

Field Level Cash Flow
Field level cash flow decreased by approximately $113 million to approximately $110 million for the year ended December 31, 2019, from approximately $223 million for the year ended December 31, 2018. The decrease was primarily due to the divestitures completed in 2018 and 2019.

Blue Mountain Reporting Segment

	Year Ended December 31, 2019	2018	Variance
	(in thousands)		
Marketing revenues	$ 159,706	$ 142,018	$ 17,688
Marketing expenses	120,014	127,263	(7,249)
Severance taxes and ad valorem taxes	1,378	883	495
Total direct operating expenses	121,392	128,146	(6,754)
Field level cash flow (1)	$ 38,314	$ 13,872	$ 24,442

(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 $18 million or 12% to approximately $160 million for the year ended December 31, 2019, from approximately $142 million for the year ended December 31, 2018. The increase was due to revenues from the new water services business in 2019 and higher throughput volumes related to the commissioning of the cryogenic natural gas processing facility in 2018. These increases were partially offset by lower prices. Average daily throughput volumes increased to approximately 117 MMcf/d for the year ended December 31, 2019, from 95 MMcf/d for the year ended December 31, 2018.

Marketing Expenses
Marketing expenses decreased by approximately $7 million or 6% to approximately $120 million for the year ended December 31, 2019, from approximately $127 million for the year ended December 31, 2018. The decrease was due to lower prices during 2019, partially offset by expenses related to the new water services business in 2019 and higher volumes.

Field Level Cash Flow
Field level cash flow increased by approximately $24 million or 176% to approximately $38 million for the year ended December 31, 2019, from approximately $14 million for the year ended December 31, 2018. The increase was due to increased revenues from the new water services business in 2019, higher throughput volumes and the operations of the cryogenic natural gas processing facility in 2018.

Indirect Income and Expenses Not Allocated to Segments

Gains (Losses) on Commodity Derivatives
Gains on commodity derivatives were approximately $10 million for the year ended December 31, 2019, compared to losses of approximately $23 million for the year ended December 31, 2018, representing a variance of approximately $33 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 "Item 7A–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. General and administrative expenses decreased by approximately $183 million or 75% to approximately $62 million for the year ended December 31, 2019, from approximately $245 million for the year ended December 31, 2018. The decrease was primarily due to lower share-based compensation expenses, lower severance costs and lower salaries and benefits related expenses due to lower headcount primarily offset by lower transition service fees recorded as a reduction of general and administrative expenses during the year ended December 31, 2018. General and administrative expenses per Mcfe decreased to $0.70 per Mcfe for the year ended December 31, 2019, from $2.05 per Mcfe for the year ended December 31, 2018.

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, which consisted primarily of seismic data expenses, remained constant at approximately $5 million for the year ended December 31, 2019, and approximately $5 million for the year ended December 31, 2018.

Depreciation, Depletion and Amortization
Depreciation, depletion and amortization decreased by approximately $18 million or 19% to approximately $77 million for the year ended December 31, 2019, from approximately $95 million for the year ended December 31, 2018. The decrease was primarily due to lower total production volumes partially offset by Blue Mountain Midstream's increase in depreciation expense related to the commissioning of the cryogenic natural gas processing facility at the end of the second quarter of 2018 and related compression and gathering systems.

Impairment of Long-Lived Assets
During the year ended December 31, 2019, the Company recorded noncash impairment charges of approximately $207 million to reduce the carrying value of its properties sold located in the Hugoton Basin and Michigan and to reduce the carrying value of properties held for sale located in Oklahoma and Texas. During the years ended December 31, 2019, and December 31, 2018, the Company recorded noncash impairment charges of approximately $1 million and $16 million, respectively, associated with proved oil and natural gas properties in the Texas, Uinta Basin and Michigan/Illinois regions due to a decline in commodity prices and higher operating costs.

(Gains) Losses on Sale of Assets and Other, Net
During the year ended December 31, 2019, the Company recorded the following amounts related to divestitures (see Note 4):

- Net gain of approximately $4 million on the sale of its interest in properties located in Illinois;
- Net gain of approximately $376,000 on the sale of its interests in properties located in North Louisiana;
- Net loss of approximately $10 million on the sale of its interest in non-operated properties in the Hugoton Basin; and
- Net gain of approximately $28 million on the Arkoma Assets Sale.

During the year ended December 31, 2018, the Company recorded the following amounts related to divestitures (see Note 4):

- Net gain of approximately $12 million on the sale of its interest in properties located in New Mexico (the "New Mexico Assets Sale");
- Net gain of approximately $83 million, including costs to sell of approximately $2 million, on the sale of its interest in properties located in the Altamont Bluebell Field in Utah (the "Altamont Bluebell Assets Sale");
- Net gain of approximately $54 million, including costs to sell of approximately $2 million, on the sale of its interest in properties located in West Texas (the "West Texas Assets Sale"); and
- Net gain of approximately $46 million, including costs to sell of approximately $1 million, on the sale of its Oklahoma and Texas Panhandle properties (the "Oklahoma and Texas Assets Sale").

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

Other Income and (Expenses)

	Year Ended December 31, 2019	Year Ended December 31, 2018	Variance
	(in thousands)		
Interest expense, net of amounts capitalized	$ (6,997)	$ (2,417)	$ (4,580)
Other, net	(444)	(677)	233
	$ (7,441)	$ (3,094)	$ (4,347)

Interest expense increased primarily due to higher outstanding debt during 2019. For the year ended December 31, 2019, "other, net" is primarily related to writing off a portion of the unamortized deferred financing fees of approximately $700,000 and commitment fees for the undrawn portion of the Credit Facilities, partially offset by interest and rental income. For the year ended December 31, 2018, "other, net" is primarily interest income, partially offset by commitment fees for the undrawn portion of the Credit Facilities. See "Debt" under "Liquidity and Capital Resources" below for additional details.

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 directly associated with the Chapter 11 proceedings since the Petition Date. For the years ended December 31, 2019, and December 31, 2018, reorganization items were approximately $13 million and $5 million, respectively. For the year ended December 31, 2019, the Company recognized a gain of approximately $14 million related to rulings regarding costs and income associated with the Chapter 11 proceeding. Costs incurred for the years ended December 31, 2019, and December 31, 2018, primarily related to legal and professional fees.

Income Tax Expense

The Company recognized an income tax expense of approximately $128 million compared to $30 million for the years ended December 31, 2019, and December 31, 2018, respectively. During the third quarter of 2019, and for the first time since inception, the Company's earnings show a cumulative loss which was primarily due to losses generated during 2019. Based on the cumulative loss and projections of future taxable income for the periods in which our deferred tax assets are deductible, the Company recorded a full valuation allowance of approximately $171 million to reduce its federal and state net deferred tax assets to an amount that is more likely than not to be realized. 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 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 2019, the Company recorded a net gain of approximately $4 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 for the year ended December 31, 2018. See Note 4 for additional information.

Net (Loss) Income

Net (loss) income decreased by approximately $335 million to a net loss of approximately $294 million for the year ended December 31, 2019, from net income of approximately $41 million for the year ended December 31, 2018. The decrease was primarily due to a noncash impairment charge recorded to the Company's properties sold, the Hugoton Basin Assets Sale and the Michigan Asset Sale, a valuation allowance, lower production revenue, lower gains on sales of assets and lower commodity revenues, partially offset by lower expenses and gains on commodity derivatives during the year ended December 31, 2019. 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

Comparison of the Year Ended December 31, 2018, and the Ten Months Ended December 31, 2017, and the Two Months Ended February 28, 2017

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 statements of operations.

(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, 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.

	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.

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

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 or 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
	Year Ended December 31, 2018	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017
(in thousands)			
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 "Item 7A−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 amounts related to 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;
- 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;
- Net gain of approximately $30 million, including costs to sell of approximately $1 million, on the sale of its interest in the Salt Creek Field in Wyoming (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;
- 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 2018, the Company recorded a net 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.

Liquidity and Capital Resources

The Company's sources of cash have primarily consisted of proceeds from its divestitures of oil and natural gas properties, net cash provided by operating activities and borrowing under the Blue Mountain Credit Facility. As a result of divesting certain oil and natural gas properties during the year ended December 31, 2019, the Company received approximately $447 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, for distributions to shareholders, 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.

Statements of Cash Flows

The following is a comparative cash flow summary:

	Successor			Predecessor
	Year Ended December 31,		Ten Months Ended December 31,	Two Months Ended February 28,
(in thousands)	2019	2018	2017	2017
Net cash:				
Net cash provided by (used in) operating activities	$ 114,441	$ (6,594)	$ 231,021	$ 152,714
Net cash provided by (used in) investing activities	265,336	168,162	1,257,352	(58,756)
Net cash used in financing activities	(280,385)	(632,713)	(1,111,473)	(437,730)
Net increase (decrease) in cash, cash equivalents and restricted cash	$ 99,392	$ (471,145)	$ 376,900	$ (343,772)

Operating Activities
Cash provided by operating activities was approximately $114 million for the year ended December 31, 2019, compared to cash used in operating activities of approximately $7 million for the year ended December 31, 2018. 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 for the two months ended February 28, 2017, respectively.

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

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

	Successor			Predecessor
	Year Ended December 31,		Ten Months Ended December 31,	Two Months Ended February 28,
(in thousands)	2019	2018	2017	2017
Cash flow from investing activities:				
Capital expenditures	$ (178,216)	$ (207,129)	$ (260,316)	$ (58,006)
Acquisition of property, plant and equipment	(3,380)	—	—	—
Proceeds from sale of properties and equipment and other	446,932	368,291	1,172,025	(166)
Net cash provided by (used in) investing activities – continuing operations	265,336	161,162	911,709	(58,172)
Net cash provided by (used in) investing activities – discontinued operations	—	7,000	345,643	(584)
Net cash provided by (used in) investing activities	$ 265,336	$ 168,162	$ 1,257,352	$ (58,756)

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, water facilities and related compression and gathering systems. Capital expenditures decreased primarily due to lower spending on plant and pipeline construction related to Blue Mountain Midstream partially offset by higher oil and natural gas capital spending. The Company made no material acquisitions of properties during the years ended December 31, 2019, and December 31, 2018, the ten months ended December 31, 2017, and the two months ended February 28, 2017.

Proceeds from sale of properties and equipment and other for the year ended December 31, 2019, include cash proceeds received of approximately $286 million from the Hugoton Basin Assets Sale, approximately $59 million (excluding a deposit of approximately $5 million received in 2018) from the Arkoma Assets Sale, approximately $29 million from the sale of non-operated properties in the Hugoton Basin, approximately $39 million from the Michigan Assets Sale, approximately $4 million from the sale of its interest in properties located in Illinois, approximately $2 million from the sale of its interests in properties located in North Louisiana, and approximately $20 million from Blue Mountain's agreement with a customer. Proceeds for the year ended December 31, 2019, also include deposits of approximately $6 million for 2020 divestitures. 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. See Note 4 for additional details of divestitures.

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

See below for details regarding accrued and paid capital expenditures for the periods presented:

	Successor			Predecessor
	Year Ended December 31,		Ten Months Ended December 31,	Two Months Ended February 28,
(in thousands)	2019	2018	2017	2017
Oil and natural gas	$ 63,457	$ 36,251	$ 199,866	$ 39,409
Plant and pipeline	103,885	131,576	93,318	4,990
Other	4,489	2,434	5,626	1,243
Capital expenditures, excluding acquisitions	$ 171,831	$ 170,261	$ 298,810	$ 45,642
Capital expenditures, excluding acquisitions – discontinued operations	$ —	$ —	$ 2,033	$ 436

The increase in capital expenditures was primarily due to higher oil and natural gas development activities partially offset by lower plant and pipeline construction activities associated with Blue Mountain Midstream. For 2020, the Company estimates its total capital expenditures, excluding acquisitions, will be approximately $52 million, including approximately $25 million related to its oil and natural gas capital program and approximately $27 million related to Blue Mountain Midstream. This estimate is under continuous review and subject to ongoing adjustments.

Financing Activities
Cash used in financing activities was approximately $280 million for the year ended December 31, 2019, compared to approximately $633 million for the year ended December 31, 2018. 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 distributions to shareholders and 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.

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

	Successor			Predecessor
	Year Ended December 31,		Ten Months Ended December 30,	Two Months Ended February 28,
(in thousands)	2019	2018	2017	2017
Proceeds from borrowings:				
Riviera Credit Facility	$ —	$ 40,000	$ —	$ —
Blue Mountain Credit Facility	72,600	4,500	—	—
Successor's previous credit facility	—	—	190,000	—
	$ 72,600	$ 44,500	$ 190,000	$ —
Repayments of debt:				
Riviera Credit Facility	$ (20,000)	$ (20,000)	$ —	$ —
Blue Mountain Credit Facility	(7,300)	—	—	—
Successor's previous credit facility	—	—	(790,000)	—
Successor term loan	—	—	(300,000)	—
Predecessor's credit facility	—	—	—	(1,038,986)
	$ (27,300)	$ (20,000)	$ (1,090,000)	$ (1,038,986)

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 January 31, 2020, there were no borrowings outstanding and approximately $89 million of available borrowing capacity under the Riviera Credit Facility (which includes a $701,000 reduction for outstanding letters of credit). As of January 31, 2020, total borrowings outstanding under the Blue Mountain Credit Facility were approximately $73 million and there was approximately $115 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.

Dividends

Although the Company paid a one-time cash distribution on December 12, 2019, the Company is not currently paying a regular 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.

Cash Distributions

On November 21, 2019, the Board of Directors of the Company declared a cash distribution of $4.25 per share. A cash distribution totaling approximately $249 million was paid on December 12, 2019, to shareholders of record as of the close of business on December 5, 2019. In addition, approximately $11 million for potential future distributions was recorded in restricted cash at December 31, 2019. In December 2019, distributions payable of approximately $2 million related to outstanding share-based compensation awards was also recorded. These amounts are included in “other accrued liabilities” and “asset retirement obligations and other noncurrent liabilities” on the consolidated balance sheet at December 31, 2019.

Share Repurchase Program

On July 18, 2019, the Company’s Board of Directors increased the share repurchase authorization to $150 million of the Company’s outstanding shares of common stock. During the year ended December 31, 2019, the Company repurchased an aggregate of 8,475,514 shares of common stock at an average price of $12.72 per share for a total cost of approximately $108 million. Included in this number are private purchases of 2,380,425 shares of common stock purchased at a discount to market, at an average price of $10.91 for a total cost of approximately $26 million. See Note 12 for additional information. For the period from January 1, 2020 through February 21, 2020, the Company repurchased 171,107 shares of common stock at an average price of $7.84 for a total cost of approximately $1 million. At February 21, 2020, approximately $23 million was available for share repurchases under the program. Any share repurchases are subject to restrictions in the Riviera Credit Facility.

Tender Offer

On June 13, 2019, the Company’s Board of Directors announced the intention to commence a tender offer to purchase $40 million of the Company’s common stock. In July 2019, upon the terms and subject to the conditions described in the Offer to Purchase dated June 18, 2019, the Company repurchased an aggregate of 2,666,666 shares of common stock at a price of $15.00 per share for a total cost of approximately $40 million (excluding expenses of approximately $440,000 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.

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.

Commitments and Contractual Obligations

The following is a summary of the Company's commitments and contractual obligations as of December 31, 2019:

	Payments Due				
Contractual Obligations	**Total**	**2020**	**2021-2022**	**2023-2024**	**2025-Beyond**
Long-term debt obligations:					
Credit Facilities	$ 69,800	$ —	$ —	$ 69,800	$ —
Interest (1)	9,370	2,597	5,194	1,579	—
Operating lease obligations:					
Office, property and equipment leases	6,225	3,557	2,668	—	—
Other:					
Commodity derivatives	1,087	1,087	—	—	—
Asset retirement obligations	21,497	1,184	1,689	1,734	16,890
	$ 107,979	$ 8,425	$ 9,551	$ 73,113	$ 16,890

(1) Represents interest on the Blue Mountain Credit Facility computed at approximately 3.72% through its maturity in 2023.

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, 2019, 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 Securities and Exchange Commission, 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, 2019, and December 31, 2018, the Company recorded noncash impairment charges of approximately $208 million and $16 million, respectively, associated with proved oil and natural gas properties. In 2019, approximately $207 million relates to assets sold or assets held for sale at December 31, 2019. 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 assets held for sale and long-lived assets" on the consolidated and combined statements 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 years ended December 31, 2019, December 31, 2018, the ten months ended December 31, 2017, or the two months ended February 28, 2017.

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.

During the third quarter of 2019, and for the first time since Riviera's inception, the Company's earnings show a cumulative loss which is primarily due to losses generated during 2019. Based on the cumulative loss and projections of future taxable income for the periods in which our deferred tax assets are deductible, during the third quarter of 2019, the Company recorded a full valuation allowance of approximately $171 million to reduce its federal and state net deferred tax assets to an amount that is more likely than not to be realized.

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 files 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, 2019, the fair value of fixed price swaps was a net asset of approximately $6 million. A 10% increase in the NYMEX WTI oil and NYMEX Henry Hub natural gas prices above the December 31, 2019, prices would result in a net asset of approximately $3 million, which represents a decrease in the fair value of approximately $3 million; conversely, a 10% decrease in the NYMEX oil and Henry Hub natural gas prices below the December 31, 2019, prices would result in a net asset of approximately $10 million, which represents an increase in the fair value of approximately $4 million.

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.

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, 2019, the Company had debt outstanding under the Credit Facilities of $69.8 million in the aggregate which debt incurred interest at floating rates. A 1% increase in the respective market rates would result in an estimated $698,000 increase in annual interest expense. 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.

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, 2019, 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, 2019, 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, 2019, 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, 2019 and 2018, the related consolidated and combined statements of operations, equity (deficit), and cash flows for each of the years in the two-year period ended December 31, 2019, and from March 1, 2017 to December 31, 2017 (Successor periods), and from January 1, 2017 to February 28, 2017 (Predecessor period), 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, 2019 and 2018, and the results of its operations and its cash flows for the Successor and Predecessor periods 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, 2019, 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 27, 2020 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Change in Accounting Principle

As discussed in Note 3 to the consolidated and combined financial statements, the Company 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, Inc. 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 1 to the consolidated and combined financial statements, Linn Energy, Inc. (formerly known as Linn Energy, LLC), the former parent company of Riviera Resources, Inc. 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 in the Predecessor period.

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 27, 2020

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, 2019, 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, 2019, based 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 of the Company as of December 31, 2019 and 2018, the related consolidated and combined statements of operations, equity (deficit), and cash flows for each of the years in the two-year period ended December 31, 2019, and from March 1 2017 to December 31, 2017 (Successor periods), and from January 1, 2017 to February 28, 2017 (Predecessor period), and the related notes (collectively, the consolidated and combined financial statements), and our report dated February 27, 2020 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 27, 2020

RIVIERA RESOURCES, INC.

CONSOLIDATED BALANCE SHEETS

	December 31, 2019	December 31, 2018
	(in thousands, except share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 116,237	$ 18,529
Accounts receivable – trade, net	51,355	114,489
Derivative instruments	7,283	10,758
Restricted cash	32,932	31,248
Other current assets	12,853	26,721
Assets held for sale	104,773	38,396
Total current assets	325,433	240,141
Noncurrent assets:		
Oil and natural gas properties (successful efforts method)	180,307	756,552
Less accumulated depletion and amortization	(35,603)	(93,507)
	144,704	663,045
Other property and equipment	388,851	606,244
Less accumulated depreciation	(50,381)	(62,368)
	338,470	543,876
Derivative instruments	—	4,603
Deferred income taxes	—	129,091
Other noncurrent assets	7,652	12,078
	7,652	145,772
Total noncurrent assets	490,826	1,352,693
Total assets	$ 816,259	$ 1,592,834
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 80,579	$ 159,228
Derivative instruments	1,087	4,719
Other accrued liabilities	26,728	34,474
Liabilities held for sale	35,177	3,725
Total current liabilities	143,571	202,146
Noncurrent liabilities:		
Credit facilities	69,800	24,500
Asset retirement obligations and other noncurrent liabilities	29,337	103,814
Total noncurrent liabilities	99,137	128,314
Commitments and contingencies (Note 10)		
Equity:		
Preferred Stock ($0.01 par value, 30,000,000 shares authorized and no shares issued at December 31, 2019; no shares authorized or issued at December 31, 2018)	—	—
Common Stock ($0.01 par value, 270,000,000 shares authorized and 58,168,756 shares issued at December 31, 2019; 69,197,284 shares authorized or issued at December 31, 2018)	581	692
Additional paid-in capital	861,764	1,256,730
Retained (deficit) earnings	(288,794)	4,952
Total equity	573,551	1,262,374
Total liabilities and equity	$ 816,259	$ 1,592,834

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
	Year Ended December 31,		Ten Months Ended December 31,	Two Months Ended February 28,
(in thousands, except per share amounts)	2019	2018	2017	2017
Revenues and other:				
Oil, natural gas and natural gas liquids sales	$ 236,053	$ 420,102	$ 709,363	$ 188,885
Gains (losses) on commodity derivatives	10,091	(23,404)	13,533	92,691
Marketing revenues	214,280	245,081	82,943	6,636
Other revenues	19,355	23,880	20,839	9,915
	479,779	665,659	826,678	298,127
Expenses:				
Lease operating expenses	77,719	120,097	208,446	49,665
Transportation expenses	64,149	83,562	113,128	25,972
Marketing expenses	166,651	220,971	69,008	4,820
General and administrative expenses	61,671	245,291	117,347	71,745
Exploration costs	5,122	5,178	3,137	93
Depreciation, depletion and amortization	77,089	94,958	133,711	47,155
Impairment of assets held for sale and long-lived assets	208,376	15,697	—	—
Taxes, other than income taxes	15,374	29,730	47,553	14,877
(Gains) losses on sale of assets and other, net	(20,743)	(208,598)	(623,583)	672
	655,408	606,886	68,747	214,999
Other income and (expenses):				
Interest expense, net of amounts capitalized	(6,997)	(2,417)	(12,380)	(16,725)
Other, net	(444)	(677)	(6,233)	(149)
	(7,441)	(3,094)	(18,613)	(16,874)
Reorganization items, net	13,359	(5,159)	(8,533)	2,521,137
(Loss) income from continuing operations before income taxes	(169,711)	50,520	730,785	2,587,391
Income tax expense (benefit)	127,859	29,587	385,654	(166)
(Loss) income from continuing operations	(297,570)	20,933	345,131	2,587,557
Income (loss) from discontinued operations, net of income taxes	3,824	19,674	90,064	(548)
Net (loss) income	$ (293,746)	$ 40,607	$ 435,195	$ 2,587,009
(Loss) income per share:				
(Loss) income from continuing operations per share – basic and diluted	$ (4.71)	$ 0.28	$ 4.53	$ 33.96
Income (loss) from discontinued operations per share – basic and diluted	$ 0.06	$ 0.26	$ 1.18	$ (0.01)
Net (loss) income per share – basic and diluted	$ (4.65)	$ 0.54	$ 5.71	$ 33.95
Weighted average shares outstanding – basic	63,118	74,935	76,191	76,191
Weighted average shares outstanding – diluted	63,118	75,360	76,191	76,191
Distributions declared per share	$ 4.25	$ —	$ —	$ —

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

RIVIERA RESOURCES, INC.

CONSOLIDATED AND COMBINED STATEMENTS OF EQUITY (DEFICIT)

	Common Stock		Additional Paid-in Capital	Accumulated Earnings (Deficit)	Net Parent Company Investment	Total Equity (Deficit)
	Shares	Amount				
				(in thousands)		
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
Net loss		—	—	(293,746)	—	(293,746)
Repurchases of common stock	(11,116)	(112)	(148,149)	—	—	(148,261)
Issuances of common stock	88	1	1,800	—	—	1,801
Distributions to shareholders		—	(248,617)	—	—	(248,617)
December 31, 2019 (Successor)	58,169	$ 581	$ 861,764	$ (288,794)	$ —	$ 573,551

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

RIVIERA RESOURCES, INC.

CONSOLIDATED AND COMBINED STATEMENTS OF CASH FLOWS

	Successor			Predecessor
	Year Ended December 31,		Ten Months Ended December 31,	Two Months Ended February 28,
(in thousands)	2019	2018	2017	2017
Cash flow from operating activities:				
Net (loss) income	$ (293,746)	$ 40,607	$ 435,195	$ 2,587,009
Adjustments to reconcile net (loss) income to net cash provided by (used in) operating activities:				
(Income) loss from discontinued operations	(3,824)	(19,674)	(90,064)	548
Depreciation, depletion and amortization	77,089	94,958	133,711	47,155
Impairment of assets held for sale and long-lived assets	208,376	15,697	—	—
Deferred income taxes	127,873	29,701	378,512	(166)
Total (gains) losses on derivatives, net	(4,001)	25,243	(13,533)	(92,691)
Cash settlements on derivatives	8,447	(38,739)	26,793	(11,572)
Share-based compensation expenses	8,180	16,605	41,285	50,255
Amortization and write-off of deferred financing fees	3,172	1,909	3,711	1,338
(Gains) losses on sale of assets and other, net	(14,319)	(204,534)	(656,198)	1,069
Reorganization items, net	(14,316)	—	—	(2,456,074)
Changes in assets and liabilities:				
(Increase) decrease in accounts receivable – trade, net	50,190	26,956	41,094	(7,216)
(Increase) decrease in other assets	(6,604)	64,033	(265)	528
Increase (decrease) in accounts payable and accrued expenses	(27,741)	(46,792)	(92,664)	20,949
Increase (decrease) in other liabilities	(4,335)	(12,564)	7,253	2,801
Net cash provided by (used in) operating activities – continuing operations	114,441	(6,594)	214,830	143,933
Net cash provided by operating activities – discontinued operations	—	—	16,191	8,781
Net cash provided by (used in) operating activities	114,441	(6,594)	231,021	152,714
Cash flow from investing activities:				
Acquisition of property, plant and equipment	(3,380)	—	—	—
Development of oil and natural gas properties	(72,852)	(64,756)	(171,721)	(50,597)
Purchases of other property and equipment	(105,364)	(142,373)	(88,595)	(7,409)
Proceeds from sale of properties and equipment and other	446,932	368,291	1,172,025	(166)
Net cash provided by (used in) investing activities – continuing operations	265,336	161,162	911,709	(58,172)
Net cash provided by (used in) investing activities – discontinued operations	—	7,000	345,643	(584)
Net cash provided by (used in) investing activities	265,336	168,162	1,257,352	(58,756)

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RIVIERA RESOURCES, INC.

CONSOLIDATED AND COMBINED STATEMENTS OF CASH FLOWS - Continued

	Successor			Predecessor
	Year Ended December 31,		Ten Months Ended December 31,	Two Months Ended February 28,
(in thousands)	2019	2018	2017	2017
Cash flow from financing activities:				
Net transfers (to) from parent	—	(481,449)	(202,533)	636,000
Repurchases of shares	(148,588)	(153,314)	—	—
Proceeds from borrowings	154,525	44,500	190,000	—
Repayments of debt	(34,433)	(20,000)	(1,090,000)	(1,038,986)
Debt issuance costs paid	(3,272)	(2,892)	(7,729)	(151)
Payment to holders of claims under the Predecessor’s second lien notes	—	—	—	(30,000)
Distributions to shareholders	(248,617)	—	—	—
Distributions to unitholders	—	(18,717)	(1,211)	—
Other	—	(841)	—	(4,593)
Net cash used in financing activities	(280,385)	(632,713)	(1,111,473)	(437,730)
Net increase (decrease) in cash, cash equivalents and restricted cash	99,392	(471,145)	376,900	(343,772)
Cash, cash equivalents and restricted cash:				
Beginning	49,777	520,922	144,022	487,794
Ending	$ 149,169	$ 49,777	$ 520,922	$ 144,022

The accompanying notes are an integral part of these 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. (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.

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. 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).

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 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.

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 and combined 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 and combined financial statements. See Note 4 for additional information.

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. Riviera is quoted for trading on the OTCQX Market under the ticker "RVRA," and the Parent did not retain any ownership interest in the Company.

Nature of Business

At December 31, 2019, the Company's upstream reporting segment properties were located in three operating regions in the United States ("U.S."): East Texas, the Mid-Continent and North Louisiana. The Blue Mountain reporting segment consists of a cryogenic natural gas processing facility and a network of gathering pipelines and compressors and produced water services 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. In the first quarter of 2020, the Company completed the sale of its interests in non-operated properties located in the Drunkards Wash field in the Uinta Basin, the Overton field in East Texas and the Personville field in East Texas. These properties are included in "assets held for sale" on the consolidated balance sheet as of December 31, 2019. During 2019, the Company divested all of its properties located in the Hugoton Basin and Michigan/Illinois operating regions. During 2018, the Company divested all of its properties located in the Permian Basin operating region. During 2017, the Company divested all of its properties located in the 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.

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 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.

Investments in noncontrolled entities over which the Company exercises significant influence are accounted for under the equity method. At December 31, 2019, the Company had no investments accounted for under the equity method. See Note 4.

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 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 February 2016, the Financial Accounting Standards Board issued an Accounting Standards Update (“ASU”) that is intended to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet. The Company adopted this ASU effective January 1, 2019, using the modified retrospective effective date method and applied practical expedients which, among other things, allowed the Company to carryforward its historical lease classification, for the nonrecognition of short-term leases and for the combination of lease and non-lease components, by asset class. The adoption of this ASU resulted in an increase in both assets and liabilities of approximately $1 million as of January 1, 2019, related to the Company’s leasing activities with no material impact to the Company’s results of operations. The Company’s leases primarily include buildings, office equipment, and field equipment. The Company elected to combine lease and non-lease components for leases of office equipment and field equipment.

New Accounting Standards Issued But Not Yet Adopted

In June 2016, the FASB issued an ASU that is intended to change the impairment model for trade receivables, net investments in leases, debt securities, loans and certain other instruments. Adoption of this standard is effective for fiscal years beginning after December 15, 2019, and interim periods within those years. Modified retrospective application of this standard is required upon adoption. The Company does not expect that adoption will have a material impact on its results of operations or financial position.

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 $1 million and $397,000 at December 31, 2019, and December 31, 2018, 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. Capitalized interest costs were not material for the year ended December 31, 2019, or the ten months ended December 31, 2017. The Company did not capitalize any interest costs during the year ended December 31, 2018, or the 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, 2019, and December 31, 2018, the Company recorded noncash impairment charges of approximately $208 million and $16 million, respectively, associated with proved oil and natural gas properties. In 2019, approximately $207 million relates to assets sold or assets held for sale at December 31, 2019. The impairment charges recorded in 2019 and 2018 were primarily due to a decline in commodity prices and higher operating costs. 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 assets held for sale and long-lived assets" on the consolidated and combined statements 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 years ended December 31, 2019, December 31, 2018, the ten months ended December 31, 2017, or the two months ended February 28, 2017.

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 20 to 30 years for plants and pipelines.

Derivative Instruments

The Company hedges 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 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. 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, 2019, and December 31, 2018, net deferred financing fees of approximately $3 million and $5 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 years ended December 31, 2019, December 31, 2018, the ten months ended December 31, 2017, and the two months ended February 28, 2017, amortization expense of approximately $3 million, $2 million, $1 million and $1 million, respectively, is included in “interest expense, net of amounts capitalized” on the consolidated and combined statements of operations. For the year ended December 31, 2019, and the ten months ended December 31, 2017, approximately $700,000 and $3 million, respectively, was written off to expense and included in “other, net” on the consolidated and combined statements of operations related to amendments of the credit facilities. 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, 2019, and December 31, 2018. 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 files 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.

During the third quarter of 2019, and for the first time since Riviera’s inception, the Company’s earnings show a cumulative loss which is primarily due to losses generated during 2019. Based on the cumulative loss and projections of future taxable income for the periods in which our deferred tax assets are deductible, during the third quarter of 2019, the Company recorded a full valuation allowance to reduce its federal and state net deferred tax assets to an amount that is more likely than not to be realized.

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 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") (collectively with the LINN Debtors, 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.

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") 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.

Reorganization Items, Net

For the year ended December 31, 2019, the Company recognized a gain of approximately $14 million related to settlement of liabilities subject to compromise associated with the Chapter 11 proceeding. The Company incurred reorganization costs of approximately $957,000, $5 million and $9 million for the years ended December 31, 2019, December 31, 2018, and the ten months ended December 31, 2017, respectively, and recognized significant gains associated with the reorganization of the Company in connection with the Chapter 11 proceedings in the two months ended February 28, 2017. 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.

RIVIERA RESOURCES, INC.

NOTES TO CONSOLIDATED AND COMBINED FINANCIAL STATEMENTS - Continued

	Successor			Predecessor
	Year Ended December 31,		Ten Months Ended December 31,	Two Months Ended February 28,
(in thousands)	2019	2018	2017	2017
Gain on settlement of liabilities subject to compromise	$ 14,316	$ —	$ —	$ 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	(957)	(5,055)	(8,584)	(46,961)
Terminated contracts	—	—	—	(6,915)
Other	—	(104)	51	(13,315)
Reorganization items, net	$ 13,359	$ (5,159)	$ (8,533)	$ 2,521,137

Note 3 – Revenues

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.

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

Disaggregation of Revenue

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

	Year Ended December 31, 2019						
	Natural Gas	Oil	NGL	Oil, Natural Gas and NGL Sales	Marketing Revenues	Other Revenues	Total
				(in thousands)			
Hugoton Basin	$ 57,752	$ 1,394	$ 27,115	$ 86,261	$ 49,639	$ 19,126	$ 155,026
Mid-Continent	15,320	24,937	6,486	46,743	7	112	46,862
East Texas	35,906	3,335	2,325	41,566	3,464	8	45,038
Michigan/Illinois	13,551	1,869	47	15,467	—	85	15,552
North Louisiana	24,981	2,690	1,044	28,715	1,464	23	30,202
Uinta Basin	16,268	86	5	16,359	—	1	16,360
Permian Basin	—	942	—	942	—	—	942
Blue Mountain	—	—	—	—	159,706	—	159,706
Total	$ 163,778	$ 35,253	$ 37,022	$ 236,053	$ 214,280	$ 19,355	$ 469,688

	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 $43 million and $107 million as of December 31, 2019, and December 31, 2018, 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

Divestitures – 2019

On November 22, 2019, the Company completed the sale of its interest in the remaining properties located in the Hugoton Basin (the “Hugoton Basin Assets Sale”). Cash proceeds received from the sale of these properties were approximately $286 million. During the year ended December 31, 2019, the Company recorded a noncash impairment charge of approximately $100 million to reduce the carrying value of these assets to fair value. In connection with the Hugoton Basin Assets Sale, the buyer also acquired the Company’s interests in Mayzure, LLC (“Mayzure”), a wholly owned subsidiary of the Company, which was the counterparty to the volumetric production payment agreements based on helium produced from certain oil and natural gas properties in the Hugoton Basin.

The Company recognized a pre-tax loss of approximately $88 million, pre-tax income of approximately $50 million, pre-tax income of $50 million and pre-tax income of approximately $12 million for the years ended December 31, 2019, December 31, 2018, the ten months ended December 31, 2017, and the two months ended February 28, 2017, respectively, from the Hugoton Basin.

On September 5, 2019, the Company completed the sale of its interest in properties located in Illinois. Cash proceeds from the sale of these properties were approximately $4 million and the Company recorded a net gain of approximately $4 million.

On August 30, 2019, the Company completed the sale of its interest in non-core assets located in North Louisiana. Cash proceeds from the sale were approximately $2 million and the Company recorded a net gain of approximately $376,000.

On July 3, 2019, the Company completed the sale of its interest in properties located in Michigan (the “Michigan Assets Sale”). Cash proceeds from the sale of these properties were approximately $39 million. The Company recorded a noncash impairment charge to reduce the carrying value of these assets to fair value of approximately $18 million for the year ended December 31, 2019.

On May 31, 2019, the Company completed the sale of its interest in non-operated properties located in the Hugoton Basin in Kansas. Cash proceeds received from the sale of these properties were approximately $29 million and the Company recognized a net loss of approximately $10 million.

On January 17, 2019, the Company completed the sale of its interest in properties located in the Arkoma Basin in Oklahoma (the “Arkoma Assets Sale”). Cash proceeds received from the sale of these properties were approximately $64 million (including a deposit of approximately $5 million received in 2018), and the Company recognized a net gain of approximately $28 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 and losses on these divestitures are included in “(gains) losses on sale of assets and other, net” on the consolidated and combined statements of operations and were included in the upstream reporting segment.

Blue Mountain Midstream entered into an agreement with a potential customer to construct a gathering system, as well as gather and process gas. During the third quarter of 2019, a decision was made not to proceed with the gas gathering and processing contract, and as a result, the customer reimbursed Blue Mountain Midstream for capital deployed and operating expenses incurred, in addition to paying a success fee for constructing the assets. During the year ended December 31, 2019, Blue Mountain Midstream received a capital reimbursement of approximately $20 million. Blue Mountain Midstream also received approximately $4 million for the success fee and the expense reimbursement, which is included in “(gains) losses on sale of assets and other, net” on the consolidated and combined statement of operations.

Divestitures – Subsequent Events

On January 15, 2020, the Company completed the sale of its interests in non-operated properties located in the Drunkards Wash field in the Uinta Basin (the “Drunkards Wash Asset Sale”). Cash proceeds from the sale of these properties were approximately $4 million (including a deposit of approximately $450,000 received in 2019).

On January 31, 2020, the Company completed the sale of its interest in properties located in the Overton field in East Texas (the “Overton Assets Sale”). Cash proceeds from the sale of these properties were approximately $17 million (including a deposit of approximately $2 million received in 2019). During the year ended December 31, 2019, the Company recorded a noncash impairment charge of approximately $13 million to reduce the carrying value of these assets to fair value.

On February 14, 2020, the Company completed the sale of its interest in properties located in the Personville field in East Texas (the “Personville Assets Sale”). Cash proceeds from the sale of these properties were approximately $29 million (including a deposit of approximately $3 million received in 2019). During the year ended December 31, 2019, the Company recorded a noncash impairment charge of approximately $72 million to reduce the carrying value of these assets to fair value.

On November 20, 2019, the Company signed an agreement to sell its building located in Oklahoma City, Oklahoma for an amended contract price of $21 million. The sale is expected to close in the first quarter of 2020. During the year ended

December 31, 2019, the Company recorded a noncash impairment charge of approximately $5 million to reduce the carrying value of this asset to fair value.

The assets and liabilities associated with the sale of the Oklahoma office building, the Drunkards Wash Asset Sale, the Overton Assets Sale and the Personville Assets Sale are classified as held for sale on the consolidated balance sheet at December 31, 2019. The assets and liabilities associated with the Arkoma Assets Sale are classified as held for sale on the consolidated balance sheet at December 31, 2018.

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, 2019	December 31, 2018
	(in thousands)	
Assets:		
Oil and natural gas properties	$ 17,732	$ 38,083
Other property and equipment	85,798	152
Other	1,243	161
Total assets held for sale	$ 104,773	$ 38,396
Liabilities:		
Asset retirement obligations	$ 33,542	$ 2,700
Other	1,635	1,025
Total liabilities held for sale	$ 35,177	$ 3,725

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

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. 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 and combined statements of operations and were included in the upstream reporting segment.

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 and combined statements of 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 II") 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 II 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 and were classified as discontinued operations on the consolidated and combined statements of operations.

The following are summarized statements of operations information for Roan.

	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

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 and combined 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 and combined statements 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, in 2019 and 2018, the Company received additional contingent payments of approximately $5 million and $7 million, respectively, related to the satisfaction of certain operational requirements resulting in net gains of approximately $4 million and $5 million, respectively. The gains are included in "income (loss) from discontinued operations, net of income taxes" on the consolidated and combined 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
(in thousands)	Ten Months Ended December 31, 2017	Two Months Ended February 28, 2017
Revenues and other	$ 34,096	$ 14,891
Expenses	19,479	13,758
Other income and (expenses)	(3,541)	(1,681)
Income (loss) from discontinued operations before income taxes	11,076	(548)
Income tax expense	4,165	—
Income (loss) from discontinued operations, net of income taxes	$ 6,911	$ (548)

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).

Note 5 – Other Property and Equipment

Other property and equipment consists of the following:

	December 31,	
	2019	2018
	(in thousands)	
Natural gas plant and pipeline	$ 346,861	$ 523,253
Furniture and office equipment	34,797	40,277
Buildings and leasehold improvements	2,230	24,974
Vehicles	2,672	9,011
Land	2,101	6,258
Drilling and other equipment	190	2,471
	388,851	606,244
Less accumulated depreciation	(50,381)	(62,368)
	$ 338,470	$ 543,876

Note 6 – Debt

Fair Value

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

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. In January 2019, in connection with the closing of the Arkoma Assets Sale, the borrowing base was reduced to $385 million. In March 2019, the Company entered into an amendment to the Riviera Credit Facility to, among other things, allow for the issuance of the Mayzure Notes. The amendment did not result in a change to the borrowing base or maximum commitment. In connection with the April 2019 semi-annual redetermination and the closing of the Hugoton non-operated properties in May 2019, the borrowing base was reduced from $385 million to $245 million. In July 2019 in connection with the closing of the Michigan Asset Sale, the borrowing base was reduced from $245 million to $230 million. On September 27, 2019, the Company entered into an amendment to the Riviera Credit Facility to, among other things, extend its maturity date to August 4, 2021. The amendment resulted in a borrowing commitment reduction from $230 million to $90 million, primarily due to asset sales, with the next scheduled borrowing base redetermination to occur on April 1, 2020.

During the year ended December 31, 2019, the Company recorded a finance fee expense of approximately $700,000 related to writing off a portion of the unamortized deferred financing fees due to the reduction of the Riviera Credit Facility borrowing base in September 2019.

As of December 31, 2019, there were no borrowings outstanding under the Riviera Credit Facility and there was approximately $89 million of available borrowing capacity (which includes a reduction of approximately $701,000 for outstanding letters of credit). The maturity date is August 4, 2021.

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.

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 2.00% to 3.00% per annum or the alternate base rate ("ABR") plus an applicable margin ranging from 1.00% to 2.00% 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 excluding Blue Mountain Midstream, 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 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"), providing for an initial borrowing commitment of $200 million. The Blue Mountain Credit Facility together with the Riviera Credit Facility, are referred to as the "Credit Facilities").

Before Blue Mountain Midstream completed certain operational milestones (such completion of the operational milestones, the "Covenant Changeover Date"), a condition to any borrowing was 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 was less than the aggregate amount of the lenders' commitments at such time. The Covenant Changeover Date occurred February 8, 2019, which increased the current borrowing availability to $200 million. Blue Mountain Midstream no longer has 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, 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, 2019, total borrowings outstanding under the Blue Mountain Credit Facility were approximately $70 million and there was approximately $117 million of available borrowing capacity (which includes a $13 million reduction for outstanding letters of credit). The Blue Mountain Credit Facility matures on August 10, 2023. As of January 31, 2020, total borrowings outstanding under the Blue Mountain Credit Facility were approximately $73 million and there was approximately $115 million of available capacity (which includes a $12 million reduction for outstanding letters of credit).

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) a ratio of consolidated EBITDA to consolidated interest expense no less than 2.50 to 1.00, (ii) 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 (iii) 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 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.

Note 7 – Derivatives

Commodity Derivatives

The following table presents derivative positions for the periods indicated as of December 31, 2019:

		2020
Natural gas positions:		
Fixed price swaps (NYMEX Henry Hub):		
Hedged volume (MMMBtu)		10,980
Average price ($/MMBtu)	$	2.82
Oil positions:		
Fixed price swaps (NYMEX WTI):		
Hedged volume (MBbls)		201
Average price ($/Bbl)	$	63.85
Natural gas basis differential positions: (1)		
PEPL basis swaps:		
Hedged volume (MMMBtu)		7,320
Hedge differential	$	(0.45)

(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, 2019, the Company entered into commodity derivative contracts consisting of natural gas fixed price swaps and NGL fixed price swaps for 2019 and oil fixed price swaps and natural gas basis swaps for 2020. In July 2019, in connection with the closing of the Michigan Assets Sale, the Company canceled its MichCon natural gas basis swaps for 2019 and 2020. 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.

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	
	2019	**2018**
	(in thousands)	
Assets:		
Commodity derivatives	$ 7,439	$ 21,851
Liabilities:		
Commodity derivatives	$ 1,243	$ 11,209

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. A majority of 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. 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 $7 million at December 31, 2019. 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,		Ten Months Ended December 31,	Two Months Ended February 28,
	2019	2018	2017	2017
(in thousands)				
Gains (losses) on commodity derivatives	$ 10,091	$ (23,404)	$ 13,533	$ 92,691
Marketing expenses	(6,090)	(1,839)	—	—
Total gains (losses) on commodity derivatives	$ 4,001	$ (25,243)	$ 13,533	$ 92,691

The Company received net cash settlements of approximately $8 million for the year ended December 31, 2019, and paid 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.

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:

	December 31, 2019		
	Level 2	Netting [1]	Total
		(in thousands)	
Assets:			
Commodity derivatives	$ 7,439	$ (156)	$ 7,283
Liabilities:			
Commodity derivatives	$ 1,243	$ (156)	$ 1,087

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

	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

(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 the majority 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:

	Year Ended December 31,	
	2019	2018
	(in thousands)	
Asset retirement obligations at beginning of period	$ 105,259	$ 164,553
Liabilities added from drilling	624	356
Liabilities associated with assets divested	(56,362)	(62,388)
Liabilities associated with assets held for sale	(33,542)	(2,700)
Current year accretion expense	5,521	7,235
Settlements	(1,525)	(2,824)
Revision of estimates	1,522	1,027
Asset retirement obligations at end of period	$ 21,497	$ 105,259

Note 10 – Commitments and Contingencies

On May 11, 2016, the Debtors filed voluntary petitions for relief under Chapter 11 of the Bankruptcy Code in the U.S. Bankruptcy Court for the Southern District of Texas (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 an order approving and confirming the plan (the "Plan") of reorganization of the Debtors. 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.

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.

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, 2019, 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

Lessee

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 $3 million, $10 million, $6 million and $1 million for the years ended December 31, 2019, December 31, 2018, the ten months ended December 31, 2017, and the two months ended February 28, 2017, respectively.

As of December 31, 2019, future minimum lease payments were as follows (in thousands):

2020	$	3,557
2021		1,751
2022		917
2023		—
2024		—
Thereafter		—
	$	6,225

Lessor

At December 31, 2019, the Company leased a building located in Oklahoma to Roan and to a third party under lease agreements that had expiration dates in 2023 and 2024. On November 20, 2019, the Company signed an agreement to sell the building (see Note 4). The sale of the building is expected to close in the first quarter of 2020 and the leases will be terminated effective with the close of the sale. The Company has no other lease agreements for which it is the lessor. We determine if an arrangement is a lease at inception. None of our leases allow the lessee to purchase the leased asset.

Lease income for the years ended December 31, 2019, December 31, 2018, the ten months ended December 31, 2017, and the two months ended February 28, 2017, totaled approximately $2 million, $200,000, $200,000 and $40,000, respectively, not including amounts of variable lease payments that is excluded from the table below as the amounts cannot be reasonably estimated for future periods.

As of December 31, 2019, future minimum lease revenues were as follows (in thousands):

2020	$	1,998
2021		1,998
2022		1,998
2023		517
2024		129
Thereafter		—
	$	6,640

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 and combined 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 and combined 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, 2019, and December 31, 2018, there were 58,168,756 shares and 69,197,284 shares, respectively, of common stock issued and outstanding.

Share Repurchase Program

On July 18, 2019, the Company's Board of Directors increased the share repurchase authorization to $150 million of the Company's outstanding shares of common stock. During the year ended December 31, 2019, the Company repurchased an aggregate of 8,475,514 shares of common stock at an average price of $12.72 per share for a total cost of approximately $108 million. Included in this number are private purchases of 2,380,425 shares of common stock purchased at a discount to market, at an average price of $10.91 for a total cost of approximately $26 million. For the period from January 1, 2020 through February 21, 2020, the Company repurchased 171,107 shares of common stock at an average price of $7.84 for a total cost of approximately $1 million. At February 21, 2020, approximately $23 million was available for share repurchases under the program. Any share repurchases are subject to restrictions in the Riviera Credit Facility.

Tender Offer

On June 13, 2019, the Company's Board of Directors announced the intention to commence a tender offer to purchase $40 million of the Company's common stock. In July 2019, upon the terms and subject to the conditions described in the Offer to Purchase dated June 18, 2019, the Company repurchased an aggregate of 2,666,666 shares of common stock at a price of $15.00 per share for a total cost of approximately $40 million (excluding expenses of approximately $440,000 related to the tender offer).

Dividends

Although the Company paid a one-time cash distribution on December 12, 2019, the Company is not currently paying a regular 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.

Cash Distributions

On November 21, 2019, the Board of Directors of the Company declared a cash distribution of $4.25 per share. A cash distribution totaling approximately $249 million was paid on December 12, 2019, to shareholders of record as of the close of business on December 5, 2019. In addition, approximately $11 million for potential future distributions was recorded in restricted cash at December 31, 2019. In December 2019, distributions payable of approximately $2 million related to outstanding share-based compensation awards was also recorded. These amounts are included in "other accrued liabilities" and "asset retirement obligations and other noncurrent liabilities" on the consolidated balance sheet at December 31, 2019.

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, 2019, 2,337,669 shares were issuable under the Riviera Omnibus Incentive Plan pursuant to outstanding Riviera RSUs, including (i) the Riviera Legacy RSUs, (ii) 293,973 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") and (iii) 1,847,950 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, 2019, up to 1,618,159 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, 214,086 of which the Committee has designated for issuance as Restricted Shares and 89,958 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

Blue Mountain Midstream is governed by its Second Amended and Restated Limited Liability Operating Agreement (as amended, the “BMM LLC Agreement”), which provides for two classes of membership units: Class A Units, of which 100% are held by Linn Holdco II (a wholly owned subsidiary of Riviera) and Class B Units. Pursuant to the BMM LLC Agreement, Blue Mountain Midstream has the authority to issue an unlimited number of Class A Units and up to 58,750 Class B Units. As of December 31, 2019, Blue Mountain Midstream has issued 701,350 Class A Units and no Class B Units.

In July 2018, Blue Mountain Midstream adopted the Blue Mountain Midstream LLC 2018 Omnibus Incentive Plan (as amended, the “BMM Incentive Plan”) pursuant to which employees and consultants 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. The Committee (as defined in the BMM Incentive Plan) has broad authority under the BMM Incentive Plan to, among other things: (i) select participants; (ii) determine the types of awards that participants receive and the number of units 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 units or the award. The aggregate number of units available for issuance under the BMM Incentive Plan matches the maximum number of Class B Units issuable by Blue Mountain Midstream.

As of December 31, 2019, under the BMM Incentive Plan, Blue Mountain Midstream had granted awards that could result in the issuance of 56,594 Class B Units or an equivalent value in cash, at the Board’s discretion. The issued awards include 11,216 restricted security units (“BMM RSUs”) and 22,807 performance stock units (“BMM PSUs”) (45,614 at 200% of target). The BMM RSUs can be paid, at the Board’s discretion, in cash or an equivalent number of Class B Units. Payment for the BMM PSUs only occurs upon the achievement by Blue Mountain Midstream of a certain equity value (subject to certain adjustments) specified in the award agreements. If such equity value is achieved, the recipient of the BMM PSU will receive a number of Class B Units (or an equivalent value in cash, at the Board’s discretion) equal to 50% to 200% of the target number of BMM PSUs held by such individual, as specified in the award agreements.

If any unit option or other unit-based award granted under the BMM Incentive Plan expires, terminates or is canceled for any reason without having been exercised in full, the number of units underlying any unexercised award shall again be available for the purpose of awards under the BMM Incentive Plan. If any restricted units, performance awards or other unit-based awards denominated in units awarded under the BMM Incentive Plan are forfeited for any reason, the number of forfeited units shall again be available for purposes of awards under the BMM Incentive Plan. Any award under the BMM Incentive Plan settled in cash shall not be counted against the maximum unit limitation.

As is customary in incentive plans of this nature, each unit limit and the number and kind of units available under the BMM 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, unit dividends or other similar events that change the number or kind of units outstanding, and extraordinary dividends or distributions of property to Blue Mountain Midstream's unitholders.

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.

As a result of the Company's history of cash settling awards, all unvested share-based compensation awards are liability classified. At December 31, 2019, and December 31, 2018, the Company recognized liabilities of approximately $10 million and $4 million, respectively, related to outstanding share based compensation awards. These amounts are included in "other accrued liabilities" and "asset retirement obligations and other noncurrent liabilities" on the consolidated balance sheets. All cash settlements of liability classified awards are classified as operating activities on the consolidated and combined statements of cash flows. For the year ended December 31, 2019, the Company offered a partial cash conversion option to 118 grantees. Incremental share-based compensation expense related to this modification was not material. 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,		Ten Months Ended December 31,	Two Months Ended February 28,
	2019	2018	2017	2017
(in thousands)				
General and administrative expenses (1)	$ 10,618	$ 131,828	$ 41,285	$ 50,255
Marketing expenses	159	—	—	—
Total share-based compensation expenses	$ 10,777	$ 131,828	$ 41,285	$ 50,255
Income tax benefit	$ —	$ 8,846	$ 9,861	$ 5,170

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

Riviera Restricted Stock Units

The following summarizes Riviera's restricted stock units activity:

	Number of Nonvested Units	Weighted Average Grant-Date Fair Value Per Unit
Nonvested units at December 31, 2018	969,974	$ 15.42
Granted	4,813	$ 14.53
Vested	(436,158)	$ 15.45
Forfeited	(19,925)	$ 16.27
Modified	(28,985)	$ 15.41
Nonvested units at December 31, 2019	489,719	$ 15.35

The total fair value of Riviera RSUs that vested during the year ended December 31, 2019, and during the period from August 7, 2018 through December 31, 2018, was approximately $6 million and $570,000, respectively. As of December 31, 2019, there was approximately $2 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 one year.

During the year ended December 31, 2019, upon vesting of Riviera RSUs and at the election of participants, the Company repurchased 159,863 Riviera RSUs for a total cost of approximately $2 million. In addition, 88,136 shares of common stock were issued to participants (net of statutory tax withholdings) upon vesting of Riviera RSUs.

Blue Mountain Midstream Restricted Security Units

The following summarizes Blue Mountain Midstream's restricted stock unit activity:

	Number of Nonvested Units	Weighted Average Grant-Date Fair Value Per Unit
Nonvested units at December 31, 2018	—	—
Granted	11,399	$ 1,086.29
Vested	3,779	$ 1,086.29
Forfeited	183	$ 1,086.29
Nonvested units at December 31, 2019	7,437	$ 1,086.29

Blue Mountain Midstream issued BMM RSUs for the first time during the year ended December 31, 2019. The total fair value of BMM RSUs that vested during the year ended December 31, 2019, was approximately $4 million. As of December 31, 2019, there was approximately $3 million of unrecognized compensation cost related to nonvested BMM RSUs. The cost is expected to be recognized over a weighted average period of approximately 1.3 years.

Performance Shares

Riviera

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. During the year ended December 31, 2019, there were 51,206 Performance Shares forfeited. As of December 31, 2019, there was approximately $44,000 of unrecognized compensation cost related to nonvested Performance Shares. The cost is expected to be recognized over a weighted average period of approximately 1.5 years. To date, no performance targets have been met.

The fair value of share-based compensation for Riviera 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. For the years ended December 31, 2019, and December 31, 2018, expected volatility of 35% was used in the estimation of fair value of the Performance Share grants. It 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. For the years ended December 31, 2019, and December 31, 2018, the risk-free rate of 1.58% and 2.46% was based on the U.S. constant maturity treasury rate at the time of valuation with maturity corresponding to the expected vesting date. The dividend yield of zero percent was based on historical and projected Company data.

Blue Mountain Midstream

During the year ended December 31, 2019, Blue Mountain Midstream granted 22,807 BMM PSUs (45,614 at 200% of target) (the maximum number of awards available to be earned) with a fair value of approximately $144,000 as of December 31, 2019. During the year ended December 31, 2019, 118 PSUs were forfeited. As of December 31, 2019, there was no unrecognized cost related to nonvested BMM PSUs. The vesting of these awards is determined based on Blue Mountain Midstream's equity value (subject to certain adjustments) at a specified time. To date, no performance targets have been met. The cost is expected to be recognized over the life of the award.

The fair value of share-based compensation for BMM PSU grants was estimated on the balance sheet date using a Monte Carlo pricing model based on certain assumptions. Expected volatility of 30% used in the estimation of fair value of the BMM PSU 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 1.59% was based on the U.S. constant maturity treasury rate at the time of valuation with maturity corresponding to the expected vesting date. The dividend yield of zero percent was based on historical and projected Company data.

Defined Contribution Plan

The Company sponsors a 401(k) defined contribution plan for eligible employees. For the years 2019 and 2018, 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. The Company contributed approximately $2 million, $3 million, $3 million and $812,000 during the years ended December 31, 2019, December 31, 2018, the ten months ended December 31, 2017, and the two months ended February 28, 2017, 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. The diluted earnings per share calculation excludes the Riviera Performance Shares for the years ended December 31, 2019, and December 31, 2018, because no performance targets have been met. The diluted earnings per share calculation excludes approximately 208,000 restricted stock units that were anti-dilutive for the year ended December 31, 2019. No restricted stock units were anti-dilutive for the year ended December 31, 2018. 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
	Year Ended December 31,		Ten Months Ended December 31,	Two Months Ended February 28,
	2019	2018	2017	2017
(in thousands, except per share amounts)				
(Loss) income from continuing operations	$ (297,570)	$ 20,933	$ 345,131	$ 2,587,557
Income (loss) from discontinued operations, net of income taxes	3,824	19,674	90,064	(548)
Net (loss) income	$ (293,746)	$ 40,607	$ 435,195	$ 2,587,009
(Loss) income per share:				
(Loss) income from continuing operations per share – basic and diluted	$ (4.71)	$ 0.28	$ 4.53	$ 33.96
Income (loss) from discontinued operations per share – basic and diluted	$ 0.06	$ 0.26	$ 1.18	$ (0.01)
Net (loss) income per share – basic and diluted	$ (4.65)	$ 0.54	$ 5.71	$ 33.95
Weighted average shares outstanding – basic	63,118	74,935	76,191	76,191
Dilutive effect of unit equivalents	—	425	—	—
Weighted average shares outstanding – diluted	63,118	75,360	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 files 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
	Year Ended December 31,		Ten Months Ended December 31,	Two Months Ended February 28,
	2019	2018	2017	2017
(in thousands)				
Current taxes:				
Federal	$ —	$ 3	$ 7,140	$ —
State	(14)	(117)	2	—
Deferred taxes:				
Federal	111,148	25,816	363,027	—
State	16,725	3,885	15,485	(166)
	$ 127,859	$ 29,587	$ 385,654	$ (166)

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.

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

	Successor			Predecessor
	Year Ended December 31,		Ten Months Ended December 31,	Two Months Ended February 28,
	2019	2018	2017	2017
Federal statutory rate	21.0%	21.0%	35.0%	35.0%
Valuation allowance	(100.5)	—	—	—
Nondeductible compensation	(0.4)	40.6	0.8	—
Federal statutory rate change	—	—	13.8	—
State, net of federal tax benefit	4.8	3.2	2.6	—
Loss excluded from nontaxable entities	—	—	—	(35.0)
Share-based compensation	(0.1)	(8.0)	—	—
Other	(0.1)	1.8	0.6	—
Effective rate	(75.3)%	58.6%	52.8%	—%

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 and combined statements 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,	
	2019	2018
	(in thousands)	
Deferred tax assets:		
Net operating loss carryforwards	$ 60,480	$ 2,503
Share-based compensation	1,674	642
Oil and natural gas properties	105,797	125,021
Other	2,600	925
Less: valuation allowance	(170,551)	—
Total deferred tax assets	$ —	$ 129,091
Total deferred tax liabilities	$ —	$ —

The net deferred tax assets are recorded in “deferred income taxes” on the consolidated balance sheets at December 31, 2019, and December 31, 2018.

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 temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment. During the third quarter of 2019, and for the first time since Riviera’s inception, the Company’s earnings show a cumulative loss which is primarily due to losses generated during 2019. Based on the cumulative loss and projections of future taxable income for the periods in which our deferred tax assets are deductible, the Company recorded a full valuation allowance of approximately $171 million to reduce its federal and state net deferred tax assets to an amount that is more likely than not to be realized. The amount of deferred tax assets considered realizable could materially increase in the future, and the amount of valuation allowance recorded could materially decrease, if estimates of future taxable income are increased.

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, 2019, or December 31, 2018. The tax years 2018 and 2019 remain open to examination for federal and state income tax purposes.

As of December 31, 2019, the Company had approximately $246 million of indefinite lived net operating loss carryforwards for U.S. federal income tax purposes.

Note 16 – Supplemental Disclosures to the Consolidated Balance Sheets and Consolidated and Combined Statements of Cash Flows

"Other current assets" reported on the consolidated balance sheets include the following:

	December 31,	
	2019	2018
	(in thousands)	
Prepaids	$ 11,737	$ 13,493
Receivable from related party	—	8,300
Inventories	1,116	3,720
Other	—	1,208
Other current assets	$ 12,853	$ 26,721

"Other accrued liabilities" reported on the consolidated balance sheets include the following:

	December 31,	
	2019	2018
	(in thousands)	
Accrued compensation	$ 11,314	$ 16,820
Asset retirement obligations (current portion)	1,184	1,445
Deposits	6,111	10,060
Other	8,119	6,149
Other accrued liabilities	$ 26,728	$ 34,474

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 and combined statements of cash flows:

	December 31,	
	2019	2018
	(in thousands)	
Cash and cash equivalents	$ 116,237	$ 18,529
Restricted cash	32,932	31,248
Cash, cash equivalents and restricted cash	$ 149,169	$ 49,777

Supplemental disclosures to the consolidated and combined statements of cash flows are presented below:

	Successor			Predecessor
	Year Ended December 31,		Ten Months Ended December 31,	Two Months Ended February 28,
(in thousands)	2019	2018	2017	2017
Cash payments for interest, net of amounts capitalized	$ 4,232	$ 132	$ 15,165	$ 17,651
Cash payments for income taxes	$ 5	$ —	$ 275	$ —
Cash payments for reorganization items, net	$ 1,236	$ 5,572	$ 11,889	$ 21,571
Noncash investing activities:				
Accrued capital expenditures	$ 10,087	$ 10,438	$ 31,447	$ 22,191

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, 2019, “restricted cash” on the consolidated balance sheet consists of approximately $16 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), approximately $6 million related to deposits and approximately $11 million related to distributions. 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 and approximately $10 million related to deposits.

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 years ended December 31, 2019, and December 31, 2018, the Company’s largest customer represented approximately 19% and 22%, respectively, of the Company’s sales. For the ten months ended December 31, 2017, and the two months ended February 28, 2017, no individual customer exceeded 10% of the Company’s sales.

At December 31, 2019, two customers accounted for 30% of the Company’s trade accounts receivable. At December 31, 2018, one customer accounted for 18% of the Company’s trade accounts receivable.

Note 18 – Related Party Transactions

Private Share Repurchases

In May 2019, the Company purchased at a discount to market, 278,587 shares of common stock from York Select Strategy Master Fund, L.P. at an average price of $13.55 for a total cost of approximately $4 million. In July 2019, the Company purchased at a discount to market, 285,024 shares of common stock from Fir Tree Capital Opportunity Master Fund, L.P. and 39,485 shares of common stock from Fir Tree Capital Opportunity Fund (E), L.P. at an average price of $10.90 for a total cost of approximately $4 million.

Roan Resources LLC

During the periods covered by these financial statements, certain members of the Company's Board of Directors were also members of the board of directors of Roan Resources, Inc. Additionally certain of our principal stockholders were also significant stockholders of Roan Resources, Inc.

Merger with Citizen Energy
In December 2019, stockholders of Roan Resources, Inc. approved an Agreement and Plan of Merger ("Merger") between Roan Resources, Inc. and a subsidiary of Citizen Energy Operating, LLC ("Citizen Operating") under which Roan Resources, Inc., including its subsidiary Roan Resources LLC, became wholly owned subsidiaries of Citizen Operating. The effective date of the Merger was December 6, 2019, and as a result of the Merger, the Company and Roan Resources, Inc. no longer share certain mutual directors and significant stockholders. Consequently future transactions with Roan as of the date of effective date of the Merger will no longer be considered related party transactions.

Related Party Transactions
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. However, on the Reorganization Date, July 25, 2018, the equity interest in Roan was distributed to the Parent and is no longer affiliated with Riviera.

On August 31, 2017, Roan entered into a Master Services Agreement (the "MSA") with Riviera Operating, a subsidiary of the Company, 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 the year ended December 31, 2018, 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.

On March 1, 2018, the Company commenced a lease agreement with Roan to lease office space in the Company's building located in Oklahoma. The lease term was for five years and is recorded in "other, net" on the consolidated and combined statements of operations. On November 20, 2019, the Company signed an agreement to sell the building (see Note 4). The sale of the building is expected to close in the first quarter of 2020 and the leases will be terminated effective with the close of the sale.

On January 31, 2019, a subsidiary of the Company's subsidiary, Blue Mountain Midstream, entered into an agreement to gather, treat or dispose of produced water from Roan. On April 1, 2019, Blue Mountain Midstream began providing services under the agreement. The original term of the agreement is until January 31, 2029. For the year ended December 31, 2019, the Company recorded revenue from Roan of approximately $21 million, included in "marketing revenues" on the consolidated and combined statement of operations.

In addition, Blue Mountain Midstream has an agreement in place with Roan for the purchase and processing of natural gas from certain of Roan's properties. For the years ended December 31, 2019, and December 31, 2018, the Company made natural gas purchases from Roan of approximately $101 million, and $102 million, respectively, included in "marketing expenses" on the consolidated and combined 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, primarily associated with joint interest billings and natural gas purchases, included in "accounts payable and accrued expenses" on the consolidated balance sheet.

On July 17, 2019, a subsidiary of Blue Mountain Midstream entered into a 10-year agreement with Roan to gather Roan's oil in a nine Township area in central Oklahoma.

Note 19 – Segments

The Company has two reporting segments: upstream and Blue Mountain. The upstream reporting segment is engaged in the exploration, development, production, and sale of oil, natural gas, and NGLs. At December 31, 2019, the upstream segment consisted of the Company's properties in East Texas, 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 and produced water services and a crude oil gathering system located in the Merge/SCOOP/STACK play. To assess the performance of the Company's reporting segments, the CODM analyzes field level cash flow, a non-GAAP financial metric. 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," "impairment of assets held for sale and long-lived assets," "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:

	Year Ended December 31, 2019			
	Upstream	Blue Mountain	Not Allocated to Segments	Consolidated
	(in thousands)			
Oil, natural gas and natural gas liquids sales	$ 236,053	$ —	$ —	$ 236,053
Marketing revenues	54,574	159,706	—	214,280
Other revenues	19,355	—	—	19,355
	309,982	159,706	—	469,688
Lease operating expenses	77,719	—	—	77,719
Transportation expenses	64,149	—	—	64,149
Marketing expenses	40,389	120,014	6,248	166,651
Taxes other than income taxes	17,930	1,378	(3,934)	15,374
Total direct operating expenses	200,187	121,392	2,314	323,893
Field level cash flow	$ 109,795	$ 38,314	(2,314)	145,795
Gains on commodity derivatives			10,091	10,091
Other indirect income (expenses)			(325,597)	(325,597)
Loss from continuing operations before income taxes				$ (169,711)

RIVIERA RESOURCES, INC.

NOTES TO CONSOLIDATED AND COMBINED FINANCIAL STATEMENTS - Continued

	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

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,		Ten Months Ended December 31,	Two Months Ended February 28,
(in thousands)	2019	2018	2017	2017
Property acquisition costs:				
Proved	$ —	$ —	$ —	$ —
Unproved	—	—	—	—
Exploration costs	43,122	17,017	103,689	15,153
Development costs	20,335	19,271	96,178	24,256
Asset retirement costs	463	(131)	376	312
Total costs incurred – continuing operations	$ 63,920	$ 36,157	$ 200,243	$ 39,721
Total costs incurred – discontinued operations	$ —	$ —	$ 1,313	$ 269

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,	
	2019	2018
	(in thousands)	
Proved properties	$ 174,845	$ 709,053
Unproved properties	5,462	47,499
	180,307	756,552
Less accumulated depletion and amortization	(35,603)	(93,507)
	$ 144,704	$ 663,045

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
	Year Ended December 31,		Ten Months Ended December 31,	Two Months Ended February 28,
(in thousands)	2019	2018	2017	2017
Revenues and other:				
Oil, natural gas and natural gas liquids sales	$ 236,053	$ 420,102	$ 709,363	$ 188,885
Gains (losses) on commodity derivatives	10,632	(25,109)	13,533	92,691
	246,685	394,993	722,896	281,576
Production costs:				
Lease operating expenses	77,719	120,097	208,446	49,665
Transportation expenses	64,149	83,562	113,128	25,972
Severance taxes, ad valorem taxes	17,930	28,598	47,411	14,851
	159,798	232,257	368,985	90,488
Other costs:				
Exploration costs	5,122	5,178	3,137	93
Depletion and amortization	43,455	58,347	101,360	39,689
Impairment of long-lived assets	208,376	15,697	—	—
(Gains) losses on sale of assets and other, net	(19,259)	(219,237)	(678,200)	18
Income tax benefit	—	(54,588)	(4,640)	(166)
	237,694	(194,603)	(578,343)	39,634
Results of operations – continuing operations	$ (150,807)	$ 357,339	$ 932,254	$ 151,454
Results of operations – discontinued operations	$ —	$ —	$ 142,175	$ 1,246

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, 2019, December 31, 2018, and December 31, 2017, 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, 2019			
	Natural Gas (Bcf)	Oil (MMBbls)	NGL (MMBbls)	Total (Bcfe)
Proved developed and undeveloped reserves:				
Beginning of year	1,260	3.8	55.9	1,618
Revisions of previous estimates	(147)	(0.7)	(1.0)	(157)
Sales of minerals in place	(789)	(1.1)	(50.0)	(1,095)
Extensions and discoveries	29	1.0	0.6	38
Production	(72)	(0.6)	(2.1)	(88)
End of year	281	2.4	3.4	316
Proved developed reserves:				
Beginning of year	1,203	3.7	54.7	1,553
End of year	250	2.3	3.4	284
Proved undeveloped reserves:				
Beginning of year	57	0.1	1.2	65
End of year	31	0.1	—	32

	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

RIVIERA RESOURCES, INC.

SUPPLEMENTAL OIL AND NATURAL GAS DATA (Unaudited) - Continued

	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

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 the year ended December 31, 2017.

Proved reserves from continuing operations decreased by approximately 1,302 Bcfe to approximately 316 Bcfe for the year ended December 31, 2019, from 1,618 Bcfe for the year ended December 31, 2018. The year ended December 31, 2019, includes approximately 157 Bcfe of negative revisions of previous estimates (51 Bcfe of negative revisions due to lower commodity prices as well as 106 Bcfe of negative revisions primarily due to a lack of future committed capital). During the year ended December 31, 2019, several divestitures decreased reserves by approximately 1,095 Bcfe (see Note 4 for additional information of divestitures). In addition, extensions and discoveries, primarily from 61 productive wells drilled during the year, increased proved reserves by 38 Bcfe.

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.

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. See Note 15 for additional information about income taxes.

	December 31,		
	2019	2018	2017
	(in thousands)		
Future cash inflows	$ 860,324	$ 5,167,664	$ 6,730,186
Future production costs	(545,422)	(3,139,932)	(3,810,932)
Future development costs	(122,539)	(337,808)	(486,989)
Future income tax expenses	—	(226,425)	(303,803)
Future net cash flows	192,363	1,463,499	2,128,462
10% annual discount for estimated timing of cash flows	(33,568)	(716,210)	(1,083,331)
Standardized measure of discounted future net cash flows – continuing operations	$ 158,795	$ 747,289	$ 1,045,131
Representative NYMEX prices: (1)			
Natural gas (MMBtu)	$ 2.58	$ 3.10	$ 2.98
Oil (Bbl)	$ 55.69	$ 65.66	$ 51.34

(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.

RIVIERA RESOURCES, INC.

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,		
	2019	2018	2017
	(in thousands)		
Sales and transfers of oil, natural gas and NGL produced during the period	$ (76,255)	$ (187,845)	$ (438,775)
Changes in estimated future development costs	50,184	3,835	(5,276)
Net change in sales and transfer prices and production costs related to future production	(180,824)	(89,459)	400,411
Sales of minerals in place	(542,517)	(206,636)	(685,050)
Extensions, discoveries and improved recovery	38,008	2,683	187,223
Previously estimated development costs incurred during the period	4,696	—	9,704
Net change due to revisions in quantity estimates	(58,991)	(10,022)	(65,935)
Net change in income taxes	124,621	30,637	(155,257)
Accretion of discount	87,191	120,039	169,576
Changes in production rates and other	(34,607)	38,926	(67,247)
Change – continuing operations	$ (588,494)	$ (297,842)	$ (650,626)
Change – discontinued operations	$ —	$ —	$ (232,941)

The data presented should not be viewed as representing the expected cash flow from, or current value of, existing proved reserves since the computations are based on a large number of estimates and 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)			
2019:				
Oil, natural gas and natural gas liquids sales	$ 76,345	$ 66,757	$ 51,029	$ 41,922
Gains (losses) on commodity derivatives	(13,241)	20,249	5,665	(2,582)
Total revenues and other	136,454	145,550	108,054	89,721
Total expenses (1)	144,940	142,337	211,422	177,500
(Gains) losses on sale of assets and other, net	(27,265)	9,885	(7,587)	4,224
Reorganization items, net	—	(424)	(284)	14,115
Income (loss) from continuing operations	12,726	(6,676)	(225,635)	(77,985)
Income (loss) from discontinued operations, net of income taxes	—	—	—	3,824
Net income (loss)	12,726	(6,676)	(225,635)	(74,161)
Income (loss) per share from continuing operations – basic and diluted	$ 0.18	$ (0.10)	$ (3.76)	$ (1.33)
Income (loss) per share from discontinued operations – basic and diluted	$ —	$ —	$ —	$ 0.07
Net income (loss) per share – basic and diluted	$ 0.18	$ (0.10)	$ (3.76)	$ (1.26)

(1) Includes the following expenses: lease operating, transportation, marketing, general and administrative, exploration, depreciation, depletion and amortization, impairment of long-lived assets and assets held for sale and taxes, other than income taxes.

RIVIERA RESOURCES, INC.

SUPPLEMENTAL QUARTERLY DATA (Unaudited) - Continued

	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 from continuing operations – basic and diluted	$ 0.45	$ 0.11	$ (0.43)	$ 0.15
Income (loss) per share from discontinued operations – basic and diluted	$ 0.48	$ (0.02)	$ (0.20)	$ —
Net income (loss) per share – basic and 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.

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, 2019.

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 2019 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, 2020 (the "2020 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	53	President, Chief Executive Officer and Director of Riviera Resources, Inc.
Daniel Furbee	37	Executive Vice President and Chief Operating Officer of Riviera Resources, Inc.
James G. Frew	42	Executive Vice President and Chief Financial Officer of Riviera Resources, Inc.
Darren Schluter	50	Executive Vice President, Finance, Administration and Chief Accounting Officer of Riviera Resources, Inc.
Holly Anderson	42	Executive Vice President and General Counsel of Riviera Resources, Inc.
C. Gregory Harper	55	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.

No family relationships exist among any of the executive officers, directors or director nominees.

Item 11. Executive Compensation

Information required by this item is incorporated by reference to the 2020 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 2020 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, 2019:

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	—	—	1,618,159
Equity compensation plans not approved by security holders	—	—	—
	—	—	1,618,159

Item 13. Certain Relationships and Related Transactions, and Director Independence

Information required by this item is incorporated by reference to the 2020 Proxy Statement.

Item 14. Principal Accounting Fees and Services

Information required by this item is incorporated by reference to the 2020 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+	—	Purchase and Sale Agreement, dated August 28, 2019, by and between Riviera Upstream, LLC and Riviera Operating, LLC, as seller, and Scout Energy Group V LP, as buyer (incorporated by reference to Exhibit 10.1 to Form 10-Q filed November 7, 2019)
2.2+*	—	Purchase and Sale Agreement, dated December 19, 2019, by and between Riviera Operating, LLC, as seller, and Crescent Pass Energy, LLC, as buyer
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++	—	Purchase and Sale Agreement, dated August 28, 2019, by and between Riviera Upstream, LLC and Riviera Operating, LLC, as seller, and Scout Energy Group V LP, as buyer (incorporated by reference to Exhibit 10.1 to Form 10-Q filed November 7, 2019)
10.2	—	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)
10.3	—	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)
10.4	—	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)
10.5	—	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)
10.6	—	Third Amendment to Credit Agreement dated March 12, 2019, 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 10.1 to Form 8-K filed March 14, 2019)
10.7	—	Fourth Amendment to Credit Agreement dated September 27, 2019, 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 10.1 to Form 8-K filed October 3, 2019)

Index to Exhibits - Continued

Exhibit Number		Description
10.8	—	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)
10.9	—	First Amendment to Blue Mountain Midstream LLC Second Amended and Restated Limited Liability Operating Agreement (incorporated by reference to Exhibit 10.3 to Form 10-Q filed May 9, 2019)
10.10†	—	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)
10.11	—	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)
10.12	—	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)
10.13	—	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)
10.14†	—	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)
10.15†	—	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)
10.16†		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)
10.17†	—	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)
10.18†	—	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)
10.19†	—	Riviera Resources, Inc. 2018 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.1 to Form S-8 filed August 7, 2018)
10.20†	—	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)
10.21†	—	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)
10.22†	—	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)
10.23†	—	First Amendment to the Blue Mountain Midstream LLC 2018 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.2 to Form 10-Q filed May 9, 2019)
10.24†	—	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)
10.25†	—	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)
10.26*#	—	Amended and Restated Gas Gathering and Processing Agreement, dated April 1, 2017, between Linn Energy Holdings, LLC and Linn Midstream, LLC
10.27*	—	Release from Dedication to the Amended and Restated Gas Gathering and Processing Agreement, dated October 9, 2018, between Blue Mountain Midstream LLC and Roan Resources LLC
10.28*	—	Amendment No. 1 to the Amended and Restated Gas Gathering and Processing Agreement, dated November 1, 2018, between Blue Mountain Midstream LLC (as successor to Linn Midstream, LLC) and Roan Resources LLC (as successor to Linn Energy Holdings, LLC)
21.1*	—	List of Significant Subsidiaries

Index to Exhibits - Continued

Exhibit Number		Description
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*	—	2019 Report of DeGolyer and MacNaughton
101.INS*	—	Inline XBRL Instance Document
101.SCH*	—	Inline XBRL Taxonomy Extension Schema Document
101.CAL*	—	Inline XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	—	Inline XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	—	Inline XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	—	Inline XBRL Taxonomy Extension Presentation Linkbase Document
104	—	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101).

† Management contract or compensatory plan or agreement.

* Filed herewith.

+ Schedules and similar attachments have been omitted pursuant to Item 601(b)(2) of Regulation S-K. Riviera agrees to furnish a supplemental copy of any omitted schedule or attachment to the SEC upon request.

++ Certain schedules and similar attachments have been omitted pursuant to Item 601(a)(5) of Regulation S-K. The Company agrees to furnish a supplemental copy of any omitted schedule or attachment to the Securities and Exchange Commission upon request.

Certain confidential portions of this exhibit have been redacted pursuant to Item 601(b)(10)(iv) of Regulation S-K. The omitted information is (i) not material and (ii) would likely cause us competitive harm if publicly disclosed. We agree to furnish supplementally an unredacted copy of the exhibit to the Securities and Exchange Commission on its 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 27, 2020	By:	/s/ David B. Rottino David B. Rottino President and Chief Executive Officer
Date: February 27, 2020	By:	/s/ James G. Frew James G. Frew Executive Vice President and Chief Financial Officer
Date: February 27, 2020	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 27, 2020
/s/ James G. Frew James G. Frew	Executive Vice President, Chief Financial Officer (Principal Financial Officer)	February 27, 2020
/s/ Darren R. Schluter Darren R. Schluter	Executive Vice President, Finance, Administration and Chief Accounting Officer (Principal Accounting Officer)	February 27, 2020
/s/ Matthew Bonanno Matthew Bonanno	Director	February 27, 2020
/s/ Joseph A. Mills Joseph A. Mills	Director	February 27, 2020
/s/ C. Gregory Harper C. Gregory Harper	Director	February 27, 2020
/s/ Evan Lederman Evan Lederman	Director	February 27, 2020
Andrew Taylor	Director	February 27, 2020

Exhibit 2.2
Execution Version

PURCHASE AND SALE AGREEMENT

DATED DECEMBER 19, 2019, BY AND BETWEEN

RIVIERA UPSTREAM, LLC AND RIVIERA OPERATING, LLC

AS SELLER,

AND

CRESCENT PASS ENERGY, LLC

AS BUYER

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EXHIBITS AND SCHEDULES

<u>PURCHASE AND SALE AGREEMENT</u>

This PURCHASE AND SALE AGREEMENT (this "Agreement") is made as of December 19, 2019 (the "Execution Date"), by and between Riviera Upstream, LLC, a Delaware limited liability company ("Riviera Upstream"), and Riviera Operating, LLC, a Delaware limited liability company ("Riviera Operating" and, together with Riviera Upstream, the "Seller"), and Crescent Pass Energy, LLC, a Delaware limited liability company ("Buyer"). Seller and Buyer are sometimes hereinafter referred to individually as a "Party" and collectively as the "Parties."

RECITAL

Seller desires to sell, and Buyer desires to purchase, all of Seller's right, title and interest in and to certain oil and gas properties and related assets and contracts, effective as of the Effective Time, for the consideration and on the terms set forth in this Agreement.

AGREEMENT

For and in consideration of the promises contained herein and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties, intending to be legally bound, agree as follows:

ARTICLE 1 DEFINITIONS

For purposes of this Agreement, in addition to other capitalized terms defined in this Agreement, the following terms have the meanings specified or referred to in this Article 1 when capitalized:

"AAA" – the American Arbitration Association.

"Accounting Expert" – as defined in Section 2.05(e).

"AFE" – as defined in Section 3.13.

"Affiliate" – with respect to a Party, any Person directly or indirectly controlled by, controlling, or under common control with, such Party, including any subsidiary of such Party and any "affiliate" of such Party within the meaning of Reg. §240.12b-2 of the Securities Exchange Act of 1934, as amended. As used in this definition, "control" means possession, directly or indirectly, of the power to direct or cause the direction of management, policies, or action through ownership of voting securities, contract, voting trust, or membership in management or in the group appointing or electing management or otherwise through formal or informal arrangements or business relationships. The terms "controlled by," "controlling," and other derivatives shall be construed accordingly.

"Aggregate Defect Deductible" – an amount equal to three percent (3%) of the unadjusted Purchase Price.

"Aggregate Environmental Defect Value" – as defined in Section 11.12.

"Aggregate Title Defect Value" – as defined in Section 11.07.

"Agreement" – as defined in the preamble to this Agreement.

"Allocated Values" – the values assigned among the Assets as set forth on Schedule 2.07.

"Applicable Contracts" – all Contracts to which Seller or any of its Affiliates is a party or is bound to the extent related to any of the Assets and (in each case) that will be binding on Buyer after the Closing, including: communitization agreements; net profits agreements; production payment agreements; area of mutual interest agreements; joint venture agreements; confidentiality agreements; farmin and farmout agreements; bottom hole agreements; crude oil, condensate, and natural gas purchase and sale, gathering, transportation, and marketing agreements; hydrocarbon storage agreements; acreage contribution agreements; operating agreements; balancing agreements; pooling declarations or agreements; unitization agreements; processing agreements; saltwater disposal agreements; facilities or equipment leases; and other similar contracts and agreements, but exclusive of any master service agreements and Contracts to the extent relating to the Excluded Assets.

"Asset Taxes" – ad valorem, property, excise, severance, production, sales, real estate, use, personal property and similar Taxes based upon the operation or ownership of the Assets, the production of Hydrocarbons or the receipt of proceeds therefrom, but excluding, for the avoidance of doubt, Income Taxes and Transfer Taxes.

"Assets" – all of Seller's right, title, and interest in, to, and under the following, without duplication, except to the extent constituting Excluded Assets:

(a) all of the oil and gas leases, subleases, and other leaseholds located in the Designated Area (including the oil and gas leases, subleases and other leaseholds described in Exhibit A), together with (i) any and all other right, title and interest of Seller in and to the leasehold estates created thereby subject to the terms, conditions, covenants and obligations set forth in such leases or Exhibit A (such interest in such leases, the "Leases"), (ii) all related rights and interests in the lands covered by the Leases and any lands pooled or unitized therewith (such lands, the "Lands"), (iii) all tenements, hereditaments, and appurtenances belonging to such Leases and the Lands and (iv) all Royalties applicable to the Leases and the Lands;

(b) any and all oil, gas, water, CO2 and disposal wells located on any of the Lands (such interest in such wells, including the wells set forth in Exhibit B, the "Wells"), and all Hydrocarbons produced therefrom or allocated thereto from and after the Effective Time;

(c) all fee mineral interests in the Designated Area, including those described in Exhibit A-1 (such interest, the "Fee Minerals");

(d) all rights and interests in, under or derived from all communitization, unitization and pooling agreements, declarations and orders in effect with respect to any of the Leases or Wells and the units created thereby (the "Units") (the Leases, the Lands, the Fee Minerals, the Units and the Wells being collectively referred to hereinafter as the "Properties" or individually as a "Property");

(e) to the extent they may be assigned, transferred, or re-issued (in each case without the payment of any fee unless Buyer agrees in writing to pay such fee; *provided*, that Seller shall use commercially reasonable efforts to cause the transfer of all such rights and interests to Buyer) all permits, licenses, allowances, water rights, registrations, consents, certificates, orders, approvals, variances, authorizations, servitudes, easements, rights-of-way, surface leases, other surface interests and surface rights to the extent (i) appurtenant to, or (ii) used or held for use in connection with, the Assets or otherwise relating to the ownership, operation, production, gathering, treatment, processing, storing, sale or disposal of Hydrocarbons or produced water from the Properties or any of the Assets, including those described on Exhibit A-2; *provided* that to the extent any of the foregoing assets are not located within the Designated Area, such assets shall only be included to the extent they are primarily used or primarily held for use in connection with the Properties or other Assets or otherwise relating to the ownership, operation, production, gathering, treatment, processing, storing, sale or disposal of Hydrocarbons or produced water from the Properties or any of the Assets (the "Surface Rights");

(f) all equipment, machinery, tools, inventory, fixtures, improvements and other personal, movable and mixed property located on any of the Properties or other Assets that is used or held for use in connection therewith, including those items listed in Exhibit C, and including well equipment, casing, tubing, pumps, motors, machinery, platforms, rods, tanks, boilers, fixtures, compression equipment, flowlines, pipelines, gathering systems associated with the Wells, manifolds, processing and separation facilities, pads, structures, materials, and other items used or held for use in the operation thereof; *provided* that to the extent any of the foregoing assets are not located within the Designated Area, such assets shall only be included to the extent they are primarily used or primarily held for use in connection with the Properties or other Assets (collectively, the "Personal Property");

(g) the real property described on Exhibit A-3 and any Personal Property located thereon;

(h) all pipelines and gathering systems described on Exhibit A-4 (the "Gathering System");

(i) all surface fee property in the Designated Area, including as described on Exhibit A-5;

(j) the vehicles described on Exhibit D;

(k) all salt water disposal wells and evaporation pits that are located on the Lands;

(l) to the extent assignable (with consent, if applicable, but without the payment of any fee unless Buyer agrees in writing to pay such fee; *provided* Seller shall use commercially reasonable efforts to cause the transfer of all such rights and interests to Buyer), all Applicable Contracts and all rights thereunder, insofar as and only to the extent relating to the Assets;

(m) all Imbalances relating to the Assets;

(n) the Suspense Funds;

(o) originals (if available, and otherwise copies) and copies in digital form (if available) of all of the books, files, records, information and data, whether written or electronically stored, primarily relating to the Assets in Seller's or its Affiliates' possession or control, including: (i) land and title records (including division order files, prospect files, maps, lease records, abstracts of title, title opinions and title curative documents); (ii) Applicable Contract files; (iii) correspondence; (iv) operations, environmental, production, Asset Taxes and accounting records;
(v) facility and well records; and (vi) to the extent assignable (with consent, if applicable, but without the payment of any fee unless Buyer agrees in writing to pay such fee; *provided* Seller shall use commercially reasonable efforts to cause the transfer of all such rights and interests to Buyer), geological and seismic data and information (excluding interpretive data) (collectively, "Records");

(p) all Hydrocarbons produced from or allocated to the Wells in storage or existing in stock tanks, pipelines or plants (including inventory) and upstream of the sales meter as of the Effective Time;

(q) all information technology assets, including desktop computers, laptop computers, servers, networking equipment and any associated peripherals and other computer hardware, computer software, all radio and telephone equipment, SCADA and measurement technology, and other production related mobility devices (such as SCADA controllers), well communication devices, and any other information technology systems and licenses associated with the foregoing, in each case only to the extent such assets and licenses are (i) (A) used or held for use in connection with the Properties, if located within the Designated Area or (B) primarily used or primarily held for use in connection with the Properties, if not located within the Designated Area, (ii) assignable (with consent, if applicable, but without the payment of any fee unless Buyer agrees in writing to pay such fee; *provided* Seller shall use commercially reasonable efforts to cause the transfer of all such rights and interests to Buyer), (iii) located on the Property and (iv) useful in the operation of the Properties as currently operated (the "Production Related IT Equipment");

(r) all (i) trade credits, accounts receivable, notes receivable, take-or-pay amounts receivable, and other receivables and general intangibles, attributable to the Assets with respect to periods of time from and after the Effective Time; and (ii) liens and security interests in favor of Seller or its Affiliates, whether choate or inchoate, under any Legal Requirement or Contract to the extent arising from, or relating to, the ownership, operation, or sale or other disposition on or after the Effective Time of any of the Assets or to the extent arising in favor of Seller or its Affiliates as the operator or non-operator of any Asset;

(s) all rights of Seller and its Affiliates to audit the records of any Person and to receive refunds or payments of any nature, and all amounts of money relating thereto, whether before, on or after the Effective Time, to the extent relating to the obligations assumed by Buyer pursuant to this Agreement or with respect to which Buyer has an obligation to indemnify Seller;

(t) all rights, claims, and causes of action (including warranty and similar claims, indemnity claims, and defenses) of Seller or any of its Affiliates whether arising before, on, or after the Effective Time to the extent such rights, claims, and causes of action directly relate to any of the Assumed Liabilities; and

(u) the Pre-Effective Time Midstream Costs, subject to Seller's right to recoup such costs in accordance with this Agreement.

To the extent that any of the foregoing are used or relate to both the Assets and certain of the Excluded Assets, such as, by way of example but not limitation, ingress and egress rights and road and pipeline easements, such assets or rights shall be jointly owned by Seller, as part of the Excluded Assets, and by Buyer, as part of the Assets.

"Assignment" – the Assignment and Bill of Sale from Seller to Buyer, pertaining to the Assets, substantially in the form attached to this Agreement as Exhibit F.

"Assumed Liabilities" – as defined in Section 2.06.

"Assumed Litigation" – the litigation set forth in Part A of Schedule 3.05.

"Available Employee"– the individuals identified in the Employee Letter as "Available Employees", which individuals are employees of Seller or its Affiliate to whom Buyer or its Affiliate may, but shall not be obligated to, make an offer of employment pursuant to Section 12.03.

"Breach" – a "Breach" of a representation, warranty, covenant, obligation, or other provision of this Agreement or any certificate delivered pursuant to Section 2.04(a)(iv) or Section 2.04(b)(iv) of this Agreement shall be deemed to have occurred if there is or has been any inaccuracy in or breach of, or any failure to perform or comply with, such representation, warranty, covenant, obligation, or other provision.

"Business Day" – any day other than a Saturday, Sunday, or any other day on which commercial banks in the State of Texas are authorized or required by law or executive order to close; *provided, however* any day during the Dead Period will not be considered a Business Day.

"Buyer" – as defined in the preamble to this Agreement.

"Buyer Group" – Buyer and its Affiliates, and their respective Representatives.

"Buyer's Closing Documents" – as defined in Section 4.02(a).

"Casualty Loss" – as defined in Section 11.14.

"Closing" – the closing of the Contemplated Transactions.

"Closing Date" – as defined in Section 2.03.

"COBRA" – as defined in Section 12.04.

"Code" – the Internal Revenue Code of 1986, as amended.

"Complete Remediation" – with respect to an Environmental Defect, a remediation or cure of such Environmental Defect which has been completed in accordance with the Lowest Cost Response and is in compliance with the requirements of applicable Environmental Law.

"Confidentiality Agreement" – that certain confidentiality agreement dated as of July 15, 2019 by and between Crescent Pass Energy, LLC and Riviera Resources, Inc.

"Consent" – any approval, consent, ratification, waiver, or other authorization (including any Governmental Authorization) from any Person that is required to be obtained in connection with the execution or delivery of this Agreement or the consummation of the Contemplated Transactions.

"Contemplated Transactions" – all of the transactions contemplated by this Agreement, including:

(a) the sale of the Assets by Seller to Buyer;

(b) the performance by the Parties of their respective covenants and obligations under this Agreement; and

(c) Buyer's acquisition, ownership, and exercise of control over the Assets. "Continuing Employee" – an Available Employee who accepts an offer of employment made pursuant to Section 12.03, passes Buyer's or its Affiliate's applicable and lawful pre- employment screening processes, and becomes employed by Buyer or one of its Affiliates pursuant to the process set forth in Section 12.03.

"Contract" – any written or oral contract, agreement or any other legally binding arrangement, but excluding, however, any Lease, easement, right-of-way, permit or other instrument creating or evidencing an interest in the Assets or any real or immovable property related to or used in connection with the operations of any Assets.

"Controlled Group Liabilities" – any and all liabilities of Seller or any of its ERISA Affiliates (i) under Title IV of ERISA, (ii) under Sections 206(g), 302 or 303 of ERISA, (iii) under Sections 412, 430, 431, 436 or 4971 of the Code and (iv) as a result of the failure to comply with the continuation of coverage requirements of Section 601 et seq. of ERISA and Section 4980B of the Code.

"Cure" – as defined in Section 11.06(a)(i).

"Damages" – any and all claims, demands, payments, charges, judgments, assessments, losses, liabilities, damages, penalties, fines, expenses, costs, fees, settlements, and deficiencies, including any attorneys' fees, legal, and other costs and expenses suffered or incurred therewith.

"Dead Period" – the period of time beginning on the Execution Date and ending January 5, 2020.

"De Minimis Environmental Defect Cost" – Fifty Thousand Dollars ($50,000.00).

"De Minimis Title Defect Cost" – with respect to each Well, the lesser of Fifty Thousand Dollars ($50,000.00) and fifty percent (50%) of the Allocated Value ascribed to such Well in Schedule 2.07.

"Deed" – the Deed from Seller to Buyer, pertaining to the applicable surface fee interests and Fee Minerals included in the Assets, substantially in the form attached to this Agreement as Exhibit G.

"Defect Notice Date" – as defined in Section 11.04.

"Defensible Title" – title of Seller with respect to the Wells and the Gathering System that, as of the Effective Time and the Closing Date and subject to the Permitted Encumbrances, is
(i) deducible of record or (ii) evidenced by unrecorded instruments or elections made or delivered pursuant to any joint operating agreement, pooling agreement or unitization agreement, and substantially similar contracts:

(a) with respect to each currently producing formation for each Well (in each case, subject to any reservations, limitations or depth restrictions described in Exhibit B for such Well), entitles Seller to receive not less than the Net Revenue Interest set forth in Exhibit B for such producing formation, except (i) for decreases in connection with those operations in which Seller or its successors or assigns may from and after the Execution Date and in accordance with the terms of this Agreement elect to be a non-consenting co-owner, (ii) decreases resulting from the establishment or amendment from and after the Execution Date of pools or units in accordance with this Agreement, (iii) decreases required to allow other Working Interest owners to make up past underproduction or pipelines to make up past under deliveries described in Schedule 3.09, or
(iv) as set forth in Exhibit B;

(b) with respect to each currently producing formation for each Well (in each case, subject to any reservations, limitations or depth restrictions described in Exhibit B for such Well), obligates Seller to bear not more than the Working Interest set forth in Exhibit B for such producing formation, except (i) increases resulting from contribution requirements with respect to defaulting co-owners from and after the Execution Date under applicable operating agreements,
(ii) increases to the extent that such increases are accompanied by a proportionate increase in Seller's Net Revenue Interest, or (iii) as set forth in Exhibit B; and

(c) is free and clear of all Encumbrances.

"Deposit Amount" – an amount equal to ten percent (10%) of the unadjusted Purchase Price (including any interest accrued thereon).

"Designated Area" – the area described in Schedule 1.1 as the "Designated Area."

"Dispute Notice" – as defined in Section 2.05(e).

"Disputed Matter" – as defined in Section 11.15(a).

"Effective Time" – July 1, 2019, at 12:01 a.m. local time at the location of the Assets.

"Employee Letter" – as defined in Section 12.03(a).

"Employee Start Date" – the date of an Available Employee's commencement of employment with Buyer or its Affiliate.

"Encumbrance" – any defect, charge, burden, encumbrance, equitable interest, privilege, lien, mortgage, deed of trust, production payment, option, pledge, collateral assignment, security interest, or other arrangement substantially equivalent to any of the foregoing, including, with respect to the Gathering System, any restrictions on any lessee's use of the surface in connection with the Hydrocarbon operations that would affect such use or operations (as currently used by Seller or its Affiliates).

"Environmental Condition" – any event occurring or condition existing on or prior to the Execution Date as a result of the operation of an Asset that presently requires remediation under, or that represents a current violation of, any Environmental Law, other than any such event or condition to the extent caused by or relating to the presence of NORM (so long as such presence does not constitute a current violation of Environmental Laws) or that was disclosed in writing to Buyer prior to the Execution Date.

"Environmental Defect" – an Environmental Condition discovered by Buyer or its Representatives as a result of any environmental diligence conducted by or on behalf of Buyer pursuant to Section 11.09 of this Agreement.

"Environmental Defect Cure Period" – as defined in Section 11.11(a).

"Environmental Defect Notice" – as defined in Section 11.10.

"Environmental Defect Value" – with respect to each Environmental Defect, the amount of the Lowest Cost Response to cure such Environmental Defect.

"Environmental Law" – any applicable Legal Requirement in effect as of the Execution Date relating to pollution or the protection of the environment, natural resources, or occupational health and safety, including, but not limited to, those Legal Requirements relating to the storage, handling, and use of Hazardous Materials and those Legal Requirements relating to the generation, processing, treatment, storage, transportation, disposal or other management thereof. The term "Environmental Law" does not include good or desirable operating practices or standards that may be voluntarily employed or adopted by other oil and gas well operators or recommended, but not required, by a Governmental Body.

"Environmental Liabilities" – all costs, Damages, expenses, liabilities, obligations, and other responsibilities arising from or under either Environmental Laws or Third Party claims relating to the environment or Hazardous Materials, and which relate to the Assets or the ownership or operation of the same.

"ERISA" – the Employee Retirement Income Security Act of 1974, as amended.

"ERISA Affiliate" – with respect to any entity, any other entity, trade or business that is a member of a group described in Section 414(b), (c), (m) or (o) of the Code or Section 4001(b)(1) of ERISA that includes such first entity, or that is a member of the same "controlled group" as such first entity pursuant to Section 4001(a)(14) of ERISA.

"Escrow Account" – as defined in Section 2.02.

"Escrow Agent" – JPMorgan Chase Bank, N.A.

"Escrow Agreement" – as defined in Section 2.02.

"Excess Credit Support Costs" – as defined in Section 7.08.

"Excluded Assets" – with respect to Seller, (a) all of Seller's corporate minute books, financial records and other business records that relate to Seller's business generally (including the ownership and operation of the Assets); (b) except to the extent related to any Assumed Liabilities, all trade credits, all accounts, all receivables of Seller and all other proceeds, income or revenues of Seller attributable to the Assets that are attributable to any period of time prior to the Effective Time (other than the Suspense Funds); (c) except to the extent related to any Assumed Liabilities all claims and causes of action of Seller or its Affiliates that are attributable to periods of time prior to the Effective Time (including claims for adjustments or refunds); (d) except to the extent related to any Assumed Liabilities subject to Section 11.14, all rights and interests of Seller (i) under any policy or agreement of insurance or indemnity, (ii) under any bond, or (iii) to any insurance or condemnation proceeds or awards arising, in each case, from acts, omissions or events or damage to or destruction of property; (e) except to the extent of an upward adjustment to the Purchase Price, Seller's rights with respect to all Hydrocarbons produced and sold from the Assets with respect to all periods prior to the Effective Time; (f) all claims of Seller or any of its Affiliates for refunds of, rights to receive funds from any Governmental Body, or loss carry forwards or credits with respect to any and all Seller Taxes; (g) all information technology assets, including desktop computers, laptop computers, servers, networking equipment and any associated peripherals and other computer hardware, computer software, all radio and telephone equipment, SCADA and measurement technology, and other production-related mobility devices (such as SCADA controllers), well communication devices, and any other information technology systems to the extent such assets are not Production Related IT Equipment; (h) except to the extent related to any Assumed Liabilities, all rights, benefits and releases of Seller or its Affiliates under or with respect to any Contract that are attributable to periods of time prior to the Effective Time; (i) all of Seller's proprietary computer software, patents, trade secrets, copyrights, names, trademarks, logos and other intellectual property; (j) all documents and instruments of Seller that may be protected by an attorney-client privilege or any attorney work product doctrine; (k) all data set that cannot be disclosed to Buyer as a result of confidentiality arrangements under existing written agreements; *provided* Seller shall use commercially reasonable efforts to cause the transfer of all such rights and interest to Buyer; (l) all audit rights or obligations of Seller for which Seller bears responsibility arising under any of the Applicable Contracts or otherwise with respect to any period prior to the Effective Time or to any of the Excluded Assets, except for any Imbalances assumed by Buyer or to the extent related to any Assumed Liabilities; (m) Seller's interpretations of any geophysical or other seismic and related technical data and information relating to the Assets, including Seller's reserve reports; (n) documents prepared or received by Seller or its Affiliates with respect to (i) lists of prospective purchasers for such transactions compiled by Seller, (ii) bids submitted by other prospective purchasers of the Assets, (iii) analyses by Seller or its Affiliates of any bids submitted by any prospective purchaser, (iv) correspondence between or among Seller, its Representatives, and any prospective purchaser other than Buyer, and (v) correspondence between Seller or any of its Representatives with respect to any of the bids, the prospective purchasers or the transactions contemplated by this Agreement; (o) except for field offices described on Exhibit A-3, any offices, office leases and any personal property located in or on such offices or office leases; (p) other than any tract of land described in the Surface Deeds listed on Exhibit A-5, any fee simple surface estate; (q) any fee mineral interests that are not Fee Minerals, and any right to production revenues associated therewith; (r) a copy of all Records; (s) any Contracts that constitute master services agreements or similar contracts; (t) any Hedge Contracts; (u) any debt instruments; (v) any of Seller's assets other than the Assets; (w) all personnel files and related records for Available Employees; (x) any leases, rights and other assets specifically listed in Exhibit E; (y) all Seller Benefit Plans; and (z) the Specified Receivables.

"Excluded Seller-Operated Assets" – as defined in Section 11.11(b).

"Execution Date" – as defined in the preamble to this Agreement.

"Expert" – as defined in Section 11.15(b).

"Expert Decision" – as defined in Section 11.15(d).

"Expert Proceeding Notice" – as defined in Section 11.15(a).

"Fee Minerals" – as set forth in paragraph (c) of the definition of "Assets".

"Final Amount" – as defined in Section 2.05(e).

"Final Settlement Date" – as defined in Section 2.05(e).

"Final Settlement Statement" – as defined in Section 2.05(e).

"Financing" – as defined in Section 6.05.

"Fundamental Representations" – those representations set forth in Sections 3.01, 3.02, 3.03 and 3.06.

"GAAP" – generally accepted accounting principles in the United States as interpreted as of the Execution Date.

"Gathering System" – as set forth in paragraph (h) of the definition of "Assets."

"Governmental Authorization" – any approval, consent, license, permit, registration, variance, exemption, waiver, or other authorization issued, granted, given, or otherwise made available by or under the authority of any Governmental Body or pursuant to any Legal Requirement.

"Governmental Body" – any (a) nation, state, county, city, town, village, district, or other jurisdiction of any nature; (b) federal, state, local, municipal, foreign, or other government; (c) governmental or quasi-governmental authority of any nature (including any governmental agency, branch, department, official, or entity and any court or other tribunal); (d) multi-national organization or body; or (e) body or authority exercising, or entitled to exercise, any administrative, arbitration, executive, judicial, legislative, police, regulatory, or taxing authority or power of any nature.

"Group" – either Buyer Group or Seller Group, as applicable.

"Hazardous Materials" – any (a) chemical, constituent, material, pollutant, contaminant, substance, or waste that is regulated by any Governmental Body, or may form the basis of liability, under any Environmental Law, in each case due to its dangerous or deleterious properties or characteristics; (b) petroleum, Hydrocarbons, or petroleum products; (c) friable asbestos and asbestos-containing materials; and (d) polychlorinated biphenyls.

"Hedge Contract" – any Contract to which Seller or any of its Affiliates is a party with respect to any swap, forward, put, call, floor, cap, collar option, future or derivative transaction or option or similar agreement, whether exchange traded, "over-the-counter" or otherwise, involving, or settled by reference to, one or more rates, currencies, commodities (including Hydrocarbons), equity or debt instruments or securities, or economic, financial or pricing indices or measures of economic, financial or pricing risk or value or any similar transaction or any combination of these transactions.

"Hydrocarbons" – oil and gas and other hydrocarbons (including condensate) produced or processed in association therewith (whether or not such item is in liquid or gaseous form), or any combination thereof, and any minerals produced in association therewith.

"Imbalances" – over-production or under-production or over-deliveries or under-deliveries with respect to Hydrocarbons produced from or allocated to the Assets, regardless of whether such over-production or under-production or over-deliveries or under-deliveries arise at the wellhead, pipeline, gathering system, transportation system, processing plant, or other location, including any imbalances under gas balancing or similar agreements, imbalances under production handling agreements, imbalances under processing agreements, imbalances under the Leases, and imbalances under gathering or transportation agreements.

"Income Tax" – any income or franchise Taxes based upon, measured by, or calculated with respect to gross or net income, gross or net profits, capital, or similar measures (or multiple bases, including corporate, franchise, business and occupation, business license, or similar Taxes, if gross or net income, gross or net profits, capital, or a similar measure is one of the bases on which such Tax is based, measured, or calculated).

"Individual Claim Threshold" – as defined in Section 10.05(a).

"Instruments of Conveyance" – the Assignment and Deed. **Except for the special warranty of Defensible Title by, through and under Seller and its Affiliates contained therein, the Instruments of Conveyance shall be without warranty of title, whether express, implied, statutory, or otherwise, it being understood that Buyer shall have the right to conduct pre-Closing title due diligence as described in Article 11, and that the rights and remedies set forth in Article 11 and such special warranty shall be Buyer's sole rights and remedies with respect to title.**

"Knowledge" – an individual will be deemed to have "Knowledge" of a particular fact or other matter if such individual is actually aware of such fact or other matter, without any duty of due inquiry. Seller will be deemed to have "Knowledge" of a particular fact or other matter if any of the following individual(s) has Knowledge of such fact or other matter: David B. Rottino, Seller's President and Chief Executive Officer; Daniel Furbee, Executive Vice President and Chief Operating Officer; James G. Frew, Executive Vice President and Chief Financial Officer; Darren Schluter, Executive Vice President, Finance, Administration and Chief Accounting Officer; Cato Clark Vice President, Land; and Andrew Ray, Vice President, Operations for the Assets. Buyer will be deemed to have "Knowledge" of a particular fact or other matter if any of the following individual(s) has Knowledge of such fact or other matter: Tyler Fenley, Buyer's Chief Executive Officer.

"Lands" – as set forth in paragraph (a) of the definition of "Assets".

"Leases" – as set forth in paragraph (a) of the definition of "Assets".

"Legal Requirement" – any federal, state, local, municipal, foreign, international, or multinational law, Order, constitution, ordinance, or rule, including rules of common law, regulation, statute, treaty, or other legally enforceable directive or requirement.

"Lowest Cost Response" – the response required or allowed under Environmental Laws in effect on the date this Agreement is executed that addresses and resolves (for current and future use in the same manner as currently used) the identified Environmental Condition in the most cost- effective manner (considered as a whole) as compared to any other response that is required or allowed under but nevertheless complies with Environmental Laws. The Lowest Cost Response shall include taking no action, leaving the condition unaddressed, periodic monitoring or the recording of notices in lieu of remediation, if such responses are allowed under Environmental Laws and approved by the applicable Governmental Body. The Lowest Cost Response shall not include any costs or expenses relating to the assessment, remediation, removal, abatement, transportation and disposal of any (i) asbestos or asbestos containing materials or (ii) NORM (except to the extent such costs are presently required and necessary to bring the applicable Asset into compliance with Environmental Laws).

"Management Services Agreement" – as defined in Section 11.11(b).

"Material Adverse Effect" – any change, inaccuracy, effect, event, result, occurrence, condition or fact (for the purposes of this definition, each, an "event") (whether foreseeable or not and whether covered by insurance or not) that has had or would be reasonably likely to have, individually or in the aggregate with any other event or events, (i) an adverse effect on the ownership, operation or financial condition of the Assets, taken as a whole, in an aggregate amount equal to or exceeding fifteen percent (15%) of the unadjusted Purchase Price or (ii) a material adverse effect on the ability of Seller to consummate the transactions contemplated by this Agreement and perform its obligations hereunder; *provided*, *however*, that the term "Material Adverse Effect" shall not include material adverse effects resulting from (i) entering into this Agreement or the announcement of the Contemplated Transactions; (ii) general changes in Hydrocarbon prices; (iii) any action or omission of Seller taken in accordance with the terms of this Agreement or with the prior written consent of Buyer; (iv) any effect resulting from general changes in industry, economic or political conditions in the United States; (v) civil unrest, any outbreak of disease or hostilities, terrorist activities or war or any similar disorder; (vi) acts or failures to act of any Governmental Body (including any new regulations related to the upstream industry), except to the extent arising from Seller's action or inaction; (vii) acts of God, including hurricanes and storms; (viii) any reclassification or recalculation of reserves in the ordinary course of business; (ix) natural declines in well performance; (x) general changes in Legal Requirements, in regulatory policies, or in GAAP; (xi) changes in the stock price of Buyer; or (xii) matters that are cured (without cost to Buyer) or no longer exist by the earlier of Closing and the termination of this Agreement.

"Material Contracts" – as defined in Section 3.10.

"Net Revenue Interest" – with respect to any Well, the interest in and to all Hydrocarbons produced, saved and sold from or allocated to such Well (in each case, limited to the applicable currently producing formation for any such Well, and subject to any reservations, limitations or depth restrictions described in Exhibit B for any such Well), after satisfaction of all other Royalties.

"Non-Recourse Person" – as defined in Section 13.18.

"NORM" – naturally occurring radioactive material.

"Order" – any award, decision, injunction, judgment, order, ruling, subpoena, or verdict entered, issued, made, or rendered by any court, administrative agency, or other Governmental Body or by any arbitrator.

"Organizational Documents" – (a) the articles or certificate of incorporation and the bylaws of a corporation; (b) the articles of organization and resolutions of a limited liability company; (c) the certificate of limited partnership and limited partnership agreement of a limited partnership; and (d) any amendment to any of the foregoing.

"Outside Date" – as defined in Section 9.01(d).

"Party" or "Parties" – as defined in the preamble to this Agreement.

"Permits" – all environmental and other governmental (whether federal, state, local or tribal) certificates, consents, permits (including conditional use permits), licenses, Orders, authorizations, franchises and related instruments or rights solely relating to the ownership, operation or use of the Assets.

"Permitted Encumbrance" – any of the following:

(a) the terms and conditions of all Leases and Contracts if the net cumulative effect of such Leases and Contracts does not (i) materially interfere with the operation or use of any of the Assets (as currently operated and used), (ii) operate to reduce the Net Revenue Interest of Seller with respect to any Well as to the currently producing formation to an amount less than the Net Revenue Interest set forth in Exhibit B for such Well for such currently producing formation, or (iii) obligate Seller to bear a Working Interest with respect to any Well in any amount greater than the Working Interest set forth in Exhibit B for such Well (unless the Net Revenue Interest for such Well is greater than the Net Revenue Interest set forth in Exhibit B, in the same or greater proportion as any increase in such Working Interest) (items (i) through (iii) above, the "Subject Burdens"); *provided*, *however*, that any drilling obligations included in Leases will be considered

Permitted Encumbrances so long as Seller is not in breach of such obligations; any Preferential Purchase Rights, Consents and similar agreements;

(b) excepting circumstances where such rights have already been triggered prior to the Effective Time, rights of reassignment arising upon final intention to abandon or release the Assets;

(c) liens for Taxes not yet due or delinquent, or, if delinquent, that are being contested in good faith by appropriate proceedings by or on behalf of Seller in the ordinary course of business and are set forth on Schedule PE;

(d) all rights to consent by, required notices to, filings with, or other actions by Governmental Bodies in connection with the conveyance of the Leases, if the same are customarily sought and received after the Closing;

(e) all Legal Requirements and all rights reserved to or vested in any Governmental Body (i) to control or regulate any Asset in any manner; (ii) by the terms of any right, power, franchise, grant, license or permit, or by any provision of law, to terminate such right, power, franchise, grant, license or permit or to purchase, condemn, expropriate or recapture or to designate a purchaser of any of the Assets; (iii) to use such property in a manner which does not materially impair the use of such property for the purposes for which it is currently owned and operated; or
(iv) to enforce any obligations or duties affecting the Assets to any Governmental Body with respect to any right, power, franchise, grant, license or permit;

(f) rights of a common owner of any interest currently held by Seller and such common owner as tenants in common or through common ownership to the extent that the same does not result in any Subject Burden;

(g) easements, conditions, covenants, restrictions, servitudes, permits, rights-of-way, surface leases, and other rights in the Assets for the purpose of operations, facilities, roads, alleys, highways, railways, pipelines, transmission lines, transportation lines, distribution lines, power lines, telephone lines, removal of timber, grazing, logging operations, canals, ditches, reservoirs and other like purposes, or for the joint or common use of real estate, rights-of-way, facilities and equipment, which, in each case, do not result in any Subject Burden;

(h) vendors, carriers, warehousemen's, repairmen's, mechanics', workmen's, materialmen's, construction or other like liens arising by operation of law in the ordinary course of business or incident to the construction or improvement of any property in respect of obligations which are (i) not yet due or (ii) being contested in good faith by appropriate proceedings by or on behalf of Seller as set forth on Schedule PE;

(i) Encumbrances created under Leases or any joint operating agreements applicable to the Assets or by operation of law in respect of obligations that are (i) not yet due or (ii) being contested in good faith by appropriate proceedings by or on behalf of Seller as set forth on Schedule PE;

(j) any Encumbrance affecting the Assets that is discharged by Seller or waived in writing (or expressly deemed to be waived) by Buyer pursuant to the terms of this Agreement at or prior to Closing;

(k) the Assumed Litigation;

(l) defects based solely on assertions that Seller's files lack information (including title opinions);

(m) lessor's royalties, overriding royalties, production payments, net profits interests, reversionary interests and similar burdens if the net cumulative effect of such burdens does not result in any Subject Burden;

(n) defects or irregularities of title (i) as to which the relevant statute(s) of limitations or prescription would bar any attack or claim against Seller's title; (ii) to the extent arising out of lack of evidence of, or other defects with respect to, authorization, execution, delivery, acknowledgment, or approval of any instrument in Seller's chain of title absent reasonable evidence of an actual claim of superior title from a Third Party attributable to such matter; (iii) to the extent consisting of the failure to recite marital status or omissions of heirship proceedings in documents; (iv) resulting from lack of survey, unless a survey is expressly required by applicable Legal Requirements; (v) resulting from failure to record releases of liens, production payments, or mortgages that have expired by their own terms or the enforcement of which are barred by the applicable statute(s) of limitations or prescription; (vi) resulting from or related to probate proceedings or the lack thereof that have been outstanding for five (5) years or more; (vii) based on a gap in Seller's chain of title (A) so long as such gap does not provide a Third Party with a superior claim or (B) unless Buyer affirmatively shows such gap to exist in such records by an abstract of title, title opinion or landman's title chain; (viii) consisting of the lack of a lease amendment or consent authorizing pooling or unitization, *provided*, that: (A) the applicable Well has been permitted by the Texas Railroad Commission or other applicable Governmental Body,
(B) the applicable Lease pooled or allocated to such Well does not expressly prohibit both pooling and allocation wells by the lessee as to including all or a portion of such Lease in a proposed pooled or allocation well proration unit permitted by the Texas Railroad Commission and (C) solely as to allocation wells, the allocation of Hydrocarbons produced from such Well among such Lease or tracts is based upon the length of the "as drilled" horizontal wellbore open for production, the total length of the horizontal wellbore, or other methodology that is intended to reasonably attribute to each such Lease or leasehold tract its share of such production; or (ix) that have been cured by prescription or limitations;

(o) Imbalances set forth on Schedule 3.09;

(p) calls on Hydrocarbon production under existing Contracts set forth on Schedule 3.10;

(q) any matters expressly referenced or set forth on Exhibit A or Exhibit B;

(r) mortgages on the lessor's interest under a Lease, whether or not subordinate to such Lease, that have expired on their own terms or the enforcement of which are barred by applicable statute(s) of limitations or prescription; and

(s) any maintenance of uniform interest provision in an operating agreement if waived in writing with respect to the Contemplated Transactions by the party or parties having the right to enforce such provision or if the violation of such provision would not give rise to the unwinding of the sale of the affected Asset from Seller to Buyer or give rise to a claim for Damages against Buyer.

"Person" – any individual, firm, corporation (including any non-profit corporation), general or limited partnership, limited liability company, joint venture, estate, trust, association, organization, labor union, or other entity or Governmental Body.

"Personal Property" – as set forth in paragraph (f) of the definition of "Assets".

"Phase I Environmental Site Assessment" – a Phase I environmental property assessment and limited compliance review of the Assets that satisfies the basic assessment requirements set forth under the current ASTM International Standard Practice for Environmental Site Assessments (Designation E1527-13 or E2247-16) or any other visual site assessment or limited compliance review of records, reports or documents.

"Post-Closing Date" – as defined in Section 2.05(e).

"Pre-Effective Time Midstream Costs" – all accounts receivable owed to Seller as a result of gathering, processing or other midstream related costs, expenses or charges which arose prior to the Effective Time.

"Preferential Purchase Right" – any right or agreement that enables any Person to purchase or acquire any Asset or any interest therein or portion thereof as a result of or in connection with the execution or delivery of this Agreement or the consummation of the Contemplated Transactions.

"Preliminary Amount" – the Purchase Price, adjusted as provided in Section 2.03, based upon the best information available at the time of the Closing.

"Preliminary Settlement Statement" – as defined in Section 2.03.

"Proceeding" – any proceeding, action, arbitration, audit, hearing, investigation, request for information, litigation, or suit (whether civil, criminal, administrative, investigative, or informal) commenced, brought, conducted, or heard by or before, or otherwise involving, any Governmental Body or arbitrator.

"Production Related IT Equipment" – as set forth in paragraph (q) of the definition of "Assets".

"Property" or "Properties" – as set forth in paragraph (d) of the definition of "Assets".

"Property Costs" – all operating expenses (including utilities, payroll for field employees, costs of insurance and rentals), capital expenditures (including rentals, options, other lease maintenance payments and costs of acquiring equipment (other than equipment that constitutes Excluded Assets or Retained Assets)), respectively, actually paid to a Third Party and incurred in

the ordinary course of business to the extent attributable to the use, operation, and ownership of the Assets, but excluding any cost, expense or Damages attributable to (a) personal injury or death, property damage, torts, breach of contract, or violation of any Legal Requirement, (b) obligations relating to the abandonment or plugging of Wells, dismantling or decommissioning facilities, closing pits and restoring the surface around such Wells, facilities and pits prior to Closing,
(c) Retained Liabilities, curing Title Defects, Environmental Defects or Breaches of this Agreement by Seller and the matters covered by the indemnities in Section 10.02, (d) obligations with respect to Imbalances, (e) obligations to pay Royalties or other interest owners revenues or proceeds relating to the Assets whether or not held in suspense, including Suspense Funds, (f) broker fees and other property acquisition costs, (g) any Asset Taxes, Taxes or Transfer Taxes and
(h) claims for indemnification or reimbursement from any Third Party with respect to costs of the types described in the preceding clauses (a) through (h), whether such claims are made pursuant to contract or otherwise.

"Purchase Price" – as defined in Section 2.02.

"Records" – as set forth in paragraph (o) of the definition of "Assets".

"Representative" – with respect to a particular Person, any director, officer, manager, employee, agent, consultant, advisor, or other representative of such Person, including legal counsel, accountants, and financial advisors.

"Required Consent" – any Consent with respect to which (a) there is a provision within the applicable instrument that such Consent may be withheld in the sole and absolute discretion of the holder or words of similar effect, or (b) there is provision within the applicable instrument expressly stating that an assignment in violation thereof (i) is void or voidable, (ii) triggers the payment of specified liquidated damages, or (iii) causes termination of the applicable Assets to be assigned or words of similar effect. For the avoidance of doubt, "Required Consent" does not include any Consents of Governmental Bodies that are customarily obtained after Closing.

"Retained Assets" – any rights, titles, interests, assets, and properties that are originally included in the Assets under the terms of this Agreement, but that are subsequently excluded from the Assets or sale under this Agreement pursuant to the terms of this Agreement at any time before or after the Closing.

"Retained Employee-Related Liabilities" – all Damages and obligations that arise out of or in connection with (a) any Seller Benefit Plan or any other employee benefit or compensation plan, program or arrangement sponsored, maintained or contributed to by Seller or any of its ERISA Affiliates or to which Seller or any of its ERISA Affiliates was obligated to contribute at any time on or prior to the Closing, including all Controlled Group Liabilities; (b) the employment or engagement of any individual by Seller or any of its Affiliates who does not become a Continuing Employee, including all Damages and obligations arising at any time with respect to any act or omission or other practice arising from or relating to an employment or independent contractor relationship or the termination thereof (other than any Damages that arise out of or in connection with Buyer's or its Affiliate's hiring practices or failure to hire any individual); and (c) the employment or engagement of a Continuing Employee to the extent existing or arising on or prior to such Continuing Employee's Employee Start Date.

“Retained Liabilities” – Damages, liabilities and obligations arising out of (a) the disposal or transportation prior to Closing of any Hazardous Materials generated or used in connection with the ownership or operation of the Assets and taken from the Assets to any offsite location;

(b) personal injury (including death) claims attributable to Seller’s or its Affiliate’s ownership, management or operation of the Assets prior to the Closing; (c) failure to properly pay or the improper payment of, in accordance with the terms of any Lease, Contract or applicable Legal Requirement, all Royalties and other working interest amounts (in each case) with respect to the Assets that are payable by Seller or any of its Affiliates and attributable to Seller’s ownership, management or operation of the Assets prior to the Effective Time; (d) any civil or administrative fines or penalties and criminal sanction imposed on Seller or its Affiliates by any Governmental Body in connection with any pre-Closing violation of, or failure to comply with, any Legal Requirements, including Environmental Laws, (e) any Retained Employee-Related Liabilities, except as set forth in Article 12; (f) Seller Taxes; (g) any Excluded Assets; (h) the Retained Litigation; (i) the gross negligence or willful misconduct of Seller or its Affiliates with respect to the ownership or operation of the Assets prior to the Closing Date or (j) Pre-Effective Time Midstream Costs including any recoupment thereof (regardless of whether such recoupment was undertaken by or paid directly to Seller or Buyer); *provided* that, from and after the date that is

(1) twenty-four (24) months following the Closing Date with respect to clause (b) and (2) thirty- six (36) months following the Closing Date with respect to clauses (a) and (c), all Damages and obligations arising out of the matters described in such respective clause shall no longer be Retained Liabilities and shall be deemed Assumed Liabilities.

“Retained Litigation” – (a) any matter set forth in Part B of Schedule 3.05 (or that should have been, but is not, set forth in Part B of Schedule 3.05) and (b) any matter related to the bankruptcy case of Linn Energy, LLC and its subsidiaries that commenced on May 11, 2016 and concluded on September 27, 2018.

“Riviera Operating” – as defined in the preamble to this Agreement.

“Riviera Upstream” – as defined in the preamble to this Agreement.

“Royalties” – royalties, overriding royalties, production payments, carried interests, net profits interests, reversionary interests, options, back-in interests, contractual rights to production and other burdens upon, measured by or payable out of production, excluding, for the avoidance of doubt, any Taxes.

“Scheduled Closing Date” – as defined in Section 2.03.

“Seller” – as defined in the preamble to this Agreement.

“Seller Benefit Plan” – (a) each “employee benefit plan,” as such term is defined in Section 3(3) of ERISA; and (b) each personnel policy, equity option plan, equity appreciation rights plan, restricted equity plan, phantom equity plan, equity based compensation arrangement, bonus plan or arrangement, incentive award plan or arrangement, vacation policy, severance pay plan, policy or agreement, deferred compensation agreement or arrangement, executive compensation or supplemental income arrangement, consulting agreement, employment agreement, retention agreement, change of control agreement and each other employee benefit plan, agreement, arrangement, program, practice or understanding which is not described in clause (a) above, in each case, sponsored, maintained or contributed to by Seller or any of its Affiliates or with respect to which Seller or any of its Affiliates has, or could have, any direct or indirect liability.

"Seller Closing Documents" – as defined in Section 3.02(a).

"Seller Group" – Seller and its Affiliates, and their respective Representatives.

"Seller Party" – each of Riviera Upstream and Riviera Operating individually.

"Seller Taxes" – (i) all Income Taxes imposed by any applicable laws on Seller any of its direct or indirect owners or Affiliates, or any combined, unitary, or consolidated group of which any of the foregoing is or was a member, (ii) Asset Taxes and Transfer Taxes allocable to Seller pursuant to Section 13.02(b) (taking into account, and without duplication of, such Asset Taxes effectively borne by Seller as a result of (a) the adjustments to the Purchase Price made pursuant to Section 2.05(d)(i)(B) or Section 2.05(d)(ii)(B), as applicable, and (b) any payments made from one Party to the other in respect of Asset Taxes pursuant to Section 13.02(b)), (iii) any Taxes imposed on or with respect to the Excluded Assets and/or the Retained Assets, and (iv) any and all other Taxes imposed on or with respect to the ownership or operation of the Assets or the production of Hydrocarbons or the receipt of proceeds therefrom for any Tax period (or portion of any Straddle Period) ending before the Effective Time.

"Specified Receivables" – all accounts receivable owed to Seller as operator of any Wells to satisfy previous overpayments by Seller to Third Parties and the right to recoup the same out of proceeds of production in respect of such Wells; *provided*, *however*, for the avoidance of doubt, "Specified Receivables" shall not include the Pre-Effective Time Midstream Costs.

"Straddle Period" – any Tax period beginning before and ending after the Effective Time.

"Subject Burdens" – as defined in paragraph (a) of the definition of "Permitted Encumbrance."

"Surface Rights" – as defined in paragraph (e) of the definition of "Assets."

"Suspense Funds" – proceeds of production and associated penalties and interest in respect of any of the Wells that are payable to any Third Party and are being held in suspense by Seller as the operator of such Wells.

"Tax" or "Taxes" – (a) any and all federal, state, provincial, local, foreign and other taxes, levies, fees, imposts, duties, assessments, unclaimed property and escheat obligations and other governmental charges of a similar nature imposed by any Governmental Body, including income, profits, franchise, alternative or add-on minimum, gross receipts, environmental, registration, withholding, employment, social security (or similar), disability, occupation, ad valorem, property, value added, capital gains, sales, goods and services, use, real or personal property, capital stock, license, branch, payroll, estimated, unemployment, severance, compensation, utility, stamp, premium, windfall profits, transfer, gains, production and excise taxes, and customs duties, together with any interest, penalties, fines or additions thereto and (b) any liability in respect of any item described in clause (a) above that arises by reason of a contract, assumption or transferee or successor liability.

"Tax Allocation" – as defined in Section 2.07.

"Tax Returns" – any and all reports, returns, declarations, claims for refund, elections, disclosures, estimates, information reports or returns or statements supplied or required to be supplied to a Governmental Body in connection with Taxes, including any schedule or attachment thereto or amendment thereof.

"Third Party" – any Person other than a Party or an Affiliate of a Party.

"Threatened" – a claim, Proceeding, dispute, action, or other matter will be deemed to have been "Threatened" if any demand or statement has been made in writing to a Party or any of its officers, directors, or employees that would lead a prudent Person to conclude that such a claim, Proceeding, dispute, action, or other matter is likely to be asserted, commenced, taken, or otherwise pursued in the future.

"Title Benefit" – as defined in Section 11.08(a).

"Title Benefit Notice" – as defined in Section 11.08(a).

"Title Benefit Properties" – as defined in Section 11.08(a).

"Title Benefit Value" – as defined in Section 11.08(a).

"Title Defect" – any Encumbrance, defect or other matter that causes Seller not to have Defensible Title in and to the Wells without duplication; *provided*, that the following shall not be considered Title Defects:

(a) defects arising out of the lack of corporate or other entity authorization unless Buyer provides affirmative evidence that such corporate or other entity action was not authorized and results in another Person's actual and superior claim of title to the relevant Assets;

(b) defects based on a gap in Seller's chain of title in the county or parish records, unless such gap provides a Third Party with a superior claim or Buyer affirmatively shows such gap to exist in such records by an abstract of title, title opinion or landman's title chain, which documents (if any) shall be included in a Title Defect Notice (for the avoidance of doubt, a non- certified, cursory or limited title chain will satisfy this requirement);

(c) defects based solely upon the failure to record any federal or state Lease or any assignments of interest in such Lease in any county real property record; *provided* that failures to record any federal or state Lease or any assignments of interest in such Lease in the applicable public record may be defects if the failure to so record cannot be cured by filing the same after the Effective Time in the applicable public record;

(d) defects arising from any change in applicable Legal Requirement after the Execution Date;

(e) defects arising from any prior oil and gas lease taken more than fifteen (15) years prior to the Effective Time relating to the lands covered by a Lease not being surrendered of record, unless Buyer provides affirmative evidence that a Third Party is conducting operations on, or asserting ownership of, the Assets, sufficient proof of which shall include written communication by a party with record title to such prior lease asserting the validity of the lease;

(f) defects that affect only which non-Seller Person has the right to receive royalty payments rather than the amount or the proper payment of such royalty payment;

(g) defects based solely on the lack of information in Seller's files;

(h) defects arising from a mortgage (that is not in default or subject to foreclosure) encumbering the oil, gas or mineral estate of any lessor that would customarily be accepted in taking oil and gas leases or purchasing undeveloped oil and gas leases and for which the lessee would not customarily seek a subordination of such lien to the oil and gas leasehold estate prior to conducting drilling activities on the Lease unless a notice of default or complaint of foreclosure has been duly filed or any similar action taken by the mortgagee thereunder and in such case such mortgage has not been subordinated to the Lease applicable to such Asset;

(i) defects based solely upon the title of record being held in the name of Linn Energy Holdings, LLC, Linn Operating, Inc. or Linn Operating, LLC, *provided* Seller provides certified copies of name changes or certificates of conversion, as appropriate, showing the relationship between these entities and the Sellers; and

(j) defects or irregularities that would customarily be waived by a reasonably prudent owner or operator of oil and gas properties in the same geographic area where the Assets are located.

"Title Defect Cure Period" – as defined in Section 11.06(a).

"Title Defect Notice" – as defined in Section 11.04.

"Title Defect Property" – as defined in Section 11.04.

"Title Defect Value" – as defined in Section 11.05.

"Transaction Documents" – collectively, this Agreement, the Escrow Agreement, the Seller's Closing Documents, the Buyer's Closing Documents and those other documents executed and delivered by the Parties pursuant to or in connection with this Agreement.

"Transfer Tax" – all transfer, documentary, sales, purchase, use, stamp, registration and similar Taxes (but excluding Income Taxes) and all required documentary, filing and recording fees and expenses arising out of, or in connection with, the transfer of the Assets under this Agreement.

"Transition Period" – the "Term" as defined in the TSA.

"Treasury Regulations" – the final or temporary regulations promulgated by the U.S. Department of the Treasury under the Code.

"TSA" – the Transition Services Agreement between Riviera Operating, LLC and Buyer, in substantially the same form as Exhibit I.

"Units" – as set forth in paragraph (d) of the definition of "Assets".

"Wells" – as set forth in paragraph (b) of the definition of "Assets".

"Working Interest" – with respect to any Well, the interest in and to such Well that is burdened with the obligation to bear and pay costs and expenses of maintenance, development and operations on or in connection with such Well (in each case, limited to the applicable currently producing formation and subject to any reservations, limitations or depth restrictions described in Exhibit B, but without regard to the effect of any Royalties or other burdens).

ARTICLE 2
SALE AND TRANSFER OF ASSETS; CLOSING

2.01 **Assets**. Subject to the terms and conditions of this Agreement, at the Closing, Seller shall sell and transfer (or shall cause to be sold and transferred) the Assets to Buyer, and Buyer shall purchase, pay for, and accept the Assets from Seller.

2.02 **Purchase Price; Deposit**. Subject to any adjustments that may be made under Section 2.05, the purchase price for the Assets will be $34,000,000.00 (the "Purchase Price"). Contemporaneously with the execution of this Agreement, Buyer has deposited by wire transfer in same day funds into an escrow account (the "Escrow Account") established pursuant to the terms of a mutually agreeable Escrow Agreement (the "Escrow Agreement") an amount equal to the Deposit Amount. The Deposit Amount shall be held by the Escrow Agent, and if the Closing occurs, on or before the Closing Date, the Parties shall execute and deliver to the Escrow Agent a joint instruction letter directing the Escrow Agent to release the Deposit Amount to Seller at Closing, which Deposit Amount shall be applied as a credit toward the Preliminary Amount as provided in Section 2.04(b)(i). If this Agreement is terminated prior to the Closing in accordance with Section 9.01, then the provisions of Section 9.02 shall apply and the distribution of the Deposit Amount shall be governed in accordance therewith.

2.03 **Closing; Preliminary Settlement Statement**. The Closing shall take place at the offices of Seller at 600 Travis Street, Suite 1700, Houston, Texas 77002 on or before February 14, 2020 (unless mutually agreed upon by the Parties) (the "Scheduled Closing Date"), or if all conditions to Closing under Article 7 and Article 8 have not yet been satisfied or waived, within ten (10) Business Days, exclusive of any Business Days within the Dead Period, after such conditions have been satisfied or waived, subject to the provisions of Article 9 (the date the Closing actually occurs, the "Closing Date"). Subject to the provisions of Articles 7, 8, and 9, failure to consummate the purchase and sale provided for in this Agreement on the date and time and at the place determined pursuant to this Section 2.03 shall not result in the termination of this Agreement and shall not relieve either Party of any obligation under this Agreement. Not later than five (5) Business Days prior to the Closing Date, Seller will deliver to Buyer a statement setting forth in reasonable detail Seller's good faith determination of the Preliminary Amount (the "Preliminary

Settlement Statement”). Within two (2) Business Days after its receipt of the Preliminary Settlement Statement, Buyer may submit to Seller in writing any objections or proposed changes thereto and Seller shall consider all such objections and proposed changes in good faith. The estimate agreed to by Seller and Buyer, or, absent such agreement, delivered in the Preliminary Settlement Statement by Seller in accordance with this Section 2.03, will be the Preliminary Amount to be paid by Buyer to Seller at the Closing.

2.04 **Closing Obligations**. At the Closing:

(a) Each Seller Party shall deliver (and execute and acknowledge, as appropriate), or cause to be delivered by the appropriate Person (and executed and acknowledged, as appropriate), to Buyer:

(i) the Instruments of Conveyance in the appropriate number for recording in the real property records where the Assets are located, together with any assignments, on appropriate forms, of state and federal Leases comprising portions of the Assets, if any, in sufficient counterparts necessary to facilitate filing with the applicable Governmental Bodies;

(ii) possession of the Assets (except the Suspense Funds, which shall be conveyed to Buyer by way of one or more adjustments to the Purchase Price as provided in Section 2.05(d)(ii)(E));

(iii) an executed counterpart of a joint instruction letter directing the Escrow Agent to release an amount equal to the Deposit Amount (less any amounts retained in the Escrow Account pursuant to Section 11.06 or Section 11.11) to Seller;

(iv) a certificate, in substantially the form set forth in Exhibit H executed by an officer of such Seller Party, certifying on behalf of such Seller Party that the conditions to Closing set forth in Sections 7.01 and 7.02 have been fulfilled;

(v) a certificate of non-foreign status of each Seller (or, if such Seller is classified as an entity disregarded as separate from another Person for U.S. federal income purposes, of such Person) meeting the requirements of Treasury Regulation Section 1.1445-2(b)(2), in form and substance satisfactory to the Buyer, duly executed, and dated as of the Closing Date;

(vi) an executed counterpart of the Preliminary Settlement Statement;

(vii) for each Well operated by Seller or its Affiliates on the Closing Date, such regulatory documentation on forms prepared by Buyer (with assistance from Seller) as necessary to designate Buyer as operator of such Well; *provided* that Seller may elect to provide such forms to Buyer at the end of the Transition Period;

(viii) a recordable release in form and substance reasonably acceptable to Buyer of any trust, mortgages, financing statements, fixture filings and security agreements, in each case, securing indebtedness for borrowed money made by such Seller Party or its Affiliates affecting the Assets;

(ix) an executed counterpart of the TSA, in substantially the same form as Exhibit I; and

(x) such documents as Buyer or counsel for Buyer may reasonably request, including letters-in-lieu of transfer order to Third Party operators and purchasers of production from the Wells (which shall be prepared and provided by Buyer (with assistance from Seller) and reasonably satisfactory to Seller); *provided* that Seller may elect to provide such documents to Buyer at the end of the Transition Period;

(b) Buyer shall deliver (and execute and acknowledge, as appropriate) to Seller:

(i) the Preliminary Amount (less the Deposit Amount) by wire transfer to the accounts specified by Seller in written notices given by Seller to Buyer at least two (2) Business Days prior to the Closing Date;

(ii) an executed counterpart of a joint instruction letter directing the Escrow Agent to release an amount equal to the Deposit Amount (less any amounts retained in the Escrow Account pursuant to Section 11.06 or Section 11.11) to Seller;

(iii) the Instruments of Conveyance in the appropriate number for recording in the real property records where the Assets are located, together with any assignments, on appropriate forms, of state and federal Leases comprising portions of the Assets, if any, in sufficient counterparts necessary to facilitate filing with the applicable Governmental Bodies;

(iv) a certificate, in substantially the form set forth in Exhibit H executed by an officer of Buyer, certifying on behalf of Buyer that the conditions to Closing set forth in Sections 8.01 and 8.02 have been fulfilled;

(v) an executed counterpart of the Preliminary Settlement Statement;

(vi) evidence of replacement bonds, guarantees, and other sureties pursuant to Section 6.03(a) and evidence of such other authorizations and qualifications as may be necessary for Buyer to own the Assets;

(vii) for each Well operated by Seller or its Affiliates on the Closing Date, such regulatory documentation on forms prepared by Buyer (with assistance from Seller) as necessary to designate Buyer as operator of such Well;

(viii) an executed counterpart of the TSA, in substantially the same form as Exhibit I; and

(ix) such other documents as Seller or counsel for Seller may reasonably request, including letters-in-lieu of transfer order to Third Party operators and purchasers of production from the Wells (which shall be prepared and provided by Buyer (with assistance from Seller) and reasonably satisfactory to Seller).

2.05 **Allocations and Adjustments**. If the Closing occurs:

(a) Buyer shall be entitled to all production and products from or attributable to the Assets from and after the Effective Time and the proceeds thereof, and to all other income, proceeds, receipts, and credits earned with respect to the Assets on or after the Effective Time, and shall be responsible for (and entitled to any refunds with respect to) all Property Costs attributable to the Assets and incurred from and after the Effective Time. Seller shall be entitled to all production and products from or attributable to the Assets prior to the Effective Time and the proceeds thereof, and shall be responsible for (and entitled to any refunds with respect to) all Property Costs attributable to the Assets and incurred prior to the Effective Time. "Earned" and "incurred," as used in this Agreement, shall be interpreted in accordance with generally accepted accounting principles and Council of Petroleum Accountants Society (COPAS) standards. Seller shall be entitled to all proceeds that constitute the Pre-Effective Time Midstream Costs.

(b) Without limiting the allocation of costs and receipts set forth in Section 2.05(a), for each Well operated by Seller or its Affiliate and excluding the recoupment of the Pre-Effective Time Midstream Costs, Buyer shall retain all overhead charges and rates received by Seller or its Affiliate in its capacity as "Operator" under any Third Party operating agreement or COPAS accounting procedure attributable to such Well for time periods between the Effective Time and the last day of the Transition Period.

(c) For purposes of allocating revenues, production, proceeds, income, accounts receivable, and products under this Section 2.05, liquid Hydrocarbons produced into storage facilities will be deemed to be "from or attributable to" the Wells when they pass through the pipeline connecting into the storage facilities into which they are run, and gaseous Hydrocarbons and liquid Hydrocarbons produced into pipelines will be deemed to be "from or attributable to" the Wells when they pass through the receipt point sales meters on the pipelines through which they are transported. In order to accomplish the foregoing allocation of production, the Parties shall rely upon the gauging, metering, and strapping procedures which were conducted by Seller on or about the Effective Time and, unless demonstrated to be inaccurate, shall utilize reasonable interpolating procedures to arrive at an allocation of production when exact gauging, metering, and strapping data is not available on hand as of the Effective Time. Asset Taxes shall be prorated in accordance with Section 13.02(b). Seller shall provide to Buyer evidence of any meter readings and any gauging and strapping procedures conducted on or about the Effective Time in connection with the Assets, together with all data necessary to support any estimated allocation, for purposes of establishing the adjustment to the Purchase Price pursuant to Section 2.05(d).

(d) The Purchase Price shall be, without duplication,

(i) increased by the following amounts:

(A) the aggregate amount of proceeds received by Buyer from the sale of Hydrocarbons produced from and attributable to the Assets during any period prior to the Effective Time to which Seller is entitled under Section 2.05(a) (net of any (x) Royalties and (y) Third Party gathering, processing, transportation and other similar midstream costs and other proceeds received by Buyer with respect to the Assets for which Seller would otherwise be entitled under Section 2.05(a));

(B) the amount of all Asset Taxes allocable to Buyer pursuant to Section 13.02(b) but paid or economically borne by Seller;

(C) the aggregate amount of all non-reimbursed Property Costs that have been paid by Seller that are attributable to the ownership and operation of the Assets after the Effective Time (including the amount of any prepayments of Property Costs made by Seller that are set forth on Schedule 2.05(d)(i)(C) and applied against operations conducted after the Effective Time);

(D) the amount of any other upward adjustment specifically provided for in this Agreement or mutually agreed upon by the Parties;

(E) to the extent that proceeds for such volumes have not been received by Seller, an amount equal to the value of all Hydrocarbons attributable to the Assets in storage or existing in stock tanks, pipelines or plants (including inventory but excluding tank bottoms, linefill and linepack) as of the Effective Time;

(F) if applicable, the amount, if any, of Imbalances in favor of Seller, *multiplied by* \$2.28 per Mcf, or, to the extent that the Applicable Contracts provide for cash balancing that will be received by Buyer at or after Closing, the actual cash balance amount determined to be due to Seller as of the Effective Time; and

(ii) decreased by the following amounts:

(A) the aggregate amount of proceeds received by Seller from the sale of Hydrocarbons produced from and attributable to the Assets from and after the Effective Time to which Buyer is entitled under Section 2.05(a) (net of any (x) Royalties and (y) gathering, processing, transportation and other midstream costs and other proceeds received by Seller with respect to the Assets for which Buyer would otherwise be entitled under Section 2.05(a));

(B) theamountofallAssetTaxesallocabletoSellerpursuantto Section 13.02(b) but paid or economically borne by Buyer;

(C) the aggregate amount of all downward adjustments pursuant to Article 11;

(D) the aggregate amount of all non-reimbursed Property Costs that are attributable to the ownership or operation of the Assets prior to the Effective Time (excluding prepayments with respect to any period after the Effective Time) and paid by Buyer;

(E) the amount of the Suspense Funds;

(F) the amount of any other downward adjustment specifically provided for in this Agreement or mutually agreed upon by the Parties; and

(G) if applicable, the amount, if any, of Imbalances owing by Seller, *multiplied by* $2.28 per Mcf, or, to the extent that the Applicable Contracts provide for cash balancing that will be paid by Buyer at or after Closing, the actual cash balance amount determined to be owed by Seller as of the Effective Time.

(e) As soon as practicable after the Closing, but no later than ninety (90) days following the Closing Date, Seller shall prepare and submit to Buyer a statement (the "Final Settlement Statement") setting forth each adjustment or payment which was not finally determined as of the Closing Date and showing the values used to determine such adjustments to reflect the final adjusted Purchase Price based on actual credits, charges, receipts and other items before and after the Effective Time where available. Seller shall use its commercially reasonable efforts to supply available documentation in reasonable detail to support any credit, charge, receipt or other item, including all documentation used by Seller in the preparation of such statement. On or before thirty (30) days after receipt of the Final Settlement Statement, Buyer shall deliver to Seller a written report containing any changes that Buyer proposes be made to the Final Settlement Statement and an explanation of any such changes and the reasons therefor together with any supporting information (the "Dispute Notice"). During such thirty (30)-day period, Buyer shall be given reasonable access to Seller's and its Affiliates' books and records relating to the matters required to be accounted for in the Final Settlement Statement to allow Buyer to conduct an audit and review of such items. Any changes not included in the Dispute Notice shall be deemed waived. If Buyer fails to timely deliver a Dispute Notice to Seller containing changes Buyer proposes to be made to the Final Settlement Statement, the Final Settlement Statement as delivered by Seller will be deemed to be mutually agreed upon by the Parties and will be final and binding on the Parties. Upon delivery of the Dispute Notice, the Parties shall undertake to agree with respect to any disputed amounts identified therein by the date that is one hundred twenty (120) days after the Closing Date (the "Post-Closing Date"). Except for Title Defect and Environmental Defect adjustments pursuant to Section 2.05(d)(ii)(C), which shall be subject to the arbitration provisions of Section 11.15, if the Parties are still unable to agree regarding any item set forth in the Dispute Notice as of the Post-Closing Date, then the Parties shall submit to the independent accounting firm of KPMG (the "Accounting Expert") a written notice of such dispute along with reasonable supporting detail for the position of Buyer and Seller, respectively, and the Accounting Expert shall finally determine such disputed item in accordance with the terms of this Agreement. The Accounting Expert shall act as an expert and not an arbitrator. In determining the proper amount of any adjustment to the Purchase Price related to the disputed item, the Accounting Expert shall not increase the Purchase Price more than the increase proposed by Seller nor decrease the Purchase Price more than the decrease proposed by Buyer, as applicable. The decision of such Accounting Expert shall be binding on the Parties, and the fees and expenses of such Accounting Expert shall be borne one-half (1/2) by Seller and one-half (1/2) by Buyer. The date upon which all adjustments and amounts in the Final Settlement Statement are agreed to (or deemed agreed to) or fully and finally determined by the independent accounting firm as set forth in this Section 2.05(e) shall be called the "Final Settlement Date," and the final adjusted Purchase Price shall be called the "Final Amount." If the Final Amount is more than the Preliminary Amount, Buyer shall pay to Seller an amount equal to the Final Amount, *minus* the Preliminary Amount; or the Final Amount is less than the Preliminary Amount, Seller shall pay to Buyer an amount equal to the Preliminary Amount, *minus* the Final Amount. Such payment shall be made within five (5) Business Days after the Final Settlement Date by wire transfer of immediately available funds to the accounts specified pursuant to wire instructions delivered in advance by Seller or Buyer, as

applicable. From and after the Final Settlement Date, until the one (1) year anniversary of the Closing Date, (i) should any Party or its Affiliates receive any proceeds or other income to which another Party or its Affiliates is entitled hereunder, then such Party shall promptly disclose and remit (or cause to be promptly remitted) the same to the Party who is entitled to such amounts and
(ii) should Buyer pay any costs or expenses for which Seller or its Affiliates is responsible hereunder, then Seller shall reimburse Buyer for such costs and expenses paid by Buyer.

2.06 **Assumption**. Without limiting Buyer's rights, and Seller's obligations under the Transaction Documents (including Article 10 of this Agreement), if the Closing occurs, from and after the Closing Date, Buyer shall assume, fulfill, perform, pay and discharge the following liabilities arising from, based upon, related to, or associated with the Assets and only to the extent not (i) related to the Excluded Assets or (ii) constituting Retained Liabilities (collectively, the "Assumed Liabilities"): any and all Damages and obligations, known or unknown, allocable to the Assets prior to, at, or after the Effective Time, including any and all Damages and obligations:
(a) attributable to or resulting from the use, maintenance, ownership or operation of the Assets, regardless whether arising before, at or after the Effective Time, except for Property Costs which shall have been accounted for as provided under Section 2.05; (b) imposed by any Legal Requirement or Governmental Body relating to the Assets, (c) for plugging, abandonment, decommissioning, and surface restoration of the Assets, including oil, gas, injection, water, or other wells and all surface facilities; (d) subject to Buyer's rights and remedies set forth in Article 10 and Article 11 and the special warranty of Defensible Title set forth in the Instruments of Conveyance, attributable to or resulting from lack of Defensible Title to the Assets;
(e) attributable to the Suspense Funds, to the extent actually received by Buyer (or for which a reduction to the Purchase Price was made); (f) attributable to the Imbalances; (g) subject to Buyer's rights and remedies set forth in Article 11, attributable to or resulting from all Environmental Liabilities relating to the Assets; (h) related to the conveyance of the Assets to Buyer at Closing (including, subject to Section 11.02 and Section 11.03, arising from the conveyance thereof without consent or in violation of a Preferential Purchase Right); (i) Asset Taxes and Transfer Taxes allocable to Buyer pursuant to Section 13.02(b) (taking into account, and without duplication of, such Asset Taxes effectively borne by Buyer as a result of the adjustments to the Purchase Price made pursuant to Section 2.05(d)(i)(B) or Section 2.05(d)(ii)(B), as applicable, and any payments made from one Party to the other in respect of Asset Taxes pursuant to Section 13.02(b)) and attributable to the Leases and the Applicable Contracts; and
(j) attributable to the Assumed Litigation. Buyer acknowledges that: (i) the Assets have been used in connection with the exploration for, and the development, production, treatment, and transportation of, Hydrocarbons; (ii) spills of wastes, Hydrocarbons, produced water, Hazardous Materials, and other materials and substances may have occurred in the past or in connection with the Assets; (iii) there is a possibility that there are currently unknown, abandoned wells, plugged wells, pipelines, and other equipment on or underneath the property underlying the Assets; (iv) it is the intent of the Parties that, subject to the terms of the Transaction Documents, all liability associated with the above matters described in clauses (i) through (iii) of this sentence as well as any responsibility and liability to decommission or plug such wells (including the Wells) in accordance with all Legal Requirements be passed to Buyer effective as of the Effective Time and that Buyer shall assume all responsibility and liability for such matters and all claims and demands related thereto; (v) the Assets may contain asbestos, Hazardous Materials, or NORM; (vi) NORM may affix or attach itself to the inside of wells, materials, and equipment as scale or in other forms;
(vii) wells, materials, and equipment located on the Assets may contain NORM; (viii) and special

procedures may be required for remediating, removing, transporting, and disposing of asbestos, NORM, Hazardous Materials, and other materials from the Assets. From and after the Closing, regardless of whether arising prior to, at, or after the Effective Time, subject to Seller's indemnity obligations under Section 10.02 (subject to the limitations and restrictions in Article 10), Buyer shall assume, with respect to the Assets, all responsibility and liability for any assessment, remediation, removal, transportation, and disposal of the materials at the Assets.

2.07 **Allocation of Purchase Price**. The Purchase Price shall be allocated among the Assets as set forth in Schedule 2.07 hereto. Seller and Buyer agree to be bound by the Allocated Values set forth in Schedule 2.07 for purposes of Article 11 hereof. Seller and Buyer further agree that for the purpose of making the requisite filings under Section 1060 of the Code, and the regulations thereunder, the Parties shall use commercially reasonable efforts to agree to an allocation of the Purchase Price and any other items constituting consideration for Tax purposes among the Assets in a manner that is consistent, to the extent possible, with the Allocated Values, as set forth on Schedule 2.07 (the "Tax Allocation"). If Seller and Buyer reach an agreement with respect to the Tax Allocation, Seller and Buyer each agree to report, and to cause their respective Affiliates to report, the federal, state, and local income and other Tax consequences of the Contemplated Transactions, and in particular to report the information required by Section 1060(b) of the Code, and to jointly prepare Form 8594 (Asset Acquisition Statement under Section 1060 of the Code) as promptly as possible following the Closing Date, and to update the Tax Allocation to take into account subsequent adjustments to the Purchase Price, including any adjustments pursuant to the Agreement to determine the Final Amount, in a manner consistent with the Tax Allocation, and shall not take any position inconsistent therewith in connection with any Proceeding with respect to Taxes, unless required to do so by any Legal Requirement after notice to and discussions with the other Party, or with such other Party's prior written consent; *provided*, *however*, that neither Party shall be unreasonably impeded in its ability to negotiate, compromise and/or settle any Tax Proceedings in good faith in connection with such Tax Allocation.

ARTICLE 3 REPRESENTATIONS AND WARRANTIES OF SELLER

Each Seller Party represents and warrants to Buyer as of the Execution Date and the Closing Date, the following:

3.01 **Organization and Good Standing**. Such Seller Party is a Delaware limited liability company, and is duly organized, validly existing, and in good standing under the laws of the State of Delaware and, where required, is duly qualified to do business and is in good standing in each jurisdiction in which the Assets are located, with full limited liability company power and authority to conduct its business as it is now being conducted, and to own or use the properties and assets that it purports to own or use. Such Seller Party is not a "foreign person" for purposes of Section 1445 of the Code.

3.02 **Authority; No Conflict**.

(a) The execution, delivery, and performance of this Agreement and the Contemplated Transactions have been duly and validly authorized by all necessary limited liability company action on the part of such Seller Party. This Agreement has been duly executed and delivered by such Seller Party and at the Closing, all instruments executed and delivered by such Seller Party at or in connection with the Closing shall have been duly executed and delivered by such Seller Party. This Agreement constitutes the legal, valid, and binding obligation of such Seller Party, enforceable against such Seller Party in accordance with its terms, except as such enforceability may be limited by applicable bankruptcy or other similar laws affecting the rights and remedies of creditors generally and by general principles of equity (regardless of whether such enforceability is considered in a Proceeding in equity or at law). Upon execution and delivery by such Seller Party of the Instruments of Conveyance at the Closing, such Instruments of Conveyance shall constitute legal, valid and binding transfers and conveyances of the Assets. Upon the execution and delivery by such Seller Party of any other documents at the Closing (collectively with the Instruments of Conveyance, such Seller Party's "Seller Closing Documents"), such Seller Closing Documents shall constitute the legal, valid, and binding obligations of such Seller Party, enforceable against such Seller Party in accordance with their terms, except as such enforceability may be limited by applicable bankruptcy or other similar laws affecting the rights and remedies of creditors generally and by general principles of equity (regardless of whether such enforceability is considered in a Proceeding in equity or at law).

(b) Except as set forth in Schedule 3.02(b), and assuming the receipt of all Consents and the waiver of all Preferential Purchase Rights (in each case) applicable to the Contemplated Transactions and listed on Schedule 3.11, neither the execution and delivery of this Agreement by such Seller Party nor the consummation or performance of any of the Contemplated Transactions by such Seller Party shall, directly or indirectly (with or without notice or lapse of time):

(i) contravene, conflict with, or result in a violation of (A) any provision of the Organizational Documents of such Seller Party, or (B) any resolution adopted by the board of directors, managers or officers of such Seller Party;

(ii) contravene, conflict with, or result in a violation of, or give any Governmental Body or other Person the right to challenge any of the Contemplated Transactions, to terminate, accelerate, or modify any terms of, or to exercise any remedy or obtain any relief under, any Contract or agreement or any Legal Requirement or Order to which such Seller Party, or any of the Assets, may be subject;

(iii) contravene, conflict with, or result in a violation or breach of any of the terms or requirements of, or give any Governmental Body the right to revoke, withdraw, suspend, cancel, terminate, or modify, any Governmental Authorization that relates to the Assets; or

(iv) result in the imposition, creation or continuance of any Encumbrance upon or with respect to any of the Assets except for Permitted Encumbrances.

3.03 **Bankruptcy**. Except for claims or matters related to the bankruptcy case of Linn Energy, LLC and its subsidiaries commenced on May 11, 2016 and concluded on September 27, 2018, for which the United States Bankruptcy Court for the Southern District of Texas retains jurisdiction, there are no bankruptcy, reorganization, receivership, or arrangement proceedings pending or being contemplated by such Seller Party or, to such Seller Party's Knowledge, Threatened against such Seller Party.

3.04 **Taxes**. Except as disclosed on Schedule 3.04:

(a) All material Tax Returns required to be filed by such Seller Party with respect to Asset Taxes have been duly and timely filed and all such Tax Returns are correct and complete in all material respects.

(b) All material Asset Taxes required to be paid by such Seller Party for which the Buyer may be liable that are or have become due have been timely paid in full, and such Seller Party is not delinquent in the payment of any such Asset Taxes.

(c) There is not currently in effect any extension or waiver of any statute of limitations of any jurisdiction regarding the assessment or collection of any Asset Taxes. No extension of time within which to file any Tax Return with respect to the Asset Taxes is currently in effect.

(d) There are no Tax Proceedings pending or Threatened in writing against Seller relating to or in connection with any Asset Taxes.

(e) Other than Permitted Encumbrances, there are no liens on any of the Assets currently existing, pending or, to the Knowledge of such Seller Party, Threatened with respect to any Assets related to any unpaid Taxes.

(f) All material Tax withholding and deposit requirements imposed by applicable Legal Requirements with respect to any of the Assets have been satisfied in all respects.

(g) No Asset is subject to any co-ownership or other arrangement that is treated, or required to be treated, as a partnership for federal, state or local income Tax purposes for which there has not been made a valid election under Section 761(a) of the Code (or similar applicable provision) to be excluded from the provisions of Subchapter K of Chapter 1 of Subtitle A of the Code.

(h) All material Assets have been properly listed and described on the property Tax rolls for all periods prior to and including the Closing Date and no portion of such Assets constitutes omitted property for property Tax purposes.

3.05 **Legal Proceedings**. Other than the Assumed Litigation and the Retained Litigation, in each case, set forth in Schedule 3.05, such Seller Party has not been served with or made aware of any Proceeding, and to such Seller Party's Knowledge, there is no pending or Threatened Proceeding against such Seller Party or any of its Affiliates, in each case, that
(a) relates to such Seller Party's management, ownership or operation of any of the Assets, or
(b) challenges, or may have the effect of preventing, delaying, making illegal, or otherwise interfering with, any of the Contemplated Transactions. To Seller's Knowledge, there are no pending or Threatened Proceedings related to the operation or Seller's ownership of the Assets to which Seller or any of its Affiliates is party.

3.06 **Brokers**. Neither such Seller Party nor its Affiliates have incurred any obligation or liability, contingent or otherwise, for broker's or finder's fees with respect to the Contemplated Transactions other than obligations that are and will remain the sole responsibility of such Seller Party and its Affiliates.

3.07 **Compliance with Legal Requirements**. Except as set forth in Schedule 3.07, (a) there is no uncured violation by such Seller Party or any Affiliate of such Seller Party of any Legal Requirements (other than Environmental Laws) with respect to such Seller Party's ownership of the Assets, (b) all Assets operated by Third Parties have been operated in all material respects in compliance with all applicable Legal Requirements (other than Environmental Laws) and (c) neither such Seller Party nor any of its Affiliates have received any written notice from any Governmental Body or Third Party of any violation of or default by such Seller Party or any of its Affiliates or any operator of the Assets with respect to any Legal Requirement (other than Environmental Laws) applicable to the Assets that remains unresolved.

3.08 **Prepayments**. Except for any Imbalances, such Seller Party has not received payment under any Contract for the sale of Hydrocarbons produced from the Assets which requires delivery in the future to any party of Hydrocarbons previously paid for and not yet delivered.

3.09 **Imbalances**. Except as set forth in Schedule 3.09, there are no Imbalances with respect to such Seller Party's obligations relating to the Wells as of the Effective Time.

3.10 **Material Contracts**. Schedule 3.10 sets forth all Applicable Contracts with respect to such Seller Party of the type described below as of the Execution Date (collectively, the "Material Contracts"):

(a) any Applicable Contract that is a Hydrocarbon purchase and sale, transportation, gathering, treating, processing, compression, marketing, or similar Applicable Contract that is not terminable by such Seller Party without penalty on sixty (60) days' or less notice, including any Contract that includes an acreage dedication or minimum volume commitment;

(b) any Applicable Contract that can reasonably be expected to result in aggregate payments or receipt of revenue by such Seller Party of more than One Hundred Thousand Dollars ($100,000.00) net to such Seller Party's interest during the current or any subsequent fiscal year or more than Three Hundred Thousand Dollars ($300,000.00) in the aggregate net to such Seller Party's interest over the term of such Applicable Contract (based on the terms thereof and contracted (or if none, current) quantities where applicable);

(c) any Applicable Contract that is an indenture, mortgage, loan, deed of trust credit agreement, sale-leaseback, guaranty of any obligation, bond, letter of credit, or similar financial Contract;

(d) any Applicable Contract that constitutes a partnership agreement, joint venture agreement, area of mutual interest agreement, non-compete agreement or similar agreement that otherwise purports to limit or prohibit the manner in which, or the locations in which, Seller may conduct its business, joint exploration agreement, joint development agreement, joint operating agreement, unit operating agreement, drilling contract, farmin or farmout agreement, carry agreement, net profits interest agreement, participation agreement, production sharing agreement, pooling agreements, unitization agreement or similar Contract to dispose of, farmout, lease or exchange all or part of the Assets or where any material obligation (which, for the avoidance of doubt, does not include confidentiality or indemnification obligations) has not been completed prior to the Effective Time;

(e) any Applicable Contract that provides for a call upon, option to purchase or similar right under any agreements with respect to the Hydrocarbons produced from or attributable to the Assets;

(f) any Applicable Contract that provides for, as its primary purpose, an indemnity;

(g) any Applicable Contract that contains any area of mutual interest agreements or similar provisions;

(h) any Applicable Contract that is a commitment to acquire, generate or develop seismic or similar agreement; and

(i) any Applicable Contract with any Affiliate of such Seller Party that is binding on any Assets and that will not be terminated at or prior to Closing.

Complete and accurate copies of all Material Contracts (including any and all amendments and supplements thereto) have been provided to Buyer prior to the Execution Date. Except as set forth on Schedule 3.10, (i) each Material Contract constitutes a legal, valid and binding obligation of such Seller Party and, to the Knowledge of such Seller Party, each other party thereto; (ii) neither such Seller Party nor any of its Affiliates has received from any other party to a Material Contract any written notice of termination or intention to terminate any Material Contract and, to the Knowledge of such Seller Party, no event has occurred which (with notice or lapse of time, or both) would constitute a default of such Seller Party under any Material Contract or give such Seller Party or any other party to any Material Contract the right to terminate or modify any Material Contract, (iii) such Seller Party is not and, to the Knowledge of such Seller Party, no other party to any Material Contract is, in material breach of the terms, provisions or conditions of the Material Contract and (iv) none of the Material Contracts are oral contracts or agreements.

3.11 **Consents and Preferential Purchase Rights**. Except as set forth in Schedule 3.11, none of the Assets (or any portion thereof) is subject to any Preferential Purchase Rights or Consents required to be obtained or complied with by such Seller Party which may be applicable to the Contemplated Transactions, except for Consents and approvals of Governmental Bodies that are customarily obtained after Closing, Contracts that are terminable upon not greater than sixty (60) days' notice without payment of any fee.

3.12 **Permits**. Except as set forth in Schedule 3.12, (a) such Seller Party and its Affiliates, has acquired all Permits from appropriate Governmental Bodies to conduct operations on such Assets in material compliance with all applicable Legal Requirements; (b) no Proceeding is pending or, to such Seller Party's Knowledge, Threatened to suspend, revoke or terminate any such Permit or declare any such Permit invalid; and (c) such Seller Party and any Third Party operator of the Assets is in compliance in all material respects with all such Permits.

3.13 **Current Commitments**. Schedule 3.13 sets forth, as of the Execution Date, all approved authorizations for expenditures and other approved capital commitments, individually equal to or greater than One Hundred Thousand Dollars ($100,000.00) (net to such Seller Party's interest) (the "AFEs") relating to the Assets to drill or rework any Wells or for other capital expenditures for which all of the activities anticipated in such AFEs have not been completed by the Effective Time.

3.14 **Environmental Laws**. Except as disclosed on Schedule 3.14, (a) there are no Proceedings pending, or to such Seller Party's Knowledge, Threatened in writing, before any Governmental Body with respect to the Assets alleging material violations of, or material liabilities under, Environmental Laws, or claiming remediation obligations, (b) such Seller Party has received no notice from any Governmental Body of any alleged or actual material violation or non-compliance with, or material liability under, any Environmental Law or of material non- compliance with the terms or conditions of any Permits required under Environmental Law, arising from, based upon, associated with or related to the Assets or the ownership or operation of any thereof and (c) to such Seller Party's Knowledge, such Seller Party has provided or otherwise made available to Buyer or will provide or otherwise make available to Buyer prior to the Defect Notice Date, complete and accurate copies of all readily available non-privileged historical environmental reports or studies prepared by or at the direction of Seller within the past five (5) years that are in such Seller Party's possession or control that address material environmental concerns relating to the Assets prior to the Execution Date.

3.15 **Employee Matters**. In connection with the consummation of the Contemplated Transactions, no payments of money or property, acceleration of benefits, or provisions of other rights have or will be made hereunder or under the Seller Benefit Plans that, in the aggregate, would be reasonably likely to result in imposition of the sanctions imposed under Sections 280G and 4999 of the Code (determined without regard to the exception contained in Section 280G(b)(4) of the Code), whether or not some other subsequent action or event would be required to cause such payment, acceleration or provision to be triggered. No Available Employee is represented by a labor union or other representative of employees with respect to such Available Employee's employment with Seller Party or its Affiliates, and neither such Seller Party nor any of its Affiliates is a party to, subject to, or bound by a collective bargaining agreement or any other Contract with a labor union or representative of employees. There are no, and for the past three years there have not been, strikes, lockouts or work stoppages existing or, to such Seller Party's Knowledge, Threatened, with respect to: (i) any Available Employee's employment with Seller Party or its Affiliates, or (ii) Seller Party's or its Affiliate's employment of any other individual who has provided services with respect to the Assets. In the past three years there have been no union certification or representation petitions or similar demands with respect to the Assets, such Seller Party, or an Available Employee with respect to such Available Employee's employment with Seller Party or its Affiliates and, to such Seller Party's Knowledge, no such union organizing campaign or similar effort is pending or Threatened with respect to the Assets, such Seller Party or an Available Employee.

3.16 **Wells**. Except as disclosed on Schedule 3.16(a), (a) all Wells have been drilled and completed within the limits permitted by all applicable Leases and Contracts and at locations that comply with applicable Legal Requirements, (b) no Well is subject to material penalties on allowable production after the Effective Time because of any overproduction, and (c) there are no Wells that such Seller Party or its Affiliate or any Third Party operator is currently obligated by applicable Legal Requirements or contract to plug, dismantle or abandon that have been plugged, dismantled or abandoned in a manner that does not comply in all material respects with Legal Requirements or that are currently subject to exceptions to a requirement to plug, dismantle or abandon issued by a Governmental Body. All Wells plugged and abandoned by Seller have been plugged and abandoned in accordance with applicable Legal Requirements and the Leases. To Seller's Knowledge as of the Execution Date, Schedule 3.16(b) sets forth the payout balances (net to the Working Interest of Seller) as of the date set forth on such Schedule for each Well that is subject to a reversion or other adjustment at some level of cost recovery or payout.

3.17 **Royalties**. Except for any Suspense Funds or as set forth in Schedule 3.17, such Seller Party or its Affiliate has duly and properly paid, or caused to be duly and properly paid, all Royalties due by such Seller Party and its Affiliates during the period of such Seller Party's ownership of the Assets; *provided*, *however*, without limiting Buyer's rights to indemnification under Section 10.02(c), that no failure to comply with the foregoing that does not result in the termination of a Lease shall be considered a breach of this Section 3.17.

3.18 **Leases**. Except as set forth in Schedule 3.18, (a) neither such Seller Party nor any of its Affiliates has received any written notice from any lessor under the Leases either (i) seeking to terminate, cancel or rescind any such Leases, or (ii) alleging any unresolved material default under the Leases and (b) none of such Seller Party or its Affiliates is in material default or breach under any of the Leases which would result in damages in excess of Fifty Thousand Dollars ($50,000) net to Seller's interest or cause a Lease to terminate. Notwithstanding anything herein to the contrary, the representations set forth in this Section 3.18 do not address the quality or quantum of Seller's title to the Leases.

3.19 **Non-Consent Operations**. Except as disclosed on Schedule 3.19, no operations are being conducted or have been conducted on the Assets with respect to which such Seller Party has elected to be a nonconsenting party under the applicable operating agreement and with respect to which such Seller Party's rights have not yet reverted to it. Schedule 3.19 sets forth the payout balances as of the Execution Date for each Well subject to payout.

3.20 **Surface Rights**. Except as set forth on Schedule 3.20, (a) such Seller Party is not in material breach of or material default under any such Surface Right which would result in damages in excess of Fifty Thousand Dollars ($50,000) net to Seller's interest or cause a Surface Right to terminate; or (b) no event has occurred or circumstance exists that, with the delivery of notice, the passage of time or both, would constitute such a material breach or default or permit the termination of any such Surface Right that is needed to operate the Assets as currently operated by Seller. Notwithstanding anything herein to the contrary, the representations set forth in this Section 3.20 do not address the quality or quantum of Seller's title to the Surface Rights.

3.21 **Condemnation.** As of the Execution Date, there is no actual or Threatened taking (whether permanent, temporary, whole or partial) of any part of the Assets by reason of condemnation or Threatened condemnation.

3.22 **Knowledge Qualifier for Non-Operated Assets.** To the extent that such Seller Party has made any representations or warranties in this Article 3 in connection with matters relating to non-operated Assets, each and every such representation and warranty shall be deemed to be qualified by the phrase, "To such Seller Party's Knowledge"; *provided*, *however*, that no representation or warranty as to any Seller Party or its Affiliates' receipt of a written notice with respect to non-operated Assets shall be qualified by "Seller Party's Knowledge" unless explicitly provided in the applicable representation and/or warranty.

3.23 **Disclosures with Multiple Applicability; Materiality**. If it is reasonably apparent on its face that any fact, condition, or matter disclosed in Seller's disclosure Schedules applies to more than one Section of this Article 3, a single disclosure of such fact, condition, or matter on Seller's disclosure Schedules shall constitute disclosure with respect to all sections of this Article 3 to which it is reasonably apparent that such fact, condition, or other matter applies, regardless of the section of Seller's disclosure Schedules in which such fact, condition, or other matter is described. Inclusion of a matter on Seller's disclosure Schedules with respect to a representation or warranty that is qualified by "material" or "Material Adverse Effect" or any variant thereof shall not necessarily be deemed an indication that such matter does, or may, be material or have a Material Adverse Effect. Matters may be disclosed on a Schedule to this Agreement for purposes of information only.

3.24 **Gathering System**. Such Seller Party has, and the Assets, including the Gathering System, include, all easements, rights of way, licenses and authorizations, from Governmental Bodies necessary to access, construct, operate, maintain and repair the Wells and equipment included in the Assets in the ordinary course of business as currently conducted by such Seller Party.

3.25 **Certain Restrictions**. Except as disclosed on Schedule 3.25, Seller is not a party to or otherwise bound by any obligation of confidentiality or similar restriction to any Third Party that would (i) materially restrict Buyer's access rights described in Section 5.01 or (ii) result in any material asset or property that would otherwise be an "Asset" to be an "Excluded Asset".

ARTICLE 4 REPRESENTATIONS AND WARRANTIES OF BUYER

Buyer represents and warrants to Seller, as of the Execution Date and the Closing Date, the following:

4.01 **Organization and Good Standing**. Buyer is a limited liability company and duly organized, validly existing, and in good standing under the laws of Delaware and is duly qualified to do business and is in good standing in each jurisdiction in which the Assets are located.

4.02 **Authority; No Conflict**.

(a) This Agreement constitutes the legal, valid, and binding obligation of Buyer, enforceable against Buyer in accordance with its terms, except as such enforceability may be limited by applicable bankruptcy or other similar laws affecting the rights and remedies of creditors generally and by general principles of equity (regardless of whether such enforceability is considered in a Proceeding in equity or at law). Upon the execution and delivery by Buyer of the Instruments of Conveyance and any other documents executed and delivered by Buyer at the Closing (collectively, "Buyer's Closing Documents"), Buyer's Closing Documents shall constitute the legal, valid, and binding obligations of Buyer enforceable against Buyer in accordance with their respective terms, except as such enforceability may be limited by applicable bankruptcy or other similar laws affecting the rights and remedies of creditors generally and by general principles of equity (regardless of whether such enforceability is considered in a Proceeding in equity or at law). Buyer has the requisite right, power, authority, and capacity to execute and deliver this

Agreement and Buyer's Closing Documents, and to perform its obligations under this Agreement and Buyer's Closing Documents.

(b) Neither the execution and delivery of this Agreement by Buyer nor the consummation or performance of any of the Contemplated Transactions by Buyer shall give any Person the right to prevent, delay, or otherwise interfere with any of the Contemplated Transactions.

(c) Neither the execution and delivery of this Agreement by Buyer nor the consummation or performance of any of the Contemplated Transactions by Buyer shall (i) contravene, conflict with, or result in a violation of any provision of the Organizational Documents of Buyer, (ii) contravene, conflict with, or result in a violation of any resolution adopted by the board of managers, or members of Buyer, or (iii) contravene, conflict with, or result in a violation of, or give any Governmental Body or other Person the right to challenge any of the Contemplated Transactions, to terminate, accelerate, or modify any terms of, or to exercise any remedy or obtain any relief under, any agreement or any Legal Requirement or Order to which Buyer may be subject.

(d) Buyer is not and shall not be required to give any notice to or obtain any Consent from any Person in connection with the execution and delivery of this Agreement or the consummation or performance of any of the Contemplated Transactions.

4.03 **Certain Proceedings**. There is no Proceeding pending against Buyer that challenges, or may have the effect of preventing, delaying, making illegal, or otherwise interfering with, any of the Contemplated Transactions. To Buyer's Knowledge, no such Proceeding has been Threatened.

4.04 **Knowledgeable Investor**. Buyer is an experienced and knowledgeable investor in the oil and gas business. Prior to entering into this Agreement, Buyer was advised by its own legal, tax, and other professional counsel concerning this Agreement, the Contemplated Transactions, the Assets, and their value, and it has relied solely thereon and on the representations and obligations of Seller in this Agreement and the documents to be executed by Seller in connection with this Agreement at the Closing. Buyer is acquiring the Assets for its own account and not for sale or distribution in violation of the Securities Act of 1933, as amended, the rules and regulations thereunder, any applicable state blue sky laws, or any other applicable Legal Requirements.

4.05 **Qualification**. Buyer is an "accredited investor," as such term is defined in Regulation D of the Securities Act of 1933, as amended. Buyer is not acquiring the Assets in connection with a distribution or resale thereof in violation of federal or state securities laws and the rules and regulations thereunder. Without limiting Section 6.02, Buyer is, or as of the Closing will be, qualified under applicable Legal Requirements to hold leases, rights-of-way, and other rights issued or controlled by (or on behalf of) any applicable Governmental Body and will be qualified under applicable Legal Requirements to own the Assets. Buyer has, or as of the Closing will have, posted such bonds as may be required for the ownership or, where applicable, operatorship by Buyer of the Assets. To Buyer's Knowledge, no fact or condition exists with respect to Buyer or the Assets which may cause any Governmental Body to withhold its approval of the Contemplated Transactions.

4.06 **Brokers**. Neither Buyer nor its Affiliates have incurred any obligation or liability, contingent or otherwise, for broker's or finder's fees with respect to the Contemplated Transactions other than obligations that are or will remain the sole responsibility of Buyer and its Affiliates.

4.07 **Financial Ability**. At Closing, Buyer will have sufficient cash, available lines of credit, or other sources of immediately available funds to enable it to (a) deliver the amounts due at the Closing, (b) take such actions as may be required to consummate the Contemplated Transactions, and (c) timely pay and perform Buyer's obligations under this Agreement and Buyer's Closing Documents. Buyer expressly acknowledges that the failure to have sufficient funds at Closing shall in no event be a condition to the performance of its obligations hereunder, and in no event shall the Buyer's failure to perform its obligations hereunder be excused by failure to receive funds from any source.

4.08 **Securities Laws**. The solicitation of offers and the sale of the Assets by Seller have not been registered under any securities laws. At no time has Buyer been presented with or solicited by or through any public promotion or any form of advertising in connection with the Contemplated Transactions. Buyer is not acquiring the Assets with the intent of distributing fractional, undivided interests that would be subject to regulation by federal or state securities laws, and that if it sells, transfers, or otherwise disposes of the Assets or fractional undivided interests therein, it shall do so in compliance with applicable federal and state securities laws.

4.09 **Due Diligence**. Without limiting or impairing any representation, warranty, covenant or agreement of Seller contained in this Agreement and the Seller Closing Documents, or Buyer's right to rely thereon, subject to Buyer's rights to access the Assets to conduct a due diligence review in accordance with this Agreement, as of the Closing Date, Buyer and its Representatives have been permitted access to all materials relating to the Assets, been afforded the opportunity to ask all questions of Seller (or Seller's Representatives) concerning the Assets, been afforded the opportunity to investigate the condition of the Assets, and had the opportunity to take such other actions and make such other independent investigations as Buyer deems necessary to evaluate the Assets and understand the merits and risks of an investment therein and to verify the truth, accuracy, and completeness of the materials, documents, and other information provided or made available to Buyer (whether by Seller or otherwise). **WITHOUT LIMITING OR IMPAIRING ANY REPRESENTATION, WARRANTY, COVENANT OR AGREEMENT OF SELLER CONTAINED IN THIS AGREEMENT AND SELLER'S CLOSING DOCUMENTS (INCLUDING THE SPECIAL WARRANTY OF DEFENSIBLE TITLE SET FORTH IN THE INSTRUMENTS OF CONVEYANCES), OR BUYER'S RIGHT TO RELY UPON EACH OF THE FOREGOING OR BUYER'S RIGHTS UNDER ARTICLE 9, BUYER HEREBY WAIVES ANY CLAIMS ARISING OUT OF ANY MATERIALS, DOCUMENTS, OR OTHER INFORMATION PROVIDED OR MADE AVAILABLE TO BUYER (WHETHER BY SELLER OR OTHERWISE), WHETHER UNDER THIS AGREEMENT, AT COMMON LAW, BY STATUTE, OR OTHERWISE.**

4.10 **Basis of Buyer's Decision**. By reason of Buyer's knowledge and experience in the evaluation, acquisition, and operation of oil and gas properties, Buyer has evaluated the merits and the risks of purchasing the Assets from Seller and has formed an opinion based solely on Buyer's knowledge and experience, Buyer's due diligence, and Seller's representations, warranties, covenants, and agreements contained in this Agreement and the Seller Closing Documents, and not on any other representations or warranties by Seller. Buyer has not relied and shall not rely on any statements by Seller or its Representatives (other than those representations, warranties, covenants, and agreements of Seller contained in this Agreement and the Seller Closing Documents) in making its decision to enter into this Agreement or to close the Contemplated Transactions. **BUYER UNDERSTANDS AND ACKNOWLEDGES THAT NEITHER THE UNITED STATES SECURITIES AND EXCHANGE COMMISSION NOR ANY OTHER GOVERNMENTAL BODY HAS PASSED UPON THE ASSETS OR MADE ANY FINDING OR DETERMINATION AS TO THE FAIRNESS OF AN INVESTMENT IN THE ASSETS OR THE ACCURACY OR ADEQUACY OF THE DISCLOSURES MADE TO BUYER, AND, EXCEPT AS SET FORTH IN ARTICLE 9, BUYER IS NOT ENTITLED TO CANCEL, TERMINATE, OR REVOKE THIS AGREEMENT, WHETHER DUE TO THE INABILITY OF BUYER TO OBTAIN FINANCING OR PAY THE PURCHASE PRICE, OR OTHERWISE.**

4.11 **Business Use, Bargaining Position**. Buyer is purchasing the Assets for commercial or business use. Buyer has sufficient knowledge and experience in financial and business matters that enables it to evaluate the merits and the risks of transactions such as the Contemplated Transactions, and Buyer is not in a significantly disparate bargaining position with Seller. Buyer expressly acknowledges and recognizes that the price for which Seller has agreed to sell the Assets and perform its obligations under the terms of this Agreement has been predicated upon the inapplicability of the Texas Deceptive Trade Practices - Consumer Protection Act, V.C.T.A. BUS & COMM ANN. § 17.41 et seq., to the extent applicable, or any similar Legal Requirement. **BUYER FURTHER RECOGNIZES THAT SELLER, IN DETERMINING TO PROCEED WITH ENTERING INTO THIS AGREEMENT, HAS EXPRESSLY RELIED ON THE PROVISIONS OF THIS ARTICLE 4.**

4.12 **Bankruptcy**. There are no bankruptcy, reorganization, receivership, or arrangement Proceedings pending or being contemplated by Buyer or, to Buyer's Knowledge, Threatened against Buyer. Buyer is, and will be immediately after giving effect to the Contemplated Transactions, solvent.

ARTICLE 5 COVENANTS OF SELLER

5.01 **Access and Investigation**.

(a) Between the Execution Date and the Closing (but excluding the Dead Period), to the extent doing so would not violate (x) applicable Legal Requirements or (y) Seller's obligations to any Third Party or other restrictions on Seller, Seller shall afford Buyer and its Representatives access during Seller's regular hours of business (with one day prior notice if a field visit is required) to reasonably appropriate Seller's management and personnel with knowledge of the Assets, any Seller-operated Assets, Records, contracts, books and records (including all readily- available non-privileged historical environmental reports, records and correspondence), and other documents and data related to the Assets, and promptly furnish Buyer and its Representatives with existing electronic copies of all such Records, contracts, books and records, and other existing documents and data related to the Assets as Buyer or its Representatives may reasonably request, except in each case any such contracts, books and records or other documents and data that are Excluded Assets (and upon Buyer's request, Seller shall use reasonable efforts to obtain the consent of Third Party operators to give Buyer and its Representatives reasonable access to similar information with respect to Assets not operated by Seller or its Affiliates; *provided* that Seller shall not be required to make payments or undertake obligations in favor of any Third Parties in order to obtain such consent) and Seller's offices, personnel and the Assets may be unavailable for access during the Dead Period; ***PROVIDED*** **THAT, EXCEPT AS EXPRESSLY PROVIDED IN THIS AGREEMENT, THE CERTIFICATE DELIVERED BY SELLER AT CLOSING OR IN THE INSTRUMENTS OF CONVEYANCE, SELLER MAKES NO REPRESENTATION OR WARRANTY, AND EXPRESSLY DISCLAIMS ALL REPRESENTATIONS AND WARRANTIES AS TO THE ACCURACY OR COMPLETENESS OF THE DOCUMENTS, INFORMATION, BOOKS, RECORDS, FILES AND OTHER DATA THAT IT MAY PROVIDE OR DISCLOSE TO BUYER.**

(b) Notwithstanding the provisions of Section 5.01(a), (i) Buyer's investigation shall be conducted in a manner that (to the extent practicable) minimizes interference with the field operation of the business of Seller and any applicable Third Parties, and (ii) subject to Section 11.09 and except as otherwise provided in this Section 5.01(b), Buyer's right of access shall not entitle Buyer to operate equipment or conduct subsurface or other invasive testing or sampling. Buyer's Environmental review shall not exceed the review contemplated by a Phase I Environmental Site Assessment of the Assets without Seller's prior written permission, which may not be unreasonably withheld if Buyer's Phase I Environmental Site Assessment recommends such testing as necessary to prove the existence of an Environmental Defect, subject to Section 11.09. If Buyer is entitled to conduct an environmental review beyond a Phase I Environmental Assessment pursuant to the foregoing sentence, Buyer shall use commercially reasonable efforts to engage a consulting or engineering firm set forth on Schedule 5.01(b) for purposes of such review (and any other consulting or engineering firm engaged by Buyer for purposes of conducting such environmental review shall be subject to Seller's prior approval which shall not be unreasonably withheld). For the avoidance of doubt, Buyer may engage any consulting or engineering firm for purposes of conducting Buyer's Phase I Environmental Site Assessment as Buyer determines in its sole discretion.

(c) Buyer acknowledges that, pursuant to its right of access to the Records and the Assets, Buyer will become privy to confidential and other information of Seller and Seller's Affiliates and the Assets and that such confidential information shall be held confidential by Buyer and Buyer's Representatives in accordance with the terms of the Confidentiality Agreement. If the Closing should occur, the foregoing confidentiality restriction on Buyer, including the Confidentiality Agreement, shall terminate (except as to the Excluded Assets); *provided* that such termination of the Confidentiality Agreement shall not relieve any party thereto from any liability thereunder for the breach of such agreement prior to the Execution Date.

5.02 **Conduct of Business**. Except (x) as set forth on Schedule 5.02, or (y) as required by applicable Legal Requirements, between the Execution Date and the Closing, Seller shall operate its business with respect to its ownership and operation of the Assets in the ordinary course as a reasonably prudent operator, and, without limiting the generality of the preceding, shall:

(a) not transfer, sell, hypothecate, encumber, or otherwise dispose of any of the Assets, except as required under any presently existing Leases or Contracts, and except for sales of Hydrocarbons, equipment and inventory in the ordinary course of business;

(b) subject to clause (e) below, use its commercially reasonable efforts not to abandon any Asset (except the abandonment or expiration of Leases in accordance with their terms, upon no later than five (5) Business Days' prior written notice to Buyer of such abandonment);

(c) not commence, propose, or agree to participate in any single operation (including, without limitation, completion work, workovers, repairs, maintenance or modifications with respect to the Wells and/or facilities, as applicable) with respect to the Wells or Leases with an anticipated cost in excess of One Hundred Thousand Dollars ($100,000.00) (net to Seller's interest), except for any emergency operations to the extent necessary to protect life or health or prevent environmental or property damage;

(d) not execute, terminate, cancel, extend, or materially amend or modify any Material Contract or Lease other than the execution or extension of a Contract for the sale, exchange, transportation, gathering, treating, or processing of Hydrocarbons terminable without penalty on thirty (30) days' or shorter notice

(e) use commercially reasonable efforts to keep Buyer apprised of any drilling, re- drilling, completion or workover operations proposed or conducted by Seller with respect to the Assets;

(f) not make any election (or fail to make an election, the result of which is) to go non- consent with respect to any of the Assets without providing at least five (5) days' prior written notice to Buyer and receiving affirmative consent from Buyer with respect thereto; *provided*, *however*, if Buyer does not respond to such notice within five (5) days of receipt thereof, Buyer shall be deemed to have consented to Seller's election;

(g) unless Buyer fails to provide consent under clause (c) above, use commercially reasonable efforts to maintain in full force and effect each Lease, and, with respect to any Lease, timely and properly pay all lease renewals, shut-in royalties, delay rentals or other lease extension payments that become due after the date of this Agreement but prior to Closing in accordance with the terms of the applicable Lease;

(h) not waive, release, assign, settle or compromise any Proceeding, material right or claim relating to the Assets, other than the Retained Liabilities or waivers, releases, assignments, settlements or compromises that involve only the payment of monetary damages not in excess of One Hundred Thousand Dollars ($100,000.00) individually (excluding amounts to be paid under insurance policies);

(i) pay (or cause to be paid) any and all Asset Taxes that could result in an Encumbrance with respect to the Assets that become due and payable on or prior to the Closing Date;

(j) provide Buyer with prompt written notice upon receipt by Seller or its Affiliates of any notice of termination of, or alleging Seller's or its Affiliate's default under or material breach of, any Lease; and

(k) not commit to do, or enter into any agreement with respect to, any of the foregoing prohibited actions.

Buyer acknowledges that Seller owns undivided interests in certain of the properties comprising the Assets, and Buyer agrees that the acts or omissions of the other Working Interest owners who are not Seller or an Affiliate of Seller shall not constitute a Breach of the provisions of this Section 5.02, nor shall any action required by a vote of Working Interest owners constitute such a Breach so long as Seller or its Affiliate has voted its interest in a manner that complies with the provisions of this Section 5.02. Further, no action or inaction of any Third Party operator with respect to any Asset shall constitute a Breach of this Section 5.02 to the extent Seller uses commercially reasonable efforts to cause such Third Party operator to operate such applicable Asset in a manner consistent with this Section 5.02. Seller may seek Buyer's approval to perform any action that would otherwise be restricted by this Section 5.02, and Buyer's approval of any such action shall not be unreasonably withheld, conditioned, or delayed, and shall be considered granted ten (10) days (unless a shorter time (not to be less than two (2) days) is reasonably required by the circumstances and such shorter time is specified in Seller's notice) after delivery of notice from Seller to Buyer requesting such consent unless Buyer notifies Seller to the contrary during such ten (10)-day period. Notwithstanding the foregoing provisions of this Section 5.02, in the event of an emergency involving life or health or environmental or property damage, Seller may take such action as reasonably necessary and shall notify Buyer of such action promptly thereafter. Any matter approved (or deemed approved) by Buyer pursuant to this Section 5.02 that would otherwise constitute a Breach of one of Seller's representations and warranties in Article 3 shall be deemed to be an exclusion from all representations and warranties for which it is relevant.

5.03 **Insurance**. Seller shall maintain in force during the period from the Execution Date until the Closing, all of Seller's insurance policies pertaining to the Assets in the amounts and with the coverages currently maintained by Seller.

5.04 **Consent and Waivers**. Seller shall use commercially reasonable efforts to obtain prior to the Closing written waivers of all Preferential Purchase Rights and all Consents necessary for the transfer of the Assets to Buyer; *provided* that in the event Seller is unable to obtain all such waivers of Preferential Purchase Rights and Consents after using such commercially reasonable efforts, such failure to satisfy shall not constitute a Breach of this Agreement. Neither Seller nor Buyer shall be required to make any payments to, or undertake any obligations for the benefit of, the holders of such rights in order to obtain the Required Consents. Buyer shall reasonably cooperate with Seller in seeking to obtain such Consents.

5.05 **Amendment to Schedules**. Until the fifth (5th) Business Day before Closing, Seller shall have the right (but not the obligation) to supplement the Schedules relating to the representations and warranties set forth in Article 3 with respect to any matters occurring subsequent to the Execution Date, which, if existing at the Execution Date, would have been required to be set forth or described in such Schedules. For the avoidance of doubt, and notwithstanding anything in this Agreement to the contrary, Seller shall not be entitled to supplement Schedule 6.03 pursuant to this Section 5.05. Except to the extent such updates are a direct result of actions taken with Buyer's consent pursuant to Section 5.02, prior to Closing, any such supplement shall not be considered for purposes of determining if Buyer's Closing conditions have been met under Section 7.01 or for determining any remedies available under this Agreement; *provided*, *however*, if Buyer is entitled to terminate this Agreement pursuant to Section 9.01(b) as a result of the matter underlying any such supplement and Buyer elects to waive such right to terminate this Agreement and the Closing occurs, then such supplements shall be incorporated into Seller's disclosure Schedules and any claim related to any matter disclosed in the supplements which resulted in Buyer's right to terminate this Agreement pursuant to Section 9.01(b) shall be deemed waived and Buyer shall not be entitled to make a claim thereon under this Agreement or otherwise with respect to such matters, but only with respect to such matters; *provided further*, *however*, that Buyer shall in no way be deemed to have waived any claim related to any matter disclosed in the supplements which does not result in Buyer's right to terminate this Agreement pursuant to Section 9.01(b) and may assert such claims under Article 10.

5.06 **Successor Operator**. While Buyer acknowledges that it desires to succeed Seller (or its Affiliates) as operator those Assets or portions thereof that Seller (or its Affiliates) may presently operate, Buyer acknowledges and agrees that Seller cannot and does not covenant or warrant that Buyer shall become successor operator of such Assets because such Assets (or portions thereof) may be subject to operating or other agreements that control the appointment of a successor operator. Seller agrees, however, that as to the Assets that Seller or its Affiliate operates, Seller shall use commercially reasonable efforts to support Buyer's effort to become successor operator of such Assets (to the extent permitted under any applicable operating agreement) effective as of the Closing (at Buyer's sole cost and expense) and to designate or appoint, to the extent legally possible and permissible under any applicable operating agreement, Buyer as successor operator of such Assets effective as of Closing.

5.07 **Affiliate Contracts**. Unless otherwise designated in writing to Buyer, Seller will terminate or cause its respective Affiliates to terminate, effective as of the Closing Date, any contracts or agreements between Seller and its Affiliates insofar and only insofar as such contracts or agreements relate to or bind the Assets.

5.08 **Employee Matters**. Between the Execution Date and the Closing Date, Seller shall not, and shall cause its Affiliates to not, (a) enter into any collective bargaining agreement or other Contract with any labor union or similar representative of any Available Employees or (b) transfer the employment of any Available Employee.

ARTICLE 6 OTHER COVENANTS

6.01 **Notification and Cure**. Between the Execution Date and the Closing Date, Buyer shall promptly notify Seller in writing and Seller shall promptly notify Buyer in writing if Seller or Buyer, as applicable, obtain Knowledge of any Breach, in any material respect, of the other Party's representations and warranties or covenants as of the Execution Date, or of an occurrence after the Execution Date that would cause or constitute a Breach, in any material respect, of any such representation and warranty or covenant had such representation and warranty or covenants been made as of the time of occurrence or discovery of such fact or condition; *provided* that failure to provide such notice shall not limit a Party's rights or remedies under this Agreement. If any of Buyer's or Seller's representations or warranties are untrue or shall become untrue in any material respect between the Execution Date and the Closing Date, or if any of Buyer's or Seller's covenants or agreements to be performed or observed prior to or on the Closing Date shall not have been so performed or observed in any material respect, and if such Breach of representation, warranty, covenant or agreement shall (if curable) be fully cured by the Closing (or, if the Closing does not occur, by the termination of this Agreement), then such breach shall be considered not to have occurred for all purposes of this Agreement.

6.02 **Satisfaction of Conditions**. Between the Execution Date and the Closing Date Seller shall use commercially reasonable efforts to cause the conditions in Article 7 to be satisfied, and Buyer shall use commercially reasonable efforts to cause the conditions in Article 8 to be satisfied.

6.03 **Replacement of Insurance, Bonds, Letters of Credit, and Guaranties**.

(a) The Parties understand that none of the insurance currently maintained by Seller or Seller's Affiliates covering the Assets, nor any of the bonds, letters of credit, or guaranties, if any, posted by Seller or Seller's Affiliates with Governmental Bodies or co-owners and relating to the Assets will be transferred to Buyer. On or before the Closing Date, Buyer shall obtain, and deliver to Seller evidence of, all necessary replacement bonds, letters of credit, and guaranties, and evidence of such other authorizations, qualifications, and approvals to the extent necessary for Buyer to own and, with respect to Assets currently operated by Seller or its Affiliates, operate such Assets. For informational purposes only, Schedule 6.03 describes the bonds, letters of credit, and guarantees currently maintained by Seller or Seller's Affiliates covering the Assets; *provided*, *however*, that Seller makes no representations or warranties as to the accuracy of Schedule 6.03 or its application to Buyer as the owner or operator of any of the Assets.

(b) Promptly (but in no event later than thirty (30) days) after Closing, Buyer shall, at its sole cost and expense, make all filings with Governmental Bodies necessary to assign and transfer the Assets and title thereto and to comply with applicable Legal Requirements, and Seller shall reasonably assist Buyer with such filings. Buyer shall indemnify, defend, and hold harmless Seller Group from and against all Damages arising out of Buyer's holding of such title of the Assets after the Closing and prior to the securing of any necessary Consents and approvals of the Contemplated Transactions from Governmental Bodies.

6.04 **Governmental Reviews**. Seller and Buyer shall (and shall cause their respective Affiliates to), in a timely manner, make all other required filings (if any) with, prepare applications to, and conduct negotiations with Governmental Bodies as required to consummate the Contemplated Transactions. Each Party shall, to the extent permitted pursuant to applicable Legal Requirements, cooperate with and use all reasonable efforts to assist the other with respect to such filings, applications and negotiations. Buyer shall bear the cost of all filing or application fees payable to any Governmental Body with respect to the Contemplated Transactions, regardless of whether Buyer, Seller, or any Affiliate of any of them is required to make the payment. Buyer shall indemnify, defend and hold harmless Seller Group from and against any and all amounts actually paid by Seller arising out of Buyer's holding of such title of the Assets after the Closing and prior to securing of any necessary Consents and approvals of the Contemplated Transactions from Governmental Bodies.

6.05 **Financing Cooperation**. Prior to the Closing Date, Seller shall, and shall use its commercially reasonable efforts to cause its Affiliates to provide all customary cooperation as reasonably requested by Buyer and its Affiliates (including causing its and their Representatives and auditors to so cooperate) to assist Buyer in the arrangement of any capital markets debt or equity financing, any bank debt, or any other financing arrangement necessary or desirable to fund the Purchase Price and any other amounts required to be paid in connection with the consummation of the transactions contemplated by this Agreement, including any necessary offering documents related thereto (the "Financing"); *provided* that such requested cooperation does not materially and adversely interfere with operations of Seller and the Assets, that any information requested by Buyer is reasonably available to Seller or any of its Affiliates or its and their Representatives, and that any and all costs associated with this cooperation shall be borne entirely by the Buyer.

6.06 **Pre-Effective Time Midstream Costs**. For a period from and after the Closing Date, until the one (1) year anniversary thereof Buyer shall use its commercially reasonable efforts to recoup Pre-Effective Time Midstream Costs on behalf of Seller to the extent that doing so would not violate applicable Legal Requirements or Applicable Contracts (as reasonably determined by Buyer in its sole discretion operating in good faith). Without duplication of any adjustments made pursuant to Section 2.05(d)(i), if Buyer receives after Closing any proceeds constituting Pre- Effective Time Midstream Costs, Buyer shall fully disclose, account for, and promptly remit the same to Seller.

6.07 **Seller's Remediation Obligation**. Seller shall use commercially reasonable efforts to complete all remediation required in connection with the *Irongate Holdings* matter set forth on Schedule 3.05 prior to the last day of the Transition Period; *provided*, that if Seller does not complete such remediation prior to the last day of the Transition Period Seller shall, upon execution of an access and indemnity agreement in a form to be mutually agreed by the Parties, continue such remediation for a period of no longer than 30 days after the last day of the Transition Period.

ARTICLE 7
CONDITIONS PRECEDENT TO BUYER'S OBLIGATION TO CLOSE

Buyer's obligation to purchase the Assets and to take the other actions required to be taken by Buyer at the Closing is subject to the satisfaction, at or prior to the Closing, of each of the following conditions (any of which may be waived by Buyer, in whole or in part):

7.01 **Accuracy of Representations**. All of Seller's representations and warranties in this Agreement must have been true and correct in all respects (without regard to materiality, Material Adverse Effect or other similar qualifiers) as of the Execution Date, and must be true and correct in all respects (without regard to materiality, Material Adverse Effect or other similar qualifiers) as of the Closing Date as if made on the Closing Date, other than any such representation and warranty that refers to a specified date, which need only be true and correct in all respects (without regard to materiality, Material Adverse Effect or other similar qualifiers) on and as of such specified date, except for those Breaches, if any, of such representations and warranties that in the aggregate would not have a Material Adverse Effect.

7.02 **Seller's Performance**. All of the covenants and obligations that Seller is required to perform or to comply with pursuant to this Agreement at or prior to the Closing must have been duly performed and complied with in all material respects.

7.03 **No Proceedings**. Since the Execution Date, there must not have been commenced or Threatened against Seller, or against any of Seller's Affiliates, any Proceeding (other than any matter initiated by either Buyer or its Affiliates) seeking to restrain, enjoin, or otherwise prohibit or make illegal, or seeking to recover material damages on account of, any of the Contemplated Transactions.

7.04 **No Orders**. On the Closing Date, there shall be no Order pending or remaining in force of any Governmental Body having appropriate jurisdiction that attempts to restrain, enjoin, or otherwise prohibit the consummation of the Contemplated Transactions, or that grants material damages in connection therewith.

7.05 **Necessary Consents and Approvals**. All Consents from Governmental Bodies and approvals from Governmental Bodies required for the Contemplated Transactions (other than Consents and approvals of assignments by Governmental Bodies that are customarily obtained after Closing) shall have been granted, or the necessary waiting period shall have expired, or early termination of the waiting period shall have been granted.

7.06 **Closing Deliverables**. Seller shall have delivered (or be ready, willing and able to deliver at the Closing) to Buyer the documents and other items required to be delivered by Seller under Section 2.04.

7.07 **Certain Adjustments**. The sum of all Title Defect Values asserted by Buyer in good faith and without taking into account the Aggregate Defect Deductible *plus* all Environmental Defect Values asserted by Buyer in good faith without taking into account the Aggregate Defect Deductible, *plus* the aggregate downward Purchase Price adjustments under Section 11.02, *plus* the aggregate downward Purchase Price adjustments under Section 11.03, *plus* the aggregate downward Purchase Price adjustment under Section 11.09, *plus* the aggregate downward Purchase Price adjustments under Section 11.14, do not exceed an amount equal to twenty percent (20%) of the unadjusted Purchase Price.

7.08 **Credit Support Obligations**. The aggregate cost to Buyer or its Affiliates of obtaining all necessary replacement bonds, letters of credit, and guaranties, and evidence of such other authorizations, qualifications, and approvals required for Buyer to own and operate the Assets after Closing for bonds, letters of credit or guaranties not listed on Schedule 6.03 (or for amounts in excess of those amounts listed on Schedule 6.03) (such costs, the "Excess Credit Support Costs") does not exceed an amount equal to three percent (3%) of the unadjusted Purchase Price; *provided* that if the Excess Credit Support Costs exceed an amount equal to three percent (3%) of the unadjusted Purchase Price, Seller may elect, in its sole discretion, to reduce the Purchase Price by the amount of such excess, in which event the condition set forth in this Section 7.08 shall be deemed satisfied.

ARTICLE 8
CONDITIONS PRECEDENT TO SELLER'S OBLIGATION TO CLOSE

Seller's obligation to sell the Assets and to take the other actions required to be taken by Seller at the Closing is subject to the satisfaction, at or prior to the Closing, of each of the following conditions (any of which may be waived by Seller, in whole or in part):

8.01 **Accuracy of Representations**. All of Buyer's representations and warranties in this Agreement must have been true and correct in all material respects (or, with respect to representations and warranties qualified by materiality or Material Adverse Effect, true and correct in all respects) as of the Execution Date, and must be true and correct in all material respects (or, with respect to representations and warranties qualified by materiality or Material Adverse Effect, true and correct in all respects) as of the Closing Date as if made on the Closing Date, other than any such representation and warranty that refers to a specified date, which need only be true and correct in all material respects (or, if qualified by materiality or Material Adverse Effect, true and correct in all respects) on and as of such specified date.

8.02 **Buyer's Performance**. All of the covenants and obligations that Buyer is required to perform or to comply with pursuant to this Agreement at or prior to the Closing must have been duly performed and complied with in all material respects.

8.03 **No Proceedings**. Since the Execution Date, there must not have been commenced or Threatened against Buyer or against any of its Affiliates, any Proceeding (other than any matter initiated by Seller or an Affiliate of Seller) seeking to restrain, enjoin, or otherwise prohibit or make illegal, or seeking to recover material damages on account of, any of the Contemplated Transactions.

8.04 **No Orders**. On the Closing Date, there shall be no Order pending or remaining in force of any Governmental Body having appropriate jurisdiction that attempts to restrain, enjoin, or otherwise prohibit the consummation of the Contemplated Transactions, or that grants material damages in connection therewith.

8.05 **Necessary Consents and Approvals**. All Consents from Governmental Bodies and approvals from Governmental Bodies required for the Contemplated Transactions (other than Consents and approvals of assignments by Governmental Bodies that are customarily obtained after Closing) shall have been granted, or the necessary waiting period shall have expired, or early termination of the waiting period shall have been granted.

8.06 **Closing Deliverables**. Buyer shall have delivered (or be ready, willing and able to deliver at the Closing) to Seller the documents and other items required to be delivered by Buyer under Section 2.04(b).

8.07 **Qualifications**. Buyer shall have obtained all authorizations, qualifications, and approvals required to be obtained prior to Closing under Section 6.03(a).

8.08 **Certain Adjustments**. The sum of all Title Defect Values asserted by Buyer in good faith and without taking into account the Aggregate Defect Deductible *plus* all Environmental Defect Values asserted by Buyer in good faith without taking into account the Aggregate Defect

Deductible, *plus* the aggregate downward Purchase Price adjustments under Section 11.02, *plus* the aggregate downward Purchase Price adjustments under Section 11.03, *plus* the aggregate downward Purchase Price adjustment under Section 11.09, *plus* the aggregate downward Purchase Price adjustments under Section 11.14, do not exceed an amount equal to twenty percent (20%) of the unadjusted Purchase Price.

ARTICLE 9
TERMINATION

9.01 **Termination Events**. This Agreement may, by written notice given prior to or at the Closing, be terminated:

(a) by mutual written consent of Seller and Buyer;

(b) by Buyer, if Seller has committed a material Breach of this Agreement and such Breach causes any of the conditions to Closing set forth in Article 7 not to be satisfied as of the Scheduled Closing Date (or, if prior to the Scheduled Closing Date, such Breach is of such a magnitude or effect that it will not be possible for such condition to be satisfied as of the Scheduled Closing Date); *provided*, *however*, that in the case of a Breach that is capable of being cured, Seller shall have a period of ten (10) Business Days following receipt of such written notice from Buyer to Seller to attempt to cure the Breach and the termination under this Section 9.01(b) shall not become effective unless Seller fails to cure such Breach prior to the end of such ten (10) Business Day period; *provided*, *further*, Buyer shall not be entitled to terminate this Agreement pursuant to this Section 9.01(b) if Buyer is in material Breach of this Agreement;

(c) by Seller, if Buyer has committed a material Breach of this Agreement and such breach causes any of the conditions to Closing set forth in Article 8 not to be satisfied as of the Scheduled Closing Date (or, if prior to the Scheduled Closing Date, such Breach is of such a magnitude or effect that it will not be possible for such condition to be satisfied as of the Scheduled Closing Date); *provided*, *however*, that in the case of a Breach that is capable of being cured, Buyer shall have a period of ten (10) Business Days following receipt of such written notice from Seller to Buyer to attempt to cure the Breach and the termination under this Section 9.01(c) shall not become effective unless Buyer fails to cure such Breach prior to the end of such ten (10) Business Day period; *provided*, *further*, Seller shall not be entitled to terminate this Agreement pursuant to this Section 9.01(c) if Seller is in material Breach of this Agreement;

(d) by either Seller or Buyer if the Closing has not occurred on or before March 15, 2020 (the "Outside Date"), or such later date as the Parties may agree upon in writing; *provided* that neither Party shall be entitled to terminate this Agreement pursuant to this Section 9.01(d) if such Party is in material Breach of this Agreement;

(e) by either Seller or Buyer if (i) any Legal Requirement has made the consummation of the Contemplated Transactions illegal or otherwise prohibited, or (ii) a Governmental Body has issued an Order, or taken any other action permanently restraining, enjoining, or otherwise prohibiting the consummation of the Contemplated Transactions, and such order, decree, ruling, or other action has become final and nonappealable; or

(f) by Buyer, on any date after the Scheduled Closing Date if the condition set forth in Section 7.08 is not satisfied as of the Scheduled Closing Date.

9.02 **Effect of Termination; Distribution of the Deposit Amount**.

(a) If this Agreement is terminated pursuant to Section 9.01, all further obligations of the Parties under this Agreement shall terminate; *provided* that (i) such termination shall not impair nor restrict the rights of either Party against the other with respect to the Deposit Amount pursuant to Section 9.02(b), and (ii) except to the extent either Party has received the Deposit Amount (or, with respect to Buyer, damages of an amount up to the Deposit Amount) as liquidated damages pursuant to Section 9.02(b), the termination of this Agreement shall not relieve any Party from liability for any failure to perform or observe in any material respect any of its agreements or covenants contained herein which are to be performed or observed at or prior to Closing, except to the extent either Party has received the Deposit Amount (or, with respect to Buyer, damages of an amount up to the Deposit Amount) as liquidated damages pursuant to Section 9.02(b), to the extent such termination results from the material Breach by a Party of any of its covenants or agreements hereunder, the other Party shall be entitled to all remedies available at law or in equity with respect to such Breach and shall be entitled to recover court costs and reasonable attorneys' fees in addition to any other relief to which such Party may be entitled, and the following provisions shall survive the termination: Article 1, Section 2.02, Article 9, Sections 10.03(c), 10.05, 10.06, 10.07, 10.11, 10.12, 10.13, Article 13 (other than Section 13.01) and any such terms as set forth in this Agreement that are necessary to give context to any of the foregoing surviving Sections.

(b) Notwithstanding anything to the contrary in Section 9.02(a):

(i) If Seller has the right to terminate this Agreement pursuant to Section 9.01(c) or pursuant to Section 9.01(d), if at such time Seller could have terminated this Agreement pursuant to Section 9.01(c) (without regard to any cure periods contemplated therein), then, in either case, Seller shall have the right to terminate this Agreement and receive the Deposit Amount as liquidated damages (and not as a penalty). If Seller elects to terminate this Agreement pursuant to this Section 9.02(b)(i) and receive the Deposit Amount as liquidated damages, (x) the Parties shall, within two (2) Business Days of Seller's election, execute and deliver to the Escrow Agent a joint instruction letter directing the Escrow Agent to release the Deposit Amount to Seller via wire transfer of immediately available funds to the account designated by Seller and (y) Seller shall be free to enjoy immediately all rights of ownership of the Assets and to sell, transfer, encumber, or otherwise dispose of the Assets to any Person without any restriction under this Agreement.

(ii) If Buyer has the right to terminate this Agreement pursuant to Section 9.01(b) or pursuant to Section 9.01(d), if at such time Buyer could have terminated this Agreement pursuant to Section 9.01(b) (without regard to any cure periods contemplated therein), then, in either case, Buyer shall have the right, at its sole discretion, to either (1) enforce specific performance by Seller of this Agreement, without posting any bond or the necessity of proving the inadequacy as a remedy of monetary damages, in which event the Deposit Amount will be applied as called for herein, or (2) if Buyer does not seek and successfully enforce specific performance, terminate this Agreement and (in addition to receiving back the Deposit Amount) seek to recover actual damages from Seller in an amount up to, but not exceeding to the Deposit Amount, as liquidated damages (and not as a penalty). If Buyer elects to terminate this Agreement pursuant to this Section 9.02(b)(ii) and seek damages then, within two (2) Business Days of Buyer's election, (x) Seller and Buyer shall execute and deliver to the Escrow Agent a joint instruction letter directing the Escrow Agent to release the Deposit Amount to Buyer via wire transfer of immediately available funds to the account designated by Buyer and (y) Seller shall be free to enjoy immediately all rights of ownership of the Assets and to sell, transfer, encumber, or otherwise dispose of the Assets to any Person without any restriction under this Agreement.

(c) The Parties recognize that the actual damages for a Party's material Breach of this Agreement would be difficult or impossible to ascertain with reasonable certainty and agree that the Deposit Amount would be a reasonable liquidated damages amount for such material Breach.

(d) If this Agreement is terminated by either Buyer or Seller pursuant to Section 9.01 for any reason other than as described in Section 9.02(b), then, in any such case, the Parties shall, within two (2) Business Days of such termination, execute and deliver to the Escrow Agent a joint instruction letter directing the Escrow Agent to release the Deposit Amount to Buyer (free and clear of any claims by Seller thereon) via wire transfer of immediately available funds to the account designated by Buyer.

9.03 **Return of Records Upon Termination**. Upon termination of this Agreement, Buyer shall promptly return to Seller or destroy all title, engineering, geological and geophysical data, environmental assessments and reports, maps, documents and other information furnished by Seller to Buyer in connection with its due diligence investigation of the Assets and an officer of Buyer shall certify Buyer's compliance with the preceding clause (a) to Seller in writing.

ARTICLE 10 INDEMNIFICATION; REMEDIES

10.01 **Survival**. The survival periods for the various representations, warranties, covenants and agreements contained herein shall be as follows: Fundamental Representations shall survive indefinitely, the representations and warranties in Section 3.04 shall survive for the applicable statute of limitations plus sixty (60) days, the representations and warranties in Section 3.24 shall survive for three (3) months after the last day of the Transition Period, the special warranty of Defensible Title set forth in the Instruments of Conveyance shall survive for thirty-six (36) months after Closing, all other representations and warranties of Seller shall survive for twelve (12) months after Closing (except for the representations and warranties in Section 3.14, which shall survive for six (6) months after Closing), all covenants and agreements of the Seller to be performed prior to the Closing shall survive for twelve (12) months after Closing, all covenants and agreements of Seller to be performed on or after Closing shall survive until fully performed and all other representations, warranties, covenants and agreements of Buyer shall survive indefinitely. Representations, warranties, covenants and agreements shall be of no further force and effect after the date of their expiration; *provided* that there shall be no termination of any bona fide claim asserted pursuant to this Agreement with respect to such a representation, warranty, covenant or agreement prior to its expiration date. The indemnities in Sections 10.02(a), 10.02(b), 10.03(a) and 10.03(b) shall terminate as of the termination date of each respective representation, warranty, covenant or agreement that is subject to indemnification thereunder, except in each case as to matters for which a specific written claim for indemnity has been delivered to the indemnifying person on or before such termination date. The indemnities in Section 10.02(c) shall continue indefinitely (except for indemnities related to (a) clause (c) of the definition of "Retained Liabilities," which shall continue for thirty-six (36) months after the Closing, (b) clauses (b) and (i) of the definition of "Retained Liabilities," which shall continue for twenty-four (24) months after the Closing, and (c) indemnity for Seller Taxes, which shall survive for the applicable statute of limitations plus sixty (60) days). All other indemnities, and all other provisions of this Agreement, shall survive the Closing without time limit except as may otherwise be expressly provided herein.

10.02 **Indemnification and Payment of Damages by Seller**. Except as otherwise limited in this Article 10, from and after the Closing, Seller shall defend, release, indemnify, and hold harmless Buyer Group from and against, and shall pay to the Buyer Group the amount of, any and all Damages, whether or not involving a Third Party claim or incurred in the investigation or defense of any of the same or in asserting, preserving, or enforcing any of their respective rights under this Agreement arising from, based upon, related to, or associated with:

(a) any Breach of any representation or warranty made by Seller in this Agreement or any of the other Transaction Documents;

(b) any Breach by Seller of any covenant, obligation, or agreement of Seller in this Agreement or any of the other Transaction Documents;

(c) the Retained Liabilities; and

(d) the use, ownership and operation of the Retained Assets (unless and until such Retained Assets are conveyed to Buyer in accordance with this Agreement) and the Excluded Assets.

Notwithstanding anything to the contrary contained in this Agreement, after the Closing, the remedies provided in this Article 10 and Article 11, along with the special warranty of Defensible Title set forth in the Instruments of Conveyance, are Buyer Group's exclusive legal remedies against Seller with respect to this Agreement and the Contemplated Transactions, including Breaches of the representations, warranties, covenants, obligations, and agreements of the Parties contained in this Agreement or the affirmations of such representations, warranties, covenants, obligations, and agreements contained in the certificate delivered by Seller at Closing pursuant to Section 2.04, and, except for the remedies provided in this Article 10 and Article 11, along with the special warranty of Defensible Title set forth in the Instruments of Conveyance, **BUYER RELEASES SELLER GROUP FROM ANY AND ALL CLAIMS, CAUSES OF ACTION, PROCEEDINGS, OR OTHER LEGAL RIGHTS AND REMEDIES OF BUYER GROUP, KNOWN OR UNKNOWN, WHICH BUYER MIGHT NOW OR SUBSEQUENTLY HAVE, BASED ON, RELATING TO OR IN ANY WAY ARISING OUT OF THIS AGREEMENT, THE CONTEMPLATED TRANSACTIONS, THE OWNERSHIP, USE OR OPERATION OF THE ASSETS PRIOR TO THE CLOSING, OR THE CONDITION, QUALITY, STATUS, OR NATURE OF**

THE ASSETS PRIOR TO THE CLOSING, INCLUDING ANY AND ALL CLAIMS RELATED TO ENVIRONMENTAL MATTERS OR LIABILITY OR VIOLATIONS OF ENVIRONMENTAL LAWS AND INCLUDING RIGHTS TO CONTRIBUTION UNDER THE COMPREHENSIVE ENVIRONMENTAL RESPONSE, COMPENSATION, AND LIABILITY ACT OF 1980, AS AMENDED, BREACHES OF STATUTORY OR IMPLIED WARRANTIES, NUISANCE, OR OTHER TORT ACTIONS, RIGHTS TO PUNITIVE DAMAGES, COMMON LAW RIGHTS OF CONTRIBUTION, AND RIGHTS UNDER INSURANCE MAINTAINED BY SELLER OR ANY OF SELLER'S AFFILIATES. Nothing in this Agreement or otherwise shall release or relieve Seller for actual fraud.

10.03 **Indemnification and Payment of Damages by Buyer**. Except as otherwise provided in this Article 10 and Article 11, along with the special warranty of Defensible Title set forth in the Instruments of Conveyance, from and after the Closing, Buyer shall assume, be responsible for, pay on a current basis, and shall defend, release, indemnify, and hold harmless Seller Group from and against, and shall pay to Seller Group the amount of any and all Damages, whether or not involving a Third Party claim or incurred in the investigation or defense of any of the same or in asserting, preserving, or enforcing any of their respective rights under this Agreement arising from, based upon, related to, or associated with:

(a) any Breach of any representation or warranty made by Buyer in this Agreement or any of the other Transaction Documents;

(b) any Breach by Buyer of any covenant, obligation, or agreement of Buyer in this Agreement or any of the other Transaction Documents;

(c) any Damages arising out of or relating to Buyer's and its Representatives' access to the Assets and contracts, books and records and other documents and data relating thereto prior to the Closing, including Buyer's title and environmental inspections pursuant to Sections 11.01 and 11.10, including Damages attributable to personal injury, illness or death, or property damage; and

(d) the Assumed Liabilities.

Notwithstanding anything to the contrary contained in this Agreement, from and after Closing, the remedies provided in this Article 10 and the special warranty of Defensible Title set forth in the Instruments of Conveyance are Seller Group's exclusive legal remedies for Buyer's Breaches, all other legal rights and remedies being expressly waived by Seller Group.

10.04 **Indemnity Net of Insurance**. The amount of any Damages for which an indemnified Party is entitled to indemnity under this Article 10 shall be reduced by the amount of insurance or indemnification proceeds actually received by the indemnified Party or its Affiliates with respect to such Damages (net of any collection costs, and excluding the proceeds of any insurance policy issued or underwritten, or indemnity granted, by the indemnified Party or its Affiliates).

10.05 **Limitations on Liability**. Except with respect to the Fundamental Representations and the representations and warranties included in Section 3.04, if the Closing occurs, Seller shall not have any liability for any indemnification under Section 10.02(a): for any Damages with respect to any occurrence, claim, award or judgment that do not individually exceed Fifty

Thousand Dollars ($50,000.00) net to Seller's interest (the "Individual Claim Threshold"); or unless and until the aggregate Damages for which claim notices for claims meeting the Individual Claim Threshold are delivered by Buyer exceed two percent (2%) of the unadjusted Purchase Price, and then only to the extent such Damages exceed two percent (2%) of the unadjusted Purchase Price. Except with respect to the Fundamental Representations and the representations and warranties included in Section 3.04, in no event will Seller be liable for Damages indemnified under Section 10.02(a) to the extent such damages, exceed twenty percent (20%) of the unadjusted Purchase Price. Notwithstanding anything herein to the contrary, in no event will Seller's aggregate liability under this Agreement exceed one hundred percent (100%) of the unadjusted Purchase Price.

(b) Notwithstanding anything herein to the contrary, the obligations and rights of the Parties and the Damages, for which any Party is obligated to indemnify or entitled to indemnity under Section 10.02 or Section 10.03 shall be determined and calculated by excluding and without giving effect to any qualifiers as to materiality, Material Adverse Effect or other similar qualifiers set forth in any representation or warranty (including any bringdown of such representation or warranty in any certificate delivered pursuant to this Agreement).

10.06 **Procedure for Indemnification--Third Party Claims**.

(a) Promptly after receipt by an indemnified party under Section 10.02 or 10.03 of a Third Party claim for Damages or notice of the commencement of any Proceeding against it, such indemnified party shall, if a claim is to be made against an indemnifying Party under such Section, give notice to the indemnifying Party of the commencement of such claim or Proceeding, together with a claim for indemnification pursuant to this Article 10. The failure of any indemnified party to give notice of a Third Party claim or Proceeding as provided in this Section 10.06 shall not relieve the indemnifying Party of its obligations under this Article 10 except to the extent such failure results in insufficient time being available to permit the indemnifying Party to effectively defend against the Third Party claim or participate in the Proceeding or otherwise prejudices the indemnifying Party's ability to defend against the Third Party claim or participate in the Proceeding.

(b) If any Proceeding referred to in Section 10.06(a) is brought against an indemnified party and the indemnified party gives notice to the indemnifying Party of the commencement of such Proceeding, the indemnifying Party shall be entitled to participate in such Proceeding and, to the extent that it wishes (unless the indemnifying Party is also a party to such Proceeding and the indemnified party determines in good faith that joint representation would be inappropriate, or the indemnifying Party fails to provide reasonable assurance to the indemnified party of its financial capacity to defend such Proceeding and provide indemnification with respect to such Proceeding), to assume the defense of such Proceeding with counsel reasonably satisfactory to the indemnified party, and, after notice from the indemnifying Party to the indemnified party of the indemnifying Party's election to assume the defense of such Proceeding, the indemnifying Party shall not, as long as it diligently conducts such defense, be liable to the indemnified party under this Article 10 for any fees of other counsel or any other expenses with respect to the defense of such Proceeding, in each case subsequently incurred by the indemnified party in connection with the defense of such Proceeding. Notwithstanding anything to the contrary in this Agreement, the indemnifying Party shall not be entitled to assume or continue control of the defense of any such Proceeding if such

Proceeding relates to or arises in connection with any criminal proceeding, such Proceeding seeks an injunction or equitable relief against any indemnified Party, in the case of an indemnification claim by Buyer pursuant to Section 10.02(a) (other than with respect to a Fundamental Representation or Section 3.04), such Proceeding has or would reasonably be expected to result in Damages in excess of the amount set forth in Section 10.05 (i.e., twenty percent (20%) of the unadjusted Purchase Price), or the indemnifying Party has failed or is failing to defend in good faith such Proceeding. If the indemnifying Party assumes the defense of a Proceeding, no compromise or settlement of such Third Party claims or Proceedings may be effected by the indemnifying Party without the indemnified party's prior written consent unless (A) there is no finding or admission of any violation of Legal Requirements or any violation of the rights of any Person and no effect on any other Third Party claims that may be made against the indemnified party, and (B) the sole relief provided is monetary damages that are paid in full by the indemnifying Party, and (C) an indemnified party shall have no liability with respect to any compromise or settlement of such Third Party claims or Proceedings effected without its consent (to the extent required by the preceding sentence).

10.07 **Procedure for Indemnification – Other Claims**. A claim for indemnification for any matter not involving a Third Party claim may be asserted by notice to the Party from whom indemnification is sought.

10.08 **Indemnification of Group Members**. The indemnities in favor of Buyer and Seller provided in Section 10.08 and Section 10.03, respectively, shall be for the benefit of and extend to such Party's present and former Group members. Any claim for indemnity under this Article 10 by any Group member other than Buyer or Seller must be brought and administered by the relevant Party to this Agreement. No indemnified party other than Buyer and Seller shall have any rights against either Seller or Buyer under the terms of this Article 10 except as may be exercised on its behalf by Buyer or Seller, as applicable, pursuant to this Section 10.08. Each of Seller and Buyer may elect to exercise or not exercise indemnification rights under this Section on behalf of the other indemnified party affiliated with it in its sole discretion and shall have no liability to any such other indemnified party for any action or inaction under this Section.

10.09 **Extent of Representations and Warranties**.

(a) **NOTWITHSTANDING ANYTHING TO THE CONTRARY CONTAINED IN THIS AGREEMENT, EXCEPT AS AND TO THE EXTENT EXPRESSLY SET FORTH IN THIS AGREEMENT, THE CERTIFICATES DELIVERED BY SELLER AT CLOSING OR IN THE INSTRUMENTS OF CONVEYANCE, SELLER MAKES NO REPRESENTATIONS OR WARRANTIES WHATSOEVER, AND DISCLAIMS ALL LIABILITY AND RESPONSIBILITY FOR ANY REPRESENTATION, WARRANTY, STATEMENT, OR INFORMATION MADE OR COMMUNICATED (ORALLY OR IN WRITING) TO BUYER (INCLUDING ANY OPINION, INFORMATION, OR ADVICE THAT MAY HAVE BEEN PROVIDED TO BUYER OR ITS AFFILIATES OR REPRESENTATIVES BY ANY AFFILIATES OR REPRESENTATIVES OF SELLER OR BY ANY INVESTMENT BANK OR INVESTMENT BANKING FIRM, ANY PETROLEUM ENGINEER OR ENGINEERING FIRM, SELLER'S COUNSEL, OR ANY OTHER AGENT, CONSULTANT, OR REPRESENTATIVE OF SELLER). WITHOUT LIMITING THE GENERALITY OF THE FOREGOING, EXCEPT AS AND TO THE EXTENT EXPRESSLY SET FORTH IN THIS AGREEMENT, THE CERTIFICATES DELIVERED BY SELLER AT CLOSING OR IN THE INSTRUMENTS OF CONVEYANCE, SELLER EXPRESSLY DISCLAIMS AND NEGATES ANY REPRESENTATION OR WARRANTY, EXPRESS, IMPLIED,**

AT COMMON LAW, BY STATUTE, OR OTHERWISE, RELATING TO (A) THE TITLE TO ANY OF THE ASSETS, (B) THE CONDITION OF THE ASSETS (INCLUDING ANY IMPLIED OR EXPRESS WARRANTY OF MERCHANTABILITY, FITNESS FOR A PARTICULAR PURPOSE, OR CONFORMITY TO MODELS OR SAMPLES OF MATERIALS), IT BEING DISTINCTLY UNDERSTOOD THAT, EXCEPT AS AND TO THE EXTENT EXPRESSLY SET FORTH IN THIS AGREEMENT, THE CERTIFICATES DELIVERED BY SELLER AT CLOSING OR IN THE INSTRUMENTS OF CONVEYANCE, THE ASSETS ARE BEING SOLD "AS IS," "WHERE IS," AND "WITH ALL FAULTS AS TO ALL MATTERS," (C) ANY INFRINGEMENT BY SELLER OF ANY PATENT OR PROPRIETARY RIGHT OF ANY THIRD PARTY, (D) ANY INFORMATION, DATA, OR OTHER MATERIALS (WRITTEN OR ORAL) FURNISHED TO BUYER BY OR ON BEHALF OF SELLER (INCLUDING THE EXISTENCE OR EXTENT OF HYDROCARBONS OR THE MINERAL RESERVES, THE RECOVERABILITY OF SUCH RESERVES, ANY PRODUCT PRICING ASSUMPTIONS, AND THE ABILITY TO SELL HYDROCARBON PRODUCTION AFTER THE CLOSING), AND (E) THE ENVIRONMENTAL CONDITION AND OTHER CONDITION OF THE ASSETS AND ANY POTENTIAL LIABILITY ARISING FROM OR RELATED TO THE ASSETS.

(b) Buyer acknowledges and affirms that it has made, and prior to Closing will make, its own independent investigation, analysis, and evaluation of the Contemplated Transactions and the Assets (including Buyer's own estimate and appraisal of the extent and value of Seller's Hydrocarbon reserves attributable to the Assets and an independent assessment and appraisal of the environmental risks associated with the acquisition of the Assets). Buyer acknowledges that in entering into this Agreement, it has relied on the aforementioned investigation and the express representations and warranties of Seller contained in this Agreement and the Seller Closing Documents.

10.10 **Compliance With Express Negligence Test**. **THE PARTIES AGREE THAT ANY INDEMNITY, DEFENSE, AND/OR RELEASE OBLIGATION ARISING UNDER THIS AGREEMENT SHALL APPLY WITHOUT REGARD TO THE NEGLIGENCE, STRICT LIABILITY, OR OTHER FAULT OF THE INDEMNIFIED PARTY, WHETHER ACTIVE, PASSIVE, JOINT, CONCURRENT, COMPARATIVE, CONTRIBUTORY OR SOLE, OR ANY PRE-EXISTING CONDITION, ANY BREACH OF CONTRACT OR BREACH OF WARRANTY, OR VIOLATION OF ANY LEGAL REQUIREMENT, EXCEPT TO THE EXTENT SUCH DAMAGES WERE OCCASIONED BY THE GROSS NEGLIGENCE OR WILLFUL MISCONDUCT OF THE INDEMNIFIED PARTY OR ANY GROUP MEMBER THEREOF, IT BEING THE PARTIES' INTENTION THAT DAMAGES TO THE EXTENT ARISING FROM THE GROSS NEGLIGENCE OR WILLFUL MISCONDUCT OF THE INDEMNIFIED PARTY OR ANY GROUP MEMBER THEREOF NOT BE COVERED BY THE RELEASE, DEFENSE, OR INDEMNITY OBLIGATIONS IN THIS AGREEMENT.** The foregoing is a specifically bargained for allocation of risk among the Parties, which the Parties agree and acknowledge satisfies the express negligence rule and conspicuousness requirement under Texas law.

10.11 **Limitations of Liability**. Notwithstanding anything to the contrary contained in this Agreement, **IN NO EVENT SHALL SELLER OR BUYER EVER BE LIABLE FOR, AND EACH PARTY RELEASES THE OTHER FROM, ANY CONSEQUENTIAL, SPECIAL, INDIRECT, EXEMPLARY, OR PUNITIVE DAMAGES OR CLAIMS RELATING TO OR ARISING OUT OF THE CONTEMPLATED TRANSACTIONS OR THIS AGREEMENT**; *provided*, *however*, that any consequential, special, indirect, exemplary, or punitive damages recovered by a Third Party (including a Governmental Body, but excluding any Affiliate of any Group member) against a Person entitled to indemnity pursuant to this Article 10 shall be included in the Damages recoverable under such indemnity.

Notwithstanding the foregoing, lost profits shall not be excluded by this provision as to recovery hereunder to the extent constituting direct Damages.

10.12 **No Duplication**. Any liability for indemnification hereunder shall be determined without duplication of recovery by reason of the state of facts giving rise to such liability constituting a Breach of more than one representation, warranty, covenant, obligation, or agreement herein. Neither Buyer nor Seller shall be liable for indemnification with respect to any Damages based on any sets of facts to the extent the Purchase Price is being or has been adjusted pursuant to Section 2.05 by reason of the same set of facts.

10.13 **Disclaimer of Application of Anti-Indemnity Statutes**. Seller and Buyer acknowledge and agree that the provisions of any anti-indemnity statute relating to oilfield services and associated activities shall not be applicable to this Agreement and/or the Contemplated Transactions.

10.14 **Waiver of Right to Rescission**. Seller and Buyer acknowledge that, following the Closing, the payment of money, as limited by the terms of this Agreement, shall be adequate compensation for Breach of any representation, warranty, covenant or agreement contained herein or for any other claim arising in connection with or with respect to the Contemplated Transactions. As the payment of money shall be adequate compensation, following Closing, Seller and Buyer waive any right to rescind this Agreement or any of the Contemplated Transactions.

ARTICLE 11
TITLE MATTERS AND ENVIRONMENTAL MATTERS; PREFERENTIAL PURCHASE RIGHTS; CONSENTS

11.01 **Title Examination and Access**. Buyer may make or cause to be made at its expense such examination as it may desire of Seller's title to the Assets. For such purposes, until the Closing Date (but excluding the Dead Period), Seller shall give to Buyer and its Representatives access during Seller's regular hours of business to originals and copies (including electronic copies if available), of all of the Records, files, records, contracts, correspondence, maps, data, reports, plats, abstracts of title, lease files, well files, unit files, division order files, production marketing files, title opinions, title files, title records, ownership maps, surveys and any other information, data, records and files that Seller or its Affiliates have relating to the title to the Assets, the past or present operation thereof and the marketing of production therefrom, in accordance with, and subject to the limitations in, Section 5.01.

11.02 **Preferential Purchase Rights**. Seller shall, within ten (10) Business Days after the Execution Date, provide all notices necessary to comply with or obtain the waiver of all Preferential Purchase Rights which are applicable to the Contemplated Transactions prior to the Closing Date and in compliance with the contractual provisions applicable thereto. To the extent any such Preferential Purchase Rights are exercised by any holders thereof or if the time period for exercising any Preferential Purchase Right has not expired, in each case, then the Asset(s) subject to such Preferential Purchase Rights shall not be sold to Buyer and shall be excluded from the Assets and sale under this Agreement and shall be considered Retained Assets. The Purchase Price shall be adjusted downward by the Allocated Value of the Asset(s) so retained. After the Closing, if the holder of such Preferential Purchase Right exercises the Preferential Purchase Right, then Buyer shall convey the affected Asset(s) to such party, and shall receive the consideration for such affected Asset(s) directly from such party. If any holder of a Preferential Purchase Right initially elects to exercise that Preferential Purchase Right, but after the Closing Date, refuses to consummate the purchase of the affected Asset(s), then, subject to the Parties' respective rights and remedies as to the obligation to consummate the Contemplated Transactions, Buyer shall purchase such Asset(s) for the Allocated Value thereof (subject to the adjustments pursuant to Section 2.05), and the closing of such transaction shall take place on a date reasonably designated by Seller not more than sixty (60) days after the Closing Date. If such holder's refusal to consummate the purchase of the affected Asset(s) occurs prior to the Closing Date, then, subject to the Parties' respective rights and remedies as to the obligation to consummate the Contemplated Transactions, Buyer shall purchase the affected Asset(s) at the Closing in accordance with the terms of this Agreement.

11.03 **Consents**. Seller shall within ten (10) Business Days after the Execution Date provide all notices required to comply with or obtain all Consents required for the transfer of the Assets and in compliance with the contractual provisions applicable thereto.

(a) If Seller fails to obtain any Consent necessary for the transfer of any Asset to Buyer, Seller's failure shall be handled as follows:

(i) If the Consent is not a Required Consent and has not been denied in writing, then the affected Assets shall nevertheless be conveyed at the Closing as part of the Assets. Any Damages that arise due to the failure to obtain such Consent shall be borne by Buyer.

(ii) If the Consent is a Required Consent or a Consent that has been denied in writing, the Purchase Price shall be adjusted downward by the Allocated Value of the affected Assets burdened by such Consents (including, with respect to any such Consent burdening a Lease or Applicable Contract, all Leases and Wells affected by the Applicable Contract or Lease for which Consent is refused), and such affected Assets shall be treated as Retained Assets.

(b) Notwithstanding the provisions of Section 11.03(a), if Seller obtains a Consent described in Section 11.03(a)(ii) within sixty (60) days after the Closing, then Seller shall promptly deliver conveyances of the affected Asset(s) to Buyer and Buyer shall pay to Seller an amount equal to the Allocated Value of the affected Asset(s) in accordance with wire transfer instructions provided by Seller (subject to the adjustments set forth in Section 2.05).

11.04 **Title Defects**. Buyer shall notify Seller in writing of any Title Defects ("Title Defect Notice(s)") following Buyer's discovery thereof prior to 5:00 p.m. Central Time on February 7, 2020 (the "Defect Notice Date"). To be effective, each Title Defect Notice shall be in writing and include (a) a description of the alleged Title Defect and the Well or portion thereof affected by such alleged Title Defect (each, a "Title Defect Property"), (b) the Allocated Value of each Title Defect Property, (c) supporting documents reasonably necessary for Seller to verify the existence of the alleged Title Defect, and (d) the Title Defect Value and the computations thereof upon which Buyer's belief is based. To give Seller an opportunity to commence reviewing and curing Title Defects, Buyer may, but shall not be obligated to, give Seller, on a weekly basis prior to the Defect Notice Date, written notice of any alleged Title Defects (as well as any claims that would be claims under the special warranty of Defensible Title set forth in the Instruments of Conveyance) discovered by Buyer during the preceding week, which notice may be preliminary in nature and supplemented prior to the Defect Notice Date; *provided*, that the failure to provide any such preliminary notice shall not affect Buyer's right to assert Title Defects at any time prior to the Defect Notice Date. Except for Buyer's right to indemnification pursuant to Article 10, and subject to Section 11.13, Buyer forever waives, and Seller shall have no liability for, Title Defects not asserted by a Title Defect Notice meeting substantially all of the requirements set forth in the preceding sentence no later than 5:00 p.m. Central Time on the Defect Notice Date.

11.05 **Title Defect Value**. The diminution of value of each Title Defect Property attributable to any Title Defect that burdens, encumbers or affects such Title Defect (the "Title Defect Value") shall be determined as follows:

(a) if the Parties agree on the Title Defect Value, then that amount shall be the Title Defect Value;

(b) if the Title Defect is an Encumbrance that is undisputed and liquidated in amount, then the Title Defect Value shall be the amount necessary to be paid to remove the Title Defect from the Title Defect Property;

(c) if the Title Defect represents a negative discrepancy between (i) Seller's actual Net Revenue Interest for the Title Defect Property as to the currently producing formation and (ii) the Net Revenue Interest set forth for such Title Defect Property in Exhibit B for the currently producing formation, then the Title Defect Value shall be the product of (A) the Allocated Value of such Title Defect Property, *multiplied* by (B) a fraction, the numerator of which is (1) the remainder of (x) the Net Revenue Interest set forth for such Title Defect Property in Exhibit B for the currently producing formation *minus* (y) the actual Net Revenue Interest of Seller for such Title Defect Property and the denominator of which is (2) the Net Revenue Interest set forth for such Title Defect Property in Exhibit B for the currently producing formation;

(d) if the Title Defect with respect to a Well represents an increase of (i) Seller's actual Working Interest for any Title Defect Property over (ii) the Working Interest set forth for such Title Defect Property in Exhibit B (except (A) increases resulting from contribution requirements with respect to defaulting co-owners from and after the Execution Date under applicable operating agreements, or (B) increases to the extent that such increases are accompanied by a proportionate increase in Seller's Net Revenue Interest), then the Title Defect Value shall be the product of
(A) the Allocated Value of such Title Defect Property, *multiplied* by (B) a fraction, the numerator of which is (1) the remainder of (x) the actual Working Interest for such Well for the currently producing formation *minus* (y) the Working Interest set forth for such Title Defect Property in Exhibit B and the denominator of which is (2) the Working Interest set forth for such Title Defect Property in Exhibit B for the currently producing formation; and

(e) if the Title Defect represents an obligation or Encumbrance upon or other defect in title to the Title Defect Property of a type not described above, then the Title Defect Value shall be determined by taking into account the Allocated Value of the Title Defect Property, the portion of the Title Defect Property affected by the Title Defect, the legal effect of the Title Defect, the potential economic effect of the Title Defect over the life of the Title Defect Property, the values placed upon the Title Defect by Buyer and Seller and such other reasonable factors as are necessary to make a proper evaluation.

In no event, however, shall the total of the Title Defect Values related to a particular Asset exceed the Allocated Value of such Asset. The Title Defect Value with respect to a Title Defect shall be determined without any duplication of any costs or losses included in any other Title Defect Value hereunder, or for which Buyer otherwise receives credit in the calculation of the Purchase Price.

11.06 **Seller's Cure or Contest of Title Defects**.

Seller may contest any asserted Title Defect or Buyer's good faith estimate of the Title Defect Value as described in Section 11.06(b) and may seek to cure any asserted Title Defect as described in Section 11.06(a).

(a) Seller shall have the right to cure any Title Defect on or before sixty (60) days after the Defect Notice Date (the "Title Defect Cure Period") by giving written notice to Buyer of its election to cure prior to the Closing Date. During the period of time from Closing to the expiration of the Title Defect Cure Period, Buyer agrees to reasonably cooperate with Seller, including by giving Seller reasonable access during normal business hours to all Records in Buyer's or its Affiliates' possession or control, to the extent necessary or convenient to facilitate Seller's attempt to cure any such Title Defects. An election by Seller to attempt to cure a Title Defect shall be without prejudice to the rights of Seller under Section 11.06(c) or Section 11.15 and shall not constitute an admission against interest or a waiver of Seller's right to dispute the existence, nature or value of, or cost to cure, the alleged Title Defect. If Seller elects to cure and:

(i) actually cures the Title Defect ("Cure"), prior to the Closing, then the Asset affected by such Title Defect shall be conveyed to Buyer at the Closing, and no Purchase Price adjustment will be made for such Title Defect; or

(ii) does not Cure the Title Defect prior to the Closing, then Seller shall:

(A) convey the affected Asset to Buyer and retain the applicable Title Defect Value in the Escrow Account at Closing (or, if such Title Defect Value exceeds the balance of the Escrow Account, Buyer shall deliver the amount of such excess to the Escrow Agent at Closing); *provided*, *however* that (1) if Seller Cures the Title Defect within the time provided in this Section 11.06, then the Parties will instruct the Escrow Agent to release the applicable Title Defect Value (together with any interest thereon) to Seller within two (2) Business Days of Seller providing Buyer with the evidence of such Cure and (2) if the Seller is unable to Cure the Title Defect within the time provided in this Section 11.06, then the Parties will instruct the Escrow Agent to release the applicable Title Defect Value (together with any interest thereon) to the Buyer, unless the Title Defect or Title Defect Value is disputed, in which case subsection (c), below, shall apply; or

(B) if and only if Buyer agrees to this remedy in its sole discretion, indemnify Buyer against all Damages (up to the Allocated Value of the applicable Title Defect Property) resulting from such Title Defect with respect to such Title Defect Property pursuant to an indemnity agreement prepared by Seller in a form and substance reasonably acceptable to Buyer.

(b) If Seller does not elect to cure the Title Defect, subject to Seller's continuing right to dispute the Title Defect, Seller shall convey the affected Asset to Buyer at the Closing and the Purchase Price shall be adjusted downward by the applicable Title Defect Value set forth in the Title Defect Notice for such Asset subject to the provisions of subsection (c) below.

(c) Seller and Buyer shall attempt to agree on the existence and Title Defect Value for all Title Defects. Representatives of the Parties, knowledgeable in title matters, shall meet during the Title Defect Cure Period for this purpose. However, either Party may at any time prior to the final resolution of the applicable Title Defect hereunder submit any disputed Title Defect or the Title Defect Value to arbitration in accordance with the procedures set forth in Section 11.15. If a contested Title Defect or Title Defect Value cannot be resolved prior to Closing, except as otherwise provided herein, the Asset affected by such Title Defect shall nevertheless be conveyed to Buyer at the Closing, and the portion of the Purchase Price equal to the Title Defect Value asserted by Buyer in connection with the disputed Title Defect will be retained in the Escrow Account at Closing (or, if such Title Defect Value exceeds the balance of the Escrow Account, Buyer shall deliver the amount of such excess to the Escrow Agent at Closing). Within two (2) Business Days of such final decision or determination, the Parties will instruct the Escrow Agent to release the amount equal to the finally determined or decided Title Defect Value (together with any interest earned thereon), if any, to Buyer, and the difference between the asserted Title Defect Value and the finally agreed or determined or decided Title Defect Value (together with any interest earned thereon) if any, to Seller.

11.07 **Limitations on Adjustments for Title Defects**. Notwithstanding the provisions of Sections 11.04, 11.05 and 11.06, other than with respect to the special warranty of title to be provided in the Instruments of Conveyance, Seller shall be obligated to adjust the Purchase Price to account for uncured Title Defects only to the extent that the sum of (x) the aggregate Title Defect Values of all uncured Title Defects (the "Aggregate Title Defect Value") *plus* (y) the Aggregate Environmental Defect Value exceeds the Aggregate Defect Deductible. In addition, if the Title Defect Value for any single Title Defect Property is less than the De Minimis Title Defect Cost (and the aggregate of all Title Defect Values for all Title Defects based upon a single matter creating such Title Defect is less than the De Minimis Title Defect Cost), such value shall not be considered in calculating the Aggregate Title Defect Value. The Title Defect Values of all Title Defects affecting any single Title Defect Property shall be aggregated for purposes of determining whether the De Minimis Title Defect Cost has been reached.

11.08 **Title Benefits**.

(a) If Seller discovers any right, circumstance or condition that operates (i) to increase the Net Revenue Interest in the currently producing formation for any Well above that shown in Exhibit B, to the extent the same does not cause a greater than proportionate increase in Seller's Working Interest therein above that shown in Exhibit B, or (ii) to decrease the Working Interest of

Seller in any Well as to the currently producing formation below that shown in Exhibit B for such Well, to the extent the same causes a decrease in Seller's Working Interest for such Well that is proportionately greater than the decrease in Seller's Net Revenue Interest therein below that shown in Exhibit B (each, a "Title Benefit"), then Seller shall, from time to time and without limitation, have the right, but not the obligation, to give Buyer written notice of any such Title Benefits (a "Title Benefit Notice"), as soon as practicable but not later than 5:00 p.m. Central Time on the Defect Notice Date, stating with reasonable specificity the Assets affected (the "Title Benefit Properties"), the particular Title Benefit claimed and the Title Benefit Value (calculated as provided below). Buyer shall also promptly furnish Seller with any Title Benefit Notice (including a description of such Title Benefit and the Assets affected thereby with reasonable specificity) which is discovered by any of Buyer's or any of its Affiliates' Representatives, employees, title attorneys, landmen or other title examiners prior to 5:00 p.m. Central Time on the Defect Notice Date. The increase in value of each Title Benefit Property attributable to any Title Benefit (the "Title Benefit Value") shall be determined by the following methodology, terms and conditions (without duplication): (A) if the Parties agree on the Title Benefit Value, then that amount shall be the Title Benefit Value; (B) if the Title Benefit represents a discrepancy between (1)Seller's actual Net Revenue Interest in the currently producing formation for any Well and (2) the Net Revenue Interest set forth for such Title Benefit Property in Exhibit B for the current producing formation, then the Title Benefit Value shall be the product of (X) the Allocated Value of such Title Benefit Property *multiplied* by (Y) a fraction, the numerator of which is (1) the remainder of (I) the actual Net Revenue Interest for the currently producing formation for such Title Benefit Property *minus*
(II) the Net Revenue Interest of Seller for such Title Defect Property set forth in Exhibit B for the currently producing formation and the denominator of which is (2) the Net Revenue Interest set forth for such Title Benefit Property in Exhibit B for the currently producing formation; and (C)if the Title Benefit is of a type not described above, then the Title Benefit Value shall be determined by taking into account the Allocated Value of the Title Benefit Property, the portion of such Title Benefit Property affected by such Title Benefit, the legal effect of the Title Benefit, the potential economic effect of the Title Benefit over the life of such Title Benefit Property, the values placed upon the Title Benefit by Buyer and Seller and such other reasonable factors as are necessary to make a proper evaluation.

(b) Seller and Buyer shall attempt to agree on the existence and Title Benefit Value for all Title Benefits on or before the end of the Title Defect Cure Period. If Buyer agrees with the existence of the Title Benefit and Seller's good faith estimate of the Title Benefit Value, then the Aggregate Title Defect Value shall be offset by the amount of such Title Benefit Value. If the Parties cannot reach agreement by the end of the Title Defect Cure Period, the Title Benefit or the Title Benefit Value in dispute shall be submitted to arbitration in accordance with the procedures set forth in Section 11.15. Notwithstanding the foregoing, the Parties agree and acknowledge that there shall be no upward adjustment to the Purchase Price for any Title Benefit. If a contested Title Benefit cannot be resolved prior to the Closing, Seller shall convey the affected Asset to Buyer and Buyer shall pay for the Asset at the Closing in accordance with this Agreement as though there were no Title Benefits; *provided*, *however*, if the Title Benefit contest results in a determination that a Title Benefit exists, then the Aggregate Title Defect Value shall be adjusted downward by the Title Benefit Value as determined in such contest (which adjustment shall be made on the Final Settlement Statement).

11.09 **Buyer's Environmental Assessment**. Beginning on the Execution Date and ending at 5:00 p.m. Central Time on the Defect Notice Date (but excluding the Dead Period), Buyer shall have the right, at its sole cost, risk, liability and expense, to conduct a Phase I Environmental Site Assessment of the Assets. During Seller's regular hours of business (but excluding the Dead Period) and after providing Seller with written notice of any such activities no less than two (2) Business Days in advance (subject to the written permission of any applicable Third Party operator or other Third Party whose permission is legally required, which Seller shall reasonably cooperate with Buyer in securing), Buyer and its Representatives shall be permitted to enter upon the Assets, inspect the same, review all of Seller's readily-available files and records (other than those for which Seller has an attorney-client privilege or that are Excluded Assets) relating to the Assets, and generally conduct visual, non-invasive tests, examinations and investigations. No sampling or other invasive inspections of the Assets may be conducted prior to Closing without Seller's prior written consent, which may be withheld in Seller's sole discretion. Buyer's access shall be in accordance with, and subject to the limitations in, Section 5.01. Notwithstanding anything in this Agreement to the contrary, (a) if Buyer is not granted access to any Asset to conduct its Phase I Environmental Site Assessment of the Assets, Buyer may elect, in its sole discretion, to exclude such Asset, together with all associated Assets, and reduce the Purchase Price by the Allocated Value of such Assets (which will become Retained Assets), and
(b) if Buyer determines in good faith that (based on the results of its Phase I Environmental Site Assessment) sampling or testing of environmental media or operation of equipment is recommended on an Asset to confirm the existence of or the Environmental Defect Value and Buyer is not granted permission and access to conduct such activities, then (x) Buyer may nevertheless assert an Environmental Defect on such Asset, or (y) Buyer may elect to exclude such Asset, together with all associated Assets, and reduce the Purchase Price by the Allocated Value of such Asset(s) (which will become Retained Assets).

11.10 **Environmental Defect Notice**. Buyer shall notify Seller in writing of any Environmental Defect ("Environmental Defect Notice(s)") following Buyer's discovery thereof prior to 5:00 p.m. Central Time on the Defect Notice Date. To be effective, each Environmental Defect Notice shall be in writing and include: (i) the Asset(s) affected; (ii) a reasonably detailed description of the alleged Environmental Defect and the basis for such assertion under the terms of this Agreement; (iii) Buyer's good faith estimate of the Environmental Defect Value with respect to such Environmental Defect; and (iv) appropriate documentation reasonably necessary for Seller to substantiate Buyer's claim and calculation of the Environmental Defect Value. Notwithstanding anything herein to the contrary, except for Buyer's right to indemnification pursuant to Article 10, and subject to Section 11.13, Buyer forever waives Environmental Defects not asserted by an Environmental Defect Notice meeting substantially all of the requirements set forth in the preceding sentence no later than 5:00 p.m. Central Time on the Defect Notice Date. **NOTWITHSTANDING ANYTHING HEREIN TO THE CONTRARY, EXCEPT FOR BUYER'S RIGHT TO INDEMNIFICATION PURSUANT TO ARTICLE 10, AND SUBJECT TO SECTION 11.13, BUYER FOREVER WAIVES, AND SELLER SHALL HAVE NO LIABILITY FOR, ENVIRONMENTAL DEFECTS NOT ASSERTED BY AN ENVIRONMENTAL DEFECT NOTICE MEETING SUBSTANTIALLY ALL OF THE REQUIREMENTS SET FORTH IN THE PRECEDING SENTENCE BY THE DEFECT NOTICE DATE.**

11.11 **Exclusion, Cure or Contest of Environmental Defects**. Except as otherwise provided for in Section 11.09, (x) either Party, in its sole discretion, may elect to exclude at Closing any Asset (which will become a Retained Asset) affected by an asserted Environmental Defect if the Environmental Defect Value with respect to such Environmental Defect equals or exceeds the Allocated Value of the affected Asset(s) and reduce the Purchase Price by the Allocated Value(s) thereof and (y) Seller, in its sole discretion, (1) may contest any asserted Environmental Defect or Buyer's good faith estimate of the Environmental Defect Value as described in Section 11.11(b) and/or (2) may seek to remediate or cure any asserted Environmental Defect to the extent of the Lowest Cost Response as described in Section 11.11(a); *provided*, *however*, that if Seller, in accordance with clause (1) above, contests Buyer's good faith estimate of the Environmental Defect Value of any Asset which Buyer has elected to exclude in accordance with this Section 11.11, then the applicable Asset shall be excluded from the Closing until the dispute as to the Environmental Defect Value with respect to such Asset is resolved pursuant to Section 11.15.

(a) Seller shall have the right to remediate or cure an Environmental Defect to the extent of the Lowest Cost Response on or before the Closing Date (the "Environmental Defect Cure Period") by giving written notice to Buyer to that effect prior to the Closing Date. If Seller elects to pursue remediation or cure as set forth in this clause (a), Seller shall implement such remediation or cure in a manner that is in compliance with all applicable Legal Requirements in a prompt and timely fashion for the type of remediation or cure. If Seller elects to pursue remediation or cure and:

(i) completes a Complete Remediation of an Environmental Defect prior to the Closing Date, the affected Asset(s) shall be included in the Assets conveyed at Closing, and no Purchase Price adjustment will be made for such Environmental Defect; or

(ii) does not complete a Complete Remediation prior to the Closing, unless Seller or Buyer elects to exclude such affected Asset(s) in accordance with Section 11.09 or this Section 11.11, then Seller shall convey the affected Asset(s) to Buyer and retain the applicable Environmental Defect Value set forth in the Environmental Defect Notice for the affected Asset(s) in the Escrow Account at Closing (or, if such Environmental Defect Value(s) exceed the balance of the Escrow Account, Buyer shall deliver the amount of such excess to the Escrow Agent at Closing); *provided* that (i) if the Seller completes a Complete Remediation of the Environmental Defect prior to the end of the Environmental Defect Cure Period, the Parties will instruct the Escrow Agent to release the amount equal to the associated Environmental Defect Value (together with any interest thereon) to Seller within two (2) Business Days or (ii) if the Seller does not complete a Complete Remediation of the Environmental Defect prior to the end of the Environmental Defect Cure Period, the Parties will instruct the Escrow Agent to release the amount equal to the associated Environmental Defect Value (together with any interest thereon) to the Buyer within two (2) Business Days.

(b) Seller and Buyer shall attempt to agree on the existence and Environmental Defect Value of all Environmental Defects. Representatives of the Parties, knowledgeable in environmental matters, shall meet for this purpose. However, a Party may at any time prior to the final resolution of the applicable Environmental Defect hereunder elect to submit any disputed item to arbitration in accordance with the procedures set forth in Section 11.15. If a contested Environmental Defect not otherwise excluded under the provisions of Section 11.09 or Section 11.11 cannot be resolved prior to the Closing, the affected Asset(s) shall be included with the Assets conveyed to Buyer at Closing and the portion of the Purchase Price equal to the estimated Environmental Defect Value set forth in the Environmental Defect Notice for such contested Environmental Defect will be retained in the Escrow Account at Closing (or, if such Environmental Defect Value(s) exceed the balance of the Escrow Account, Buyer shall deliver the amount of such excess to the Escrow Agent at Closing), and the final determination of the Environmental Defect and/or Environmental Defect Value shall be resolved pursuant to Section 11.15. Within five (5) Business Days of such final determination, the Parties will instruct the Escrow Agent to release the amount equal to the finally determined Environmental Defect Value (together with any interest earned thereon), if any, to Buyer, and the difference between the asserted Environmental Defect Value and finally determined Environmental Defect Value (together with any interest earned thereon) if any, to Seller. If Seller is the operator of record of any Assets excluded pursuant to Section 11.11 and such exclusion is contested by Seller pursuant to Section 11.11, pending resolution of such dispute pursuant to Section 11.15 ("Excluded Seller- Operated Assets") then, if Closing occurs, (i) prior to the expiration of the Transition Period the Parties shall enter into a Management Services Agreement in a form to be agreed to by the Parties (the "Management Services Agreement") and (ii) from and after the expiration of the Transition Period, Buyer shall operate such Excluded Seller-Operated Assets on behalf of Seller in accordance with the terms set forth in the Management Services Agreement until (x) five (5) Business Days following the date such dispute is finally resolved pursuant to Section 11.15, if it is determined that Buyer is entitled to exclude such Excluded Seller-Operated Asset pursuant to Section 11.11, or (y) the date on which such Excluded Seller-Operated Asset is conveyed to Buyer, if it is determined that Buyer is not entitled to exclude such Excluded Seller-Operated Asset pursuant to Section 11.11.

11.12 **Limitations**. Notwithstanding the provisions of Section 11.09 and 11.11, no adjustment to the Purchase Price for Environmental Defect Values shall be made unless and until the sum of (x) the aggregate value of all Environmental Defect Values (the "Aggregate Environmental Defect Value") *plus* (y) the Aggregate Title Defect Value (after taking into account any offsetting Title Benefit Values) exceeds the Aggregate Defect Deductible. If the Environmental Defect Value with respect to any single Environmental Defect is less than the De Minimis Environmental Defect Cost, such cost shall not be considered in calculating the Aggregate Environmental Defect Value; *provided, however*, Environmental Defects that are similar in nature (e.g., missing air permit) and arising from the same underlying facts or conditions affecting the same Asset may be aggregated for the purposes of determining whether the De Minimis Environmental Defect Cost has been reached.

11.13 **Exclusive Remedies**. Except as otherwise provided for under this Agreement, the rights and remedies granted to Buyer in this Article 11 are the exclusive rights and remedies against Seller related to any Environmental Condition, or Damages related thereto. **OTHER THAN WITH RESPECT TO BUYER'S RIGHT TO INDEMNIFICATION UNDER ARTICLE 10 ARISING FROM A BREACH OF THE REPRESENTATIONS IN SECTION 3.14, BUYER EXPRESSLY WAIVES, AND RELEASES SELLER GROUP FROM, ANY AND ALL OTHER RIGHTS AND REMEDIES IT MAY HAVE UNDER ENVIRONMENTAL LAWS AGAINST SELLER REGARDING ENVIRONMENTAL CONDITIONS, WHETHER FOR CONTRIBUTION, INDEMNITY OR OTHERWISE.** The foregoing is a specifically bargained for allocation of risk among the Parties, which the Parties agree and acknowledge satisfies the express negligence rule and conspicuousness requirement under Texas law.

11.14 **Casualty Loss and Condemnation**. If, after the Execution Date but prior to the Closing Date, any portion of the Assets is destroyed by fire or other casualty or is expropriated or taken in condemnation or under right of eminent domain (a "Casualty Loss"), this Agreement shall remain in full force and effect, and Buyer and Seller shall, subject to the conditions to Closing set forth in Article 7 and Article 8, as applicable, nevertheless be required to close the Contemplated Transactions. In the event that the amount of the costs and expenses associated with repairing or restoring the Assets affected by such Casualty Loss exceeds One Hundred Fifty Thousand Dollars ($150,000) net to Seller's interest, (except to the extent Seller has, prior to the Closing, caused the Assets affected by such Casualty Loss to be repaired or restored to at least a substantially similar condition as prior to such Casualty Loss, at Seller's sole cost and expense) the unadjusted Purchase Price will be reduced at Closing by the aggregate amount necessary to repair or restore the affected Asset(s) to a substantially similar condition as prior to such Casualty Loss (as determined by Buyer in good faith).

11.15 **Expert Proceedings**.

(a) Each matter referred to this Section 11.15 (a "Disputed Matter") shall be conducted in accordance with the Commercial Arbitration Rules of the AAA as supplemented to the extent necessary to determine any procedural appeal questions by the Federal Arbitration Act (Title 9 of the United States Code), but only to the extent that such rules do not conflict with the terms of this Section 11.15. Any notice from one Party to the other referring a dispute to this Section 11.15 shall be referred to herein as an "Expert Proceeding Notice".

(b) The arbitration shall be held before a one member arbitration panel (the "Expert"), mutually agreed by the Parties. Unless waived in writing by the Parties, the Expert must be a neutral party who has never been an officer, director or employee of or performed material work for a Party or any Party's Affiliate within the preceding five (5)-year period and agree in writing to keep strictly confidential the specifics and existence of the dispute as well as all proprietary records of the Parties reviewed by the Expert in the process of resolving such dispute. The Expert must have not less than ten (10) years' experience as a lawyer or consultant in the state where the Assets giving rise to the Disputed Matter are located with experience in exploration and production issues related to title or environmental matters as applicable. If disputes exist with respect to both title and environmental matters, the Parties may mutually agree to conduct separate arbitration proceedings with the title disputes and environmental disputes being submitted to separate Experts. If, within five (5) Business Days after delivery of an Expert Proceeding Notice, the Parties cannot mutually agree on an Expert, then within seven (7) Business Days after delivery of such Expert Proceeding Notice, each Party shall provide the other with a list of three (3) acceptable, qualified experts, and within ten (10) Business Days after delivery of such Expert Proceeding Notice, the Parties shall each separately rank from one through six in order of preference each proposed expert on the combined lists, with a rank of one being the most preferred expert and the rank of six being the least preferred expert, and provide their respective rankings to the Houston office of the AAA. Based on those rankings, the AAA will appoint the expert with the combined lowest numerical ranking to serve as the Expert for the Disputed Matters. If the rankings result in a tie or the AAA is otherwise unable to determine an Expert using the Parties' rankings, the AAA will appoint an arbitrator from one of the Parties' lists as soon as practicable upon receiving the Parties' rankings. Each Party will be responsible for paying one-half (1/2) of the fees charged by the AAA for the services provided in connection with this Section 11.15(b).

(c) Within five (5) Business Days following the receipt by either Party of the Expert Proceeding Notice, the Parties will exchange their written description of the proposed resolution of the Disputed Matters. *Provided* that no resolution has been reached, within five (5) Business Days following the selection of the Expert, the Parties shall submit to the Expert the following: this Agreement, with specific reference to this Section 11.15 and the other applicable provisions of this Article 11, Buyer's written description of the proposed resolution of the Disputed Matters, together with any relevant supporting materials, Seller's written description of the proposed resolution of the Disputed Matters, together with any relevant supporting materials, and the Expert Proceeding Notice.

(d) The Expert shall make its determination by written decision within fifteen (15) days following receipt of the materials described in Section 11.15(c) above (the "Expert Decision"). The Expert Decision with respect to the Disputed Matters shall be limited to the selection of the single proposal for the resolution of the aggregate Disputed Matters proposed by a Party that best reflects the terms and provisions of this Agreement, *i.e.*, the Expert must select either Buyer's proposal or Seller's proposal for resolution of the aggregate Disputed Matters.

(e) The Expert Decision shall be final and binding upon the Parties, without right of appeal, absent manifest error. In making its determination, the Expert shall be bound by the rules set forth in this Article 11. The Expert may consult with and engage disinterested Third Parties to advise the Expert, but shall disclose to the Parties the identities of such consultants. Unless waived in writing by the Parties, any such consultant shall not have worked as an employee or consultant for either Party or its Affiliates during the five (5)-year period preceding the arbitration nor have any financial interest in the dispute.

(f) The Expert shall act as an expert for the limited purpose of determining the specific matters submitted for resolution herein and shall not be empowered to award damages, interest, or penalties to either Party with respect to any matter. Each Party shall bear its own legal fees and other costs of preparing and presenting its case. All costs and expenses of the Expert shall be borne by the non-prevailing Party in any such arbitration proceeding.

ARTICLE 12 EMPLOYMENT MATTERS

12.01 **Seller Benefit Plans**. Effective as of immediately prior to the applicable Employee Start Date, (a) each Continuing Employee shall cease to accrue further benefits and shall cease to be active participants under the Seller Benefit Plans and (b) Seller or its Affiliate (i) shall terminate the employment of such Continuing Employee and (ii) as applied to Continuing Employees' employment with Buyer or its Affiliate, hereby waives and releases any non-competition agreements or obligations between Seller or any of its Affiliates and such Continuing Employee that would restrict or encumber such Continuing Employee's ability to perform any of his or her duties as an employee of Buyer or its Affiliate. Neither Buyer nor any of its Affiliates shall assume any of the Seller Benefits Plans.

12.02 **Claims under Seller Benefit Plans**. To the extent that an Available Employee was a participant in a Seller Benefit Plan, the Seller Benefit Plans shall be responsible for providing welfare benefits (including medical, hospital, dental, accidental death and dismemberment, life, disability and other similar benefits) to any participating Available Employees for all claims incurred prior to their Employee Start Date under and subject to the generally applicable terms and conditions of such plans. For purposes of this Section 12.02, a claim is incurred with respect to accidental death and dismemberment, disability, life and other similar benefits when the event giving rise to such claim occurred and medical, hospital, dental and other similar benefits when the services with respect to such claim are rendered.

12.03 **Available Employees' Offers and Post-Employee Start Date Employment and Benefits**.

(a) Within two (2) Business Days of the Execution Date, Seller shall deliver to Buyer a schedule that includes a list of all Available Employees (the "Employee Letter"). The Employee Letter shall include the following with respect to each Available Employee: name, job title, principal location of employment, base salary or hourly rate of pay in effect as of the Execution Date, total compensation paid in 2018, vacation allotment, status as exempt or non-exempt under the Fair Labor Standards Act, as amended, annual cash bonus or incentive compensation target, start date, details of any visa or work permit, and any vehicle described on Exhibit D assigned to the Available Employee by the Seller. The Available Employees represent the entirety of the individuals whose employment principally involves providing or performing services with respect to the Assets.

(b) Beginning five (5) Business Days following the Execution Date, Seller or its Affiliate shall make available to Buyer or its Affiliate upon request reasonable access to the Available Employees for the purpose of interviewing such Available Employees and of making employment offers, or evaluating such Available Employees for employment offers, as contemplated in this Section 12.03 and in compliance with applicable law. Beginning ten (10) Business Days following the Execution Date and ending eight (8) Business Days prior to the anticipated Closing Date, Buyer or its Affiliate may make offers of employment to those Available Employees to whom Buyer or its Affiliate elects to make an offer of employment on such terms as Buyer or its Affiliate may determine, in their sole discretion, with such offers providing such Available Employees at least five (5) Business Days to either accept or reject such offers, and providing for a start date of the day following the last day of the Transition Period. Buyer will provide copies of all offers made to Available Employees to Seller promptly after making such offers, regardless of whether such offer is accepted or rejected by the Available Employee. Seller and its Affiliates shall not interfere with any such employment offer or negotiations by Buyer or its Affiliate or discourage any Available Employee from accepting employment with Buyer or its Affiliates.

(c) No later than the date that is three (3) Business Days prior to the anticipated Closing Date, Buyer shall notify Seller as to each Available Employee who has accepted employment with Buyer or any of its Affiliates, which acceptance shall be conditioned upon the occurrence of the Closing and may be conditioned on the satisfaction of Buyer's or its Affiliate's applicable pre-employment screening processes, and each Available Employee who has rejected Buyer's offer of employment. Buyer shall indemnify and hold harmless Seller and its Affiliates with respect to all Damages relating to or arising out of Buyer's or its Affiliates' employee selection and employment offer process described in this Section 12.03 (including any claim of discrimination or other illegality in such selection and offer process). Buyer's or Buyer's Affiliate's employment offers to Available Employees shall, in each case, be effective as of the day following the last day of the Transition Period; *provided*, *however*, if an Available Employee is on a long-term leave of absence (including medical leave, short-term or long-term disability, or other similar leave, but excluding vacation, paid time off and parental leave), Buyer or Buyer's Affiliate's employment offer to such Available Employee shall be effective as of the date on which the applicable Available Employee returns from such leave of absence (so long as such return occurs within ninety (90) days after the expiration of the Transition Period or such later time as may be required by applicable Legal Requirements).

(d) **Buyer shall indemnify and hold harmless Seller and its Affiliates with respect to all Damages relating to or arising out of Buyer's or its Affiliate's employee selection and employment offer process described in this Section 12.03 (including any claim of discrimination or other illegality in such selection and offer process).**

(e) As to each Available Employee who does not become a Continuing Employee, Buyer agrees that it and its Affiliates shall not employ such Available Employee from the Closing Date to a date that is three (3) months from the Closing Date.

(f) **Buyer shall indemnify, defend and hold Seller and its Affiliates harmless from and against any and all liability of any kind or nature arising from the employment of the Continuing Employees by Buyer after his or her Employee Start Date, including any liability related to any employee benefit plan sponsored or maintained by Buyer or its ERISA Affiliates after the Employee Start Date**. **Seller shall indemnify, defend and hold Buyer and its Affiliates harmless from and against any and all liability of any kind or nature or related to (a) the employment of any Available Employee who does not become a Continuing Employee, including any liability related to any Seller Benefit Plan and (b) the employment of the Continuing Employees by Seller before the Employee Start Date, including any liability related to any employee benefit plan sponsored or maintained by Seller or its ERISA Affiliates before the Employee Start Date.**

12.04 **Health Coverage**. Following the applicable Employee Start Date, Buyer or its Affiliate shall make available to each Continuing Employee the opportunity to elect to participate, effective as of the Employee Start Date, in Buyer's or its Affiliate's group health plan covering similarly situated employees of Buyer or its Affiliate, as applicable. Seller shall provide continuation health care coverage to all individuals who are M&A qualified beneficiaries (within the meaning assigned to such term under Q&A-4 of Treasury Regulation Section 54.4980B-9 other than any Continuing Employees and/or their dependents whose qualifying event occurs as a result of the Contemplated Transactions) in accordance with the continuation health care coverage requirements of Section 4980B of the Code and Title I, Subtitle B, Part 6 of ERISA ("COBRA") or any similar provisions of any state Legal Requirement. Seller and its Affiliates shall not be required and shall have no obligation to offer or to provide continuation coverage under COBRA or any similar provisions of any state Legal Requirement to any Continuing Employees and/or their dependents after they become employees of the Buyer.

12.05 **WARN Act**. From the date of this Agreement until the expiration of the Transition Period, Seller shall not and shall cause its Affiliates not to terminate the employment of any Available Employees such that a "plant closing" or "mass layoff" (as those terms are defined in the WARN Act or any similar state Legal Requirement) occurs prior to the expiration of the Transition Period without complying with the WARN Act. Buyer agrees that it or its Affiliate will make offers of employment, as described in Section 12.03, to a sufficient number of Available Employees and on terms and conditions of employment such that there will be no notice or other obligations with respect to an Available Employee required by the WARN Act as a result of the transactions contemplated by this Agreement. Buyer agrees to provide any notice required under the WARN Act or any similar state Legal Requirement with respect to any “plant closing” or “mass layoff” affecting Continuing Employees that may occur on or after the expiration of the Transition Period. Buyer shall indemnify, defend and hold Seller harmless from and against any liability, damages, fines or costs (including reasonable attorneys’ fees) under the WARN Act or any similar state Legal Requirement owed to any Available Employee for any “plant closing” or “mass layoff” occurring on or after the expiration of the Transition Period. In addition, Buyer shall not effectuate a “plant closing” or “mass layoff” or any other similar triggering event under the WARN Act or any other applicable Legal Requirement for six (6) months after the Employee Start Date, affecting any Continuing Employee, except in compliance with the WARN Act or other applicable Legal Requirement.

12.06 **No Third Party Beneficiary Rights**. Nothing herein, expressed or implied, shall confer upon any Available Employees (or any of their beneficiaries or alternate payees) any rights or remedies (including any right to employment or continued employment, or any right to compensation or benefits for any period) of any nature or kind whatsoever, under or by reason of this Agreement or otherwise. In addition, the provisions of this Article 12, are for the sole benefit of the Parties and are not for the benefit of any Third Party. Nothing in this Article 12, express or implied, shall be deemed an amendment of any plan providing benefits to any Available Employee, or construed to prevent Buyer or its Affiliates from terminating or modifying to any extent or in any respect any employee benefit plan that Buyer or its Affiliates may establish or maintain.

ARTICLE 13 GENERAL PROVISIONS

13.01 **Records**. Seller, at Buyer’s cost and expense, shall deliver (a) all pay decks and divisions of interest related to the Assets at the Closing, (b) all electronic Records to Buyer as soon as practicable after the Closing, and (c) all other Records (including electronic Records previously not provided pursuant to clause (b)) to Buyer no later than thirty (30) days after the expiration of the Transition Period. With respect to any original Records delivered to Buyer, (a) Seller shall be entitled to retain copies of such Records, and (b) Buyer shall retain any such original Records for at least seven (7) years beyond the Closing Date, during which seven (7)-year period Seller shall be entitled to obtain access to such Records, at reasonable business hours and upon prior notice to Buyer, so that Seller may make copies of such original Records, at its own expense, as may be reasonable or necessary for Tax purposes or in connection with any Proceeding or Threatened Proceeding against Seller.

13.02 **Expenses and Tax Matters**.

(a) Except as otherwise expressly provided in this Agreement, each Party to this Agreement shall bear its respective expenses incurred in connection with the preparation, execution, and performance of this Agreement and the Contemplated Transactions, including all fees and expenses of agents, representatives, counsel, and accountants. However, the prevailing Party in any Proceeding brought under or to enforce this Agreement, excluding any expert proceeding pursuant to Section 11.15 or Section 2.05(e), shall be entitled to recover court costs and arbitration costs, as applicable, and reasonable attorneys' fees from the non-prevailing Party or Parties, in addition to any other relief to which such Party is entitled.

(b) (i) All Transfer Taxes in connection with the filing and recording of the assignments, conveyances or other Instruments of Conveyance required to convey title to the Assets to Buyer shall be borne by Buyer.

(ii) Seller shall be allocated and bear all Asset Taxes attributable to any Tax period ending prior to the Effective Time and the portion of any Straddle Period ending immediately prior to the Effective Time. Buyer shall be allocated and bear all Asset Taxes attributable to (x) any Tax period beginning at or after the Effective Time and (y) the portion of any Straddle Period beginning at the Effective Time; *provided*, however, that Seller (not Buyer) shall be allocated and bear the portion, if any, of any such Asset Taxes that consist of penalties, interest or additions to tax to the extent attributable to a breach by a Seller Party of the representations set forth in Section 3.04. For purposes of determining the allocations described in this Section 13.02(b), (i) Asset Taxes that are attributable to the severance or production of Hydrocarbons (other than such Asset Taxes described in clause (iii), below) shall be allocated to the period in which the severance or production giving rise to such Asset Taxes occurred, (ii) Asset Taxes that are based upon or related to sales or receipts or imposed on a transactional basis (other than such Asset Taxes described in clause (i) or (iii)), shall be allocated to the period in which the transaction giving rise to such Asset Taxes occurred, and (iii) Asset Taxes that are ad valorem, property or other Asset Taxes imposed on a periodic basis pertaining to a Straddle Period shall be allocated between the portion of such Straddle Period ending immediately prior to the Effective Time and the portion of such Straddle Period beginning at the Effective Time by prorating each such Asset Tax based on the number of days in the applicable Straddle Period that occur before the date on which the Effective Time occurs, on the one hand, and the number of days in such Straddle Period that occur on or after the date on which the Effective Time occurs, on the other hand. For purposes of the preceding sentence, any exemption, deduction, credit or other item that is calculated on an annual basis shall be allocated pro rata per day between the portion of the Straddle Period ending immediately prior to the Effective Time and the portion of the Straddle Period beginning at the Effective Time. To the extent the actual amount of any Asset Taxes described in this Section 13.02(b) is not determinable at Closing, Buyer and Seller shall utilize the most recent information available in estimating the amount of such Asset Taxes for purposes of Section 2.05.

(iii) Upon determination of the actual amount of such Asset Taxes and Transfer Taxes, timely payments will be made from one Party to the other to the extent necessary to cause each Party to bear the amount of such Asset Tax and Transfer Tax that is allocable to such Party under this Section 13.02(b). Any allocation of Asset Taxes and Transfer Taxes between the Parties shall be in accordance with this Section 13.02(b).

(c) Except as required by applicable Legal Requirements, in respect of Asset Taxes, Seller shall be responsible for timely remitting all Asset Taxes due with respect to the Assets on or prior to the Effective Time (subject to Seller's right to reimbursement by Buyer under Section 13.02(b)), and Buyer shall be responsible for timely remitting all Asset Taxes due with respect to the Assets after the Effective Time (subject to Buyer's right to reimbursement by Seller under Section 13.02(b)), in each case, to the applicable taxing authority, and Seller shall prepare and timely file any Tax Return for Asset Taxes with respect to the Assets required to be filed on or before the Closing Date, and Buyer shall prepare and timely file any Tax Return for Asset Taxes with respect to the Assets required to be filed after the Closing Date (including Tax Returns relating to any Straddle Period). Each Party shall indemnify and hold the other Party harmless for any failure to file such Tax Returns and to make such payments. Buyer shall prepare all such Tax Returns relating to any Straddle Period on a basis consistent with past practice except to the extent otherwise required by applicable Legal Requirements. Buyer shall provide Seller with a copy of any Tax Return relating to any Straddle Period for Seller's review at least ten (10) days prior to the due date for the filing of such Tax Return (or within a commercially reasonable period after the end of the relevant Taxable period, if such Tax Return is required to be filed less than ten (10) days after the close of such Taxable period), and Buyer shall incorporate all reasonable comments of Seller provided to Buyer in advance of the due date for the filing of such Tax Return.

(d) Buyer and Seller agree to furnish or cause to be furnished to the other, upon request, as promptly as practicable, such information and assistance relating to the Assets, including access to books and records, as is reasonably necessary for the filing of all Tax Returns by Buyer or Seller, the making of any election relating to taxes, the preparation for any audit by any taxing authority and the prosecution or defense of any claim, suit or Proceeding relating to any tax. The Parties agree to retain all books and records with respect to Tax matters pertinent to the Assets relating to any Tax period beginning before the Closing Date until sixty (60) days after the expiration of the statute of limitations of the respective Tax periods (taking into account any extensions thereof) and to abide by all record retention agreements entered into with any taxing authority.

13.03 **Notices**. All notices, consents, waivers, and other communications under this Agreement must be in writing and shall be deemed to have been duly given when (a) delivered by hand (with written confirmation of receipt), (b) sent by electronic mail with receipt acknowledged, with the receiving Party affirmatively obligated to promptly acknowledge receipt, or (c) when received by the addressee, if sent by a nationally recognized overnight delivery service (receipt requested), in each case to the appropriate recipients, addresses, and emails set forth below (or to such other recipients, addresses, or emails as a Party may from time to time designate by notice to the other Party):

NOTICES TO BUYER:

Crescent Pass Energy, LLC 19500 State Hwy
249, Suite 570
Houston, TX 77070
Attention: Tyler Fenley, Chief Executive Officer E-mail:
tyler@crescentpass.com
With copy to (which shall not constitute a notice): Talara Capital
Management, LLC
712 Main St Suite 920
Houston, TX 77002
Attention: David Young, Director E-mail:
dyoung@talaracapital.com

NOTICES TO SELLER:

Riviera Operating, LLC Riviera
Upstream, LLC
600 Travis Street, Suite 1700
Houston, Texas 77002 Attention:
General Counsel
E-mail: Handerson@Rvraresources.com

13.04 **Governing Law; Jurisdiction; Service of Process; Jury Waiver**. **THIS AGREEMENT AND ANY CLAIM, CONTROVERSY OR DISPUTE ARISING UNDER OR RELATED TO THIS AGREEMENT OR THE TRANSACTIONS CONTEMPLATED HEREBY OR THE RIGHTS, DUTIES AND THE LEGAL RELATIONS AMONG THE PARTIES HERETO AND THERETO SHALL BE GOVERNED AND CONSTRUED IN ACCORDANCE WITH THE LAWS OF THE STATE OF TEXAS, EXCLUDING ANY CONFLICTS OF LAW RULE OR PRINCIPLE THAT MIGHT REFER CONSTRUCTION OF SUCH PROVISIONS TO THE LAWS OF ANOTHER JURISDICTION; *PROVIDED*, *HOWEVER*, THAT ANY MATTERS RELATED TO REAL PROPERTY SHALL BE GOVERNED BY THE LAWS OF THE STATE WHERE SUCH REAL PROPERTY IS LOCATED. WITHOUT LIMITING THE PARTIES' AGREEMENT TO ARBITRATE IN SECTION 11.15 OR THE DISPUTE RESOLUTION PROCEDURE PROVIDED IN SECTION 2.05(E) AND SECTION 11.15 WITH RESPECT TO DISPUTES ARISING THEREUNDER, THE PARTIES HERETO CONSENT TO THE EXERCISE OF JURISDICTION IN PERSONAM BY THE FEDERAL COURTS OF THE UNITED STATES LOCATED IN HOUSTON, TEXAS OR THE STATE COURTS LOCATED IN HOUSTON, TEXAS FOR ANY ACTION ARISING OUT OF THIS AGREEMENT, ANY TRANSACTION DOCUMENTS, OR ANY TRANSACTION CONTEMPLATED HEREBY OR THEREBY. ALL ACTIONS OR PROCEEDINGS WITH RESPECT TO, ARISING DIRECTLY OR INDIRECTLY IN CONNECTION WITH, OUT OF, RELATED TO, OR FROM THIS AGREEMENT, ANY TRANSACTION DOCUMENTS OR ANY TRANSACTION CONTEMPLATED HEREBY OR THEREBY SHALL BE**

EXCLUSIVELY LITIGATED IN SUCH COURTS DESCRIBED ABOVE HAVING SITES IN HOUSTON, TEXAS AND EACH PARTY IRREVOCABLY SUBMITS TO THE JURISDICTION OF SUCH COURTS SOLELY IN RESPECT OF ANY PROCEEDING ARISING OUT OF OR RELATED TO THIS AGREEMENT. EACH PARTY HERETO VOLUNTARILY, INTENTIONALLY AND IRREVOCABLY WAIVES, TO THE FULLEST EXTENT PERMITTED BY APPLICABLE LEGAL REQUIREMENTS, ANY RIGHT IT MAY HAVE TO A TRIAL BY JURY IN RESPECT OF ANY ACTION, SUIT OR PROCEEDING ARISING OUT OF OR RELATING TO THIS AGREEMENT, ANY TRANSACTION DOCUMENTS OR ANY TRANSACTION CONTEMPLATED HEREBY OR THEREBY. THE PARTIES FURTHER AGREE, TO THE EXTENT PERMITTED BY LAW, THAT A FINAL AND NONAPPEALABLE JUDGMENT AGAINST A PARTY IN ANY ACTION OR PROCEEDING CONTEMPLATED ABOVE SHALL BE CONCLUSIVE AND MAY BE ENFORCED IN ANY OTHER JURISDICTION WITHIN OR OUTSIDE THE UNITED STATES BY SUIT ON THE JUDGMENT, A CERTIFIED OR EXEMPLIFIED COPY OF WHICH SHALL BE CONCLUSIVE EVIDENCE OF THE FACT AND AMOUNT OF SUCH JUDGMENT. TO THE EXTENT THAT A PARTY OR ANY OF ITS AFFILIATES HAS ACQUIRED, OR HEREAFTER MAY ACQUIRE, ANY IMMUNITY FROM JURISDICTION OF ANY COURT OR FROM ANY LEGAL PROCESS (WHETHER THROUGH SERVICE OR NOTICE, ATTACHMENT PRIOR TO JUDGMENT, ATTACHMENT IN AID OF EXECUTION, EXECUTION OR OTHERWISE) WITH RESPECT TO ITSELF OR ITS PROPERTY, SUCH PARTY (ON ITS OWN BEHALF AND ON BEHALF OF ITS AFFILIATES) HEREBY IRREVOCABLY
(I) WAIVES SUCH IMMUNITY IN RESPECT OF ITS OBLIGATIONS WITH RESPECT TO THIS AGREEMENT AND (II) SUBMITS TO THE PERSONAL JURISDICTION OF ANY COURT DESCRIBED IN THIS SECTION 13.04.

13.05 **Further Assurances**. The Parties agree (a) to furnish upon request to each other such further information, (b) to execute, acknowledge, and deliver to each other such other documents, and (c) to do such other acts and things, all as the other Party may reasonably request for the purpose of carrying out the intent of this Agreement and the documents referred to in this Agreement.

13.06 **Waiver**. The rights and remedies of the Parties are cumulative and not alternative. Neither the failure nor any delay by either Party in exercising any right, power, or privilege under this Agreement or the documents referred to in this Agreement shall operate as a waiver of such right, power, or privilege, and no single or partial exercise of any such right, power, or privilege shall preclude any other or further exercise of such right, power, or privilege or the exercise of any other right, power, or privilege. To the maximum extent permitted by applicable Legal Requirement, (a) no claim or right arising out of this Agreement or the documents referred to in this Agreement can be discharged by one Party, in whole or in part, by a waiver or renunciation of the claim or right unless in writing signed by the other Party, (b) no waiver that may be given by a Party shall be applicable except in the specific instance for which it is given, and (c) no notice to or demand on one Party shall be deemed to be a waiver of any obligation of such Party or of the right of the Party giving such notice or demand to take further action without notice or demand as provided in this Agreement or the documents referred to in this Agreement.

13.07 **<u>Entire Agreement and Modification</u>**. This Agreement supersedes all prior discussions, communications, and agreements (whether oral or written) between the Parties with respect to its subject matter and constitutes (along with the documents referred to in this Agreement) a complete and exclusive statement of the terms of the agreement between the Parties with respect to its subject matter. This Agreement may not be amended or otherwise modified except by a written agreement executed by both Parties. No representation, promise, inducement, or statement of intention with respect to the subject matter of this Agreement has been made by either Party that is not embodied in this Agreement together with the documents, instruments, and writings that are delivered pursuant hereto, and neither Party shall be bound by or liable for any alleged representation, promise, inducement, or statement of intention not so set forth. In the event of a conflict between the terms and provisions of this Agreement and the terms and provisions of any Schedule or Exhibit hereto, the terms and provisions of this Agreement shall govern, control, and prevail.

13.08 **<u>Assignments, Successors, and No Third Party Rights</u>**. Neither Party may assign any of its rights, liabilities, covenants, or obligations under this Agreement without the prior written consent of the other Party (which consent may be granted or denied at the sole discretion of the other Party); *provided* that Buyer (without consent of Seller) may assign all or part of its rights under this Agreement (including its rights to receive the Assets) to one or more Affiliates, and any assignment (other than an assignment by Buyer to an Affiliate) made without such consent shall be void, and in the event of such consent (or an assignment by Buyer to an Affiliate), such assignment nevertheless shall not relieve such assigning Party of any of its obligations under this Agreement without the prior written consent of the other Party. Subject to the preceding sentence, this Agreement shall apply to, be binding in all respects upon, and inure to the benefit of the successors and permitted assigns of the Parties. Nothing expressed or referred to in this Agreement or any other Transaction Document shall be construed to give any Person other than the Parties and their permitted assignees (and Buyer Group and Seller Group who are entitled to indemnification under <u>Article 10</u>), any legal or equitable right, remedy, or claim under or with respect to this Agreement or any provision of this Agreement. Subject to the preceding sentence and except as otherwise set forth in this Agreement, this Agreement, any other agreement contemplated herein, and all provisions and conditions hereof and thereof, are for the sole and exclusive benefit of the Parties and such other agreements (and Buyer Group and Seller Group who are entitled to indemnification under <u>Article 10</u>), and their respective successors and permitted assigns.

13.09 **<u>Severability</u>**. If any provision of this Agreement is held invalid or unenforceable by any court of competent jurisdiction, the other provisions of this Agreement shall remain in full force and effect. Any provision of this Agreement held invalid or unenforceable only in part or degree shall remain in full force and effect to the extent not held invalid or unenforceable.

13.10 **<u>Article and Section Headings, Construction</u>**. The headings of Sections, Articles, Exhibits, and Schedules in this Agreement are provided for convenience only and shall not affect its construction or interpretation. All references to "Section," "Article," "Exhibit," or "Schedule" refer to the corresponding Section, Article, Exhibit, or Schedule of this Agreement. Unless expressly provided to the contrary, the words "hereunder," "hereof," "herein," and words of similar import are references to this Agreement as a whole and not any particular Section, Article, Exhibit, Schedule, or other provision of this Agreement. Each definition of a defined term herein shall be equally applicable both to the singular and the plural forms of the term so defined. All words used in this Agreement shall be construed to be of such gender or number, as the circumstances require. Unless otherwise expressly provided, the word “including” does not limit the preceding words or terms and (in its various forms) means including without limitation. For any “agreement”, “waiver,” “notice” or words of similar import to be effective, such agreement, waiver or notice must be in writing and delivered by one Party to the other Party pursuant to Section 13.03. If the date specified in this Agreement for giving notice or taking any action is not a Business Day (or, if the period during which any notice is required to be given or any action taken expires on a date which is not a Business Day), then the date for giving such notice or taking such action (or the expiration date of such period during which notice is required to be given or action taken) shall be the next day which is a Business Day. Each Party has had substantial input into the drafting and preparation of this Agreement and has had the opportunity to exercise business discretion in relation to the negotiation of the details of the Contemplated Transactions. This Agreement is the result of arm’s-length negotiations from equal bargaining positions. This Agreement shall not be construed against either Party, and no consideration shall be given or presumption made on the basis of who drafted this Agreement or any particular provision hereof or who supplied the form of Agreement.

13.11 **Counterparts**. This Agreement may be executed and delivered (including by facsimile or e-mail transmission) in one or more counterparts, each of which shall be deemed to be an original copy of this Agreement and all of which, when taken together, shall be deemed to constitute one and the same agreement.

13.12 **Press Release**. If any Party wishes to make a press release or other public announcement respecting this Agreement or specific to the Contemplated Transactions, such Party will provide a courtesy copy to the other Party of the language relevant to the transaction prior to the release or public announcement. Neither Party will issue a press release or other public announcement that includes the name of a non-releasing Party or its Affiliates without the prior written consent of such non-releasing Party (which consent may be withheld in such non-releasing Party’s sole discretion); *provided*, *however*, the foregoing shall not restrict disclosures by the Party
(a) to the extent that such disclosures are required by applicable securities or other Legal Requirements or the applicable rules of any stock exchange having jurisdiction over the Parties,
(b) to Governmental Bodies or any Third Party holding Preferential Purchase Right, rights of Consent, or other rights that may be applicable to the Contemplated Transaction as reasonably necessary to provide notices, seek waivers, amendments, or terminations of such rights, or seek such Consents or (c) to the extent that such disclosure is limited to the fact that the Assets have been sold. Seller and Buyer shall each be liable for the compliance of their respective Affiliates with the terms of this Section 13.12.

13.13 **Confidentiality**. The Confidentiality Agreement shall terminate on the Closing Date and will thereafter be of no further force or effect. Each Party shall keep confidential, and cause its Affiliates and instruct its Representatives to keep confidential, all terms and provisions of this Agreement, except as required by Legal Requirements or any standards or rules of any stock exchange to which such Party or any of its Affiliates is subject, for information that is available to the public on the Closing Date, or thereafter becomes available to the public other than as a result of a breach of this Section 13.13, to the extent required to be disclosed in connection with complying with or obtaining a waiver of any Preferential Purchase Right or Consent, to any

Affiliate or Representative, in the case of Buyer, to any potential purchaser of (or joint venture partner with respect) to all or any portion of the Assets and any direct or indirect (current or potential) investor or lender and to the extent that such Party must disclose the same in any Proceeding brought by or Threatened by or against it to enforce or defend its rights under this Agreement. This Section 13.13 shall not prevent either Party from recording the Instruments of Conveyance delivered at the Closing or from complying with any disclosure requirements of Governmental Bodies that are applicable to the transfer of the Assets. Additionally, from and after the Closing, Seller shall keep confidential and not use any of the Records other than for Tax purposes or in connection with the Retained Liabilities, Excluded Assets or any Proceeding or Threatened Proceeding against Seller. The covenant set forth in this Section shall terminate two (2) years after the Closing Date.

13.14 **Name Change**. As promptly as practicable, but in any event within sixty (60) days after the Closing Date, Buyer shall eliminate, remove or paint over the use of the names “Linn” or “Riviera” and variants thereof from the Assets, and, except with respect to such grace period for eliminating the existing usage, shall have no right to use any logos, trademarks, or trade names belonging to Seller or any of its Affiliates. Buyer shall be solely responsible for any direct or indirect costs or expenses resulting from the change in use of name and any resulting notification or approval requirements.

13.15 **Preparation of Agreement**. Both Seller and Buyer and their respective counsel participated in the preparation of this Agreement. In the event of any ambiguity in this Agreement, no presumption shall arise based on the identity of the draftsman of this Agreement.

13.16 **Appendices, Exhibits and Schedules**. All of the Appendices, Exhibits and Schedules referred to in this Agreement are hereby incorporated into this Agreement by reference and constitute a part of this Agreement. Each Party to this Agreement and its counsel has received a complete set of Appendices, Exhibits and Schedules prior to and as of the execution of this Agreement.

13.17 **Joint and Several Liability**. Riviera Upstream and Riviera Operating shall be jointly and severally liable for all of the duties and obligations of the other under this Agreement and the other Transaction Documents.

13.18 **Non-Recourse Persons**. The Parties acknowledge and agree that no past, present, or future director, manager, officer, employee, incorporator, member, partner, stockholder, agent, attorney, representative, Affiliate, or financing source (including, without limitation, Talara Capital Management, LLC, any investment fund managed by Talara Capital Management, LLC or any of their respective Affiliates), and any of the foregoing Person’s respective past, present, or future directors, managers, officers, employees, incorporators, members, partners, stockholders, agents, attorneys, representatives, Affiliates, or financing sources of Seller (excluding, in each case, Seller, and subject to such exclusion, a “Non-Recourse Person”), in such capacity, shall have any liability or responsibility (in contract, tort, or otherwise) for, and Buyer hereby waives, releases, remises and forever discharges, and shall cause each member of the Buyer Group to waive, release, remise and forever discharge, any Damages, suits, legal or administrative proceedings, claims, demands, losses, costs, obligations, liabilities, interests, charges, or causes of action whatsoever, in law or in equity, known or unknown, against each Non-Recourse Person which are based on, related to, or arise out of the ownership or operation of the Assets, the Excluded Assets or negotiation, performance, and consummation of this Agreement or the other Transaction Documents or the Contemplated Transactions hereunder or thereunder. Each Non- Recourse Person is expressly intended as a third-party beneficiary of this Section 13.18.

[*Signature Page Follows*]

IN WITNESS WHEREOF, the Parties have executed and delivered this Agreement as of the date first written above.

SELLER:

Riviera Upstream, LLC

By: /s/ David Rottino

Name: David Rottino
Title: President and Chief Executive Officer

Riviera Operating, LLC

By: /s/ David Rottino

Name: David Rottino
Title: President and Chief Executive Officer

<u>BUYER</u>:

Crescent Pass Energy, LLC

By:<u>/s/ Tyler Fenley</u>
Name: Tyler Fenley
Title: Chief Executive Officer

Exhibit 10.26

[Certain confidential portions of this exhibit have been redacted pursuant to Item 601(b)(10)(iv) of Regulation S-K and marked with asterisks. The omitted information is (i) not material and (ii) would likely cause us competitive harm if publicly disclosed.]

CONFIDENTIAL

AMENDED AND RESTATED GAS GATHERING AND PROCESSING AGREEMENT BY AND BETWEEN LINN ENERGY HOLDINGS, LLC AND LINN MIDSTREAM, LLC EFFECTIVE APRIL 1, 2017

[Signature Page to Amended and Restated Gas Gathering and Processing Amendment]

AMENDED AND RESTATED GAS GATHERING AND PROCESSING AGREEMENT

THIS AMENDED AND RESTATED GAS GATHERING AND PROCESSING AGREEMENT (as may be amended, restated, supplemented or otherwise modified from time to time, this "***Agreement***"), effective for all purposes hereunder as of April 1, 2017 (the "***Effective Date***") by and between Linn Energy Holdings, LLC, a Delaware limited liability company by and through its Agent Linn Operating, LLC ("***Producer***") and Linn Midstream, LLC, a Delaware limited liability company ("***Linn Midstream***", and Producer, each a "***Party***", and collectively, the "***Parties***").

RECITALS:

WHEREAS, Linn Operating, Inc. as agent for Producer and Linn Operating, Inc. as agent for Linn Midstream entered into that certain Gas Gathering and Processing Agreement (the "***Prior GGPA***"), on and effective as of January 1, 2016.

WHEREAS, Producer and Linn Midstream have agreed to amend and restate in its entirety the Prior GGPA effective as of the Effective Date and to memorialize certain other understandings and agreements of the Parties as set forth more fully below.

WHEREAS, Producer and Linn Midstream desire that Linn Midstream will gather, process and purchase Producer's Gas (as defined in Exhibit A) produced from the Wells (as defined in Exhibit A) located within Contract Area A-1 (defined below) in accordance with the terms and conditions set forth on Exhibit A.

WHEREAS, Linn Midstream desires to purchase (and perform certain services with respect to) Producer's Committed Gas (as defined in Exhibit B) from (and for) Producer, and Producer desires to sell (and have Linn Midstream perform certain services with respect to) such Gas (as defined in Exhibit B) located within Contract Area B-1 (defined below) to Linn Midstream in accordance with the terms and conditions set forth on Exhibit B.

WHEREAS, the Parties acknowledge and desire that (a) the terms and conditions set forth on Exhibit A and Exhibits A-1 through A-5 (inclusive) shall apply solely with respect to Producer's assets or operations located on Contract Area A-1 and shall not apply with respect to Producer's assets or operations located on Contract Area B-1 and (b) the terms and conditions set forth on Exhibit B and Exhibits B-1 through B-5 (inclusive) shall apply solely with respect to Producer's assets or operations located on Contract Area B-1 and shall not apply with respect to Producer's assets or operations located on Contract Area A-1.

NOW, THEREFORE, in consideration of the premises and of the mutual promises, representations, warranties, covenants, conditions and agreements contained herein, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties, intending to be legally bound by the terms hereof, agree as follows:

ARTICLE I CONTRACT AREAS

Section 1.1. Contract Area A-1. With respect to Producer's assets or operations located on the lands within the boundaries shown or described on Exhibit A-1 (such lands, "***Contract Area A-1***"), the terms and conditions set forth on Exhibit A (and Exhibits A-1 through A-6 (inclusive)) hereto shall govern the rights and obligations of the Parties to the extent set forth therein.

Section 1.2. Contract Area B-1. With respect to Producer's assets or operations located on the lands described on Exhibit B-1 (such lands, "***Contract Area B-1***"), the terms and conditions set forth on Exhibit B (and Exhibits B-1 through B-6 (inclusive)) hereto shall govern the rights and obligations of the Parties to the extent set forth therein.

ARTICLE II MISCELLANEOUS PROVISIONS

Section 2.1. Assignment. Either Party may assign this Agreement subject to Section 2.2. Any such assignment must be all or an undivided percentage of a Party's rights, titles, interests and obligations hereunder, all or an undivided percentage of a Party's rights under Exhibit A (and Exhibits A-1 through A-5 (inclusive)) or all or an undivided percentage of a Party's rights under Exhibit B (and Exhibits B-1 through B-5 (inclusive)). This Agreement (or portions thereof) and each of its terms shall be binding upon and inure to the benefit of the successors, assigns, heirs, personal representatives, and representatives in bankruptcy of the Parties. The dedications and the other terms and conditions set forth herein are intended to run with the land notwithstanding anything to the contrary herein.

Section 2.2. Notice of Assignment. Any assignment, conveyance, farmout, sublease or any other type of transaction by Producer of its interest in any asset or interest subject to a dedication set forth herein shall be made expressly subject to the provisions of this Agreement. No transfer of or succession to the interest of Producer, however effected, shall bind Linn Midstream unless and until the original instrument or other proper proof that the claimant is legally entitled to an interest has been furnished to Linn Midstream at its office at the address shown in Section 2.12. The effective date of the transfer as to Linn Midstream's obligation under this Agreement shall be the first day of the calendar month after thirty (30) days following the date such instrument or proof is furnished to Linn Midstream. No transfer or assignment of rights by either Party under this Agreement shall diminish or increase either Party's obligations under this Agreement, unless expressly agreed by the other Party.

Section 2.3. Compliance with Laws and Regulations. This Agreement is subject to all valid statutes, rules and regulations of any duly constituted federal or state authority or regulatory body having jurisdiction. Neither Party shall be in default as a result of compliance with laws and regulations.

Section 2.4. Conflict of Law Jurisdiction, Venue; Jury Waiver.

(a) THIS AGREEMENT AND THE LEGAL RELATIONS BETWEEN THE PARTIES SHALL BE GOVERNED BY AND CONSTRUED IN ACCORDANCE WITH

THE LAWS OF THE STATE OF TEXAS WITHOUT REGARD TO PRINCIPLES OF CONFLICTS OF LAW THAT WOULD REQUIRE THE APPLICATION OF THE LAWS OF ANOTHER JURISDICTION.

(b) THE PARTIES HEREBY IRREVOCABLY SUBMIT TO THE EXCLUSIVE JURISDICTION OF THE FEDERAL COURTS OF THE UNITED STATES OF AMERICA LOCATED IN HARRIS COUNTY, TEXAS (OR, IF REQUIREMENTS FOR FEDERAL JURISDICTION ARE NOT MET, STATE COURTS LOCATED IN HARRIS COUNTY, TEXAS) AND APPROPRIATE APPELLATE COURTS THEREFROM FOR THE RESOLUTION OF ANY DISPUTE, CONTROVERSY, OR CLAIM ARISING OUT OF OR IN RELATION TO THIS AGREEMENT OR THE TRANSACTIONS CONTEMPLATED HEREBY, AND EACH PARTY HEREBY IRREVOCABLY AGREES THAT ALL ACTIONS, SUITS AND PROCEEDINGS IN RESPECT OF SUCH DISPUTE, CONTROVERSY OR CLAIM MAY BE HEARD AND DETERMINED IN SUCH COURTS. EACH PARTY HEREBY IRREVOCABLY WAIVES, TO THE FULLEST EXTENT PERMITTED BY APPLICABLE LAWS, (i) ANY OBJECTION IT MAY NOW OR HEREAFTER HAVE TO THE LAYING OF VENUE OF ANY SUCH ACTION, SUIT OR PROCEEDING IN ANY OF THE AFORESAID COURTS, (ii) ANY CLAIM IT MAY NOW OR HEREAFTER HAVE THAT ANY SUCH ACTION, SUIT OR PROCEEDING HAS BEEN BROUGHT IN AN INCONVENIENT FORUM, AND (iii) THE RIGHT TO OBJECT, IN CONNECTION WITH SUCH ACTION, SUIT OR PROCEEDING, THAT ANY SUCH COURT DOES NOT HAVE ANY JURISDICTION OVER SUCH PERSON. EACH PARTY AND EACH SELLER'S REPRESENTATIVE HEREBY IRREVOCABLY CONSENTS TO THE SERVICE OF ANY PAPERS, NOTICES OR PROCESS AT THE ADDRESS SET OUT IN SECTION 2.12 IN CONNECTION WITH ANY ACTION, SUIT OR PROCEEDING AND AGREES THAT NOTHING HEREIN WILL AFFECT THE RIGHT OF THE OTHER PARTIES TO SERVE ANY SUCH PAPERS, NOTICES OR PROCESS IN ANY OTHER MANNER PERMITTED BY APPLICABLE LAW. EACH PARTY AGREES THAT A JUDGMENT IN ANY SUCH DISPUTE, CONTROVERSY OR CLAIM MAY BE ENFORCED IN OTHER JURISDICTIONS BY SUIT ON THE JUDGMENT OR IN ANY OTHER MANNER PROVIDED BY APPLICABLE LAW.

(c) EACH PARTY WAIVES, TO THE FULLEST EXTENT PERMITTED BY APPLICABLE LAW, ANY RIGHT IT MAY HAVE TO A TRIAL BY JURY IN RESPECT OF ANY ACTION, SUIT OR PROCEEDING ARISING OUT OF OR RELATING TO THIS AGREEMENT OR ANY TRANSACTION CONTEMPLATED HEREBY.

Section 2.5. Default and Non-Waiver. No waiver by a Party of any one or more defaults by the other Party in the performance of any provisions of this Agreement shall operate as a waiver of any future default or defaults, whether of a like or different character.

Section 2.6. Confidentiality. All terms and provisions of this Agreement are confidential, and the Parties shall use all reasonable efforts to prevent disclosure of the terms and provisions of this Agreement to any third party; provided, however, a Party is permitted to disclose the terms and conditions of this Agreement to its officers, directors, employees, agents, consultants, affiliates, and independent public accountants, and as may be necessary to comply with any legal obligations or court order. In addition, Producer may disclose this Agreement to any bona fide potential purchaser of Producer's interest in its assets subject to this Agreement, and Linn Midstream may disclose this Agreement to any bona fide potential purchaser of Linn Midstream's interest in any or all of its assets subject to this Agreement, provided that in either case, such potential purchaser agrees in writing to be bound by the confidentiality provisions of this Agreement.

Section 2.7. Negotiations. Each Party acknowledges that it has had the opportunity to negotiate the terms of this Agreement and to obtain the assistance of counsel in reviewing its terms prior to execution. The Parties agree, therefore, that this Agreement shall not be construed against or in favor of either Party as a result of the manner in which this Agreement was negotiated, prepared, drafted or executed, but shall be construed in a neutral manner.

Section 2.8. Complete Agreement. This Agreement constitutes the final and complete agreement between the Parties, and there are no oral promises, prior agreements, understandings, obligations, warranties, or representations between the Parties relating to this Agreement other than those set forth herein.

Section 2.9. Amendments. All waivers, modifications, amendments and changes to this Agreement shall be in writing and executed by the authorized representatives of the Parties.

Section 2.10. Relationships of the Parties. The relations between the Parties are those of independent contractors. This Agreement creates no joint venture, partnership, association, other special relationship, or fiduciary obligations.

Section 2.11. Third party Beneficiaries. Except to the limited extent expressly set forth herein, there are no third party beneficiaries under this Agreement.

Section 2.12. Notices. Except as may otherwise be provided, all notices, payments, data or documents to be furnished must be mailed to the respective Party at its address (whether physical or electronic) set out below and shall be sufficiently given if: (a) deposited in the United States mail, postage prepaid; (b) sent by private express mail or courier service; or (c) transmitted electronically, and addressed to the respective Party at its specified address (whether physical or electronic) set out below. Either Party may change its address at any time upon written notice to the other Party.

If to Producer:

Linn Energy Holdings, LLC 600
Travis Street, Suite 1400
Attention: Marketing Administration
Facsimile: 832-209-4300
Email: MarketingAdministration@linnenergy.com If to
Linn Midstream:
Linn Midstream, LLC

600 Travis Street, Suite 1400 Attention:
Marketing Administration Facsimile: 832-
209-4300
Email: MarketingAdministration@linnenergy.com

Section 2.13. Captions. The captions in this Agreement have been inserted for convenience only and shall be given no substantive meaning or significance whatsoever in construing the terms and provisions of this Agreement.

Section 2.14. Counterparts. This Agreement may be executed in any number of counterparts, all of which shall be considered together as one instrument. Any executed counterpart transmitted by facsimile or similar transmission by any Party shall be deemed an original and shall be binding upon such Party.

Section 2.15. Prior Agreements. This Agreement supersedes and replaces any previous Agreement as of the Effective Date for the purchase and sale of gas between the Parties or their predecessors-in-interest insofar as it applies or applied to any gas produced from any sources covered by this Agreement and specifically replaces the Prior GGPA in its entirety from and after the Effective Date. Notwithstanding anything to the contrary in this Section 2.15, for the avoidance of doubt, the dedications of acreage and production by Producer in Exhibit A and Exhibit B are effective as of January 1, 2016, which is the original effective date of the Prior GGPA.

Section 2.16. Memorandum of Agreement; Further Assurances. At or after the Execution Date, Producer and Linn Midstream shall execute and deliver a Memorandum of this Agreement substantially in the form of Exhibit C attached hereto. Linn Midstream shall cause such Memorandum to be duly recorded in the appropriate real property or other records affecting the assets subject hereto. After the Execution Date each Party shall take such other actions as the other Party may reasonably request, to accomplish the purposes of this Agreement and to put third parties on notice of the dedications hereunder.

Section 2.17. Severability. If any provision of this Agreement would, under applicable law, be invalid or unenforceable in any respect, such provision shall (to the extent permitted by applicable law) be construed by modifying or limiting it so as to be valid and enforceable to the maximum extent compatible with, and possible under, applicable law. The provisions hereof are severable, and in the event any provision hereof should be held invalid or unenforceable in any respect, it shall not invalidate, render unenforceable, or otherwise affect any other provision of this Agreement.

Section 2.18. Term. This Agreement shall survive, (a) with respect to the terms and conditions set forth on Exhibit A (and Exhibits A-1 through A-5), for so long as the terms and conditions set forth on Exhibit A survive as provided therein, and (b) with respect to the terms and conditions set forth on Exhibit B (and Exhibits B-1 through B-5), for so long as the terms and conditions set forth on Exhibit B survive as provided therein.

Section 2.19. Limitation on Damages. Notwithstanding anything to the contrary contained in this Agreement or the exhibits attached hereto, in no event shall either Party be liable to the other Party for any exemplary or punitive damages or any special, indirect, incidental, or consequential damages of any character including, without limitation, loss of use, lost profits or revenue, cost of capital, cancellation of permits, unabsorbed transportation or storage charges, tort, or lost production, REGARDLESS OF WHETHER CLAIMS FOR SUCH DAMAGES ARE BASED ON CONTRACT, WARRANTY, NEGLIGENCE, STRICT LIABILITY, OR OTHERWISE.

IN WITNESS WHEREOF, this Agreement has been signed by each of the Parties on the Execution Date.

PARTIES:

LINN ENERGY HOLDINGS, LLC
By and through its Agent, Linn Operating, LLC

By: /s/ Mark E. Ellis
Name: Mark E. Ellis
Title: President and CEO

LINN MIDSTREAM, LLC

By: /s/ Mark E. Ellis
Name: Mark E. Ellis
Title: President and CEO

[Signature Page to Amended and Restated Gas Gathering and Processing Amendment]

LIST OF EXHIBITS AND SCHEDULES

Exhibit A and Exhibits A-1 through A-5

See attached.

EXHIBIT A
AMENDED AND RESTATED GAS GATHERING AND PROCESSING AGREEMENT

Terms and Conditions

This Exhibit A is attached to and made a part of that certain Amended and Restated Gas Gathering and Processing Agreement effective April 1, 2017, by and between Producer and Linn Midstream.

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ARTICLE I
DEFINITIONS

Section 1.1 Defined Terms. Each capitalized term in this Exhibit A and Exhibits A-1 through A-5 (inclusive) has the meaning given to it in this Section 1.1 of this Exhibit A.

(a) ***"Affiliate"*** means, with respect to either Party, any Person that directly or indirectly controls, is controlled by or is under common control with such Party, and "control" means the power to direct or cause the direction of the management and policies of such Person or Party, whether directly or indirectly, through one or more intermediaries or otherwise, and whether by virtue of the ownership of shares or other equity interests, the holding of voting rights or contractual rights, partnership interests or otherwise; provided, however, that none of Producer or any of its wholly owned direct or indirect subsidiaries shall be deemed an Affiliate of Linn Midstream or any of its wholly owned direct or indirect subsidiaries.

(b) ***"Agreement"*** means the main body of the Amended and Restated Gas Gathering and Processing Agreement to which this Exhibit A is attached.

(c) ***"AMI"*** means the geographical area designated on the map attached to the Agreement as Exhibit A-1.

(d) ***"Btu"*** means the amount of heat required to raise the temperature of one avoirdupois pound of pure water from 58.5° Fahrenheit to 59.5° Fahrenheit.

(e) ***"Commingled Residue Gas Stream"*** has the meaning set forth in Section 5.1 of this Exhibit A.

(f) ***"Condensate"*** means distillates, drip gas and other free liquids collected in the System.

(g) ***"Day," "day"*** or ***"Daily"*** means a period of 24 consecutive hours, beginning at 9:00 a.m. Central Time and ending at 8:59 a.m. Central Time; provided, however, that on the Day on which Daylight Saving Time becomes effective, the period shall be 23 consecutive hours; and on the Day on which Standard Time becomes effective, the period shall be 25 consecutive hours.

(h) ***"Dedicated Lease"*** means, subject to Section 10.1 of this Exhibit A, (i) each Lease owned by Producer or any of its Affiliates as of the Original Effective Date in the AMI and (ii) each Lease acquired by Producer or any of its Affiliates in the AMI after the Original Effective Date.

(i) ***"Defaulting Party"*** has the meaning set forth in Section 16.1 of this Exhibit A.

(j) ***"Downstream Pipeline"*** means the pipeline(s) which are immediately downstream of the Plant tailgate.

(k) ***"Drilling Notice"*** means written notice of a potential New Well that is prepared by Producer in good faith that includes the New Well's location, the estimated spud date, estimated completion date, estimated initial daily production, estimated average daily production, formation, the operator, Producer's working interest, plat of the New Well's location, and authorization for Linn Midstream to begin acquiring rights-of-way and equipment necessary for the connection of the New Well.

(l) ***"Effective Date"*** has the meaning set forth in the Agreement.

(m) ***"EFM"*** has the meaning set forth in Section 6.1 of this Exhibit A.

(n) ***"Event of Default"*** means the events described in Section 16.1 of this Exhibit A.

(o) ***"Facilities"*** means, collectively, the System, the Plant and all associated pipelines and equipment owned or controlled by Linn Midstream between the Receipt Point(s) and the Downstream Pipeline.

(p) ***"Fixed Recovery Percentage"*** has the meaning set forth in Section 5.2 of this Exhibit A.

(q) ***"Force Majeure"*** has the meaning set forth in Section 15.2 of this Exhibit A.

(r) ***"Fuel"*** means the gas and electricity used for fuel, power and equivalents required to operate the Facilities, any Gas Lift Gas and lost and unaccounted for gas.

(s) ***"Gas"*** or "gas" means hydrocarbon and non-hydrocarbon substances produced from gas and/or oil wells that is in a gaseous state.

(t) ***"Gas Lift Facilities"*** has the meaning set forth in Section 10.3 of this Exhibit A.

(u) ***"Gas Lift Gas"*** has the meaning set forth in Section 10.3 of this Exhibit A.

(v) ***"Gas Lift Imbalance"*** has the meaning set forth in Section 10.3 of this Exhibit A.

(w) ***"Gas Lift Imbalance Fee"*** has the meaning set forth in Section 10.3 of this Exhibit A.

(x) ***"Inferior Liquids"*** means mixed crude oil, slop oil, salt water, and nuisance liquids recovered by Linn Midstream in the Facilities, other than Condensate recovered in the System and Plant Products recovered in the Plant.

(y) ***"Interest Rate"*** means the then-effective per annum prime interest rate as published in The Wall Street Journal.

(z) ***"Lease"*** means any gas or liquid hydrocarbon lease, the surface and subsurface leasehold estates created thereby, fee interests and subleases, including all production depths, zones and formations covered thereby.

(aa) ***"Linn Midstream"*** means has the meaning set forth in the Preamble.

(bb) ***"MAOP"*** means the maximum allowable operating pressure of the System from time to time, which is subject to change in Linn Midstream's sole discretion.

(cc) ***"Mcf"*** means 1,000 cubic feet of gas at a base temperature of 60° Fahrenheit, and at a pressure base of 14.73 Psia and containing the amount of water vapor present at actual production pressure and temperature.

(dd) ***"MMBtu"*** means 1,000,000 Btus.
(ee) ***"MMcf"*** means 1,000 Mcf.
(ff) ***"Month"*** means the period beginning at 9:00 a.m. Central Time on the first Day of each calendar Month and ending at 8:59 a.m. Central Time on the first Day of the next succeeding calendar Month.

(gg) ***"New Well"*** means any well that will be drilled in the AMI by Producer or its Affiliates.

(hh) ***"Non-Conforming Gas"*** means any of Producer's Gas received at the Receipt Point(s) that fails to meet the quality specifications set forth in Section 8.1 of this Exhibit A (except with respect to Plant Product content).

(ii) ***"Non-Defaulting Party"*** has the meaning set forth in Section 16.1(a) of this Exhibit A.

(jj) ***"Operating Capacity"*** means the maximum volume of gas that each of the System and the Plant are capable of gathering, receiving and processing (as applicable).

(kk) ***"Original Effective Date"*** means January 1, 2016.

(ll) ***"Party"*** and ***"Parties"*** have the meaning set forth in the Preamble.

(mm) ***"Performance Assurance"*** has the meaning set forth in Section 11.4 of this Exhibit A.

(nn) ***"Person"*** means any natural person, group, corporation, limited partnership, general partnership, limited liability company, joint stock company, joint venture, association, company, estate, trust, bank trust company, land trust, business trust, or other organization, whether or not a legal entity, custodian, trustee-executor, administrator, nominee, or entity in a representative capacity and any government or agency or political subdivision thereof.

(oo) ***"Plant"*** means any Gas processing plant and/or treating facility and other related facilities, whether owned by Linn Midstream or third parties, utilized for processing Producer's Gas for the removal of Plant Products. Linn Midstream shall have the right, in its sole discretion, to cause Producer's Gas to be processed in any plant, but consistent with the terms of this Exhibit A.

(pp) ***"Plant Products"*** means those natural gas liquids, including ethane, propane, iso-butane, normal butane, and natural gasoline, and mixtures thereof, that are removed from Producer's Gas in the liquid extraction process at the Plant.

(qq) ***"Plant System"*** means any group of processing plants and related facilities owned or operated by Linn Midstream or its Affiliates, which are accounted for by Linn Midstream or its Affiliates as a super system or a combined system of plants.

(rr) ***"Primary Term"*** has the meaning set forth in Section 12.1 of this Exhibit A.

(ss) ***"Prior Dedicated Section"*** means (i) any lease owned by Producer or its Affiliates as of the Original Effective Date that is within a section of land that is subject to a pre-existing dedication set forth in Exhibit A-5, and (ii) any Lease that is acquired by Producer or its Affiliates after the Original Effective Date in the AMI that is subject to a pre-existing dedication.

(tt) ***"Processing"*** means the process that the Plant performs on the Gas to remove Plant Products.

(uu) ***"Producer"*** has the meaning set forth in the Preamble.

(vv) ***"Producer's Gas"*** means all Gas Producer delivers to the Receipt Point(s).

(ww) ***"Producer's Land"*** has the meaning set forth in Article XVII of this Exhibit A.

(xx) "***Psia"*** means pounds per square inch absolute.

(yy) ***"Psig"*** means pounds per square inch gauge.

(zz) ***"Receipt Point(s)"*** means Linn Midstream's meters located at the Wells upstream of the System as shown on Exhibit A-2, as may be amended from time to time pursuant to Section 10.3(d) of this Exhibit A or upon mutual agreement of Producer and Linn Midstream.

(aaa) ***"Residue Gas"*** means that portion of the Gas remaining after the extraction of Plant Products and deductions for Producer's pro rata share of Fuel delivered to a Downstream Pipeline.

(bbb) ***"Service Fee"*** has the meaning set forth in Exhibit A-4.

(ccc) ***"Shrinkage"*** means the reduction in the volume and Btu content of Producer's Gas that occurs as a result of the removal of Plant Products contained therein as determined under Section V of Exhibit A-3.

(ddd) ***"System"*** means the metered gas gathering system owned and/or operated by Linn Midstream or its Affiliates for gathering, treating, compressing and delivering Gas, as it may be expanded from time-to-time pursuant to the terms of this Exhibit A or otherwise.

(eee) ***"Taxes"*** has the meaning set forth in Section 11.3 of Exhibit A.

(fff) ***"Unit of Volume"*** means for all purposes of measurement hereunder, 1 cubic foot of gas at a temperature base of 60° Fahrenheit and a pressure base of 14.73 Psia.

(ggg) ***"Well"*** means any well on a Dedicated Lease, including any New Well.

Section 1.2 Interpretive Provisions for Exhibit A. The definitions of terms in Exhibit A shall apply equally to the singular and plural forms of the terms defined. Whenever the context may require, any pronoun shall include the corresponding masculine, feminine and neuter forms. The words "include," "includes" and "including" shall be deemed to be followed by the phrase "without limitation." The word "will" shall be construed to have the same meaning and effect as the word "shall." Unless the context requires otherwise, (a) any definition of or reference to any agreement, instrument or other document shall be construed as referring to such agreement, instrument or other document as from time to time amended, supplemented or otherwise modified, and (b) any reference herein to any Person shall be construed to include such Person's successors and assigns. Unless otherwise specified in this Exhibit A, all amounts and payments shall be in United States dollars, and all references to "$" or dollar amounts will be to lawful currency of the United States of America. All references to "$" or dollar amounts shall be to precise amounts and not rounded up or down.

ARTICLE II
GAS GATHERING AND PROCESSING; DELIVERY AND RECEIPT OBLIGATIONS

Section 2.1 Gathering of Producer's Gas. Linn Midstream shall gather Producer's Gas delivered to the Receipt Point(s) and process such Gas in accordance with Section 2.2 of this Exhibit A.

Section 2.2 Processing of Producer's Gas. Linn Midstream shall process Producer's Gas delivered to the Receipt Point(s) by means of the various processes available at the Plant. Such Processing shall separate Plant Products from Producer's Gas. The quantity of Plant Products and the quantity of Residue Gas that shall be allocable to Producer's Gas after Processing shall be determined in accordance with Section 5.2 of this Exhibit A and Article IV of the Accounting Procedure attached as Exhibit A-3.

Section 2.3 Linn Midstream's Duty to Accept Delivery. Linn Midstream shall use commercially reasonable efforts to accept all of Producer's Gas delivered to the Receipt Point(s) up to the Operating Capacity. Linn Midstream shall have full operational control over the Facilities and shall operate the Facilities in its sole reasonable discretion, and shall have the right to suspend service hereunder upon reasonable notice to Producer to perform normal and routine maintenance. Nothing herein shall obligate Linn Midstream to operate either the System or the Plant if the total quantities of gas delivered for processing by all producers are insufficient to operate either the System or the Plant economically, in Linn Midstream's sole opinion.

Section 2.4 Reservations of Linn Midstream. Linn Midstream reserves the right to own, retain, and have the sole right to the proceeds from any sale of all Condensate, distillates, drip gas, and Inferior Liquids collected in Linn Midstream's Facilities downstream of the Receipt Point(s), and such product value, if any, shall be credited to Linn Midstream and is independent and not included in the Service Fee calculation.

Section 2.5 Default. Linn Midstream shall not be required to take Gas at the Receipt Point(s) if an Event of Default under Section 16.1 of this Exhibit A has occurred with respect to Producer.

Section 2.6 Fuel. Linn Midstream shall have the right to retain from quantities of gas (i) in the case of the System, an amount equal to *** of such delivered quantities of gas at the Receipt Point(s), net of the Gas Lift Gas, per stage of compression provided, and (ii) in the case of the Plant, Producer's pro-rata share of actual Fuel consumed in the Plant or Plant System as applicable, not to exceed *** of such delivered quantities of gas at the Receipt Point(s), net of the Gas Lift Gas.

Section 2.7 Title, Possession and Control. Possession and control of Producer's Gas, including all liquefiable hydrocarbons contained therein, shall pass from Producer to Linn Midstream at the Receipt Point(s). Title to Producer's Gas including all liquefiable hydrocarbons contained therein, shall pass from Producer to Linn Midstream at the Plant tailgate.

ARTICLE III
RECEIPT AND DELIVERY PRESSURES AND RATE OF FLOW

Section 3.1 Pressure. Producer shall deliver, or cause to be delivered, to Linn Midstream the Gas to be gathered and/or processed at the line pressures existing in the System as such pressure may exist from time to time not to exceed the MAOP. Producer shall install, operate, and maintain, at its sole expense, such pressure regulating devices as may be necessary to regulate the pressure of gas prior to delivery to Linn Midstream so as not to exceed the MAOP. If Producer fails to regulate such pressure at any time during the term of this Exhibit A, then Linn Midstream may install shut-in or other pressure relieving devices at the Receipt Point(s) upstream of the measurement device. Notwithstanding anything in this Exhibit A to the contrary, if Linn Midstream installs such shut in or other pressure relieving devices and they are triggered due to Producer's failure to regulate the pressure at the Receipt Point(s) as required, then Producer is responsible for any loss of gas or any emissions of the gas stream from the shut- in or other pressure relieving devices, any damage to persons, property, or the environment, and the violation of any laws, rules, or regulations caused by such release. Linn Midstream shall not be required to open such shut-in or other pressure relieving device until Producer has rectified such over-pressure problem. Producer shall fully indemnify, defend, and hold Linn Midstream harmless for any such losses, emissions, damages, or violations.

ARTICLE IV
RESIDUE GAS

Section 4.1 Sale of Residue Gas. Each Month, Linn Midstream shall purchase Producer's share of the Commingled Residue Gas Stream, and shall pay Producer *** of the proceeds received by Linn Midstream for the sale of Producer's Residue Gas (hereinafter called "WASP Pricing").

ARTICLE V
COMMINGLED RESIDUE GAS; PLANT PRODUCT ALLOCATIONS

Section 5.1 Commingled Residue Gas Stream. Producer hereby expressly acknowledges that Producer's Gas may be commingled with other gas delivered to the Plant pursuant to gas processing agreements with third parties for Processing in the Plant so that a commingled Residue Gas stream ("***Commingled Residue Gas Stream***") may remain after the Processing of Producer's Gas and all other streams of gas delivered to the Plant for Processing. Linn Midstream shall obtain its Fuel from the Commingled Residue Gas Stream and Producer hereby authorizes Linn Midstream to do so. The balance of the Commingled Residue Gas Stream remaining after consumption of a portion thereof as Fuel shall be allocated to Producer and the other owners of the Commingled Residue Gas Stream. Producer's share of the Commingled Residue Gas Stream shall be determined in accordance with the Accounting Procedure attached as Exhibit A-3.

Section 5.2 Plant Product Allocations. The Parties shall fix the theoretical recovery percentage of Plant Products attributable to Producer's Gas delivered hereunder as follows ("***Fixed Recovery Percentage***"):

Plant Product	Ethane Recovery	Ethane Rejection
Ethane (C2)	***%	***%
Propane (C3)	***%	***%
Iso-butane (IC4)	***%	***%
Normal Butane (NC4)	***%	***%
Pentanes (C5+)	***%	***%

For any Month, Producer will have the option to elect either (i) ethane recovery or (ii) ethane rejection, in each case by providing Linn Midstream with at least eight (8) business Days' written notice prior to the beginning of such Month; *provided*, *however*, in the event Producer fails to provide a timely written notice to Linn Midstream, Producer shall be settled on its fixed recoveries set forth above, based on the performance of the Plant. Producer's share of the Plant Products shall be determined in accordance with the Accounting Procedure attached as Exhibit A-3.

ARTICLE VI
MEASUREMENT

Section 6.1 General. For billing and payment purposes, Producer's Gas received and delivered hereunder shall be measured by measurement facilities installed, operated, and maintained by Linn Midstream or its designee. Linn Midstream will provide Producer with access to a second set of taps on the meter tube located at each Receipt Point for check measurement. Such measurement stations are to be located at each Receipt Point and may also be located at the Plant Inlet, and shall be equipped with ultrasonic meters or orifice meters, or electronic flow meters ("***EFM***") commonly accepted by the industry sufficient to accomplish the accurate measurement of Gas; *provided*, *however*, that Linn Midstream has the right within its sole discretion (at its sole expense) to upgrade to or utilize more modern devices that meet industry standards.

Section 6.2 Procedure. The measurement of Gas at the Receipt Point(s) and the Plant Inlet shall be conducted in accordance with the following:

(a) Linn Midstream may determine a local atmospheric pressure from published local data, by calculating from a local elevation, or may assume the atmospheric pressure to be 14.65 Psia. Whenever conditions of temperature and pressure differ from such standard, conversion of the volume of Gas from such conditions to the standard conditions shall be made in accordance with the Ideal Gas Laws corrected for deviation of the Gas from Boyle's Law in accordance with the methods and formulae prescribed in the American Gas Association Report No. 8, Compressibility Factors of Natural Gas and Other Hydrocarbon Gases, as last amended and superseded.

(b) Measurement, both volumetric and thermal, shall be computed in accordance with the latest publications of the American Gas Association including AGA Report #3, AGA Report #7, and AGA Report #9 in conjunction with the American National Standard publication, Orifice Metering of Natural Gas, ANSI/API 2530, latest revision, and GPA 2172.

(c) The specific gravity of the Gas shall be determined at the Receipt Points by one of the following methods, at the option of Linn Midstream: (i) an on-line chromatograph; (ii) continuous sampling; or (iii) manual sampling. An on-line chromatograph shall be used at the Plant Inlet.

(d) The Gross Heating Value of the Gas shall be determined at each Receipt Point by one of the following: (i) an online chromatograph; (ii) composite sample taken by Linn Midstream or its nominee by application of the methods contained in API/GPA standards and in such amendments and revisions thereto and superseding reports thereof as recommended by the API/GPA committee or (iii) manual sampling. Linn Midstream will notify Producer before a new sample is taken pursuant to the foregoing subsections (ii) and (iii) and provide the data to Producer as a part of the monthly meter statement and analysis submittal currently in place. Upon written request by Producer, Linn Midstream will endeavor to send a new or updated gas analysis to Producer as soon as practicable. The Gross Heating Value of the Gas shall be determined at the Plant Inlet by an online chromatograph. Unless Producer installs and operates its own dehydration equipment upstream of the Facilities and reduces the water vapor content of the Gas at the Receipt Point to less than seven (7) pounds per MMcf, the Gas received by Linn Midstream at the Receipt Points shall be deemed to be fully saturated with water, and the Gas shall be measured and settled on a saturated basis.

(e) The Gross Heating Value shall be converted to the same condition stipulated for the Unit of Volume. The physical constants used in Btu computation for a perfect Gas shall be derived from the "Table of Physical Constants of Paraffin Hydrocarbons and Other Compounds" as published in the GPA Standard 2145, as may be amended from time to time and superseding revisions thereof. The analysis shall be complete, and individual values in mol percent or fraction of each hydrocarbon compound shall be listed through C_5. The C_5+ values shall be as stated in GPA standard 2261, 7.3.6 Table IV (as may be revised from time to time) or, at Linn Midstream's option, by use of an extended analysis. The analysis shall further include the mol fraction or percent individually of additional compounds contained in chromatographically measurable quantity contained in the sample as delivered. The method to be used for chromatographic analysis shall be that contained in GPA standard 2261, Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography and any superseding revisions thereof.

(f) Upon mutual agreement of the Parties, other types of Btu per cubic foot measuring devices may be installed and operated, and the Gross Heating Value shall be computed in accordance with the manufacturer's instructions for same and consistent with industry-accepted practices for transmission Btu per cubic foot measurement.

(g) Gas samples taken from the pipeline system for purposes of determining or deriving quantitative values that shall be used in the computation of Gas volume and the Gross Heating Value shall be obtained through use of a probe to be inserted sufficiently beyond the periphery of the internal pipe walls to assure that the Gas being drawn for the sample is free of any liquid accumulation from the internal pipe wall.

(h) If any standards or methods for calculations or determinations set forth in any applicable GPA publications are revised, and if both Parties are in agreement with said revision, then this Exhibit A shall be amended accordingly.

(i) Linn Midstream shall install, own, operate, and maintain standard type measuring and testing equipment necessary to measure and test Gas transported hereunder and shall keep same accurate and in good repair. Furthermore, any measurement equipment installed subsequent to the Effective Date shall meet the then most current industry standards. Data editing, calibrations, repairs, and adjustments of Linn Midstream's measuring and testing equipment shall be done only by employees of Linn Midstream or its designated representatives. All calibrations may be witnessed by Producer. Producer or its designated representative may, in the presence of an employee of Linn Midstream or Linn Midstream's designated representative, have access to Linn Midstream's measuring and analyzing equipment at any reasonable time, and shall have the right to witness tests, calibrations, and adjustments thereof. All witnessed calibration tests scheduled hereunder shall be at Linn Midstream's sole cost and expense and shall be preceded by reasonable notice to Producer. Upon request of either Party hereto for a special test of any meter or auxiliary equipment, Linn Midstream shall promptly verify the accuracy of same; provided, however, that the cost of such special test shall be borne by the requesting Party, unless the percentage of inaccuracy found is more than *** of a recording corresponding to the average hourly rate of Gas flow, in which case the cost of such test shall be borne by Linn Midstream. Producer shall also have the right to witness collection of manual, continuous, and on-ling chromatograph samples and to view all results.

If, upon any test, any measuring equipment is found to be inaccurate, such inaccuracy shall be taken into account in a practical manner in computing the deliveries. If the resultant aggregate inaccuracy is not more than *** of a recording corresponding to the average hourly rate of Gas flow for the period since the last preceding test, previously calculated receipts shall be deemed accurate. All equipment shall, in any case, be adjusted at the time of test to record accurately. If, however, the resultant aggregate inaccuracy in computed measurements exceeds *** of a recording corresponding to the average hourly rate of Gas flow for the period since the last preceding test, the previous recordings of such equipment shall be corrected to zero error for any period that is known definitely or agreed upon. If the period is not known definitely or agreed upon, such correction shall be for a period extending back one-half of the time elapsed since the date of the last test.

(j) If any meter or auxiliary equipment has not yet been installed or is out of service or out of repair for a period of time so that the amount of Gas delivered cannot be ascertained or computed from the reading thereof, the Gas delivered during such period shall be estimated based on the best data available, using the first of the following methods that is feasible by: (i) using the registration of any check meter or meters, if installed and accurately registering and only after such check meter or meters has been calibrated and proven to be within *** of the actual average hourly rate of Gas flow; (ii) correcting the error if the percentage of error is ascertainable by calibration tests or mathematical calculations; (iii) estimating Gas volumes on the basis of deliveries during the preceding periods under similar conditions when the equipment was registering accurately; or (iv) other method(s) mutually acceptable to both Parties.

(k) Upon request of Producer and if EFM is installed, Linn Midstream shall provide an electronic measurement audit package that complies with API Chapter 21.1 Measurement to Producer for examination, the same to be returned within *** Days. Linn Midstream's measurement audit package for a given accounting Month shall be deemed correct if no written objection thereto is served on either Party by the other within the two years following any Month and the same shall be retained for a two-year period.

(l) Producer may install, operate, and maintain, or cause to be installed, operated, and maintained, at its sole cost, risk, and expense, but in the same manner as is required for Linn Midstream's equipment hereunder, check measuring and testing equipment of standard type; provided, however, that the same does not interfere with the operation of Linn Midstream's equipment. The measurement and testing of Gas hereunder or for purposes of this Exhibit A shall, nevertheless, be effected only by Linn Midstream's equipment, except as provided in Section 6.2(j) of this Exhibit A. Linn Midstream shall have the same rights with respect to said check metering and testing equipment of Producer as are granted to Producer with respect to Linn Midstream's metering and testing equipment.

(m) If it is determined prior to, or as a result of, in-service tests, experience, and observation by either Producer or Linn Midstream that pulsations exist that affect the measurement accuracy, the operator of the equipment causing the pulsation agrees to install and operate mechanical dampening equipment necessary to eliminate such pulsations within *** days.

(n) If at any time during the term of this Exhibit A a new method or technique is developed with respect to Gas measurement or the determination of the factors used in such Gas measurement, such new method or technique may be substituted for the method set forth in this Section 6.2 of this Exhibit A when, upon agreement of both Parties, employing such new method or technique is advisable.

(o) No corrections shall be made for measurement or testing inaccuracies of *** or less.

ARTICLE VII
SERVICE FEES

For all Producer's Gas received by Linn Midstream at the Receipt Point(s), net of the Gas Lift Gas, Producer shall pay Linn Midstream the Service Fees set forth on Exhibit A-4. On the first anniversary of November 1, 2015, and on each anniversary thereafter, the Service Fees set forth on Exhibit A-4 shall automatically escalate by ***%.

ARTICLE VIII QUALITY OF
PRODUCER'S GAS

Section 8.1 Plant Tailgate Specifications. The Residue Gas and Plant Products at the tailgate of the Plant shall meet the minimum quality specifications of the Downstream Pipeline and downstream natural gas liquids market that are in place as of the Effective Date.

Section 8.2 Receipt Point(s) Specifications. Producer's Gas received at each Receipt Point shall meet the following quality specifications:

***

Section 8.3 Non-Conforming Gas. If any of Producer's Gas delivered at the Receipt Point(s) is Non-Conforming Gas, upon becoming aware of such Non-Conforming Gas, Linn Midstream may, at its option (a) continue to temporarily receive such Non-Conforming Gas, in which case Producer shall have no liability for and Linn Midstream shall indemnify and hold Producer harmless from any costs, expenses, losses, damages, and liabilities caused by Linn Midstream's receipt of such Non-Conforming Gas into the Facilities, or (b) discontinue receipt of any or all such Non-Conforming Gas, at which point Linn Midstream will temporarily release Producer's dedication of the affected wellbore(s) producing such Non-Conforming Gas until such time as the affected wellbore(s) are able to deliver Gas that meets the quality specifications set forth in this Exhibit A. If Linn Midstream elects to continue to receive Non-Conforming Gas, such election shall not serve as a waiver by Linn Midstream of its right to discontinue receipt of such Non-Conforming Gas at any time in the future; *provided*, *however*, that Linn Midstream shall continue to operate the Facilities as a prudent operator. Producer shall indemnify Linn Midstream for costs, expenses, losses, damages, and liabilities arising out of its delivery of Non-Conforming Gas to the Receipt Point prior to Linn Midstream's knowledge and receipt of Linn Midstream's written consent to continue to receive such Non-Conforming Gas. Notwithstanding any provisions herein to the contrary, if Producer's Non-Conforming Gas is delivered into Linn Midstream's pipeline without the prior knowledge and written consent and approval of Linn Midstream, and the quality deficiency of that Gas damages any Person's pipeline or facilities, Producer shall indemnify Linn Midstream for damages (in proportion to the amount of Producer's Gas delivered to Linn Midstream) caused, or to the extent contributed to by any Non-Conforming Gas delivered by Producer, including physical damage to any pipeline or facilities. Producer or Linn Midstream, as the case may be, shall immediately notify the other party upon becoming aware of Producer delivering Non-Conforming Gas to any Receipt Point.

Section 8.4 No Removal of Liquid Hydrocarbons. Producer agrees that it shall not utilize any method or technology whatsoever to remove any natural gas liquids from Producer's Gas, and it shall not deliver to the Receipt Point(s) any Producer's Gas that has had natural gas liquids removed except for any natural gas liquids in nominal amounts that may be incidentally recovered by means of conventional mechanical field separators at the wellhead, which natural gas liquids may be collected upstream of the Receipt Point(s) and shall remain property of Producer.

ARTICLE IX PLANT PRODUCTS

Section 9.1 Sale of Plant Products. Linn Midstream shall sell the Plant Products to the downstream natural gas liquids markets.

Section 9.2 Price for Plant Products. Linn Midstream shall pay to Producer each Month the product of (i) *** percent (***%) of the gallons of the respective Plant Products allocated to Producer for such Month, multiplied by (ii) the monthly average price per gallon applicable to each such Plant Product as published by Oil Price Information Service for "Any Current Month" under the heading "Mont Belvieu Average" for Non TET price postings less the NGL Fee stated in Exhibit A-4, and any other fees or charges assessed with respect to the Plant Products by any Person (other than Linn Midstream), including but not limited to storage, fuel and electricity fees. Producer hereby acknowledges that Linn Midstream shall be entitled to retain *** percent (***%) of the gallons of the respective Plant Products allocated to Producer for such Month, and that the value of such gallons shall be independent from and not included in the Service Fees set forth in this Exhibit. In the event such postings in the Oil Price

Information Service cease to be published without a designated replacement posting, Linn Midstream will select an alternative posting reasonably similar to the Oil Price Information Service.

ARTICLE X

DEDICATION; FACILITIES

Section 10.1 Dedication.

(a) Producer, on behalf of itself and its Affiliates, hereby dedicates to this Exhibit A all of its current and future fee interests, leasehold interests and any other interests to develop oil, natural gas, natural gas liquids and any other hydrocarbons (from all production depths, zones and formations) in the geographical area designated on Exhibit A-1. The dedication set forth in this Section 10.1 of this Exhibit A constitutes a covenant running with the land and shall be binding upon and inure to the benefit of the respective Parties and their successors and assigns.

(b) Any Prior Dedicated Section will not be subject to this Exhibit A until the termination of such prior dedication thereunder. Producer will not exercise any extensions to any such dedications, and Producer shall deliver any and all required notices under such Prior Dedicated Section to terminate such dedication without any extension thereof. Upon the termination of any such prior dedication, a Prior Dedicated Section shall be subject to this Exhibit A.

Section 10.2 Installation, Operation and Maintenance of Facilities.

(a) Subject to the provisions of Section 10.3 of this Exhibit A, Linn Midstream shall acquire, construct, install, operate and maintain, at Linn Midstream's sole cost and expense, the Facilities, including all rights-of-way, surface rights, gathering lines, and equipment, at a sufficient capacity as may be necessary for the proper, safe and efficient operation and maintenance of the Facilities to enable such Facilities to perform the services contemplated hereunder and accept Producer's Gas of the quality and at the pressure produced from any of Producer's Wells, provided, however, that Linn Midstream shall not be required to take delivery of any Non-Conforming Gas. Such equipment will include valves and fittings necessary to permit Producer to make its connections to the System at the applicable Receipt Point(s) and to regulate Gas deliveries according to Linn Midstream's requirements on Producer's behalf. Linn Midstream shall own, operate and maintain, at its sole cost, the Facilities.

(b) If the Facilities are not at least *** percent (***%) operational during any consecutive *** month period for any reason other than Force Majeure, the then applicable gathering fee shall be reduced by $***/MMBtu until such time as the Facilities have been restored to be *** percent (***%) operational during a consecutive *** month period.

Section 10.3 New Wells.

(a) Producer shall provide Linn Midstream with a Drilling Notice for any New Well not less than *** Days prior to the estimated spud date to allow Linn Midstream sufficient time to contract for services, procure equipment and materials, secure permits, rights-of-way or licenses in a commercially reasonable manner. Producer and Linn Midstream shall coordinate construction and drilling activities and schedules so as to minimize interference between construction and drilling activities.

(b) If (i) Producer has delivered a Drilling Notice for a New Well within the time period above and (ii) Linn Midstream has not connected such New Well to the System within *** Days after the completion of the New Well, then Linn Midstream shall discount the then- applicable Gathering Fee by $*** per MMBtu for all Producer’s Gas delivered to the Receipt Point for such New Well. Such discounted Gathering Fee shall apply on a Daily basis, equal to the number of Days subsequent to the date set forth in the Drilling Notice for such New Well, net of the *** Day grace period, after which Linn Midstream connects such New Well; provided, however, the discounted Gathering Fee shall not apply for greater than *** Days. If Linn Midstream is delayed in connecting such New Well to the System due to an event of Force Majeure, then Linn Midstream shall receive an extension of time to connect such New Well to the System for a period equal to that during which Linn Midstream’s activities were precluded by such event of Force Majeure.

(c) For New Wells located within the AMI, Linn Midstream will connect the New Well to the System, unless such connection is determined to be uneconomic by Linn Midstream in its sole discretion. If Linn Midstream determines not to connect such New Well to the System, Producer shall have the option of connecting the New Well to the System at its sole cost and expense, or Producer will be granted a release at Producer’s request of such New Well from the dedication under this Exhibit A by providing written notice to Linn Midstream. Any such release shall apply to the wellbore of the New Well, the section the wellbore is in and the surrounding eight (8) sections; provided, however, in the event such New Well is located within ***, such release shall apply to the wellbore of the New Well and the township where the wellbore is located. All other dedication under this Agreement shall survive such release.

(d) When a New Well within the AMI is connected to the System, then such new connection will be a new Receipt Point(s) and Exhibit A-2 of the Agreement shall be deemed to be automatically updated to include such new Receipt Point(s) for the purposes of this Exhibit A. Subject to a *** Day grace period after such connection, if the average monthly pressure at any Receipt Point exceeds *** Psig, Producer shall provide written notice to Linn Midstream, and Linn Midstream shall provide Producer with a plan to reduce such pressures at the affected Receipt Point to below *** Psig within *** Days of delivery of such plan. If pressures at such Receipt Point still exceed *** Psig after such sixty-day period, Linn Midstream shall discount the then-applicable Gathering Fee for the impacted Receipt Point as follows:

Pressure Range	Applicable Fee Discount
*** Psig	$***/MMBtu
*** Psig	$***/MMBtu
*** Psig	$***/MMBtu

Such discounted Gathering Fee shall apply on a Daily basis, and only for so long as the affected Receipt Point experiences pressures greater than the thresholds set forth herein. Linn Midstream will only be allowed the *** Day grace period once per calendar year for each Receipt Point.

(e) If Producer determines, after having given Linn Midstream a Drilling Notice for a New Well, that such New Well will not be completed, then Producer shall promptly notify Linn Midstream in writing. If Producer notifies Linn Midstream that a New Well will not be completed, then Producer shall reimburse Linn Midstream for the actual costs and expenses, grossed up for Taxes, if any, incurred by Linn Midstream as a result of, relating to or arising out of Linn Midstream's attempted connection of the New Well to the System, including any actual costs or expenses associated with engineering, procurement, construction, easements, labor, equipment, and materials; provided, however, that if Linn Midstream determines that any such equipment or materials can be reused in the ordinary course of Linn Midstream's business, then Producer shall only be obligated to reimburse Linn Midstream for any costs or expenses as a result of, relating to, or arising out of the engineering and relocation of such equipment and materials, but not for the cost of the procurement of such equipment and materials. Linn Midstream agrees to use reasonable efforts to reuse or reallocate such equipment and materials. Furthermore, Producer's reimbursement obligation for each such New Well shall be limited to a maximum of $***.

(f) At the written request of Producer, Linn Midstream will install, own, and operate meters and other necessary facilities, pipe, and equipment to measure the gas lift gas used by Producer (such metered gas, the ***"Gas Lift Gas"***) at any Well pad on lands within the AMI to deliver Producer's Gas from the Well pad or, if there is insufficient Gas from the Well pad, other Gas for gas lift operations (collectively, ***"Gas Lift Facilities"***). Each Month, the quantity of Gas Lift Gas measured at the Gas Lift Facilities shall be deducted from the quantity of Producer's Gas delivered by Producer and measured at the Receipt Point(s) that reside on the same Well pad as the Gas Lift Facilities. At Producer's written request, Linn Midstream will relocate the Gas Lift Facilities to another Well pad within the AMI as directed by Producer. Producer will, within thirty (30) Days of invoicing, reimburse Linn Midstream $*** for each occurrence of setting or relocating the Gas Lift Facilities. If the actual quantity of Gas Lift Gas, measured in MMBtus, measured at any Gas Lift Facilities during a Month exceeds the actual quantity of Gas, measured in MMBtus, delivered by Producer to any Receipt Point(s) upstream of such Gas Lift Facilities during the same Month (such excess, the ***"Gas Lift Imbalance"***), then Producer shall pay to Linn Midstream a fee (the ***"Gas Lift Imbalance Fee"***) equal to such Gas Lift Imbalance, in MMBtus, multiplied by the sum of (a) the per MMBtu price published in the Platt's monthly Inside FERC's Gas Market Report, as the "Index" for Henry Hub applicable to Gas delivered during such Month plus (b) *** per MMBtu.

ARTICLE XI STATEMENTS, BILLINGS AND PAYMENTS

Section 11.1 Statements. On or before the *** Day of each Month, Linn Midstream shall deliver to Producer a statement or invoice for Producer's Gas delivered to the Receipt Points during the preceding Month that includes (i) the actual quantity of Producer's Gas, measured in Mcfs and MMBtus delivered to the Receipt Point(s) during the preceding Month,
(ii) Service Fees, (iii) Gas Lift Gas and Gas Lift Imbalance Fees, if any, (iv) payment for Plant Products sold, (v) applicable third-party charges and fees, including electrical costs allocated to

Producer, (vi) Fuel, and (vii) Shrinkage. Such statement shall net all amounts due between Producer and Linn Midstream under this Exhibit A during such Month. If the actual Gas, Residue Gas or Plant Products quantities are not available, the statement shall be prepared based upon estimates. Linn Midstream shall make appropriate adjustments to reflect the actual quantity delivered on the following Month's statement or as soon thereafter as actual delivery information is available.

Section 11.2 Payment Method. Producer or Linn Midstream, as applicable, shall pay by wire transfer, check, or ACH transfer to the account or remittance address set forth herein or according to the instructions set forth in the applicable statement or invoice, the full undisputed amount payable according to such statement on or before the *** day of the Month following the Month of production. In the event of a bona fide dispute of any amounts payable under an invoice, Producer shall provide written notice to Linn Midstream of such dispute as soon as practicable, including the amount disputed and the rationale for the dispute.

Section 11.3 Taxes and Royalties. Producer shall pay or cause to be paid, and agrees to indemnify and hold Linn Midstream harmless from and against the payment of, all excise, gross production, severance, sales, occupation, and other taxes, charges, or impositions of every kind and character required by statute or any municipal or governmental authority ("***Taxes***") with respect to Gas delivered by Producer hereunder prior to its delivery by Producer to Linn Midstream at the Receipt Point(s). Producer agrees to reimburse Linn Midstream upon receipt of an invoice from Linn Midstream for the full amount of any such Taxes or charges levied upon Linn Midstream. Linn Midstream shall pay or cause to be paid all Taxes, if any, imposed upon Linn Midstream for the activity of Processing Producer's Gas after receipt of Gas at the Receipt Point(s). Producer shall pay or cause to be paid any and all sums, including, without limitation, royalties, overriding royalties, bonus payments, production payments, and the like accruing with respect to the Gas delivered to Linn Midstream by Producer hereunder.

Section 11.4 Creditworthiness. If either Party ("X") has reasonable grounds for doubting the ability of the other Party ("Y") to perform its obligations hereunder, then X shall have the right to request and receive from Y adequate assurance of performance ("***Performance Assurance***") as provided herein. Such Performance Assurance shall be due no later than ten days after X's written request and shall take one of the following forms: (a) an irrevocable letter of credit from an institution acceptable to X and in an amount reasonably acceptable to X; (b) a guaranty from a creditworthy party; or (c) prepayment or a deposit.

Section 11.5 Examination of Books and Records. Subject to the confidentiality provisions set forth herein, each Party hereto, or its representative, has the right at all reasonable times to examine the books, records, EFM data, and charts of the other Party to the extent necessary to verify the accuracy of any statement, charge, computation, or demand made hereunder. Such examinations shall be conducted at the location where the books, records, EFM data, and charts are normally located. Appropriate adjustments shall be made to any billing, invoice, or payment that is determined to be incorrect unless such billing, invoice, or payment is more than *** old and has not been noted as being under dispute within the two-year period. Any statement is final as to all Parties unless questioned within two years after payment thereof has been made.

ARTICLE XII TERM

Section 12.1 Term. This Exhibit A shall become effective as of the Effective Date and, unless terminated sooner pursuant to Section 12.2 of this Exhibit A or Section 16.2 of this Exhibit A shall remain in full force and effect until November 1, 2030 (“***Primary Term***”). Thereafter, this Exhibit A shall continue in full force and effect for successive periods of one year each until terminated by either Party with not less than one hundred and eighty (180) Days’ prior written notice, which notice shall specify a termination date at the end of the Primary Term or at the end of any annual term thereafter.

Section 12.2 Effect of Governmental Action. It is understood that performance by the Parties hereunder shall be subject to all valid rules and regulations of duly constituted governmental authorities having jurisdiction or control over the matters related hereto. If, at any time during the term of this Exhibit A, any governmental authority shall take any action that, with respect to or as a result of the gathering or Processing services provided for under this Exhibit A, subjects Linn Midstream or any of its Facilities to any greater or different regulation or jurisdiction than that existing on the Initial Gathering Date and materially adversely affects Linn Midstream, then upon written notice given to Producer, Linn Midstream may cancel and terminate this Exhibit A effective one day prior to the effective date of such governmental action.

ARTICLE XIII POSSESSION AND CONTROL

Producer shall be deemed to be in control and in possession of Producer’s Gas prior to such Gas being received by Linn Midstream at any Receipt Point(s) and shall be responsible for any damages, losses, or injuries caused thereby until the same shall have been received by Linn Midstream, except for injuries and damages that have been occasioned solely and proximately by the willful misconduct or gross negligence of Linn Midstream or its designee. Linn Midstream shall be in control and in possession of Producer’s Gas and all Residue Gas and Plant Products attributable to Producer’s Gas from and after such Producer’s Gas, Residue Gas, or Plant Products are received by Linn Midstream at the applicable Receipt Point(s) and shall be responsible for any damages, losses, or injuries caused thereby, except for injuries and damages that have been occasioned solely and proximately by the willful misconduct or gross negligence of any party downstream of the Plant tailgate.

ARTICLE XIV REPRESENTATIONS AND WARRANTIES

Section 14.1 Representations and Warranties of Producer. Producer represents and warrants that:

(a) it has the right to process Producer’s Gas and has title to all of the Plant Products contained in Producer’s Gas delivered pursuant to this Exhibit A;

(b) all royalties, Taxes, license fees, or other charges on Producer’s Gas, Residue Gas, and Plant Products have been or shall be paid when due;

(c) it has the right to deliver Producer's Gas to the Receipt Point(s) for the services to be provided pursuant to this Exhibit A;

(d) it has all requisite authority to perform its obligations under this Exhibit A, that this Exhibit A shall not violate, nor be in conflict with, any provision of its charter, bylaws, or any material agreement, and that the performance of this Exhibit A has been duly and validly authorized by all requisite action on its part; and

(e) the Agreement has been duly executed and delivered by Producer, currently constitutes a valid and binding obligation of Producer, and no consent or approval of any third party or other person or entity is necessary with respect to such execution and delivery, or to make this Agreement fully effective and binding upon Producer.

Section 14.2 Representations and Warranties of Linn Midstream. Linn Midstream represents and warrants that:

(a) it has all requisite authority to perform its obligations under this Exhibit A, that this Exhibit A does not violate, and is not in conflict with, any provision of its certificate of formation or its limited liability company agreement, and that the performance of this Exhibit A has been duly and validly authorized by all requisite action on its part; and

(b) the Agreement has been duly executed and delivered by Linn Midstream, currently constitutes a valid and binding obligation of Linn Midstream, and no consent or approval of any third party or other person or entity is necessary with respect to such execution and delivery, or to make this Agreement fully effective and binding upon Linn Midstream.

Section 14.3 Producer's Indemnification. Producer shall indemnify Linn Midstream and hold Linn Midstream harmless from all suits, actions, debts, accounts, damages, liabilities, costs, losses, and expenses (including reasonable attorneys' fees) arising from or out of (a) any misrepresentations or breach of warranty made by Producer contained in this Exhibit A (b) any direct damage caused to Facilities resulting from delivery of Non-Conforming Gas at the Receipt Point(s), (c) any loss of Producer's Gas at and upstream of the Receipt Point(s), and (d) any liability for Taxes and/or royalties related to Producer's Gas.

Section 14.4 Linn Midstream's Indemnification. Linn Midstream shall indemnify Producer and hold Producer harmless from all suits, actions, debts, accounts, damages, liabilities, costs, losses, and expenses (including reasonable attorneys' fees) arising from, or out of (a) any misrepresentations or breach of warranty made by Linn Midstream contained in this Exhibit A,
(b) any direct damage caused to Producer by the construction and operation of the System and the Plant (excluding any amounts due under this Agreement), and (c) any loss of Producer's Gas (other than Producer's share of Fuel and Shrinkage) after Linn Midstream's receipt of Producer's Gas at the Receipt Point(s) and prior to Linn Midstream's delivery of Producer's Residue Gas into the Downstream Pipeline(s) and delivery of Plant Products at the tailgate of the Plant.

Section 14.5 Indemnity Procedure. The Party seeking indemnity shall promptly notify the other Party in writing of any such suits, actions, debts, accounts, damages, liabilities, costs, losses, or expenses for which this indemnity shall apply.

ARTICLE XV FORCE MAJEURE

Section 15.1 Excused Performance. A Party shall not be responsible or liable for or deemed in breach of the Agreement (or any of the exhibits attached thereto) for any delay or failure in the performance of its obligations under this Exhibit A to the extent such performance is prevented or delayed by a Force Majeure; *provided*, *however*, that: (a) the affected Party gives the other Party reasonable notice describing the particulars of the Force Majeure and the proposed cure; (b) the suspension of performance is of no greater scope and of no longer duration than is reasonably attributable to the Force Majeure; (c) the affected Party uses commercially reasonable efforts to remedy its inability to perform its obligations under this Exhibit A; and (d) when the affected Party has knowledge that it shall be able to resume performance of its obligations under this Exhibit A, that Party shall give the other Party prompt written notice of the expected date of resumption of performance. Notwithstanding the foregoing, the existence of a Force Majeure shall not relieve any Party (x) from payment of amounts due under this Exhibit A or (y) of any other obligation under this Exhibit A, to the extent that performance of such other obligation is not precluded by such Force Majeure.

Section 15.2 Events Constituting Force Majeure. "***Force Majeure***" means acts, events, or circumstances not the fault of or reasonably within the control of the Party claiming suspension, and the effects of which such Party is unable, wholly or in part, to prevent or overcome by the exercise of prudent industry practices, including the following events: (a) acts of God or the public enemy, civil unrest, criminal activity, restraints of the government (either federal, state, or military), acts of terrorism, wars, riots, epidemics, or insurrections; (b) the elements (including storms, lightning, landslides, hurricanes, floods, earthquakes, tornados, freezing of wells or lines of pipe, and threats of any of the forgoing); (c) fire, accidents, or breakdowns; (d) strikes and any other industrial, civil, or public disturbance; (e) partial or entire failure of upstream or downstream pipelines, processing or natural gas liquid transporters to install facilities or to take or transport gas or Plant Products; (f) accidents, mechanical failure, repairs, maintenance, or alteration to lines of pipe or Plant or System equipment; (g) inability or delay to obtain rights-of-way, easements, or property rights for the construction or operation of any necessary facilities; (h) inability or delay to obtain materials, supplies, permits, or labor; (i) temporary failure of gas supply; (j) failure of Downstream Pipelines to adhere to contractual commitments to either Party.

Section 15.3 Labor Matters. It is understood and agreed that the settlement of strikes or lockouts shall be entirely within the discretion of the Party having the difficulty and that the above requirement that any Force Majeure shall be remedied with all reasonable dispatch shall not require the settlement of strikes or lockouts by acceding to the demands of the opposing Party when such course is inadvisable in the discretion of the Party having the difficulty.

ARTICLE XVI DEFAULT AND REMEDIES

Section 16.1 Events of Default. Each of the following shall constitute an "***Event of Default***" in respect of a Party (the "***Defaulting Party***") under this Exhibit A:

(a) failure by the Defaulting Party to pay when due any payment owed under this Exhibit A, which failure continues for a period of *** Days following the notice thereof from the other Party (the ***"Non-Defaulting Party"***), provided the payment is not the subject of a good faith dispute;

(b) failure by the Defaulting Party to perform any other material obligations or covenants under this Exhibit A which failure continues for a period of *** Days following notice thereof from the Non-Defaulting Party, provided, however, that if such failure is capable of being remedied within such *** period and the Defaulting Party is proceeding with diligence and in good faith to remedy such failure, then the time within which such failure may be remedied shall be extended for an additional *** Days or as otherwise agreed by the Parties;

(c) any representation or warranty herein made by the Defaulting Party shall have been false when made;

(d) (i) a receiver, liquidator, or trustee of the Defaulting Party or of any of its property shall be appointed by a court of competent jurisdiction, and such receiver, liquidator, or trustee shall not have been discharged within *** Days or by decree of such court, (ii) such Defaulting Party shall be adjudicated bankrupt or insolvent or any substantial part of its property shall have been sequestered, and such decree shall have continued undischarged and unstayed for a period of *** Days after the entry thereof, or (iii) a petition to declare bankrupt or to reorganize such Defaulting Party pursuant to any of the applicable bankruptcy law shall be filed against such Defaulting Party and shall not be dismissed within *** Days after such filing; or

(e) a Defaulting Party shall (i) file a voluntary petition in bankruptcy under applicable bankruptcy law, (ii) consent to the filing of any bankruptcy or reorganization petition against it under any bankruptcy law, (iii) file a petition, answer, or consent seeking relief or assisting in seeking relief in a bankruptcy under any bankruptcy law, (iv) consent to the filing of any bankruptcy or reorganization petition against it under any bankruptcy law, (v) file a petition, answer, or consent seeking relief or assisting in seeking relief in a proceeding under any bankruptcy law, or an answer admitting the material allegations of a petition filed against it in such a proceeding, (vi) make an assignment for the benefit of its creditors, (vii) admit in writing its inability to pay its debts generally as they become due, or (viii) consent to the appointment of a receiver, trustee, or liquidator of it or of all or any part of its property.

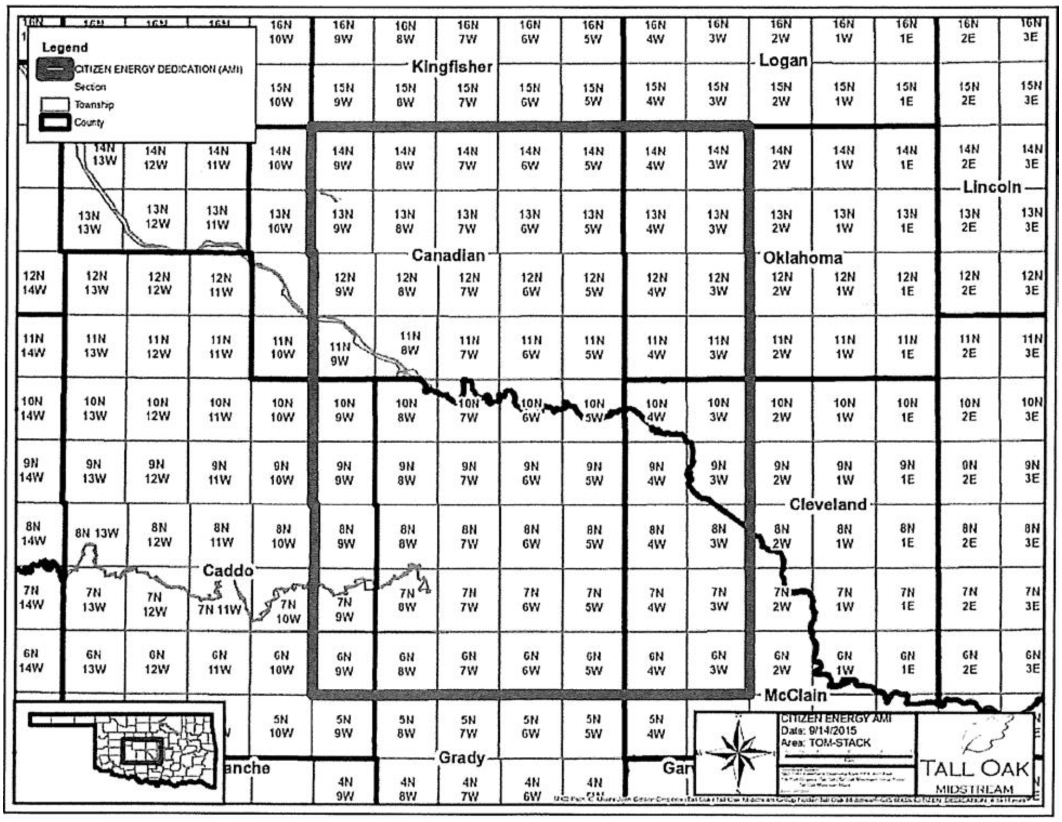
Section 16.2 Remedies. Upon an Event of Default, the Non-Defaulting Party may terminate the Agreement with respect to the terms, conditions and rights and obligations of the Parties to the extent such relating to this Exhibit A and Exhibits A-1 through A-5 (inclusive) and exercise all of its rights and remedies in equity or at law. In addition to all its other rights and remedies, a Non-Defaulting Party shall be entitled to set off amounts due and payable to the Defaulting Party against amounts owed by the Defaulting Party under this Exhibit A.

ARTICLE XVII
RIGHTS-OF-WAY

To the maximum extent that it may contractually or lawfully do so, Producer hereby grants to Linn Midstream such rights as it may have of ingress and egress upon all lands owned or controlled by Producer ("***Producer's Land***") for the purpose of installing, using, maintaining, servicing, inspecting, repairing, operating, replacing, disconnecting, and removing the Facilities or any component part thereof that are used or useful in the performance of this Exhibit A. Any property of Linn Midstream placed in or upon Producer's Land shall remain the personal property of Linn Midstream and, subject to the terms of this Exhibit A, may upon prior notice to Producer during normal business hours, be disconnected and removed by Linn Midstream at any time for any reason. Producer shall maintain, at its sole expense, easements, rights-of-way, lease roads, and other access facilities upon Producer's Land as may reasonably be deemed necessary by Linn Midstream for its performance of this Exhibit A. Linn Midstream shall indemnify and hold Producer harmless for any injury or damage caused to Producer's Lands as a result of Linn Midstream exercising its rights under this Article XVII of this Exhibit A and shall restore Producer's Lands to substantially the same condition immediately prior to conducting any surface disturbing activities.

EXHIBIT A-1 CONTRACT
AREA A-1

This Exhibit A-1 is attached to and made a part of that certain Amended and Restated Gas Gathering and Processing Agreement effective April 1, 2017, by and between Producer and Linn Midstream.



AMI			
Section	**Township**	**Range**	**County, State**
1-36	6-14N	3-9W	Canadian, Oklahoma, Caddo, Grady, McClain & Cleveland Counties in Oklahoma

EXHIBIT A-2
RECEIPT POINTS

This Exhibit A-2 is attached to and made a part of that certain Amended and Restated Gas Gathering and Processing Agreement effective April 1, 2017, by and between Producer and Linn Midstream.

Receipt Point Name	Meter Number	Well Name	WH Deliv	CDP	Gas Lift Meter Number	Receipt Point Location
HinParr 31-6-10-5 1XH	CTP00003	HinParr #31-6-10-5 #1XH	X		CTP00013	31-10N-05W, Grady, OK
Jackson 25-24-10-6 1XH	CTP00004	Jackson 25-24-10-6 1XH	X		CTP00016	25-10N-06W & 24-10N-06W; Grady, OK
Langston 13-24-9-6 1XH	CTP00005	Langston 13-24-9-6 1XH	X		CTP00015	13-09N-06W & 24-09N-06W; Grady, OK
McNeff 22-10-5 1H	CTP00006	McNeff 22-10-5 1H	X		CTP00014	22-10N-0W; Grady, OK
Braum 10-6 1XH	CTP00007	Braum 33-4-10-6 1XH		X	CTP00012	
		Braum 28-21-10-6 1XH		X		
Anderson 1H-33/2H-28	CTP00008	Anderson #1H-33		X		
		Anderson #1H-28		X		
Hardesty 1H/2H-22	CTP00009	Hardesty 1H		X		
		Hardesty 2H		X		
Huffman 1H/2H-30-19	CTP00010	Huffman 1H-30-19		X		19-10N-05W; Grady, OK
		Huffman 2H-30-19		X		
Doris 12-13-10-6 2XH	CTP00017	Doris 12-13-10-6 2XH	X			12-10N-06W & 13-10N-06W; Grady, OK
Dream Cooler 13-12-10-6 2XH	CTP00019	Dream Cooler 13-12-10-6 2XH				13-10N-06W & 12-10N-06W
Rikella 1H/2H-16-9/3H-21	CTP00020	Rikella 1H-16-9		X		16-10N-05W; Canadian, OK
		Rikella 2H-16-9		X		
		Rikella 3H-21		X		
Skaggs 1H-4/1H-5	CTP000_	Skaggs 1H-4		X		
		Skaggs 1H-5		X		

EXHIBIT A-3
PLANT ACCOUNTING PROCEDURE

This Exhibit A-3 is attached to and made a part of that certain Amended and Restated Gas Gathering and Processing Agreement effective April 1, 2017, by and between Producer and Linn Midstream.

I. General Provisions

A. Gas Gathering and Processing Agreement. All references to the "***Agreement***" shall mean the Amended and Restated Gas Gathering and Processing Agreement to which this Exhibit A-3 is attached, to the extent the terms and conditions of Exhibit A apply with respect thereto.

B. Definitions. Terms used in this Exhibit A-3 shall have the same meanings as defined in Exhibit A. The following terms shall have the meaning set forth below:

"**Btu/Gallon Liquid Ratio Factor**" means the number of Btus contained in one gallon of any component of the Plant Products measured at 60° Fahrenheit. The numerical values of such ratio for each component shall be the numerical values shown as fuel as ideal gas in the GPA Standard 2145-2000, as amended from time to time.

C. Standard Reporting. For purposes of this Exhibit A-3, all references to volumes shall mean volumes in Mcfs.

D. Plant Products. The Plant Products components of ethane, propane, iso-butane, normal butane, and natural gasoline (sometimes known as "Pentane plus (+)") shall be allocated to Producer in the manner provided herein from the Plant Products recovered in the Plant. For brevity purposes, iso-butane and normal butane shall both be referred to as just "butane" in this Exhibit A-3.

II. Basis for Allocations

A. Sampling and Analysis of Inlet Streams and Commingled Residue Gas Stream. Linn Midstream or its designee shall determine the analysis of Producer's Gas by taking sample(s) (as set forth in Article VI of Exhibit A) at the Receipt Point(s) as frequently as deemed necessary, but not less frequently than once every thirteen (13) Months.

Alternatively, Linn Midstream or its designee may, at its sole option, install, maintain, and operate a continuous gas sampler to sample Producer's Gas at said Receipt Point(s). Determination by a continuous gas sampler shall become effective the first Day of the Month in which the gas sample was collected. Spot sample determinations shall become effective the first Day of the Month following the determination, unless such spot sample is the first sample taken from such Receipt Point(s), and then such spot sample shall become effective immediately and shall remain effective until the next subsequent determination. Linn Midstream or its designee shall analyze, or shall cause to be analyzed at a reputable third party commercial laboratory, the gas samples of Producer's Gas at the Receipt Point(s). The resulting analyses shall indicate the Btu content of Producer's Gas and shall further indicate the gallons of Plant Products per Mcf

(“***GPM***”) contained in such samples. Notwithstanding the above, if there are any discrepancies between this Section II.A. of this Exhibit A-3 and Article VI of Exhibit A, it is understood that Article VI of Exhibit A shall prevail.

B. Calculation of Theoretical Gallons of Plant Products. The volume of Producer’s Gas received and/or metered at the Receipt Point(s) during a Month, less Fuel, shall be multiplied by the GPM of Plant Products contained therein at the Receipt Points (determined as provided in Section II.A. of this Exhibit A-3) to determine the total theoretical gallons of Plant Products respectively, contained in such volumes of Producer’s Gas. In the event that any Producer’s Gas is bypassed around the Plant without Processing, all references to volumes of Producer’s Gas for purpose of calculating theoretical gallons of Plant Products in Producer’s Gas shall mean the volume of Producer’s Gas received and/or metered at the at the Receipt Point(s) less Fuel minus the volume of Producer’s Gas that was bypassed.

C. Calculation of Theoretical MMBtus Delivered to the Plant. The volume of Producer’s Gas metered at the Receipt Point(s) during a Month, less Fuel, shall be multiplied by the Btu of such Producer’s Gas, determined as provided in Section II.A. of this Exhibit A-3, to arrive at the total theoretical MMBtus contained in Producer’s Gas.

III. Plant Product Recovery Percentages

Plant Product recovery percentages shall be determined in accordance with Exhibit A; *provided*, *however*, that during any time when the Fixed Recovery Percentage(s) are not achieved due to
(a) an event of Force Majeure, (b) planned maintenance, or (c) less than 35 MMcf of Gas being delivered from all sources to the Plant per Day, Linn Midstream shall have the option to apply the actual recoveries of the Plant.

IV. Determination of Plant Products

Except as otherwise provided in Section III of this Exhibit A-3, during periods when Fixed Recovery Percentages apply, the total theoretical gallons of each Plant Product contained in Producer’s Gas (determined as provided in Section II.B. of this Exhibit A-3) shall be multiplied by the Fixed Recovery Percentage of each product set forth in Section 5.2 of Exhibit A to determine the allocation of each Plant Product to Producer’s Gas.

V. Determination of Shrinkage

A. MMBtu Content of the Plant Products. The MMBtus removed from Producer’s Gas as separate Plant Products during each Month shall be determined by multiplying the number of gallons of each Plant Product, respectively, produced during such Month from Producer’s Gas, determined as provided in Section IV of this Exhibit A-3, by the Btu/Gallon Liquid Ratio Factor (determined as provided in Section I.B. of this Exhibit A-3), as applicable for each component, in effect for such Month.

B. Total MMBtus Removed from Producer’s Gas. The total MMBtus removed from Producer’s Gas as Plant Products during each Month shall equal the sum of the MMBtus removed from Producer’s Gas as Plant Products, determined as provided in Section V.A. of this Exhibit A-3.

VI. Determination of the Residue Gas Delivered to the Downstream Pipeline

The MMBtus allocable to Producer as Residue Gas shall be determined by subtracting (i) the sum of the MMBtus allocable to Producer's Gas as Shrinkage determined as provided in Section V. of this Exhibit A-3) plus the MMBtus allocable to Producer's Gas as Fuel from (ii) the sum of the theoretical MMBtus in Producer's Gas (determined as provided in Section II.C. of this Exhibit A-3) during the Month.

EXHIBIT A-4
SERVICE FEES

This Exhibit A-4 is attached to and made a part of that certain Amended and Restated Gas Gathering and Processing Agreement effective April 1, 2017, by and between Producer and Linn Midstream.

Gathering, Compression and Processing Fee	$***/Receipt Point MMBtu
NGL Fee	$***/gallon
Low Meter Fee	$*** per Receipt Point to which less than *** Mcf of Gas is delivered for the applicable Month

EXHIBIT A-5 PREEXISTING DEDICATIONS

This Exhibit A-5 is attached to and made a part of that certain Amended and Restated Gas Gathering and Processing Agreement effective April 1, 2017, by and between Producer and Linn Midstream.

Prior Dedicated Sections:

The sections, if any, dedicated under the following agreements:

Linn K#	Counter party K#	Contract Type	Linn Entity	Counterparty
224G	10-0009	Gas Purchase and Sale Agreement	Linn Energy Holdings, LLC	CimarexEnergy Company
1244G		Gas Purchase Contract	LINN OPERATING, LLC	Continuum Midstream, L.L.C.
TBD	EDM 1776-00*	Gas Purchase Contract	Linn Energy Holdings, LLC	DCP Midstream LLC
TBD	EDM 0768-00A	Gas Purchase Contract	Linn Energy Holdings, LLC	DCP Midstream LLC
TBD	EDM 1971-00*	Gas Purchase Contract	Linn Energy Holdings, LLC	DCP Midstream LLC
TBD	OKR 1306-PUR	Gas Purchase Contract	Linn Energy Holdings, LLC	DCP Midstream LLC
TBD	OKR 1320-PUR	Gas Purchase Contract	LINN OPERATING, LLC	DCP Midstream LLC
TBD	14812	Gas Purchase Contract	Linn Energy Holdings, LLC	DCP Midstream LLC
1106G	CHI 0580-000	Gas Purchase Contract	LINN OPERATING, LLC	DCP Midstream LLC
TBD	EDM 1026-00A	Gas Purchase Contract	LINN OPERATING, LLC	DCP Midstream LLC
TBD	EDM 0012-PUR	Gas Purchase Contract	LINN OPERATING, LLC	DCP Midstream LLC
TBD	OKR 0534-00*	Gas Purchase Contract	LINN OPERATING, LLC	DCP Midstream LLC
TBD	EDM 2022-00*	Gas Purchase Contract	LINN OPERATING, LLC	DCP Midstream LLC
1111G	OKR 0734-00*	Gas Purchase Contract	LINN OPERATING, LLC	DCPOperating Company LP
113G	EDM 1544-00A	Gas Purchase Contract	LINN ENERGY MID-CONT.HOLDINGS,	DCPOperating Company LP

Linn K#	Counter party K#	Contract Type	Linn Entity	Counterparty
			LLC	
1163G	SHOP 00015	GasPurchaseand Processing Agreement	LINN OPERATING, LLC	DCPOperating Company LP
1283G	OKR 0933-000	Gas Purchase Contract	LINN OPERATING, LLC	DCPOperating Company LP
1295G	OKR 0705-00*	Gas Purchase Contract	LINN OPERATING, LLC	DCPOperating Company LP
181G	OKR 1196-000	Gas Purchase Contract	LINN OPERATING, LLC	DCPOperating Company LP
212G	EDM 2049-00*	Gas Purchase Contract	LINN OPERATING, LLC	DCPOperating Company LP
219G	15233	Gas Purchase Contract	LINN OPERATING, LLC	DCPOperating Company LP
278G	16704	Gas Purchase Contract	LINN OPERATING, LLC	DCPOperating Company LP
29G	SHOP 00007	GasPurchaseand Processing Agreement	LINN OPERATING, LLC	DCPOperating Company LP
518G	CIM 0917-00*	Gas Purchase Contract	LINN OPERATING, LLC	DCPOperating Company LP
53G	15631	Gas Purchase Contract	LINN OPERATING, LLC	DCPOperating Company LP
574G	OKR 0278-00	Gas Purchase Agreement	LINN OPERATING, LLC	DCPOperating Company LP
68G	15577	Gas Purchase Agreement	LINN OPERATING, LLC	DCPOperating Company LP
76G	15455	Gas Purchase Contract	LINN OPERATING, LLC	DCPOperating Company LP
775G	EDM 2027-00*	Gas Purchase Agreement	LINN OPERATING, LLC	DCPOperating Company LP
783G	15676	Gas Purchase Contract	LINN OPERATING, LLC	DCPOperating Company LP
784G	OKR 1197-000	Gas Purchase Contract	LINN OPERATING, LLC	DCPOperating Company LP
785G	OKR 0150-00*	Gas Purchase Contract	LINN OPERATING, LLC	DCPOperating Company LP
1599G		GasGathering, Processing and Purchase Agreement	LINN OPERATING, LLC	EnLink Oklahoma GasProcessing, LP
419G	6083-00	Gas Purchase Contract	LINN OPERATING, LLC	ETC Field Services LLC
CTPr-1	CTPr-1	Gas Processing Agreement	Linn Energy Holdings, LLC	LinnMidstream, LLC
1158G	026770B	Gas Purchase Contract	LINN OPERATING, LLC	Mustang Gas Products Inc.

Linn K#	Counter party K#	Contract Type	Linn Entity	Counterparty
1411G	495152	GasPurchase Agreement	LINNOPERATING, LLC	MustangGas Products Inc.
184G	4002775	Gas Purchase Contract	LINNOPERATING, LLC	MustangGas Products Inc.
250G	8928NG D	GasPurchase Agreement	LINNOPERATING, LLC	MustangGas Products Inc.
254G	51013	GasPurchase Agreement	LINNOPERATING, LLC	MustangGas Products Inc.
256G	51008	Gas Purchase Contract	LINNOPERATING, LLC	MustangGas Products Inc.
257G	51009	GasPurchase Agreement	LINNOPERATING, LLC	MustangGas Products Inc.
63G	9518CD	GasPurchase Agreement	LINNOPERATING, LLC	MustangGas Products Inc.
828G	9845CD	CasingheadGas Contract	LINNOPERATING, LLC	MustangGas Products Inc.
KF-1280G	495103	GasPurchase Agreement	LINN ENERGY MID-CONT.HOLDINGS, LLC	MustangGas Products Inc.
1515G	1293000	Gas Purchase Contract	LINNOPERATING, LLC	OneokField Services LLC
1516G	1298000	Gas Purchase Contract	LINNOPERATING, LLC	OneokField Services LLC
1517G	2026000	Gas Purchase Contract	LINNOPERATING, LLC	OneokField Services LLC
236G	1297000	Gas Purchase Contract	LINNOPERATING, LLC	OneokField Services LLC
237G	755000	Gas Purchase Contract	LINNOPERATING, LLC	OneokField Services LLC
507G	2058001	Gas Purchase Contract	LINNOPERATING, LLC	OneokField Services LLC
1140G	ET-P5	GasPurchase Agreement	LINNOPERATING, LLC	SuperiorPipeline Company
1141G	ET-P4	Gas Purchase Contract	LINNOPERATING, LLC	SuperiorPipeline Company
1144G	CASH-P5	Gas Purchase Contract	LINNOPERATING, LLC	SuperiorPipeline Company
1145G	MINCO P18	Gas Purchase Contract	LINNOPERATING, LLC	SuperiorPipeline Company
1442G	311680	GasPurchase Agreement	LINNOPERATING, LLC	Targa Pipeline Mid Continent LLC

Exhibit B and Exhibits B-1 through B-5

See attached.

EXHIBIT B
AMENDED AND RESTATED GAS GATHERING AND PROCESSING AGREEMENT
Terms and Conditions

This Exhibit B is attached to and made a part of that certain Amended and Restated Gas Gathering and Processing Agreement effective April 1, 2017, by and between Producer and Linn Midstream.

EXHIBIT B - TABLE OF CONTENTS

I. CONSIDERATION

1.1 **Total Consideration**. As total and complete consideration for the purchase of (and performance by Linn Midstream of the services described herein with respect to) the Committed Gas hereunder, Linn Midstream shall pay Producer each Month during the Term of this Exhibit B an amount equal to the Contract Amount to be calculated in accordance with the provisions described in Exhibit B-2 attached hereto and made a part hereof.

1.2 **Consideration for all Components**. Producer acknowledges and agrees that the consideration paid by Linn Midstream hereunder shall constitute compensation in full to Producer for its sale, assignment, transfer, and conveyance of (and performance by Linn Midstream of the services described herein with respect to the Committed Gas purchased hereunder) the Committed Gas, including all liquefiable hydrocarbons contained therein.

II. TERM

2.1 **Term**. This Exhibit B shall be effective as of the Effective Date, and shall continue for a primary term ending on December 22, 2031 (the "Primary Term"), and, thereafter, shall continue Year to Year unless either Party gives the other Party written notice, at least one hundred eighty (180) Days prior to the expiration of the Primary or successor Term, of its election to terminate this Exhibit B.

III. DEFINITIONS AND SECTION REFERENCES

3.1 For the purpose of this Exhibit B, unless the context clearly indicates otherwise, the following definitions shall be applicable:

3.1.1 **AAA and AAA Rules** shall have the meanings set forth in Section 18.1.2 to this Exhibit B.

3.1.2 **AGA** shall mean the American Gas Association.

3.1.3 **Agreement** shall mean the main body of the Amended and Restated Gas Gathering and Processing Agreement to which this Exhibit is attached.

3.1.4 **Alternative Arrangements** shall have the meaning set forth in Section 4.3 to this Exhibit B.

3.1.5 **API** shall mean the American Petroleum Institute.

3.1.6 **BTU** (British Thermal Unit) shall mean the amount of heat required to raise the temperature of one (1) avoirdupois pound of pure water from fifty-eight and five-tenths degrees (58.5º) Fahrenheit to fifty-nine and five-tenths degrees (59.5º) Fahrenheit at
14.65 psia.

3.1.7 **BTU Per Gallon** shall mean the BTU per gallon values assigned to the various hydrocarbon components using as a base those values set forth in the most current GPA Publication 2145.

3.1.8 **Business Day** shall mean any Day except Saturday, Sunday or Federal Reserve Bank holidays.

3.1.9 **Bypass Gas** shall have the meaning set forth in Section 10.5 to this Exhibit B.

3.1.10 **Claimant** shall have the meaning set forth in Section 18.1.2 to this Exhibit B.

3.1.11 **Claims** shall have the meaning set forth in Section 14.1 to this Exhibit B.

3.1.12 **Committed Gas** shall have the meaning set forth in Section 5.1.1 to this Exhibit B.

3.1.13 **Connection Extension** shall have the meaning set forth in Section 5.2.1 to this Exhibit B.

3.1.14 **Connection Request** shall have the meaning set forth in Section 5.2.2 to this Exhibit B.

3.1.15 **Contract Amount** shall have the meaning set forth in Section 1 of Exhibit B-2 hereto.

3.1.16 ***

3.1.17 **Cubic Foot of Gas** for the purpose of measurement of the Gas received hereunder shall mean the amount of Gas necessary to fill one (1) cubic foot of space at a base pressure of fourteen and sixty-five hundredths (14.65) psia, and at a base temperature of sixty degrees (60°) Fahrenheit, and shall be the volume unit of measurement.

3.1.18 **Day** shall mean a calendar day. For measurement purposes described herein, a Day shall begin with the hour that is the then-beginning hour that is the standard practice of Linn Midstream.

3.1.19 **Dedicated Area** shall mean the area indicated in, and as shown on the map included in Exhibit B-1 hereto.

3.1.20 **Dedicated Interests** shall have the meaning set forth in Section 5.1.1 to this Exhibit B.

3.1.21 **Dehydration Equipment** shall mean that equipment that removes water and water vapor from the Gas or NGLs, such as with the use of glycol, methanol, molecular sieves, etc.

3.1.22 **Drilling Schedule** shall have the meaning set forth in Section 4.2 to this Exhibit B.

3.1.23 **Drip Liquids** shall mean those hydrocarbon liquids and other products that condense from the Gas in the Facilities from the Receipt Points to the inlet of the Plant(s) inlet(s).

3.1.24 **Effective Date** shall have the meaning set forth in the Agreement.

3.1.25 **Facilities** shall mean the pipeline systems owned by or otherwise contracted for by Linn Midstream, including pipelines and other appurtenant facilities, as same now exist or may hereafter be modified, extended or expanded, which enable Linn Midstream to receive the Committed Gas hereunder as well as Gas from other suppliers.

3.1.26 **Field Fuel** shall have the meaning set forth in Section 4(b) of Exhibit B-2 hereto.

3.1.27 **Field L&U** shall have the meaning set forth in Section 4(c) of Exhibit B-2 hereto.

3.1.28 **Force Majeure** shall have the meaning set forth in Section 14.3 to this Exhibit B.

3.1.29 **Gas** shall mean natural gas as produced in its natural state.

3.1.30 **Gas Lift Facility(ies)** shall have the meaning set forth in Section 5.1.3.e to this Exhibit B.

3.1.31 **Gas Lift Gas** shall have the meaning set forth in Section 5.1.3.e to this Exhibit B.

3.1.32 **Gas Lift Imbalance** shall have the meaning set forth in Section 5.1.3.e to this Exhibit B.

3.1.33 **G&P Acceptance** shall have the meaning set forth in Section 5.1.1 to this Exhibit B.

3.1.34 **G&P Notice** shall have the meaning set forth in Section 5.1.1 to this Exhibit B.

3.1.35 **Gross Heating Value of the Gas** shall mean the total or gross BTU's produced by the complete combustion of one (1.0) Cubic Foot of Gas, at a temperature of sixty degrees (60°) Fahrenheit and under a pressure of fourteen and sixty-five hundredths (14.65) psia with air of the same temperature and pressure as the Gas, when the products of combustion are cooled to the initial temperatures of the Gas and air, and when the water formed by such combustion is condensed to a liquid state at the initial temperature of the Gas.

3.1.36 **Lease, Leases, Land, and Lands** are used herein interchangeably, for editorial convenience, and each such term where used shall mean the Dedicated Area and/or the Dedicated Interests committed under this Exhibit pursuant to Article V of this Exhibit B.

3.1.37 **Linn Midstream** shall have the meaning set forth in the Preamble.

3.1.38 **LINN MIDSTREAM INDEMNITY GROUP** shall have the meaning set forth in Section 14.1 to this Exhibit B.

3.1.39 **Linn Midstream's Plant** shall mean those Plants owned by Linn Midstream.

3.1.40 **MAOP** shall mean the maximum allowable operating pressure of a pipeline.

3.1.41 **MCF** shall mean one thousand (1,000) Cubic Feet of Gas.

3.1.42 **MMBTU** shall mean one million (1,000,000) British Thermal Units.

3.1.43 **MMCF** shall mean one million (1,000,000) Cubic Feet of Gas.

3.1.44 **Month** shall mean that period beginning on the first Day of a calendar month, and ending on the first Day of the following calendar month, except that the first Month shall commence on the Day of initial receipt of Gas hereunder and shall end on the first Day of the following Month.

3.1.45 **Natural Gas Liquids or NGLs** shall mean those liquid hydrocarbons extracted by Processing from Gas, including, without limitation, incidental methane and ethane, propane, iso-butane, normal butane, natural gasoline and other miscellaneous liquids that become associated with the NGLs.

3.1.46 **NGL Market Price** shall have the meaning set forth in Section 2(a)(i) of Exhibit B-2.

3.1.47 **NGL Settlement Amount** shall have the meaning set forth in Section 2(a) of Exhibit B- 2.

3.1.48 **NGL Settlement Percent** shall have the meaning set forth in Section 2(a)(ii) of Exhibit B-2.

3.1.49 **NGL Shrinkage** for each Receipt Point shall be the MMBTU determined by multiplying the Plant Inlet Volume times (i) the Theoretical Gallons for each NGL product times (ii) the Recovery Factor for that NGL product times (iii) the BTU Per Gallon factor for that NGL product.

3.1.50 **NGL Volume** shall have the meaning set forth in Section 2(a)(iii) of Exhibit B-2.

3.1.51 **Non-Operated Well** shall have the meaning set forth in Section 5.2.3 to this Exhibit B.

3.1.52 **Non-Operated Well Connection Request** shall have the meaning set forth in Section 5.2.3 to this Exhibit B.

3.1.53 **Operated Well** shall have the meaning set forth in Section 5.2.2 to this Exhibit B.

3.1.54 **Original Effective Date** means January 1, 2016.

3.1.55 **Plant Fuel** shall have the meaning set forth in Section 4(a) of Exhibit B-2.

3.1.56 **Plant Inlet Volume** shall be the volume, for each Receipt Point, equal to the MCF of Gas attributable to such Receipt Point determined by subtracting from the volume received at such Receipt Point the Field Fuel and Field L&U applicable to such volume.

3.1.57 **Primary Term** shall have the meaning set forth in Section 2.1 to this Exhibit B.

3.1.58 **Processing** shall mean the extraction of NGLs from Gas through equipment specifically intended to extract NGLs from the Gas such as turboexpander (cryogenic), refrigeration, refrigerated lean oil absorption, ambient oil absorption, Joule Thompson or similar processes.

3.1.59 **Processing and Gathering Amount** shall have the meaning set forth in Section 6 of Exhibit B-2.

3.1.60 **Processing and Gathering Fee** shall have the meaning set forth in Section 6 of Exhibit B-2.

3.1.61 **Producer** shall have the meaning set forth in the Preamble.

3.1.62 **PRODUCER GROUP** shall have the meaning set forth in Section 5.1.1 to this Exhibit B.

3.1.63 **PRODUCER INDEMNITY GROUP** shall have the meaning set forth in Section 14.1 to this Exhibit B.

3.1.64 **Production Month** shall have the meaning set forth in Section 11.1 to this Exhibit B hereto.

3.1.65 **Psia** shall mean pounds per square inch absolute.

3.1.66 **Psig** shall mean pounds per square inch gauge.

3.1.67 **Receipt Point(s)** shall mean the inlet flange of the pipeline measurement facilities installed on the well pad at a location specified by Producer for the Well(s) to take delivery of Gas from the Wells as more fully provided in Section 5.2.1 to this Exhibit B. As such Receipt Points are installed, they shall be added to Exhibit B-3.

3.1.68 **Residue Gas** shall mean the total Gas available for sale at the tailgate of any Plant.

3.1.69 **Residue Gas Market Price** shall have the meaning set forth in Section 3(a) of Exhibit B- 2.

3.1.70 **Residue Gas Volume** for each Receipt Point shall have the meaning set forth in Section 3(c) of Exhibit B-2.

3.1.71 **Residue Settlement Amount** shall have the meaning set forth in Section 3 of Exhibit B- 2.

3.1.72 **Residue Settlement Percent** shall have the meaning set forth in Section 3(b) of Exhibit B-2.

3.1.73 **Respondent** shall have the meaning set forth in Section 18.1.2(b) to this Exhibit B.

3.1.74 **Square Root Error or SRE** shall have the meaning set forth in Section 16.6 to this Exhibit B.

3.1.75 **Theoretical Gallons** shall mean the gallons per MCF of each NGL product in the Committed Gas as measured at each Receipt Point.

3.1.76 **WAP** shall have the meaning set forth in Section 3(a) of Exhibit B-2.

3.1.77 **Well(s)** shall mean any well(s), the production from which is(are) dedicated under and committed to the Agreement pursuant to the terms of Article V of this Exhibit B (and the other terms and provisions of this Exhibit B).

3.1.78 **Year** shall mean any period of twelve (12) consecutive Months.

In addition to the foregoing definitions, when used in this Exhibit B with respect to Producer, "affiliate" shall mean any subsidiaries of Linn Energy Holdings, LLC but no other person or entity.

IV. QUANTITY AND DELIVERY

4.1 **Quantity**. Subject to the terms and conditions contained in this Exhibit B and, to the extent applicable, the Agreement, Producer agrees to sell and deliver to Linn Midstream the Committed Gas during the Term of this Exhibit B.

4.2 **Drilling Schedule**. Producer shall provide Linn Midstream with quarterly updates of its drilling schedule including the aggregate production forecasts by section of land ("Drilling Schedule"). The Drilling Schedule shall show the planned timing of drilling activity for the next *** Months, the projected spud and first flow dates, and Producer's most accurate and good faith expected flow rates by well, pad and section. Within *** Days after the receipt of the Drilling Schedule, Linn Midstream will provide Producer with projected in-service dates for each pad and/or well shown on the Drilling Schedule. For any pad and/or well which Linn Midstream projects it will not be ready to accept Gas by Producer's estimated first flow dates, Linn Midstream will detail the reason for delay and potential activity required to be able to accept Gas on Producer's estimated first flow date. Producer will consider, in its sole discretion, the alteration of the drilling and/or completion schedule as required to accommodate Linn Midstream potential delays.

4.3 **Obligation to Take**. Linn Midstream shall be obligated to use reasonable commercial efforts to purchase and receive from Producer all of the Committed Gas delivered at the Receipt Point(s). It is expressly understood that Linn Midstream shall not be obligated to take or pay for Committed Gas and, in the event of insufficient market for Gas at one or more any Receipt Points during periods in which Linn Midstream is purchasing the Gas, Linn Midstream shall only be obligated to use commercially reasonable efforts to take ratably from all sources of supply, including its own. If Linn Midstream is unable to receive Committed Gas from any Receipt Point(s), due to any reason, for *** or more consecutive days, such Receipt Point(s), at Producer's request, will be permanently released from dedication under the Agreement and Producer may sell such portion of the Committed Gas to other purchasers. Subject to Force Majeure, if any such inability by Linn Midstream to take from one or more Receipt Points persists for more than *** Days, whether consecutively or cumulatively, in any one Year, Producer shall have the right to initiate a *** cure period under which Linn Midstream shall use commercially reasonable efforts to provide commercially reasonable alternative market options for the affected Receipt Point(s) acceptable to Producer, whose acceptance will not be unreasonably withheld. In the event that Linn Midstream is unable or fails to cure during such *** cure period, then Producer shall have the right to a permanent release of the applicable portion of the Committed Gas from the section containing such affected Receipt Point(s), plus the Receipt Point(s) located in the surrounding 8 sections upon thirty *** Days' written notice to Linn Midstream.

4.4 **BUYER's Standard of Conduct**. Linn Midstream shall conduct the operations required by this Exhibit B as a reasonably prudent operator, in a good and workmanlike manner, with due diligence and dispatch, and in accordance with good midstream industry practices.

4.5 **Delivery of Uniform Flows**. Producer shall deliver all Committed Gas in such uniform hourly flows as is commercially practicable. In the event Producer anticipates a material increase or decrease in the flow of Gas at any Receipt Point(s), Producer shall provide Linn Midstream with reasonable advance notice of such change.

4.6 **Title, Possession and Control**. Title, possession, and control of Committed Gas, including all liquefiable hydrocarbons contained therein, shall pass from Producer to Linn Midstream at the Receipt Point(s).

V. DEDICATION AND CONNECTION OF WELLS

5.1 **Dedication and Connection of Wells**.

5.1.1 **Dedication**. For the Term specified in Article II of this Exhibit B and unless otherwise provided in Exhibit B-5, Section 4.3 to this Exhibit B or this Article V to this Exhibit B, Producer dedicates exclusively to the Agreement all interests which Producer and any of its affiliates (the "Producer GROUP") now own or control as well as any interests any of them may hereafter acquire or control in any and all lands, leases and/or Wells located in the Dedicated Area (the "Dedicated Interests"), insofar as the same may produce Gas, and Producer GROUP commits to Linn Midstream for sale and/or gathering and Processing under the terms of this Exhibit B all quantities of Gas owned or controlled by Producer GROUP that are produced from any Dedicated Interest as of or after the Original Effective Date, unless such Gas is dedicated pursuant to another agreement (a)

as of the Original Effective Date (including all interests, as identified on Exhibit B-5) or
(b) as of the date of acquisition by Producer GROUP for any interest acquired after the Original Effective Date, until (in the case of each of clauses (a) and (b)), such dedication terminates or expires (collectively, all such Gas is "Committed Gas"). Any interest acquired after the Original Effective Date that is dedicated pursuant to another agreement, as described in section (b) of this paragraph, shall be added to Exhibit B-5.

To Producer's knowledge, the gas contracts identified on Exhibit B-5 represent all existing gas contracts, including expiration dates, affecting the Dedicated Interests as of the Original Effective Date. Linn Midstream shall notify Producer in writing (a "G&P Notice") of Linn Midstream's election to gather and process all quantities of Gas produced from any Dedicated Interest that is associated with an expiring dedication under a contract identified on Exhibit B-5 at least *** Days prior to the expiration date of such dedication. Notwithstanding the foregoing, if Producer is required to provide notice under any such dedication to elect to continue or terminate such dedication, Producer shall notify Linn Midstream in writing of the notice provision date *** days prior to said notice date, and Linn Midstream shall provide its G&P Notice within *** Days after receiving such notice from Producer. In the event Linn Midstream timely delivers a G&P Notice with respect to an expiring dedication to gather and process Gas associated with such expiring dedication, then, upon the expiration of such dedications, such Gas shall be subject to the Agreement and shall be gathered and processed pursuant to this Exhibit B. In the event Linn Midstream does not timely provide a G&P Notice with respect to an expiring dedication, Producer's interest in the Dedicated Interests previously covered by the expired dedication shall be forever released from the Agreement.

Any sale or assignment by Producer of any interests in any of the lands, leases, or Wells dedicated hereunder may be made upon providing Linn Midstream with notice, and any such purchaser or assignee must agree that it takes such quantities of Gas, lands, leases, or Wells subject to the dedication in this Section 5.1.1 of this Exhibit B and subject to the provisions in Sections 5.1.2 and 5.1.3 of this Exhibit B and the other provisions of this Agreement, and that it will cause any subsequent purchasers or assignees of the lands, leases or Wells dedicated hereunder to do the same.

Producer's obligation to deliver Committed Gas hereunder will be met in instances where Producer's third-party operator delivers the Gas to Linn Midstream pursuant to a joint operating agreement or downstream marketing arrangement with Producer.

Producer agrees to provide Linn Midstream information containing the working interest ownership percentage associated with the lands, leases or Wells for such Committed Gas.

5.1.2 **Covenant Running with the Land**. Linn Midstream and Producer each intend that the dedication of lands, leases, and Committed Gas at in Section 5.1 of this Exhibit B is a covenant running with the lands in the Dedicated Area.

5.1.3 **Reservations**. Producer hereby expressly reserves the following rights with respect to the Dedicated Area:

(a) The right to use Gas prior to delivery to Linn Midstream for the following purposes:

(i) For fuel used above ground in the development and operation of leases dedicated to the Agreement including, but not limited to, lease fuel and fuel for production, completion and drilling operations; and

(ii) For delivery to the "lessor" from whom the leases dedicated under the Agreement were obtained, to the extent such lessors are entitled to receive Gas in-kind under the terms of the leases; and

(iii) For fuel used in the operation of the facilities which Producer GROUP or entities upstream of Producer GROUP may install in order to deliver Gas to Linn Midstream in accordance with the terms of this Exhibit B; and

(iv) As lift gas in the operation of Wells and leases dedicated to the Agreement.

(b) The right to pool or unitize the leases (or any portion thereof) with other lands and leases. In the event of pooling or unitization, this Exhibit B will cover Producer's interest in the pool or unit and the Gas attributable thereto to the extent that such interest is attributable to Producer's Gas reserves.

(c) The right to retain all oil and condensate separated from Producer's Gas by Lease Separation Facilities prior to delivery to Linn Midstream. The term "Lease Separation Facilities" shall mean conventional mechanical oil-gas field separators.

(d) The right to retain Gas that Producer and Linn Midstream mutually agree in writing is not Committed Gas.

(e) At the written request of Producer, Linn Midstream will install, own, and operate meters and other necessary facilities and equipment to measure the Gas used by Producer, pursuant to its right for lift gas operations described in Section 5.1.3.a.iv to this Exhibit B above, at any Well pad on lands within the Dedicated Area where Linn Midstream receives Committed Gas from Producer ("Gas Lift Facility(ies)"). All Gas that passes through the Gas Lift Facility(ies) for use by Producer in lift Gas operations is "Gas Lift Gas." At the written request of Producer, Linn Midstream will relocate the Gas Lift Facility(ies) to another Well pad Receipt Point within the Dedicated Area as directed by Producer. Producer will, within thirty *** of invoicing, reimburse Linn Midstream for the actual costs incurred by Linn Midstream for each occurrence of setting or relocating the Gas Lift Facility(ies), plus *** percent (***%) overhead charge, not to exceed $***. If the actual quantity of Gas Lift Gas, measured in MCFs, measured at any Gas Lift Facility during a Month is less than or equal to the actual quantity of Committed Gas measured in MCFs, delivered by Producer to the corresponding Receipt Point upstream of such Gas Lift Facility, during the same Month, then Linn Midstream shall reduce the Receipt Point volumes by the actual quantity of Gas Lift Gas, measured in MCFs, during that Month. If the actual quantity of Gas Lift Gas, measured in MCFs, measured at any Gas Lift Facility during a Month exceeds the actual quantity of Committed Gas, measured in MCFs, delivered by Producer to the corresponding Receipt Point upstream of such Gas Lift Facility during the same Month (such excess, the "Gas Lift Imbalance"), then Producer shall pay to Linn Midstream a fee (the "Gas Lift Imbalance Fee") equal to such Gas Lift Imbalance, in MCFs, multiplied by (a) the Gross Heating Value per cubic foot of Gas for the corresponding Receipt Point, multiplied times the sum of (b) the per MMBtu price published in the Platts monthly Inside FERC's Gas Market Report, as the "Index" for Henry Hub applicable to Gas delivered during such Month, plus (c) $***/MMBtu. Any taxes that may be imposed upon Linn Midstream attributable to the installation of Gas Lift Facility(ies) and/or providing Gas Lift Gas to Producer shall be reimbursed by Producer within *** Days of invoicing. Gas Lift Facility(ies) shall be included in the Linn Midstream's Facilities provision in Section 14.4 to this Exhibit B.

5.2 **Connection of Well(s)**.

5.2.1 The Receipt Point(s) at which Producer will deliver, and Linn Midstream will receive, the Committed Gas hereunder shall be point(s) of interconnect established pursuant to this Section 5.2 to this Exhibit B between the pipeline Facilities of Linn Midstream and Producer located on the space designated by Producer on Producer's well pad for each of the Wells (or set of Wells, as the case may be) and provided by Producer at no cost to Linn Midstream ("Receipt Points"). Except as set forth in Sections 5.2.2 and 5.2.3 to this Exhibit B below, Producer shall be responsible for arranging with Linn Midstream for the extension of Linn Midstream's then-existing pipeline Facilities to each Receipt Point and for Linn Midstream's construction and installation of measurement Facilities immediately downstream of such Receipt Point(s) to measure all Committed Gas delivered hereunder (each, a "Connection Extension"). Linn Midstream shall be responsible for all costs related to a Connection Extension. The Parties acknowledge that multiple Wells may be delivered by Producer to Linn Midstream through a common Receipt Point.

5.2.2 For the Receipt Points described in Section 5.1.1 to this Exhibit B which are attributable to a Well which is now or hereafter operated or controlled by any of the Producer GROUP (or their successors or assigns) ("Operated Well"), Producer shall be obligated to provide Linn Midstream with a written request to connect such Operated Well (a "Connection Request") on or before *** Days of its projected first flow date. The Connection Request will provide Producer's most accurate and good faith estimate of the Well location, the expected maximum flow, the expected average daily production for the first *** Months of production, and the projected first flow date of the Well. The information contained in the Connection Request and subsequent related communications between the Parties shall be subject to the confidentiality requirements contained in Section 19.2 to this Exhibit B. Linn Midstream shall be obligated to connect such Well pursuant to such Connection Request. Producer must provide timely access to the Receipt Point for Linn Midstream's equipment installation prior to the projected first flow date and in a period of time that does not conflict with Producer's drilling or completion operations. Linn Midstream will commence and use its commercially reasonable efforts to complete the connection of the Well specified in Producer's Connection Request prior to the projected first flow date. Subject to Force Majeure, in the event Linn Midstream has not constructed all required Facilities and is not ready to receive the Committed Gas at the Receipt Point under the Connection Request by *** Days after the projected first flow date of the Well, and Producer is ready, willing and able to deliver such Committed Gas on or before such projected first flow date of the Well, as Producer's sole and exclusive remedy (other than the right to specific enforcement of Linn Midstream's obligations under this Section 5.2.2 to this Exhibit B and any applicable rights to a release pursuant to Section 4.3 to this Exhibit B), Linn Midstream's Processing and Gathering Fee for that particular Receipt Point shall be reduced by *** for a period equal to the number of Days from the first flow date of the Well to the Day that Linn Midstream completes the connection to the Well and is ready to receive flow from such Well.

5.2.3 For the Receipt Points described in Section 5.1.1 to this Exhibit B which are attributable to a Well which is now or hereafter operated or controlled by a third party who is not a member of the Producer GROUP (or their successors or assigns) ("non-Operated Well"), and in which Producer or Producer GROUP owns greater than a cumulative *** percent (***%) working interest, Producer shall be obligated to provide Linn Midstream with a written request to connect such non-Operated Well (a "non-Operated Well Connection Request") on or before *** Days of its projected first flow date. The non-Operated Well Connection Request will provide Producer's most accurate and good faith estimate of the Well location, the expected maximum flow rate, and the expected average daily production for the first *** Months of production, Producer's percent of Gas entitlement, and the projected first flow date of the Well. Producer shall also provide Linn Midstream any available information, not subject to a confidentiality agreement, concerning the operator's development plan on the lands and leases pertaining to the non-Operated Well. The information contained in the non-Operated Well Connection Request and subsequent related communications between the Parties shall be subject to the confidentiality requirements contained in Section 19.2 to this Exhibit B. Linn Midstream shall have the option to connect such Well pursuant to such non-Operated Well Connection Request, provided that such option is only exercisable by providing notice to Producer agreeing to such Connection Request within *** Days of receiving the non-Operated Well Connection Request, and such option right shall terminate if not exercised within such time. If Linn Midstream exercises its option to so connect, Linn Midstream will commence and use its commercially reasonable efforts to complete the connection of the Well specified in Producer's non-Operated Well Connection Request prior to the projected first flow date. In the event Linn Midstream does not exercise its option to connect to the Well specified in Producer's non-Operated Well Connection Request, or the option right has terminated, Producer shall have the option to cause Linn Midstream to connect such Well at Producer's expense or to remove such Well from dedication under the Agreement.

5.2.4 On the first flow Day of each new Well connected and under which Committed Gas is delivered by Producer to Linn Midstream, Exhibit B-3 shall be amended to include an additional Receipt Point (unless such Well was connected behind an existing Receipt Point) at the measurement Facilities located on the well pad of such Operated Well or non-Operated Well.

VI. [INTENTIONALLY BLANK]

VII. RESIDUE GAS AND NGL DISPOSITION

7.1 **Activity Communications**. Producer shall provide Linn Midstream the estimated plan and Producer's most accurate and good faith estimated volumes for new Wells that may first deliver during the Month and any Well rework activity that may influence the quantity of Committed Gas during the Month. Such estimate shall be provided no later than nine o'clock a.m., Central Time of the fifth Business Day immediately preceding the *** Day of each Month. The Parties agree to communicate frequently during the Month to update the accuracy of such estimates. Linn Midstream shall monitor the actual flows to the Plant(s) and, as allowed by downstream pipelines, adjust sales quantities to match actual flows and to minimize imbalances. All communications with downstream pipelines and markets are the responsibility of Linn Midstream.

7.2 **Operational Balancing Agreements**. Linn Midstream will exercise reasonable commercial efforts to obtain Operational Balancing Agreements with all downstream gas pipelines for the mutual benefit of Linn Midstream and Producer without additional cost to Producer above that incurred by Linn Midstream.

VIII. QUALITY OF DELIVERED GAS

8.1 **Quality Specifications**. The Gas delivered at the Receipt Point(s) shall meet the quality specifications in Exhibit B-4 attached hereto and made a part hereof. Producer shall indemnify and hold Linn Midstream harmless from and against all third party claims, suits, damages, costs (including attorneys' fees), penalties or other liabilities arising out of or relating to any failure of the Committed Gas to conform to such quality specifications.

8.2 **Non-Conforming Gas**. Linn Midstream shall have the right to (i) accept Gas that does not conform to such specifications and, in such event, Linn Midstream may elect to deduct from payment due Producer such fee(s) for treatment as determined from time to time by agreement of the Parties, or (ii) refuse receipt of the nonconforming Gas.

8.3 **No Waiver**. Linn Midstream's acceptance of Gas that does not conform to quality specifications set forth herein shall not constitute a waiver of Producer's obligation to conform Gas to such specifications in the future, nor a waiver of Linn Midstream's right to refuse receipt of such nonconforming Gas at any time.

IX. ETHANE RECOVERY/REJECTION

9.1 **Ethane Recovery/Rejection**. Linn Midstream will notify Producer whether it will operate its Plant(s) in either ethane recovery or ethane rejection at least *** Days prior to the *** Day of each Month in writing via electronic mail. For purposes of this Exhibit B, for ethane recovery or ethane rejection operations, the following recovery levels shall apply:

	C2 Recovery, %	C2 Rejection, %
C2	***%	***%
C3	***%	***%
iC4	***%	***%
nC4	***%	***%
C5+	***%	***%

If Linn Midstream fails to notify Producer of a change in recovery or rejection operations, the previous Month's recovery levels shall apply for Producer. In all instances, Producer shall be settled on its fixed recovery levels as set forth above based on the then-effective operating mode of the Plant.

X. DELIVERY PRESSURE, FACILITIES AND ALTERATIONS

10.1 **Delivery Pressure**. Linn Midstream shall install Compression as necessary to meet its obligations under this Section 10.1 to this Exhibit B. Linn Midstream shall operate the Receipt Points at a pressure no higher than *** psig, and Linn Midstream may elect to receive Gas tendered by Producer at Receipt Points at *** psig or higher on average, subject to Linn Midstream's maximum allowable operating pressure. If Linn Midstream fails to provide an average Receipt Point pressure of *** psig or less at any Receipt Point for any one (1) Month, then, as Producer's sole and exclusive remedy, Linn Midstream's Processing and Gathering Fee shall be reduced by *** cents ($***) per MMBTU for all Committed Gas delivered by Producer at such Receipt Point for any subsequent Month in which the average monthly Receipt Point pressure exceeds *** psig, until such average monthly Receipt Point pressure is reduced to *** psig or below.

10.2 **Producer's Equipment**. Upon the execution of the Agreement by the Parties hereto, Producer shall install, maintain and operate, or cause to be installed, maintained and operated, at no expense to Linn Midstream, any and all facility(ies) and equipment necessary to enable Producer to deliver Committed Gas to Linn Midstream at the Receipt Point(s). Producer shall install, or cause to be installed, the necessary separation equipment upstream of the Receipt Point(s) to facilitate flow through Linn Midstream's or Linn Midstream's designee's measurement Facilities and to prevent the delivery of free liquids to Linn Midstream at the Receipt Point(s).

10.3 **Measurement Equipment**. Linn Midstream shall own, maintain and operate the measurement equipment necessary to receive Gas from Producer at the Receipt Point(s). Linn Midstream will provide Producer with access to a second set of taps on the meter tube located at each Receipt Point for check measurement.

10.4 **Pigging and Drip Liquids**. Linn Midstream shall own, maintain and operate the pigging Facilities necessary to keep the pipelines free of hydrocarbon liquids and objectionable materials. Drip Liquids recovered through pigging operations shall be the property of Linn Midstream.

10.5 **Bypass Equipment**. Linn Midstream shall own, maintain and operate the equipment necessary to permit Gas to bypass the Plant(s) during periods of emergencies ("Bypass Gas"). Linn Midstream will use commercially reasonable efforts to minimize the time that Bypass Gas is required and will advise Producer of the emergency event as soon as practicable following such event. Producer shall have the right to shut-in Gas to avoid bypass.

10.6 **Rebuild and Alterations**. Linn Midstream reserves the right, in its sole discretion, to alter, repair, maintain, expand or rebuild, without approval of Producer, any portion of the Facilities, subject to the rights and obligations contained in the Agreement. Producer shall make no alterations, additions or repairs to the Facilities.

XI. PAYMENT, EXAMINATION, INDEMNIFICATION, SUSPENSION, AND DEDUCTIONS

11.1 On or before the *** Day of each Month, Linn Midstream shall provide Producer a statement for the preceding Month ("Production Month") setting forth for each Receipt Point: (i) the total MCF of and MMBTU of Committed Gas accepted by Linn Midstream; (ii) the amount of Field Fuel, Plant Fuel, Shrinkage, NGLs, component plant products of such NGLs, and Residue Gas attributable to Producer's Committed Gas; (iii) the amount due, if any, to Linn Midstream from Producer for all fees and charges due under this Exhibit B; (iv) the amount due, if any, to Producer from Linn Midstream for all fees and charges due under this Exhibit B; and (v) the net amount due, if any, to Producer from Linn Midstream for all revenues for Gas and NGL sales netted against all fees and charges due under this Exhibit B.

11.2 **Statement and Payment**. If Producer is due any amount pursuant to Section 11.1 to this Exhibit B, Linn Midstream shall wire transfer payment according to the statement sent pursuant to Section 11.1 to this Exhibit B to Producer no later than the *** of the Month following the Production Month. Where Producer is responsible, under Section 15.1 of this Exhibit B, for revenue distribution, Linn Midstream shall remit the amount due to Producer, and it shall be the obligation of Producer to cause proper settlement and accounting to be made and to make distribution of proceeds to all owners of interest in the proceeds from the sale of Gas and NGLs delivered to Linn Midstream hereunder. If Linn Midstream is due any amount pursuant to Section 11.1 to this Exhibit B, Producer shall wire transfer such payment to Linn Midstream pursuant to the statement provided by Linn Midstream by the *** of the Month following the Production Month. If the *** of the Month falls on a Saturday, the wire transfer shall occur on the preceding Friday; otherwise, if the *** of the Month falls on a Day that is not a Business Day and is not a Saturday, the wire transfer shall occur on the next Business Day.

11.3 **Final Payment**. All payments under this Exhibit B will be final unless disputed by Linn Midstream or Producer in writing to the other Party within *** of the date of such payment.

11.4 **Examination of Records**. Linn Midstream and Producer shall have the right, at any and all reasonable times during normal business hours, and upon at least *** Business Days prior written notice, to examine the records of the other Party, to the extent necessary to verify the accuracy of any statement, charge, computation, or demand made under, or pursuant to the Agreement, and both Parties shall keep and maintain all such records for at least *** Months after the date payment is made for the receipt of Gas to which such records are applicable. Such records shall be conclusively presumed to be correct, except as to claims or corrections by the Parties made by written notice to the other Party within a *** Month period.

11.5 **Indemnification, Payment Suspension**. Linn Midstream and Producer agree to indemnify and hold the other Party harmless with respect to all costs, losses, and damages (including, without limitation, reasonable attorney’s fees) arising from or related to the breach of any of its representations or warranties contained in this Exhibit B. In the event of any claim arising from or relating to such a breach, Linn Midstream shall be entitled, at its option, in addition to any other rights it may have, to suspend payment of disputed sums due Producer hereunder until such claim is resolved, or until such time as Producer provides sureties acceptable to Linn Midstream, at which point such sums will be due along with applicable simple interest from the date such sums were originally due. Any interest paid with such sums due shall be the lesser of (a) the per annum rate of interest announced as the “prime rate” for commercial loans posted from time to time by Citibank, N.A. (New York, New York office) or its successor or a mutually agreed substitute bank, or (b) the maximum lawful interest rate then in effect under applicable law. Any suspension of payment related to disputed sums hereunder shall not constitute a breach of Linn Midstream’s payment obligations under the Agreement. Linn Midstream shall pay all undisputed amounts when due.

11.6 **Allocations**. If during any Month Linn Midstream purchases Gas from Producer hereunder at any Receipt Point(s) at which Producer owns and/or controls less than *** of the Gas purchased by Linn Midstream at such Receipt Point, Producer shall furnish, or cause to be furnished, to Linn Midstream, on or before the *** Day of each Month, any allocation statements containing data (including, but not limited to, quantity) that Linn Midstream may require to enable Linn Midstream to allocate the Gas purchased at such Receipt Point(s) during the previous Month to the various entities from which Linn Midstream purchased such Gas, and make payments applicable thereto.

11.6.1 Non-Operated Well(s). Producer authorizes the operator of each non-Operated Well to be its agent and representative for the limited purpose of providing Linn Midstream with written instructions for the allocation of Gas attributable to said Well(s).

11.6.2 Linn Midstream Reliance. Linn Midstream is entitled to rely conclusively on the allocation statement(s) provided in accordance with this section. Such reliance shall be a complete defense to any claim by Producer for any sums due for Gas delivered by Producer at the Receipt Point(s) during such period where Linn Midstream has made payment to Producer for its share of Gas, as identified in such allocation statement(s), of the total quantity of Gas received by Linn Midstream at the applicable Receipt Point(s) during the period in question (other than for measurement error as specified in Article XVI to this Exhibit B).

11.6.3 Late Statement. If any allocation statement(s) is not furnished to Linn Midstream by the *** Day of any Month for the preceding Production Month, Linn Midstream shall initially make payment for Gas delivered by Producer at the Receipt Point(s) based upon the allocation statement(s) last received by Linn Midstream applicable to such Receipt Point(s). Such payment shall be subsequently adjusted up or down following Linn Midstream's receipt of the allocation statement for the applicable Month's deliveries.

XII. WARRANTY AND EASEMENTS

12.1 **Warranty of Title**. If Linn Midstream is purchasing the Committed Gas from Producer, Producer warrants that it has the full right and authority to transfer title of the Committed Gas to Linn Midstream at the Receipt Point(s) and that the Committed Gas that is delivered is free from all liens, encumbrances and/or adverse claims. Producer further warrants that, unless otherwise required to be paid by Linn Midstream pursuant to this Exhibit B, all applicable taxes, including, but not limited to, any production, extraction or other federal, state or local lease level tax, will be paid by Producer. Producer shall indemnify and hold Linn Midstream harmless from and against all Claims arising out of or relating to a breach of Producer's foregoing representations and warranties.

12.2 **Easements**. To the extent Producer has the right to do so under any agreement to which it (or any of Producer's GROUP) is party without being in breach or violation thereof, Producer hereby permits Linn Midstream, and Linn Midstream's designee, the rights of ingress and egress on the Lands and Lease(s) to construct, install, operate, repair, inspect and maintain Linn Midstream's, and/or Linn Midstream's designee's, Facility(ies) necessary or useful to receive, gather and process Gas from Producer and/or to perform Linn Midstream's other obligations hereunder. Producer hereby assigns and grants to Linn Midstream, to the extent it has the right to do so, an easement and right-of-way upon all such Lands and Lease(s) for the purposes above. Any property of Linn Midstream, or Linn Midstream's designee, placed in or upon any said Lands and Lease(s) shall remain the personal property of Linn Midstream, or Linn Midstream's designee, and may be disconnected and removed at any time. Producer shall, at its sole cost and expense, maintain and provide all such easements, rights-of-way, lease roads, and other facilities upon such

Lease(s) as may reasonably be deemed necessary by Linn Midstream for its performance of the Agreement.

XIII. [RESERVED]

XIV. INDEMNITY, INTERRUPTION, FORCE MAJEURE, AND UNECONOMIC OPERATION OF FACILITIES

14.1 **Indemnity**. *As between Linn Midstream and Producer, Producer shall indemnify, protect and defend Linn Midstream and any of its subsidiaries (collectively, the "Linn Midstream INDEMNITY GROUP") from all losses, liabilities or claims, and associated costs and expenses (including reasonable attorneys' fees) ("Claims") relating to, or arising out of, loss or damage to real or personal property or personal injury, bodily injury, illness, or death arising out of, resulting from, or attributable to the operations of (or on behalf of) Producer or any of its subsidiaries (collectively, the "Producer INDEMNITY GROUP"), including such member's contractors, subcontractors, agents, representatives, invitees, and each of their respective officers, directors, owners, and employees, of its obligations hereunder, the operations of the Operated Wells of any member of Producer INDEMNITY GROUP, and for any Claims relating to the handling or delivery of Gas prior to its delivery to Linn Midstream at the Receipt Point(s), subsequent to the delivery, if applicable, of the Residue Gas and/or NGLs attributable to such Gas to Producer or its designee at the tailgate of Linn Midstream's Plant, without regard to the cause or causes thereof including the negligence (whether sole, joint, or concurrent), strict liability or other fault (not including gross negligence or intentional misconduct) of any member of Linn Midstream INDEMNITY GROUP, including such member's contractors, subcontractors, agents, representatives, invitees, and each of their respective officers, directors, owners, and employees, or any pre-existing condition. Similarly, Linn Midstream shall indemnify, protect and defend any member of Producer INDEMNITY GROUP from all Claims relating to, or arising out of, loss or damage to real or personal property or personal injury, bodily injury, illness, or death arising out of, resulting from, or attributable to the operations of (or on behalf of) any member of Linn Midstream INDEMNITY GROUP, including such member's contractors, subcontractors, agents, representatives, invitees, and each of their respective officers, directors, owners, and employees, of its obligations hereunder, the operations of the Facilities of any member of Linn Midstream INDEMNITY GROUP, and for any Claims relating to the handling or delivery of Gas subsequent to its receipt by Linn Midstream at the Receipt Point(s) and, prior to the delivery of the Residue Gas and/or NGLs attributable to such Gas to Producer or its designee at the tailgate of Linn Midstream's Plant, without regard to the cause or causes thereof including the negligence (whether sole, joint, or concurrent), strict liability or other fault (not including gross negligence or intentional misconduct) of any member of Producer INDEMNITY GROUP, including such member's contractors, subcontractors, agents, representatives, invitees, and each of their respective officers, directors, owners, and employees, or any preexisting condition. The obligations of the Parties under the Agreement are obligations of the Parties only and no recourse or remedy shall be available against any officer, director, or employee representative of a Party or against any affiliate, investor, member or equity owner of a Party or any of its affiliates. Each Party shall have the right, at its option, to participate at its own expense in the defense of any suit without releasing the other Party from any indemnity obligation under this Article XIV of this Exhibit B.*

14.2 **Indemnity for Underground and Pollution Damage**. *As between Linn Midstream and Producer, Producer shall assume full responsibility for and shall protect, defend, indemnify, and* *hold harmless each member of Linn Midstream INDEMNITY GROUP from and against any and all Claims for pollution or contamination, including control and removal thereof, emanating from or originating on or above the surface of the land or water from spills, leaks, or discharges of fuel, lubricants, motor oils, pipe dope, paints, solvents, ballast, bilge, sludge, garbage, or any other substances wholly in the possession and control of any member of Producer INDEMNITY GROUP, or any representatives, contractors or other agents and employees of any member of Producer INDEMNITY GROUP in the performance of Producer's obligations under the Agreement, or liquids or substances emanating or originating from Producer INDEMNITY GROUP's equipment, vessels, materials, or transport, without regard to the cause or causes thereof including the negligence (whether sole, joint, or concurrent), strict liability or other fault of any member of Linn Midstream INDEMNITY GROUP or any pre-existing condition. Similarly, Linn Midstream shall assume full responsibility for and shall protect, defend, indemnify, and hold harmless each member of Producer INDEMNITY GROUP from and against any and all Claims for pollution or contamination, including control and removal thereof, emanating from or originating on or above the surface of the land or water from spills, leaks, or discharges of fuel, lubricants, motor oils, pipe dope, paints, solvents, ballast, bilge, sludge, garbage, or any other substances wholly in the possession and control of any member of Linn Midstream INDEMNITY GROUP, or any representatives, contractors or other agents and employees of any member of Linn Midstream INDEMNITY GROUP in the performance of Linn Midstream's obligations under the Agreement, or liquids or substances emanating or originating from Linn Midstream INDEMNITY GROUP's equipment, vessels, materials, or transport, without regard to the cause or causes thereof including the negligence (whether sole, joint, or concurrent), strict liability or other fault of any member of Producer INDEMNITY GROUP or any pre-existing condition. Notwithstanding the foregoing, the assumptions of liability by Linn Midstream and Producer under this Section 14.2 to this Exhibit B apply only to the cost of, and liability for, control and removal of such pollution or contamination and do not apply to loss or damage to property, or injuries to or death of persons caused by such pollution or contamination and shall, in no event, alter, lessen, or affect the liabilities or responsibilities of Linn Midstream or Producer specified elsewhere in the Agreement. Initiation of cleanup operations or waste disposal by either Party shall not be an admission or assumption of liability by the initiating Party.*

14.3 **Force Majeure**. If Linn Midstream or Producer is rendered unable, wholly or in part, by reason of Force Majeure, from carrying out its obligations under the Agreement (other than the obligation to make payment of amounts due hereunder), then upon said Party's giving prompt written notice of such Force Majeure to the other Party, the obligations of the Party giving such notice, so far as they are affected by such Force Majeure, shall be suspended during the continuance of any inability so caused, but for no longer period, and such cause shall be remedied with all commercially reasonable dispatch. The term "Force Majeure," as used herein, shall mean an event not within the reasonable control of the Party claiming suspension, which, by the exercise of due diligence, such Party shall not have been able to avoid and shall include, to the extent these events meet the foregoing requirements, the following: acts of God; acts of federal, state, or local government, or any agencies thereof; compliance with rules, regulations, permits, or orders of any governmental authority, or any office, department, agency, or instrumentality thereof; strikes, lockouts, or other industrial disturbances; acts of the public enemy, wars, blockades, insurrections, riots, and epidemics; landslides, lightning, earthquakes, fires, storms, floods, and washouts; arrests and restraint of people; civil disturbances; explosions, leakage, breakage, or accident to equipment or pipes; freezing of Well(s) or pipes; weather-related shutdowns; inability to secure rights of way at a reasonable cost and under reasonable terms; inability to timely obtain equipment, supplies, materials, permits or labor at a reasonable cost; failures, or delays in transportation; lack of market for Linn Midstream's Gas or the Residue Gas and/or NGLs attributable to Linn Midstream's Gas; insufficient capacity on Facilities, but only to the extent such capacity constraint was caused by Producer's estimates delivered to Linn Midstream pursuant to Section 4.2 to this Exhibit B; insufficient capacity on other pipelines or facilities; receipt of non-specification or unmerchantable Gas; and any other causes, whether of the kind herein enumerated or otherwise, not within the reasonable control of the Party claiming suspension, which, by the exercise of due diligence, such Party shall not have been able to avoid. The settlement of strikes or lockouts shall be entirely within the discretion of the Party having the difficulty. The requirement that any Force Majeure shall be remedied with all commercially reasonable dispatch shall not require the settlement of strikes or lockouts by acceding to the demands of the opposing party, when such is deemed inadvisable by the Party involved. It is understood and agreed that Linn Midstream, or Linn Midstream's designee, or Producer hereto may, without liability to the other Party, interrupt the operations of its Facilities for the purpose of making necessary alterations, maintenance, or repairs thereto, but that such interruption shall be for only such time as may be commercially or operationally reasonable to safely perform such operations. Delivery and/or receipt of Gas pursuant to this Exhibit B may be suspended for such period of interruption, and such suspension shall be deemed an event of Force Majeure hereunder.

14.4 **Uneconomic Operation of a Receipt Point**. Linn Midstream, or Linn Midstream's designee, agrees to maintain its Facilities to a Receipt Point for so long as such Facilities to a Receipt Point are deemed economical to maintain, in Linn Midstream's commercially reasonable determination. If Linn Midstream's Facilities to a Receipt Point are deemed uneconomical by Linn Midstream for *** consecutive Days in any one Year, the Parties agree to meet and negotiate in good faith for the continued operation of the Facilities to such Receipt Point under mutually agreeable commercial terms, and if such agreement is not reached within *** Days, then, upon *** Days' notice, Linn Midstream may discontinue service to such Receipt Point without liability for such cessation of service through the Facilities to such Receipt Point and remove such Receipt Point from the Agreement. Linn Midstream shall be released from any further obligation or liability subsequently arising with respect to the Facilities to such Receipt Point, and applicable Well's or Wells' Committed Gas then existing at such Receipt Point shall be permanently released from the dedication contained in Section 5.1 to this Exhibit B. Notwithstanding the foregoing, Linn Midstream's economic determination shall be consistently applied among similarly situated producers connected to its Facilities. If no Receipt Point(s) remain under this Exhibit B, then Linn Midstream may, in its sole discretion, terminate the Agreement to the extent related to the terms and conditions set forth in this Exhibit B.

XV. ROYALTY AND TAXES

15.1 **Royalty**. Producer shall have the sole and exclusive obligation and liability to account for and remit all royalties, overrides, and other sums due the owners of the minerals, royalties, and other interests in, and any other persons due any proceeds derived from, the Gas and NGLs delivered hereunder.

15.2 **Taxes**. Producer shall pay or cause to be paid (or, if required by law, Linn Midstream shall withhold from the payment due from Linn Midstream to Producer pursuant to the terms of the Agreement and remit on behalf of the Producer to the appropriate government authority) all Oklahoma Gross Production Tax and other severance or production taxes imposed by any government authority with respect to the Committed Gas delivered hereunder (and the NGLs recovered therefrom). Further, Producer represents and warrants that it has timely filed, or will timely file, any and all reports which it is required to file with respect to production or severance taxes to be paid hereunder. Producer will indemnify and hold Linn Midstream harmless with respect to Producer's failure to file any and all such reports or with respect to Producer's failure to pay any and all taxes which Producer is obligated to pay pursuant to the terms of the

Agreement. Producer shall pay all taxes, fees or assessments imposed by any taxing jurisdiction on or with respect to the Committed Gas prior to the Receipt Point(s).The Parties agree that any taxes and statutory charges levied or assessed against each Party's respective properties, facilities, or operations shall be borne by such Party. For the avoidance of doubt, each of Producer and Linn Midstream shall bear its own federal and state income, franchise, and similar taxes.

XVI. MEASUREMENT OF GAS VOLUME AND TESTING

16.1 **Calibration**. At least *** for the first Year of each Well and then *** for each Well thereafter, Linn Midstream, or Linn Midstream's designee, shall verify the calibration of all of its meters at the Receipt Point(s) and make adjustments as necessary. Should Producer so desire, Linn Midstream, or Linn Midstream's designee, shall give written notice (which may include notice by electronic mail) to Producer of the time of such calibrations sufficiently in advance of holding same in order that Producer may have its representative present. With respect to any test made hereunder, a registration within plus or minus *** percent (***%) of correct shall be considered correct. In the event the meters are found to be inaccurate, such meters shall be adjusted to register accurately, and any payment based upon such registrations shall be corrected using the same methodology set forth in Section 16.2 to this Exhibit B.

16.2 **Accuracy**. Producer shall have the right to challenge the accuracy of any of Linn Midstream's or its designee's measurement equipment; and, when challenged, the equipment shall be tested and calibrated by Linn Midstream, or Linn Midstream's designee. The cost of any such special test requested by Producer shall be borne by Producer if the percentage of inaccuracy is found to be less than *** percent (***%). The cost of all other such special tests shall be borne by Linn Midstream. If, upon any test, the percentage of inaccuracy of the measurement equipment is found to be in excess of *** percent (***%), any registrations thereof, and any payment based upon such registrations, shall be corrected for any period of inaccuracy which is definitely known or agreed upon. In the event the period is not definitely known or agreed upon, registrations shall be corrected back one-half of the time elapsed since the last date of calibration.

16.3 **Repairs**. If, for any reason, the meters are out of service, or out of repair, so that the amount of Gas received cannot be ascertained or computed from the reading thereof, the Gas received during the period such meters are out of service, or out of repair, shall be estimated, and agreed upon by the Parties hereto, based on the data available using the first of the following methods that applies:

16.3.1 By using the registration of any check meter, or meters, if installed and accurately registering: or in the absence of Section 16.3.1 to this Exhibit B then,

16.3.2 By correcting the error if the percentage of error is ascertainable by calibration, special test, or mathematical calculation; or in the absence of both Sections 16.3.1 and 16.3.2 to this Exhibit B then,

16.3.3 By estimating the quantity of Gas received based on receipts during preceding periods under similar conditions when the meter was registering accurately.

16.4 **Records**. The records from the measurement equipment shall remain the property of the Party owning such equipment, and shall be kept for a period of not less than the *** Year period referenced in Section 11.3 to this Exhibit B. At any time within this period, either Party shall, upon request of the other Party, submit to the requesting Party records from the measurement equipment, together with calculations therefrom, for inspection and verification, subject to return within *** Days from receipt thereof.

16.5 **Measurement Standards**. The measurement station(s) at the Receipt Point(s) shall be equipped with meters, recording gauges, or other types of meter(s) of standard make and design used in the industry, and in accordance with applicable American Gas Association (“AGA”) or American Petroleum Institute (“API”) standards. Linn Midstream shall utilize orifice meters for gas measurement unless otherwise approved by Producer. Gas measured hereunder shall have its volume, mass, gravity, composition and/or energy content determined and computed in accordance with applicable AGA or API standards in effect at the date of installation of the measurement equipment, and shall comply with applicable state and federal regulations. At Linn Midstream’s option, Linn Midstream may update the measurement equipment and/or the determination of volume, mass, gravity, composition and/or energy content, in accordance with subsequent revisions, supplements, and appendices to said AGA standards or API standards.

16.6 **Pulsation**. The Parties shall design, install, operate and maintain their respective equipment in such a manner that pulsation-induced measurement error is minimized. Pulsation-induced error shall not exceed *** percent (***%) of square root error (“SRE”). Linn Midstream and Producer have the right to request a test of the meter facility(ies). If SRE is found to exceed the limit stated above, the Party responsible for the creation of the SRE must have a plan for the elimination of the SRE within *** Days and equipment installed or modified to correct SRE in a reasonable amount of time, not to exceed *** Months. Pulsation errors determined by the use of a SRE indicator are to be used only for the purpose of determining SRE, and are not to be used for adjusting measured volumes.

16.7 **Boyle’s Law**. The measurement hereunder shall be corrected for deviation from Boyle’s Law at the pressures and temperatures under which Gas is received hereunder.

16.8 **Temperature**. The temperature of the Gas shall be determined to the nearest *** degree (***°) Fahrenheit at the points of measurement by the continuous use of recording thermometers of standard manufacture acceptable to the Parties, to be installed in accordance with the recommendations contained in AGA Measurement Committee Report Number 3, 7, or 9, as appropriate. The arithmetical average of hourly temperatures of the Gas so determined each Day shall be used in computing temperatures of the Gas.

16.9 **Supercompressibility**. Unless otherwise allowed by state law, adjustment for the effect of supercompressibility shall be determined by test, or according to the provisions contained in AGA Measurement Committee Report Numbers 3, 7, 8, or 9, as appropriate, for the average conditions of pressure, flowing temperature, and specific gravity at which the Gas was measured during the period under consideration, and with the respective proportionate values for carbon dioxide and nitrogen fractional values, and to obtain subsequent values of these components as Linn Midstream may determine to be required from time to time.

16.10 **Check Measurement**. At the Receipt Point(s), Producer may install check measurement equipment at its own cost and expense, provided such equipment shall be so installed as not to interfere with the operations of the Linn Midstream, or Linn Midstream’s designee. Linn Midstream’s, or Linn Midstream’s designee’s, meter(s) at the Receipt Point(s) shall be the meter(s) used for all custody measurement purposes. Linn Midstream and Producer, in the presence of each other, shall have access to the other’s measurement equipment at all reasonable times. The reading, calibrating, and adjusting thereof, and the changing of charts, if any, shall be done only by the owner of the meter or its representative unless otherwise agreed.

16.11 **Sampling**. Linn Midstream, or Linn Midstream’s designee, shall obtain a sample of Gas, upon at least the same test frequency as specified in Section 16.1 to this Exhibit B, at the Receipt Point(s) by using methods contained in GPA Standard 2166 / API 14.1, as revised, “Methods for

Obtaining Natural Gas Samples for Analysis by Gas Chromatography." This sample may be obtained by utilizing a spot sampler, continuous sampler, on-stream chromatograph, or other instruments approved by Linn Midstream. Producer may request that additional samples be taken in order that Producer may have its own sample tested independently. Any additional samples requested by Producer shall be at Producer's sole cost and expense.

16.12 **Composition, Gross Heating Value, Specific Gravity**. The composition of the Gas shall be determined from the sample of the Gas by using GPA Standard 2261, as revised, "Method of Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography," with the exception of sulfur compounds. The gallons per MCF, and the Gross Heating Value of the Gas, shall be determined by using methods contained in GPA Standard 2172, as revised, "Method for Calculation of Gross Heating Value, Specific Gravity, and Compressibility of Natural Gas Mixtures from Compositional Analysis," and the Gross Heating Value of the Gas from GPA Standard 2145, as revised from time to time, "Table of Physical Constants for the Paraffin Hydrocarbons and Other Components of Natural Gas." Each composition, Gross Heating Value of the Gas, and specific gravity determination shall be effective until the next determination. The specific gravity of the Gas shall be recorded to the nearest one one-thousandth (0.001).

16.13 **Water Content**. Gas delivered at the Receipt Point(s) shall be considered to be saturated with water at measurement temperature and pressure. The water content shall be determined by Linn Midstream using practices contained in GPA Standard 181, GPA Standard 2172, AGA Measurement Committee Report Number 3, or other reasonable practices as determined appropriate by Linn Midstream or as otherwise required by applicable law.

16.14 **Assumed Atmospheric Pressure**. The atmospheric pressure shall be assumed to be the atmospheric pressure for the elevation of fourteen and four-tenths (14.4) psig, as used by Linn Midstream in that particular geographic area, regardless of the actual atmospheric pressure where Gas is measured.

16.15 **Sulfur**. The sulfur content shall be determined from tests taken at the Receipt Point(s) by methods accepted in the industry, such as GPA Standard 2377, as revised, "Method of Test for Hydrogen Sulfide and Carbon Dioxide in Natural Gas Using Length of Stain Tubes." Other sulfur species can be determined by chromatographic analysis.

16.16 **NGL Measurement**. The Natural Gas Liquids shall be measured using measurement equipment and practices accepted in the industry, and supported by AGA, API, and/or GPA standards, as applicable.

EXHIBIT B-1 - DEDICATED AREA

This Exhibit B-1 is attached to and made a part of that certain Amended and Restated Gas Gathering and Processing Agreement effective April 1, 2017, by and between Producer and Linn Midstream.

Beginning at the Northwest corner of Section 6, Township 5N, Range 5W;
Thence due East 63,360 ft. until you reach the Northeast corner of Section 1, Township 5N, Range 4W; Thence due South 31,680 ft. until you reach the Southeast corner of Section 36, Township 5N, Range 4W; Thence due East 575 ft. until you reach the Northeast corner of Section 1, Township 4N, Range 4W; Thence due South 31,680 ft. until you reach the Southeast corner of Section 36, Township 4N, Range 4W; Thence due East 15,840 ft. until you reach the Northeast corner of Section 4, Township 3N, Range 3W; Thence due South 5,280 ft. until you reach the Southeast corner of Section 4, Township 3N, Range 3W; Thence due West 79,200 ft. until you reach the Southwest corner of Section 6, Township 3N, Range 5W; Thence due North 36,960 ft. until you reach the Northwest corner of Section 6, Township 4N, Range 5W; Thence due East 575 ft. until you reach the Southwest corner of Section 31, Township 5N, Range 5W;
Thence due North 31,680 ft. until you reach the Northwest corner of Section 6, Township 5N, Range 5W, to the place of beginning, and begin further described to include all the following sections.

Section	Township	Range	County	State
1-36	5N	5W	Grady	Oklahoma
1-36	5N	4W	McClain	Oklahoma
1-36	4N	5W	Grady	Oklahoma
1-36	4N	4W	Garvin	Oklahoma
4	3N	3W	Garvin	Oklahoma
5	3N	3W	Garvin	Oklahoma
6	3N	3W	Garvin	Oklahoma
1	3N	4W	Garvin	Oklahoma
2	3N	4W	Garvin	Oklahoma
3	3N	4W	Garvin	Oklahoma
4	3N	4W	Garvin	Oklahoma
5	3N	4W	Garvin	Oklahoma
6	3N	4W	Garvin	Oklahoma
1	3N	5W	Grady	Oklahoma
2	3N	5W	Grady	Oklahoma
3	3N	5W	Grady	Oklahoma
4	3N	5W	Grady	Oklahoma
5	3N	5W	Grady	Oklahoma
6	3N	5W	Grady	Oklahoma
			Grady	Oklahoma

Exhibit "B-1" Dedicated Area

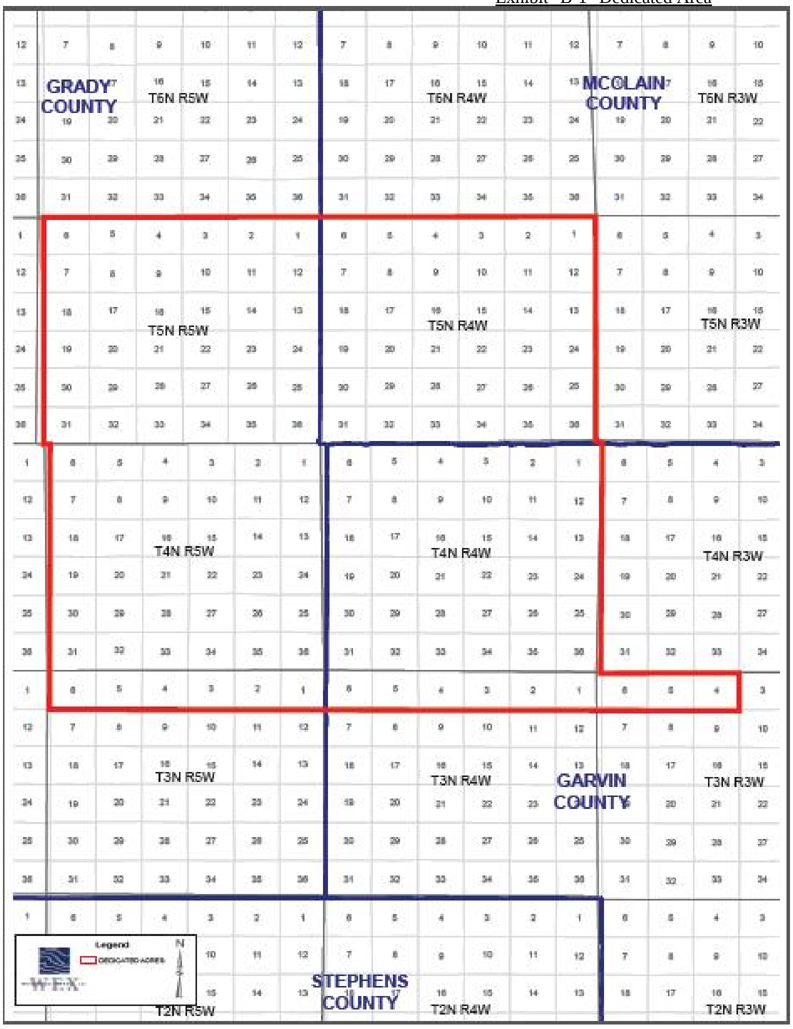


EXHIBIT B-2 – COMMERCIAL TERMS

This Exhibit B-2 is attached to and made a part of that certain Amended and Restated Gas Gathering and Processing Agreement effective April 1, 2017, by and between Producer and Linn Midstream.

1. **CONTRACT AMOUNT SHALL MEAN, FOR ALL QUANTITIES OF COMMITTED GAS RECEIVED BY LINN MIDSTREAM HEREUNDER DURING EACH MONTH, AN AMOUNT WHICH WILL BE CALCULATED BY LINN MIDSTREAM AND PAID TO PRODUCER AS FOLLOWS. THE CONTRACT AMOUNT FOR ANY MONTH EQUALS THE SUM OF (A) THE NGL SETTLEMENT AMOUNT FOR SUCH MONTH PLUS (B) THE RESIDUE SETTLEMENT AMOUNT FOR SUCH MONTH LESS (C) THE PROCESSING AND GATHERING AMOUNT FOR SUCH MONTH.**

2. **NGL SETTLEMENT AMOUNT. THE NGL SETTLEMENT AMOUNT SHALL MEAN THE TOTAL DOLLARS PAYABLE BY LINN MIDSTREAM TO PRODUCER EACH MONTH FOR PRODUCER'S TOTAL QUANTITY OF NGL PRODUCTS. LINN MIDSTREAM WILL DETERMINE PRODUCER'S TOTAL QUANTITY OF NGL PRODUCTS BY AGGREGATING THE QUANTITY OF PRODUCER'S NGL PRODUCTS FOR EACH RECEIPT POINT EACH MONTH. IN ACCORDANCE WITH THE NGL RECOVERY FACTORS DETERMINED IN SECTION 9.1 OF EXHIBIT B, THE NGL SETTLEMENT AMOUNT SHALL BE CALCULATED AS DETAILED IN SECTION 2(A) TO THIS EXHIBIT B.**

(a) The "NGL Settlement Amount" shall be the sum of all amounts calculated for each NGL product and aggregated for all Receipt Points. For each Receipt Point, Linn Midstream shall calculate (i) the NGL Market Price multiplied by (ii) the NGL Settlement Percent multiplied by (iii) the NGL Volume. The resulting totals for each product at each Receipt Point shall then be added together and such sum shall be the "NGL Settlement Amount."

(i) "NGL Market Price" shall be *** percent (***%) of the average of the daily high/low spot price for each NGL product during the applicable Month,
f.o.b. Mt. Belvieu Non-TET, as quoted by the Oil Price Information Service ("OPIS"), less a transportation and fractionation ("T&F") fee equal to *** cents ($***) per gallon for each NGL product.

(ii) "NGL Settlement Percent" shall be *** percent (***%).

(iii) "NGL Volume" in gallons for each product at each Receipt Point shall mean the Theoretical Gallons of each NGL product times (i) Plant Inlet Volume times (ii) the product recoveries for each product in Section 9.1 of Exhibit B for Ethane Rejection or Ethane Recovery as elected by Linn Midstream for such Month for each Plant.

3. **RESIDUE SETTLEMENT AMOUNT. THE "RESIDUE SETTLEMENT AMOUNT" SHALL BE CALCULATED AS FOLLOWS. FOR EACH RECEIPT POINT, LINN MIDSTREAM SHALL CALCULATE (I) THE RESIDUE GAS MARKET PRICE MULTIPLIED BY (II) THE RESIDUE SETTLEMENT PERCENT MULTIPLIED BY (III) THE RESIDUE GAS VOLUME. THE RESULTING TOTALS FOR EACH RECEIPT POINT SHALL THEN BE ADDED TOGETHER AND SUCH SUM SHALL BE THE "RESIDUE SETTLEMENT AMOUNT."**

(a) “Residue Gas Market Price” shall be *** percent (***%) of the price determined by taking the weighted average price (“WAP”) (expressed in $/MMBTU) received by Linn Midstream from the sale of the Residue Gas Volume during the applicable Month

(b) “Residue Settlement Percent” shall be *** percent (***%).

(c) “Residue Gas Volume” for each Receipt Point at which Gas is received hereunder in any Month shall be calculated by subtracting from the MMBTU contained in the Producer’s Committed Gas received at each Receipt Point hereunder the sum of the Field Fuel, Field L&U, Plant Fuel, and NGL Shrinkage attributable to such volumes based on the Theoretical Gallons contained in such volumes expressed in MMBTU.

4. PLANT FUEL, FIELD FUEL AND FIELD L&U RETENTION.

(a) Plant Fuel: Linn Midstream shall charge Producer Plant fuel (irrespective of Linn Midstream’s use of gas- or electric-driven compression) retention of *** percent (***%) of Residue Gas.

(b) Field Fuel: Linn Midstream shall charge Producer field fuel retention (irrespective of Linn Midstream’s use of gas- or electric-driven compression) of *** (***%) of Receipt Point Committed Gas MMBTUs.

(c) Field L&U: Linn Midstream shall charge Producer a Field L&U retention of *** percent (***%) of Receipt Point Committed Gas MMBTUs.

5. BYPASS GAS. BYPASS GAS ATTRIBUTABLE TO PRODUCER, WITH CONSIDERATION OF THE RESIDUE SETTLEMENT PERCENTAGE SET FORTH IN SECTION 3 OF THIS EXHIBIT B-2, SHALL BE CONSIDERED ADDITIONAL AGGREGATE RESIDUE GAS VOLUME AND SHALL BE VALUED AT THE RESIDUE GAS MARKET PRICE.

6. PROCESSING AND GATHERING FEE. THE “PROCESSING AND GATHERING FEE” IS INITIALLY * CENTS ($***) PER MMBTU OF RECEIPT POINT COMMITTED GAS.**

The Processing and Gathering Fee multiplied by the Committed Gas MMBTU (as may be adjusted pursuant to Section 9 to this Exhibit B-2 below) delivered to each Receipt Point(s) (“Processing and Gathering Amount”) yields the total monthly amount payable from Producer to Linn Midstream for this service and shall be netted against the amount owed to Producer each Month.

7. *. THE PROCESSING AND GATHERING FEE IN SECTION 6 TO THIS EXHIBIT B- 2 ABOVE AND T&F FEE IN SECTION 2(A)(I) TO THIS EXHIBIT B-2 ABOVE SHALL BE ADJUSTED ON THE FIRST ANNIVERSARY OF THE DECEMBER 22, 2017, AND THE THEN-EFFECTIVE PROCESSING AND GATHERING FEE AND T&F FEE SHALL BE ADJUSTED ON EACH SUBSEQUENT ANNIVERSARY OF DECEMBER 22, 2017 TO REFLECT INCREASES, IF ANY, ***. IN NO EVENT SHALL SUCH *** ADJUSTMENT RESULT IN A REDUCTION OF THE THEN-EFFECTIVE PROCESSING AND GATHERING FEE OR T&F FEE.** ***

EXHIBIT B-3 – RECEIPT POINTS

This Exhibit B-3 is attached to and made a part of that certain Amended and Restated Gas Gathering and Processing Agreement effective April 1, 2017, by and between Producer and Linn Midstream.

As of the Effective Date of Exhibit B, the Parties agree that the following are Receipt Points under Exhibit B, and as Receipt Point(s) are installed in the future in accordance with the terms and provisions of Exhibit B, this Exhibit B-3 shall automatically be amended to add such new Receipt Points.

Receipt Point	Meter Type	Meter No.	Legal Description	County	State

EXHIBIT B-4 – QUALITY SPECIFICATIONS

This Exhibit B-4 is attached to and made a part of that certain Amended and Restated Gas Gathering and Processing Agreement effective April 1, 2017, by and between Producer and Linn Midstream.

Quality Specifications: Unless excepted by specific exemption executed by the Parties hereto**,** Gas from each Receipt Point shall meet the following quality specifications:

***

OFF SPEC GAS: LINN MIDSTREAM MAY, AT LINN MIDSTREAM'S SOLE DISCRETION, ACCEPT GAS WHICH DOES NOT CONFORM TO THE QUALITY SPECIFICATIONS DEFINED HEREIN PROVIDED THAT SUCH ACCEPTANCE DOES NOT INTERFERE, IN LINN MIDSTREAM'S SOLE OPINION, WITH THE OPERATIONS OF LINN MIDSTREAM'S OR LINN MIDSTREAM'S DESIGNEE'S FACILITIES AND/OR ANY DOWNSTREAM FACILITY OR PIPELINE. IF ADDITIONAL TREATING IS REQUIRED TO MANAGE AND PROCESS OFF SPEC GAS TO MEET THE REQUIREMENTS OF THIS EXHIBIT B-4, LINN MIDSTREAM SHALL OFFER TO PRODUCER, FOR A FEE, TO INSTALL AND OPERATE THE FACILITIES REQUIRED TO CONDITION THE GAS TO MEET THE SPECIFICATIONS HEREIN. PRODUCER RESERVES THE RIGHT TO INSTALL WELL SITE PROCESSING TO MANAGE AND PROCESS THE OFF SPEC GAS TO MEET THE SPECIFICATIONS HEREIN.

IF ANY OF THE QUALITY SPECIFICATIONS PRESCRIBED BY ANY OR ALL DOWNSTREAM PIPELINE(S) AND/OR FACILITIES ARE MORE STRINGENT THAN THE CORRESPONDING QUALITY SPECIFICATIONS PRESCRIBED HEREIN, THE QUALITY SPECIFICATIONS DEFINED HEREIN SHALL BE SUBORDINATE TO SUCH SPECIFICATIONS PRESCRIBED BY ANY AND/OR ALL DOWNSTREAM PIPELINE(S) OR FACILITIES AND LINN MIDSTREAM SHALL OFFER, FOR A FEE, TO INSTALL THE FACILITIES REQUIRED TO CONDITION THE GAS TO MEET THE NEW SPECIFICATIONS.

EXHIBIT B-5 – DEDICATED CONTRACTS

This Exhibit B-5 is attached to and made a part of that certain Amended and Restated Gas Gathering and Processing Agreement effective April 1, 2017, by and between Producer and Linn Midstream.

Linn K#	Counterparty K#	Contract Type	Linn Entity	Counterparty
224G	10-0009	Gas Purchase and Sale Agreement	Linn Energy Holdings, LLC	Cimarex Energy Company
1244G		Gas Purchase Contract	LINN OPERATING, LLC	Continuum Midstream, L.L.C.
TBD	EDM 1776-00*	Gas Purchase Contract	Linn Energy Holdings, LLC	DCP Midstream LLC
TBD	EDM 0768-00A	Gas Purchase Contract	Linn Energy Holdings, LLC	DCP Midstream LLC
TBD	EDM 1971-00*	Gas Purchase Contract	Linn Energy Holdings, LLC	DCP Midstream LLC
TBD	OKR 1306-PUR	Gas Purchase Contract	Linn Energy Holdings, LLC	DCP Midstream LLC
TBD	OKR 1320-PUR	Gas Purchase Contract	LINN OPERATING, LLC	DCP Midstream LLC
TBD	14812	Gas Purchase Contract	Linn Energy Holdings, LLC	DCP Midstream LLC
1106G	CHI 0580-000	Gas Purchase Contract	LINN OPERATING, LLC	DCP Midstream LLC
TBD	EDM 1026-00A	Gas Purchase Contract	LINN OPERATING, LLC	DCP Midstream LLC
TBD	EDM 0012-PUR	Gas Purchase Contract	LINN OPERATING, LLC	DCP Midstream LLC
TBD	OKR 0534-00*	Gas Purchase Contract	LINN OPERATING, LLC	DCP Midstream LLC
TBD	EDM 2022-00*	Gas Purchase Contract	LINN OPERATING, LLC	DCP Midstream LLC
1111G	OKR 0734-00*	Gas Purchase Contract	LINN OPERATING, LLC	DCP Operating Company LP
113G	EDM 1544-00A	Gas Purchase Contract	LINN ENERGY MID-CONT. HOLDINGS, LLC	DCP Operating Company LP
1163G	SHOP 00015	Gas Purchase and Processing Agreement	LINN OPERATING, LLC	DCP Operating Company LP
1283G	OKR 0933-000	Gas Purchase Contract	LINN OPERATING, LLC	DCP Operating Company LP
1295G	OKR 0705-00*	Gas Purchase Contract	LINN OPERATING, LLC	DCP Operating Company LP
181G	OKR 1196-000	Gas Purchase Contract	LINN OPERATING, LLC	DCP Operating Company LP
212G	EDM 2049-00*	Gas Purchase Contract	LINN OPERATING, LLC	DCP Operating Company LP
219G	15233	Gas Purchase Contract	LINN OPERATING, LLC	DCP Operating Company LP
278G	16704	Gas Purchase Contract	LINN OPERATING, LLC	DCP Operating Company LP
29G	SHOP 00007	Gas Purchase and Processing Agreement	LINN OPERATING, LLC	DCP Operating Company LP

Linn K#	Counterparty K#	Contract Type	Linn Entity	Counterparty
518G	CIM 0917-00*	Gas Purchase Contract	LINN OPERATING, LLC	DCP Operating Company LP
53G	15631	Gas Purchase Contract	LINN OPERATING, LLC	DCP Operating Company LP
574G	OKR 0278-00	Gas Purchase Agreement	LINN OPERATING, LLC	DCP Operating Company LP
68G	15577	Gas Purchase Agreement	LINN OPERATING, LLC	DCP Operating Company LP
76G	15455	Gas Purchase Contract	LINN OPERATING, LLC	DCP Operating Company LP
775G	EDM 2027-00*	Gas Purchase Agreement	LINN OPERATING, LLC	DCP Operating Company LP
783G	15676	Gas Purchase Contract	LINN OPERATING, LLC	DCP Operating Company LP
784G	OKR 1197-000	Gas Purchase Contract	LINN OPERATING, LLC	DCP Operating Company LP
785G	OKR 0150-00*	Gas Purchase Contract	LINN OPERATING, LLC	DCP Operating Company LP
1599G		Gas Gathering, Processing and Purchase Agreement	LINN OPERATING, LLC	EnLink Oklahoma Gas Processing, LP
419G	6083-00	Gas Purchase Contract	LINN OPERATING, LLC	ETC Field Services LLC
CTPr-1	CTPr-1	Gas Processing Agreement	Linn Energy Holdings, LLC	Linn Midstream, LLC
1158G	026770B	Gas Purchase Contract	LINN OPERATING, LLC	Mustang Gas Products Inc.
1411G	495152	Gas Purchase Agreement	LINN OPERATING, LLC	Mustang Gas Products Inc.
184G	4002775	Gas Purchase Contract	LINN OPERATING, LLC	Mustang Gas Products Inc.
250G	8928NGD	Gas Purchase Agreement	LINN OPERATING, LLC	Mustang Gas Products Inc.
254G	51013	Gas Purchase Agreement	LINN OPERATING, LLC	Mustang Gas Products Inc.
256G	51008	Gas Purchase Contract	LINN OPERATING, LLC	Mustang Gas Products Inc.
257G	51009	Gas Purchase Agreement	LINN OPERATING, LLC	Mustang Gas Products Inc.
63G	9518CD	Gas Purchase Agreement	LINN OPERATING, LLC	Mustang Gas Products Inc.
828G	9845CD	Casinghead Gas Contract	LINN OPERATING, LLC	Mustang Gas Products Inc.
KF-1280G	495103	Gas Purchase Agreement	LINN ENERGY MID-CONT. HOLDINGS, LLC	Mustang Gas Products Inc.
1515G	1293000	Gas Purchase Contract	LINN OPERATING, LLC	Oneok Field Services LLC
1516G	1298000	Gas Purchase Contract	LINN OPERATING, LLC	Oneok Field Services LLC
1517G	2026000	Gas Purchase Contract	LINN OPERATING, LLC	Oneok Field Services LLC
236G	1297000	Gas Purchase Contract	LINN OPERATING, LLC	Oneok Field Services LLC
237G	755000	Gas Purchase Contract	LINN OPERATING, LLC	Oneok Field Services LLC

Linn K#	**Counterparty K#**	**Contract Type**	**Linn Entity**	**Counterparty**
507G	2058001	Gas Purchase Contract	LINN OPERATING, LLC	Oneok Field Services LLC
1140G	ET-P5	Gas Purchase Agreement	LINN OPERATING, LLC	Superior Pipeline Company
1141G	ET-P4	Gas Purchase Contract	LINN OPERATING, LLC	Superior Pipeline Company
1144G	CASH-P5	Gas Purchase Contract	LINN OPERATING, LLC	Superior Pipeline Company
1145G	MINCO P18	Gas Purchase Contract	LINN OPERATING, LLC	Superior Pipeline Company
1442G	311680	Gas Purchase Agreement	LINN OPERATING, LLC	Targa Pipeline Mid Continent LLC

Exhibit C

FORM OF MEMORANDUM OF AGREEMENT

This Exhibit C is attached to and made a part of that certain Amended and Restated Gas Gathering and Processing Agreement effective April 1, 2017, by and between Producer and Linn Midstream.

When finished recording return to:

Linn Energy Holdings, LLC 600
Travis Street, Suite 1400
Attention: Marketing Administration
Facsimile: 832-209-4300
Email: MarketingAdministration@linnenergy.com

and

Linn Midstream, LLC
600 Travis Street, Suite 1400 Attention:
Marketing Administration Facsimile: 832-
209-4300
Email: MarketingAdministration@linnenergy.com

MEMORANDUM OF AGREEMENT

State of Oklahoma §
§
County of [•] §

This MEMORANDUM OF AGREEMENT (this "***Memorandum***"), effective for all purposes as of , 2017 (the "***Effective Date***"), is by and between Linn Midstream, LLC, a Delaware limited liability company ("***Linn Midstream***"), and Linn Energy Holdings, LLC, a Delaware limited liability company ("***Producer***"). Linn Midstream and Producer may be referred to individually as a "***Party***" and collectively as the "***Parties***." Capitalized terms used but not defined herein shall have the meaning given to them in that certain Amended and Restated Gas Gathering and Processing Agreement dated effective as of April 1, 2017, by and between Linn Midstream and Producer (the "***Agreement***").

1. Pursuant to the Agreement, Producer has agreed to dedicate and deliver for gathering, transportation and processing by Linn Midstream certain gas volumes owned or controlled by Producer lawfully produced from wells now or hereafter drilled on the lands within an area of mutual interest covering the counties listed on Exhibit A attached hereto (as further described in the Agreement), including the sections described on Exhibit B to this Memorandum (other than certain gas volumes delivered from prior dedicated sections (as more fully described, and subject to the terms and conditions set forth, in the Agreement)).

2. The Agreement is effective as of the Effective Date and, subject to the other provisions thereof, shall remain in full force and effect for a term of, in the case of the properties described on Exhibit A, until the fifteenth anniversary of the Effective Date, and in the case of the properties described on Exhibit B, December 22, 2031 ("***Primary Term***"). Thereafter, the Agreement shall continue in full force and effect in accordance with its terms

3. The Notice addresses of the Parties are as follows:

Linn Midstream:	Producer:
Linn Midstream, LLC 600 Travis Street, Suite 1400 Attention: Marketing Administration Facsimile: 832-209-4300 Email: MarketingAdministration@linnenergy.com	Linn Energy Holdings, LLC 600 Travis Street, Suite 1400 Attention: Marketing Administration Facsimile: 832-209-4300 Email: MarketingAdministration@linnenergy.com

4. This Memorandum in no way modifies or amends the terms and provisions of the Agreement. This Memorandum is executed solely for the purpose of providing record notice of the Agreement and is to be recorded in the real property records of the respective counties in the area of mutual interest. This Memorandum may be executed in separate counterparts, all of which shall together constitute one and the same instrument. The terms of this Memorandum may only be modified or amended by an instrument in writing, fully executed by Linn Midstream and Producer.

[*SIGNATURE PAGE FOLLOWS*]

IN WITNESS WHEREOF, the undersigned have each caused this Memorandum to be duly executed as of the date shown on the acknowledgments set forth below with the intention that they will be effective as of the Effective Date.

LINN MIDSTREAM:

Linn Midstream, LLC
By and through its Agent, Linn Operating, LLC

By:
Name: [●]
Title: [●]

STATE OF [●])
) ss.
COUNTY OF [●])

The foregoing instrument was executed before more this day of , 2017, by [●], as authorized agent on behalf of Linn Midstream, LLC.

[Seal]

Notary Public

Commission No.
My Commission Expires:

PRODUCER:

Linn Energy Holdings, LLC
By and through its Agent, Linn Operating, LLC

By:
Name: [●]
Title: [●]

STATE OF [●])
) ss.
COUNTY OF [●])

The foregoing instrument was executed before more this day of , 2017, by , as authorized agent on behalf of Linn Energy Holdings, LLC.

[Seal]

Notary Public

Commission No.
My Commission Expires:

[NOTE: To be attached.]

Exhibit A to Memorandum of Agreement

AREA OF MUTUAL INTEREST

EXHIBIT B TO MEMORANDUM OF AGREEMENT

DEDICATED SECTIONS

[NOTE: To be inserted.]

Exhibit 10.27

<u>RELEASE FROM DEDICATION</u>

(Section 13-T7N-R4W, Grady, County OK)

WHEREAS, **ROAN RESOURCES, LLC**, ("Producer") and **BLUE MOUNTAIN MIDSTREAM LLC** ("Blue Mountain") are parties to that certain Amended and Restated Gas Gathering and Processing Agreement dated April 1, 2017 in which Producer dedicated certain leasehold interests and lands including Producer's Gas ("**Agreement**");

WHEREAS, the Agreement includes a dedication of Producer's Gas, as defined therein, between Producer and Blue Mountain that includes Section 13-T7N-R4W ("Section 13"), Grady County Oklahoma;

WHEREAS, Producer and Blue Mountain desire that Section 13 and Producer's Gas, as defined in the Agreement, from Section 13 be released from the dedication.

NOW, THEREFORE, Producer and Blue Mountain hereby agree that Section 13, and only Section 13, is released from the dedication of Producer's Gas as defined in the Agreement, and Producer waives, in this instance, the requirement contained in Section 10.3(c) of Exhibit A of the Agreement for Blue Mountain to release any additional acreage.

This Release from Dedication may be executed in duplicate counterparts, each of which shall be deemed an original instrument, but which together shall constitute but one and the same instrument.

EXECUTED effective as of the 9th day of October, 2018.

ROAN RESOURCES LLC

By:	/s/ Roger D. Brown
Name:	Roger D. Brown
Title:	Marketing/Midstream Manager

BLUE MOUNTAIN MIDSTREAM LLC
By and through its agent, Riviera Operating, LLC
f/k/a Linn Operating, LLC

By:	/s/ David A. Weathers
Name:	David A. Weathers
Title:	Executive Vice President and Chief Commercial Officer

AMENDMENT
TO
GAS GATHERING AND PROCESSING AGREEMENT

This Amendment to Gas Gathering and Processing Agreement (this "**Amendment**") is dated as of the 1st day of November, 2018, and is an amendment to that certain Amended and Restated Gas Gathering and Processing Agreement, dated and effective April 1, 2017, (the "**Existing Agreement**") by and between **Blue Mountain Midstream LLC**, successor to Linn Midstream, LLC ("**Gatherer**") and **Roan Resources LLC**, successor to Linn Energy Holdings, LLC ("**Producer**"). Gatherer and Producer are sometimes referred to in this Amendment individually as a "**Party**" and collectively as the "**Parties**."

AGREEMENT

In consideration of the premises and of the mutual covenants in this Amendment, together with other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged by each Party, the Parties agree as follows:

1. Definitions. Capitalized terms used and not defined in this Amendment have the respective meanings assigned to them in the Existing Agreement.

2. Amendments to the Existing Agreement.

a. In accordance with an acreage swap between Producer and Camino Natural Resources, LLC ("Camino") (the "Acreage Swap"), the Parties agree to release from the Existing Agreement the acreage related to the leases conveyed by Producer to Camino pursuant to the Acreage Swap in the sections listed in the table below (the "Released Acreage"), and as more particularly described on the attached Exhibit A attached hereto, effective immediately prior to the effective time of the assignment from Producer to Camino. For the avoidance of doubt, the AMI remains unchanged except for the exclusion of the Released Acreage.

Section	**Township**	**Range**	**Net Acres**	**County, State**
18	11 North	7 West	475.00	Canadian, OK
23	6 North	7 West	55.00	Grady, OK
7	12 North	7 West	14.38	Canadian, OK
27	7 North	7 West	18.49	Grady, OK
28	7 North	7 West	0.65	Grady, OK
15	10 North	7 West	187.80	Grady, OK
6	12 North	7 West	90.00	Canadian, OK
19	10 North	7 West	168.05	Grady, OK
18	10 North	7 West	601.67	Grady, OK

b. The Parties further acknowledge and agree that the following acreage, as more particularly described on the attached Exhibit B attached hereto (the "EnLink Released Acreage"), which was previously subject to a dedication between

Producer and EnLink Oklahoma Gas Processing, LP, successor to TOM-STACK, LLC ("EnLink"), has been released from dedication by EnLink and, effective immediately upon the effective date of the assignment between Producer and Camino shall be expressly included in the AMI and dedicated under the Existing Agreement pursuant to Section 10.1..

Sections	**Township**	**Range**	**Net Acres**	**County, State**
8, 17	10 North	6 West	91.07	Grady, OK
5, 29, 32	9 North	5 West	669.56	Grady, OK
28, 33	11 North	7 West	388.95	Canadian, OK
4, 9	10 North	7 West	347.21	Canadian and Grady, OK
23, 26	10 North	5 West	71.32	Canadian and Grady, OK
18	9 North	6 West	621.92	Grady, OK

3. Limited Effect. Except as expressly provided in this Amendment, all of the terms and provisions of the Existing Agreement are and will remain in full force and effect and are hereby ratified and confirmed by the Parties.

4. Representations and Warranties. Each Party hereby represents and warrants to the other Party that: (a) it has the full right, power and authority to enter into this Amendment and to perform its obligations hereunder and under the Existing Agreement as amended by this Amendment; (b) the execution of this Amendment by the individual whose signature is set forth at the end of this Amendment on behalf of such Party, and the delivery of this Amendment by such Party, have been duly authorized by all necessary action on the part of such Party; and (c) this Amendment has been executed and delivered by such Party and constitutes the legal, valid and binding obligation of such Party, enforceable against such Party in accordance with its terms.

5. In the event EnLink does not release the EnLink Released Acreage from dedication contemporaneously with the execution of this Amendment, this Amendment shall be of no force or effect and shall be void ab initio. Upon the execution of this Amendment Producer will provide Gatherer with a copy of the amendment between Producer and EnLink reflecting such release.

6. Miscellaneous.

a. This Amendment shall inure to the benefit of and be binding upon each of the Parties and each of their respective permitted successors and permitted assigns.

b. The headings in this Amendment are for reference only and do not affect the interpretation of this Amendment.

c. This Amendment may be executed in counterparts, each of which is deemed an original, but all of which constitutes one and the same agreement. Delivery of an executed counterpart of this Amendment electronically or by facsimile shall be effective as delivery of an original executed counterpart of this Amendment.

d. The Existing Agreement, as amended by Amendment, constitutes the sole and entire agreement of the Parties with respect to the subject matter contained therein, and supersedes all prior and contemporaneous understandings, agreements, representations and warranties, both written and oral, with respect to such subject matter.

IN WITNESS WHEREOF, the Parties have executed this Amendment on the date first written above.

BLUE MOUNTAIN MIDSTREAM LLC

By:	/s/ David A. Weathers
Name:	David A. Weathers
Title:	Executive Vice President and Chief Commercial Officer

ROAN RESOURCES LLC

By:	/s/ Roger D. Brown
Name:	Roger D. Brown
Title:	Marketing/Midstream Manager

Exhibit 21.1

LIST OF SIGNIFICANT SUBSIDIARIES
As of December 31, 2019

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 27, 2020, with respect to the consolidated balance sheets of Riviera Resources, Inc. as of December 31, 2019 and 2018, the related consolidated and combined statements of operations, equity (deficit), and cash flows for the years ended December 31, 2019 and 2018 , for the ten months ended December 31, 2017, and the two months ended February 28, 2017 and the related notes (collectively, the consolidated and combined financial statements), and the effectiveness of internal control over financial reporting as of December 31, 2019, which reports appear in the December 31, 2019 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 27, 2020

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

February 27, 2020

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, 2019 (the "10-K"), to be filed with the United States Securities and Exchange Commission on or about February 27, 2020, and in the registration statements on Form S-3 (No. 333-227895) and Form S-8 (No. 333-226637):

- Report as of December 31, 2019 on Reserves and Revenue of Certain Properties with interests attributable to Riviera Operating, LLC;
- Report as of December 31, 2018 on Reserves and Revenue of Certain Properties with interests attributable to Riviera Operating, LLC; and
- Report as of December 31, 2017 on Reserves and Revenue of Certain Properties owned by Linn Operating, Inc.

We further consent to the inclusion of our report of third-party dated February 27, 2020, 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 27, 2020

/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 27, 2020

/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, 2019, 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 27, 2020

/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, 2019, 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 27, 2020

/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
January 31, 2020

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, 2019, 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 January 31, 2020. The properties evaluated herein are located in Louisiana, New Mexico, Oklahoma, Texas, and Utah. Riviera has represented that these properties account for 100 percent of Riviera's net proved reserves as of December 31, 2019. 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, 2019. 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, capital costs, and abandonment costs from future gross revenue. Operating expenses include field operating expenses, transportation and processing expenses, compression charges, 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 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 estimated in this report are classified as proved. Only proved reserves have been evaluated for this report. Reserves classifications used by us 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 (revised June 2019) Approved by the SPE Board on 25 June 2019” and in Monograph 3 and Monograph 4 published by the Society of Petroleum Evaluation Engineers. 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. The proved undeveloped reserves estimates were based on opportunities identified in the plan of development provided by Riviera.

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 the evaluation of unconventional reservoirs, a performance-based methodology integrating the appropriate geology and petroleum engineering data was utilized for this report. Performance-based methodology primarily includes (1) production diagnostics, (2) decline-curve analysis, and (3) model-based analysis (if necessary, based on availability of data). Production diagnostics include data quality control, identification of flow regimes, and characteristic well performance behavior. These analyses were performed for all well groupings (or type-curve areas).

Characteristic rate-decline profiles from diagnostic interpretation were translated to modified hyperbolic rate profiles, including one or multiple b-exponent values followed by an exponential decline. Based on the availability of data, model-based analysis may be integrated to evaluate long-term decline behavior, the effect of dynamic reservoir and fracture parameters on well performance, and complex situations sourced by the nature of unconventional reservoirs.

In the evaluation of undeveloped reserves, type-well analysis was performed using well data from analogous reservoirs for which more complete historical performance data were available.

Data provided by Riviera from wells drilled through December 31, 2019, 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 April 2019. Estimated cumulative production, as of December 31, 2019, was deducted from the estimated gross ultimate recovery to estimate gross reserves. This required that production be estimated for up to 8 months. Riviera has represented that wells with data only through April 2019 were on production as of December 31, 2019.

Oil and condensate reserves estimated herein are those to be recovered by normal field separation. NGL reserves estimated herein include pentanes and heavier fractions (C_{5+}) and liquefied petroleum gas (LPG), which consists primarily of propane and butane fractions, and are the result of low-temperature plant processing. Oil, condensate, and NGL reserves included in this report are expressed in thousands of barrels (Mbbl). In these estimates, 1 barrel equals 42 United States gallons. 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 usage, flare, 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 $55.69 per barrel and held constant thereafter. The volume-weighted average prices attributable to the estimated proved reserves over the lives of the properties were $53.80 per barrel of oil and condensate and $18.15 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 $2.58 per million Btu and held constant thereafter. Btu factors provided by Riviera were used to convert prices from dollars per million Btu to dollars per thousand cubic feet. The volume-weighted average price attributable to the estimated proved reserves over the lives of the properties was $2.38 per thousand cubic feet of gas.

Production and Ad Valorem Taxes

Production taxes were calculated using the tax rates for each 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 2019 values, provided by Riviera, and were not adjusted for inflation. 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 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, NGL, and gas 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 FASB 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, 2019, 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, 2019

	Oil and Condensate (Mbbl)	**NGL (Mbbl)**	**Sales Gas (MMcf)**	**Gas Equivalent (MMcfe)**
Proved Developed	2,338	3,389	250,098	284,460
Proved Undeveloped	62	0	31,310	31,682
Total Proved	**2,400**	**3,389**	**281,408**	**316,142**

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, 2019, 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	780,934	860,324
Production and Ad Valorem Taxes	49,931	52,596
Operating Expenses	479,356	492,826
Capital and Abandonment Costs	108,253	122,539
Future Net Revenue	143,394	192,363
Present Worth at 10 Percent	133,231	158,795

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, 2019, 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 assumptions, data, procedures, and methods that it considers necessary and appropriate 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 this report of third party addressed to Riviera dated
January 31, 2020, 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 35 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