LINN ENERGY, INC.
Form 10-K
March 23, 2017

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
Form 10-K
x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2016
¨ 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: 000-51719

LINN ENERGY, INC.
(Successor in interest to Linn Energy, LLC)
(Exact name of registrant as specified in its charter)

Delaware	81-5366183
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
600 Travis Houston, Texas	77002
(Address of principal executive offices)	(Zip Code)

Registrant’s telephone number, including area code
(281) 840-4000
Securities registered pursuant to Section 12(b) of the Act:
None
Securities registered pursuant to Section 12(g) of the Act:
None
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ¨ No x
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 x

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 x No ¨
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, 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 x No ¨
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.
Large accelerated filer ¨ Accelerated filer ¨ Non-accelerated filer ¨ Smaller reporting company x
Indicate by check-mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).
Yes ¨ No x
The aggregate market value of voting and non-voting common equity held by non-affiliates of the registrant was approximately $20 million on June 30, 2016, based on $0.09 per unit, the last reported sales price of the units on the OTC Markets Group Inc.'s Pink marketplace on such date.
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 x No ¨
As of February 28, 2017, there were 91,708,500 shares of Class A common stock, par value $0.001 per share, outstanding.
Documents Incorporated By Reference:
Certain information called for in Items 10, 11, 12, 13 and 14 of Part III will be included in an amendment to 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.

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.

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

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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 present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with the regulations of the Securities and Exchange Commission, without giving effect to non-property related expenses such as general and administrative expenses, debt service, future income tax expenses or depreciation, depletion and amortization; discounted using an annual discount rate of 10%.
Tcfe. One trillion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of oil, condensate or natural gas liquids.
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.

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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.

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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

When referring to Linn Energy, Inc. (formerly known as Linn Energy, LLC) (“Successor,” “Reorganized LINN,” “LINN Energy” or the “Company”), the intent is to refer to LINN Energy, a newly formed Delaware corporation, and its consolidated subsidiaries as a whole or on an individual basis, depending on the context in which the statements are made. Linn Energy, Inc. is a successor issuer of Linn Energy, LLC pursuant to Rule 15d-5 of the Securities Exchange Act of 1934, as amended (the “Exchange Act”). When referring to the “Predecessor” in reference to the period prior to the emergence from bankruptcy, the intent is to refer to Linn Energy, LLC, the predecessor that will be dissolved following the effective date of the Plan (as defined below) and resolution of all outstanding claims, and its consolidated subsidiaries as a whole or on an individual basis, depending on the context in which the statements are made.

The reference to “Berry” herein refers to Berry Petroleum Company, LLC, which was an indirect 100% wholly owned subsidiary of LINN Energy through February 28, 2017. Berry was deconsolidated effective December 3, 2016 (see below and Note 3). The reference to “LinnCo” herein refers to LinnCo, LLC, which is an affiliate of the Predecessor. The reference to a “Note” herein refers to the accompanying Notes to Consolidated Financial Statements contained in Item 8. “Financial Statements and Supplementary Data.”

Overview

LINN Energy is an independent oil and natural gas company that was formed on February 14, 2017, in connection with the reorganization of the Predecessor. The Predecessor was publicly traded from January 2006 to February 2017. As discussed further in Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and Note 2, on May 11, 2016, Linn Energy, LLC, certain of its direct and indirect subsidiaries, and LinnCo (collectively, the “LINN Debtors”) and Berry (collectively with the LINN Debtors, the “Debtors”), filed voluntary petitions (“Bankruptcy Petitions”) for relief under Chapter 11 of the U.S. Bankruptcy Code (“Bankruptcy Code”) in the U.S. Bankruptcy Court for the Southern District of Texas (“Bankruptcy Court”). The Debtors’ Chapter 11 cases are being 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. The Company emerged from bankruptcy effective February 28, 2017.

On December 3, 2016, LINN Energy filed an amended plan of reorganization that excluded Berry. As a result of its loss of control of Berry, LINN Energy concluded that it was appropriate to deconsolidate Berry effective on the aforementioned date. The results of operations of Berry are reported as discontinued operations for all periods presented.

The Company’s properties are located in the United States (“U.S.”), in the Hugoton Basin, the Rockies, the Mid-Continent, east Texas and north Louisiana (“TexLa”), Michigan/Illinois, California, the Permian Basin and south Texas.

Proved reserves at December 31, 2016, were approximately 3,520 Bcfe, of which approximately 17% were oil, 65% were natural gas and 18% were natural gas liquids (“NGL”). Approximately 92% were classified as proved developed, with a total standardized measure of discounted future net cash flows of approximately $1.9 billion. At December 31, 2016, the Company operated 13,393 or approximately 58% of its 23,158 gross productive wells and had an average proved reserve-life index of approximately 12 years, based on the December 31, 2016, reserve reports and year-end 2016 production.

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Strategy
Prior to the Company’s emergence from voluntary reorganization under Chapter 11, the Company was an upstream master limited partnership with a strategy to acquire, develop and maximize cash flow from a growing portfolio of long-life oil and natural gas assets. Upon its emergence from bankruptcy as a corporation with an improved balance sheet and greater liquidity, the Company is transitioning to a growth-oriented exploration and production company. The Company’s current focus is on accelerating the development of its core SCOOP/STACK/Merge acreage in western Oklahoma, along with additional emerging stacked pay horizontal opportunities in the Mid-Continent, Rockies and TexLa regions. The Company has a large inventory of drilling and optimization projects to achieve organic growth and continues to add value by efficiently operating and applying new technology to mature fields. As part of its restructuring, the Company is marketing certain non-strategic assets to focus resources on growth opportunities and continues to leverage its experienced workforce and scalable infrastructure to maximize shareholder value.

Recent Developments

Emergence from Voluntary Reorganization Under Chapter 11

On October 21, 2016, the Debtors filed the Joint Chapter 11 Plan of Reorganization of Linn Energy, LLC and Its Debtor Affiliates (the “Original Plan”).

On December 3, 2016, the Debtors split the Original Plan and pursued separate plans of reorganization for the LINN Debtors, on the one hand, and Linn Acquisition Company, LLC (“LAC”) and Berry, on the other hand. Accordingly, 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 “LINN Plan”). The LINN Debtors subsequently filed amended versions of the LINN 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 LINN 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.

Pursuant to the LINN Plan, the Predecessor transferred all of its assets, including equity interests in its subsidiaries, other than LAC and Berry, to Linn Energy Holdco II LLC (“Holdco II”), a newly formed subsidiary of the Predecessor and the borrower under the Credit Agreement (“Exit Facility”) entered into in connection with the reorganization, in exchange for 100% of the equity of Holdco II and the issuance of interests in the Exit Facility to certain of the Predecessor’s creditors in partial satisfaction of their claims (the “Contribution”). Immediately following the Contribution, the Predecessor transferred 100% of the equity interests in Holdco II to the Successor in exchange for approximately $530 million in cash and an amount of equity securities in the Successor not to exceed 49.90% of the outstanding equity interests of the Successor (the “Disposition”), which the Predecessor distributed to certain of its creditors in satisfaction of their claims. Contemporaneously with the reorganization transactions and pursuant to the LINN Plan, (i) LAC assigned all of its rights, title and interest in the membership interests of Berry to Berry Petroleum Corporation, (ii) all of the equity interests in LAC and the Predecessor were canceled and (iii) LAC and the Predecessor commenced liquidation, which is expected to be completed following the resolution of the respective companies’ outstanding claims.

For additional information related to the Company’s emergence from bankruptcy and the terms of the Exit Facility, see Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and Note 2.

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2017 Oil and Natural Gas Capital Budget
For 2017, the Company estimates its total capital expenditures, excluding acquisitions, will be approximately $395 million, including approximately $300 million related to its oil and natural gas capital program and approximately $84 million related to its plant and pipeline capital. This estimate is under continuous review and subject to ongoing adjustments.
Financing Activities
See Item 7. "Management's Discuss and Analysis of Financial Condition and Results of Operations" for a description of the Exit Facility entered into in February 2017.
During the year ended December 31, 2016, the Company borrowed approximately $979 million under the LINN Credit Facility (as defined in Note 6) and made repayments of approximately $1.8 billion of a portion of the borrowings outstanding under the LINN Credit Facility and term loan. The repayments include approximately $841 million in commodity derivative settlements paid by the counterparties to the lenders under the LINN Credit Facility. As of December 31, 2016, total borrowings outstanding (including outstanding letters of credit) under the LINN Credit Facility were approximately $1.9 billion, with no remaining availability. See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" for a description of the amendment to the LINN Credit Facility entered into in April 2016. Pursuant to the terms of the LINN Plan, on the Effective Date, all obligations under the LINN Credit Facility were canceled.
Commodity Derivatives
During the year ended December 31, 2016, LINN Energy entered into commodity derivative contracts consisting of natural gas swaps for October 2016 through December 2019, oil swaps for November 2016 through December 2017, and oil collars for January 2018 through December 2019.
In April 2016 and May 2016, in connection with the Company's restructuring efforts, LINN Energy canceled (prior to the contract settlement dates) all of its then-outstanding derivative contracts for net proceeds of approximately $1.2 billion. The net proceeds were used to make permanent repayments of a portion of the borrowings outstanding under the LINN Credit Facility.
Offer to Exchange LINN Energy Units for LinnCo Shares
In March 2016, LinnCo filed a Registration Statement on Form S-4 related to an offer to exchange each outstanding unit representing limited liability company interests of LINN Energy for one common share representing limited liability company interests of LinnCo. The initial offer expired on April 25, 2016, and on April 26, 2016, LinnCo commenced a subsequent offering period that expired on August 1, 2016. During the exchange period, 123,100,715 LINN Energy units were exchanged for an equal number of LinnCo shares. As a result of the exchanges of LINN Energy units for LinnCo shares, LinnCo's ownership of LINN Energy's outstanding units increased from approximately 37% at December 31, 2015, to approximately 71% at December 31, 2016. Pursuant to the terms of the LINN Plan, on the Effective Date, all outstanding units were extinguished without recovery.
Delisting from Stock Exchange
As a result of the Company's failure to comply with the NASDAQ Global Select Market continued listing requirements, on May 24, 2016, the Company's units began trading over the counter on the OTC Markets Group Inc.'s Pink marketplace under the trading symbol "LINEQ." As a result of the cancellation of the units on the Effective Date, the units ceased to trade on the OTC Markets Group Inc.'s Pink Marketplace.
Operating Regions
The Company's properties are located in eight operating regions in the U.S.:

- Hugoton Basin, which includes properties located in Kansas, the Oklahoma Panhandle and the Shallow Texas Panhandle;

- Rockies, which includes properties located in Wyoming (Green River, Washakie and Powder River basins), Utah (Uinta Basin) and North Dakota (Williston Basin);
- Mid-Continent, which includes Oklahoma properties located in the Anadarko and Arkoma basins, as well as waterfloods in the Central Oklahoma Platform;
- TexLa, which includes properties located in east Texas and north Louisiana;
- Michigan/Illinois, which includes properties located in the Antrim Shale formation in north Michigan and oil properties in south Illinois;
- California, which includes properties located in the San Joaquin Valley and Los Angeles basins;
- Permian Basin, which includes properties located in west Texas and southeast New Mexico; and
- South Texas.

Hugoton Basin

The Hugoton Basin is a large oil and natural gas producing area located in southwest Kansas extending through the Oklahoma Panhandle into the central portion of the Texas Panhandle. The Company's Kansas and Oklahoma Panhandle properties primarily produce from the Council Grove and Chase formations at depths ranging from 2,200 feet to 3,100 feet and its Texas properties in the basin primarily produce from the Brown Dolomite formation at depths ranging from 2,900 feet to 3,700 feet. The Company's properties in this region are primarily mature, low-decline natural gas wells.

To more efficiently transport its natural gas in the Texas Panhandle to market, the Company owns and operates a network of natural gas gathering systems comprised of approximately 665 miles of pipeline and associated compression and metering facilities that connect to numerous sales outlets in the area. The Company also owns and operates the Jayhawk natural gas processing plant in southwest Kansas with a capacity of approximately 450 MMcf/d, allowing it to receive maximum value from the liquids-rich natural gas produced in the area. The Company's production in the area is delivered to the plant via a system of approximately 3,930 miles of pipeline and related facilities operated by the Company, of which approximately 2,075 miles of pipeline are owned by the Company.

Hugoton Basin proved reserves represented approximately 29% of total proved reserves at December 31, 2016, all of which were classified as proved developed. This region produced approximately 180 MMcfe/d or 21% of the Company's 2016 average daily production. During 2016, the Company invested approximately $1 million to develop the properties in this region.

Rockies

The Rockies region consists of properties located in Wyoming (Green River, Washakie and Powder River basins), northeast Utah (Uinta Basin) and North Dakota (Bakken and Three Forks formations in the Williston Basin). Wells in this diverse region produce from both oil and natural gas reservoirs at depths ranging from 1,000 feet to 15,000 feet. The Company's properties in the Jonah Field located in the Green River Basin of southwest Wyoming produce from the Lance and Mesaverde formations at depths ranging from 7,500 feet to 14,500 feet. The Company's properties in the Washakie Basin produce at depths ranging from 7,500 feet to 11,500 feet. The Company's properties in the Powder River Basin consist of a CO2 flood operated by Fleur de Lis Energy, LLC in the Salt Creek Field. The Company's properties in the Uinta Basin produce at depths ranging from 5,500 feet to 15,000 feet. The Company's nonoperated properties in the Williston Basin produce at depths ranging from 9,000 feet to 12,000 feet.

To more efficiently transport its natural gas in the Uinta Basin to market, the Company owns and operates a network of natural gas gathering systems comprised of approximately 95 miles of pipeline and associated compression and metering facilities that connect to numerous sales outlets in the area.

Rockies proved reserves represented approximately 28% of total proved reserves at December 31, 2016, of which 85% were classified as proved developed. This region produced approximately 330 MMcfe/d or 40% of the Company's 2016 average daily production. During 2016, the Company invested approximately $41 million to develop the properties in this region.

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Mid-Continent
The Mid-Continent region consists of properties located in the Anadarko and Arkoma basins in Oklahoma, as well as waterfloods in the Central Oklahoma Platform. In December 2014, the Company completed the sale of its entire position in the Granite Wash and Cleveland plays located in the Texas Panhandle and western Oklahoma. The Company's properties in this diverse region produce from both oil and natural gas reservoirs at depths ranging from 1,500 feet to 11,000 feet. As of December 31, 2016, the Company's properties in this region are primarily mature, low-decline oil and natural gas wells.
Mid-Continent proved reserves represented approximately 15% of total proved reserves at December 31, 2016, of which 81% were classified as proved developed. This region produced approximately 101 MMcfe/d or 12% of the Company's 2016 average daily production. During 2016, the Company invested approximately $31 million to develop the properties in this region and approximately $40 million in exploration activity.
TexLa
The TexLa region consists of properties located in east Texas and north Louisiana and primarily produces natural gas from the Cotton Valley, Travis Peak and Bossier Sand formations at depths ranging from 7,000 feet to 12,500 feet. Proved reserves for these mature, low-decline producing properties represented approximately 9% of total proved reserves at December 31, 2016, of which 95% were classified as proved developed. 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 635 miles of pipeline and associated compression and metering facilities that connect to numerous sales outlets in the area. This region produced approximately 72 MMcfe/d or 9% of the Company's 2016 average daily production. During 2016, the Company invested approximately $9 million to develop the properties in this region.
Michigan/Illinois
The Michigan/Illinois region consists primarily of natural gas properties in the Antrim Shale formation in north Michigan and oil properties in south Illinois. These wells produce at depths ranging from 200 feet to 4,000 feet. Michigan/Illinois proved reserves represented approximately 8% of total proved reserves at December 31, 2016, all of which were classified as proved developed. To more efficiently transport its natural gas in Michigan to market, the Company owns and operates a network of natural gas gathering systems comprised of approximately 1,480 miles of pipeline and associated compression and metering facilities that connect to numerous sales outlets in the area. This region produced approximately 30 MMcfe/d or 4% of the Company's 2016 average daily production. During 2016, the Company invested approximately $1 million to develop the properties in this region.
California
The California region consists of properties located in the South Belridge field in the San Joaquin Valley Basin and the Brea Olinda field in the Los Angeles Basin. The properties in the South Belridge field produce from the Tulare and Diatomite formations using waterflood and thermal enhanced oil recovery methods at depths ranging from 800 feet to 2,000 feet. The Brea Olinda Field was discovered in 1880 and produces from the shallow Pliocene formation to the deeper Miocene formation at depths ranging from 1,000 feet to 7,500 feet. The Company's properties in this region are primarily mature, low-decline oil wells.
California proved reserves represented approximately 5% of total proved reserves at December 31, 2016, all of which were classified as proved developed. This region produced approximately 32 MMcfe/d or 4% of the Company's 2016 average daily production. During 2016, the Company made no material investments to develop the properties in this region.
Permian Basin
The Company's properties are located in west Texas and southeast New Mexico, primarily produce at depths ranging from 2,000 feet to 12,000 feet and are primarily mature, low-decline oil and natural gas wells including several waterflood properties located across the basin.

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Permian Basin proved reserves represented approximately 4% of total proved reserves at December 31, 2016, all of which were classified as proved developed. This region produced approximately 56 MMcfe/d or 7% of the Company's 2016 average daily production. During 2016, the Company invested approximately $1 million to develop the properties in this region.

South Texas

The South Texas region consists of a widely diverse set of oil and natural gas properties located in a large area extending from north Houston to the border of Mexico. These wells produce at depths ranging from 2,000 feet to 17,000 feet. Proved reserves for these mature properties, the majority of which are natural gas with associated NGL, represented approximately 2% of total proved reserves at December 31, 2016, all of which were classified as proved developed. This region produced approximately 27 MMcfe/d or 3% of the Company's 2016 average daily production. During 2016, the Company invested approximately $2 million to develop the properties in this region.

Drilling and Acreage

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

	Year Ended December 31,		
	2016	2015	2014
Gross wells:			
Productive	211	388	506
Dry	1	5	1
	212	393	507
Net development wells:			
Productive	26	139	291
Dry	—	1	1
	26	140	292
Net exploratory wells:			
Productive	7	1	—
Dry	—	1	—
	7	2	—

The total wells above exclude 20, 196 and 411 gross wells (18, 163 and 407 net wells) drilled by Berry during the period from January 1, 2016 through December 3, 2016, and the years ended December 31, 2015, and December 31, 2014, respectively. There were no lateral segments added to existing vertical wellbores during the years ended December 31, 2016, or December 31, 2014. There were two lateral segments added to existing vertical wellbores during the year ended December 31, 2015. As of December 31, 2016, the Company had 63 gross (6 net) wells in progress (51 gross and 2 net 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.

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The following table sets forth information about the Company's drilling locations and net acres of leasehold interests as of December 31, 2016:

	Total [1]
Proved undeveloped	119
Other locations	5,096
Total drilling locations	5,215
Leasehold interests – net acres (in thousands)	2,640

[1] Does not include optimization projects.

As shown in the table above, as of December 31, 2016, the Company had 119 proved undeveloped drilling locations (specific drilling locations as to which the independent engineering firm, DeGolyer and MacNaughton, assigned proved undeveloped reserves as of such date) and the Company had identified 5,096 additional unproved drilling locations (specific drilling locations as to which DeGolyer and MacNaughton has not assigned any proved reserves) on acreage that the Company has under existing leases. Successful development wells frequently result in the reclassification of adjacent lease acreage from unproved to proved. The number of unproved drilling locations that will be reclassified as proved drilling locations will depend on the Company's drilling program, its commitment to capital and commodity prices.

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, 2016. 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 2,858 gross productive wells in which the Company owns a royalty interest only.

	Natural Gas Wells		Oil Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Operated [1]	9,030	8,012	4,363	4,039	13,393	12,051
Nonoperated [2]	7,065	2,299	2,700	308	9,765	2,607
	16,095	10,311	7,063	4,347	23,158	14,658

[1] The Company had 89 operated wells with multiple completions at December 31, 2016.

[2] The Company had 2 nonoperated wells with multiple completions at December 31, 2016.

Developed and Undeveloped Acreage

The following table sets forth information relating to leasehold acreage as of December 31, 2016:

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
	(in thousands)					
Leasehold acreage	4,532	2,617	57	23	4,589	2,640

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Future Acreage Expirations
If production is not established or the Company takes no other action to extend the terms of the related leases, undeveloped acreage will expire over the next three years as follows:

	2017		2018		2019	
	Gross	Net	Gross	Net	Gross	Net
	(in thousands)					
Leasehold acreage	4	2	9	6	4	1

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. Work 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 results of operations of Berry are reported as discontinued operations for all periods presented (see Note 3). Unless otherwise indicated, information presented herein relates only to LINN Energy’s continuing operations.
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. The Company’s natural gas production is sold to purchasers under spot price contracts, percentage-of-index contracts or percentage-of-proceeds contracts. Under percentage-of-index contracts, the Company receives a price for natural gas and NGL based on indexes published for the producing area. Under percentage-of-proceeds contracts, the Company receives a percentage of the resale price received by the purchaser for sales of residual natural gas and NGL recovered after transportation and processing of natural gas. These purchasers sell the residual natural gas and NGL based primarily on spot market prices. Although exact percentages vary daily, as of December 31, 2016, approximately 90% of the Company’s natural gas and NGL production was sold under short-term contracts at market-sensitive or spot prices. In certain circumstances, the Company has entered into natural gas processing contracts whereby the residual natural gas is sold under short-term contracts but the related NGL are sold under long-term contracts. In all such cases, the residual natural gas and NGL are sold at market-sensitive index prices. As of December 31, 2016, the Company had no natural gas or NGL delivery commitments under long-term contracts.
The Company’s oil production is primarily sold under 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, and as of December 31, 2016, approximately 90% of its oil production was sold under short-term contracts. As of December 31, 2016, the Company had no oil delivery commitments under long-term contracts.
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.

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

	Year Ended December 31,		
	2016	2015	2014
Total production:			
Natural gas (MMcf)	187,068	200,488	179,670
Oil (MBbls)	10,047	11,819	13,212
NGL (MBbls)	9,297	9,365	11,569
Total (MMcfe)	303,134	327,587	328,353
Average daily production:			
Natural gas (MMcf/d)	511	549	492
Oil (MBbls/d)	27.5	32.4	36.2
NGL (MBbls/d)	25.4	25.7	31.7
Total (MMcfe/d)	828	897	900
Weighted average prices: (1)			
Natural gas (Mcf)	$ 2.28	$ 2.56	$ 4.28
Oil (Bbl)	$ 39.12	$ 44.00	$ 87.00
NGL (Bbl)	$ 14.28	$ 12.68	$ 34.07
Average NYMEX prices:			
Natural gas (MMBtu)	$ 2.46	$ 2.66	$ 4.41
Oil (Bbl)	$ 43.32	$ 48.80	$ 93.00
Costs per Mcfe of production:			
Lease operating expenses	$ 1.05	$ 1.15	$ 1.35
Transportation expenses	$ 0.53	$ 0.51	$ 0.50
General and administrative expenses (2)	$ 0.78	$ 0.87	$ 0.83
Depreciation, depletion and amortization	$ 1.33	$ 1.69	$ 2.35
Taxes, other than income taxes	$ 0.25	$ 0.34	$ 0.52
Total production – discontinued operations: (3)			
Total (MMcfe)	80,588	105,999	113,331

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

(2) General and administrative expenses for the years ended December 31, 2016, December 31, 2015, and December 31, 2014, include approximately $34 million, $47 million and $45 million, respectively, of noncash unit-based compensation expenses. In addition, general and administrative expenses for the years ended December 31, 2016, December 31, 2015, and December 31, 2014, include costs 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) Total production of discontinued operations for 2016 is for the period from January 1, 2016 through December 3, 2016.

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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,		
	2016	2015	2014
Total production:			
Hugoton Basin Field:			
Natural gas (MMcf)	38,501	41,294	29,424
Oil (MBbls)	27	21	16
NGL (MBbls)	2,983	3,061	2,348
Total (MMcfe)	56,566	59,787	43,608
Green River Basin Field:			
Natural gas (MMcf)	44,668	*	*
Oil (MBbls)	477	*	*
NGL (MBbls)	1,349	*	*
Total (MMcfe)	55,625	*	*

*Represented less than 15% of the Company's total proved reserves for the year indicated.

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, 2016, based on reserve reports prepared by independent engineers, DeGolyer and MacNaughton:

Estimated proved developed reserves:		
Natural gas (Bcf)	2,128	
Oil (MMBbls)	93	
NGL (MMBbls)	94	
Total (Bcfe)	3,254	
Estimated proved undeveloped reserves:		
Natural gas (Bcf)	172	
Oil (MMBbls)	6	
NGL (MMBbls)	10	
Total (Bcfe)	266	
Estimated total proved reserves:		
Natural gas (Bcf)	2,300	
Oil (MMBbls)	99	
NGL (MMBbls)	104	
Total (Bcfe)	3,520	
Proved developed reserves as a percentage of total proved reserves	92	%
Standardized measure of discounted future net cash flows (in millions) (1)	$1,929	

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Representative NYMEX prices: [2]	
Natural gas (MMBtu)	$2.48
Oil (Bbl)	$42.64

[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, 2016, the Company's PUDs increased to 266 Bcfe from zero at December 31, 2015. As a result of the uncertainty regarding the Company's future commitment to capital, the Company reclassified all of its PUDs to unproved at December 31, 2015. Based on the December 31, 2016 reserve reports, the amounts of capital expenditures estimated to be incurred in 2017, 2018 and 2019 to develop the Company's PUDs are approximately $65 million, $60 million and $38 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 266 Bcfe of PUDs at December 31, 2016, 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 Corporate Reserves Manager, who has Master of Petroleum Engineering and Master of Business Administration degrees and more than 30 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.

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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 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, 2016, no individual customer exceeded 10% of the Company’s sales of oil, natural gas and NGL. 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 and master limited partnerships in acquiring properties, contracting for drilling and other related services, and securing trained personnel. The Company is also affected by competition for drilling rigs and the availability of related equipment. In the past, the oil and natural gas industry has experienced shortages of drilling rigs, equipment, pipe and personnel, which has delayed development drilling and has caused significant price increases. The Company is unable to predict when, or if, such shortages may occur or how they would affect its drilling program.

Operating Hazards and Insurance

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

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

Title to Properties

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

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Seasonal Nature of Business

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, Company operations may be impacted by ice and snow in the winter and by electrical storms and high temperatures in the spring and summer, as well as by wild fires in the fall.

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

Environmental Matters and Regulation

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

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

These laws, rules and regulations may also restrict the production rate of oil, natural gas and NGL below the rate that would otherwise be possible. The regulatory burden on the industry increases the cost of doing business and consequently affects profitability. Additionally, Congress and federal and state agencies frequently revise environmental laws and regulations, and any changes that result in more stringent and costly waste handling, disposal and cleanup requirements for the oil and natural gas industry could have a significant impact on 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 ("CAA"), and its amendments, 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 ("NEPA"), which governs 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; and
- U.S. Department of Interior regulations, which impose liability for pollution cleanup and damages.

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Various states regulate the drilling for, and the production, gathering and sale of, oil, natural gas and NGL, including imposing production taxes and requirements for obtaining drilling permits. States also regulate the method of developing new fields, the spacing and operation of wells and the prevention of waste of resources. States may regulate rates of production and may establish maximum daily production allowables from wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulations, but there can be no assurance that they will not do so in the future. The effect of these regulations may be to limit the amounts of oil, natural gas and NGL that may be produced from the Company's wells and to limit the number of wells or locations it can drill. The oil and natural gas industry is also subject to compliance with various other federal, state and local regulations and laws. Some of those laws relate to occupational safety, resource conservation and equal opportunity employment.

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

Climate Change

In December 2009, the 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 began adopting and implementing regulations to restrict emissions of GHGs under existing provisions of the CAA. The EPA has adopted three sets of rules regulating GHG emissions under the CAA, one that requires a reduction in emissions of GHGs from motor vehicles, a second that regulates emissions of GHGs from certain large stationary sources under the CAA's Prevention of Significant Deterioration and Title V permitting programs, and a third that regulates GHG emissions from fossil fuel-burning power plants. In September 2015, the EPA published a proposed rule that would update and expand the New Source Performance Standards ("NSPS") by setting additional emissions limits for volatile organic compounds and regulating methane emissions from new and modified sources in the oil and gas industry. In May 2016, the EPA finalized rules that establish 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. 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. In addition, in 2015, the U.S. participated in the United Nations Conference on Climate Change, which led to the creation of the Paris Agreement. The Paris Agreement requires countries to review and "represent a progression" in their intended nationally determined contributions, which set GHG emission reduction goals, every five years beginning in 2020. Legislation has from time to time been introduced in Congress that would establish measures restricting GHG emissions in the U.S. At the state level, almost one half of the states, including California, have begun taking actions to control and/or reduce emissions of GHGs. See "California GHG Regulations" below for additional details on current GHG regulations in the state of California. Some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events. If any such effects were to occur, they could 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.

California GHG Regulations

In October 2006, California adopted the Global Warming Solutions Act of 2006 ("Assembly Bill 32"), which established a statewide "cap and trade" program with an enforceable compliance obligation beginning with 2013 GHG emissions. The program is designed to reduce the state's GHG emissions to 1990 levels by 2020. Assembly Bill 32 sets maximum limits or caps on total emissions of GHGs from industrial sectors of which the Company is a part, as its California operations emit GHGs. The cap will decline annually through 2020. The Company is required to remit compliance instruments for each metric ton of GHG that it emits, in the form of allowances (each the equivalent of one ton of carbon dioxide) or qualifying offset credits. The availability of allowances will decline over time in accordance with the declining cap, and the cost to acquire such allowances may increase over time. Under Assembly Bill 32, the Company will be granted a certain number of

California carbon allowances ("CCA") and the Company will need to purchase CCAs and/or offset credits to cover the remaining amount of its emissions. Compliance with Assembly Bill 32 could significantly increase the Company's capital, compliance and operating costs and could also reduce demand for the oil and natural gas the Company produces. The cost to acquire compliance instruments will depend on the market price for such instruments at the time they are purchased, the distribution of cost-free allowances among various industry sectors by the California Air Resources Board and the Company's ability to limit its GHG emissions and implement cost-containment measures. The cap and trade program is currently scheduled to be in effect through 2020, although it may be continued thereafter.

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. Hydraulic fracturing operations have historically been overseen by state regulators as part of their oil and natural gas regulatory programs. However, on May 9, 2014, the EPA announced an advance notice of proposed rulemaking under the Toxic Substances Control Act, 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 would strengthen standards for well-bore integrity and management of fluids that return to the surface during and after fracturing operations on federal and Indian lands. In June 2016, a federal district judge in Wyoming, in litigation pursued by several states, industry associations and an Indian tribe struck down BLM's enforcement of the new rule; the decision was appealed by BLM and the matter remains pending before the U.S. Court of Appeals for the Tenth Circuit. In addition, 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 bills 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 Safe Drinking Water Act, the Toxic Substances Control Act and/or other regulatory mechanisms. The Interagency Working Group on Unconventional Natural Gas and Oil was created by Executive Order on April 13, 2012, and is charged with coordinating and aligning federal agency research and scientific studies on unconventional natural gas and oil resources. In December 2016, the EPA released its final report on a wide ranging study on the effects of hydraulic fracturing resources. While no widespread impacts from hydraulic fracturing were found, the EPA identified a number of activities and factors that may have increased risk for future impacts. 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 we operate 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 (including, most recently, new regulations in California requiring a permit to conduct well stimulation), bans, and/or recognition of local government authority to implement such restrictions. In many instances, litigation has ensued, some of which remains pending. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for the Company to perform fracturing to stimulate production from tight formations. In addition, any such 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 the Company's revenues, results of operations and net cash provided by operating activities.

The Company uses a significant amount of water in its hydraulic fracturing operations. 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.

Finally, 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 in certain wells identified as possible sources of seismic activity. Such concerns also have resulted in stricter regulatory requirements in some

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jurisdictions relating to the location and operation of underground injection wells. Future orders or regulations addressing concerns about seismic activity from well injection could affect the Company, either directly or indirectly, depending on the wells affected.

Solid and Hazardous Waste

Although oil and natural gas wastes generally are exempt from regulation as hazardous wastes under the federal Resource Conservation and Recovery Act ("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 the 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 May 2016, several environmental groups filed a lawsuit in the U.S. District Court for the District of Columbia that seeks to compel the EPA to review and, if necessary, revise its regulations regarding existing exemptions for exploration and production related wastes. 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 the RCRA or other applicable statutes, and therefore be subject to more rigorous and costly operating and disposal requirements.

Endangered Species Act

The federal Endangered Species Act ("ESA") restricts activities that may affect endangered and threatened species or their habitats. Some of the Company's operations may be located in areas that are designated as habitats for endangered or threatened species. 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 its six-year effort to make listing decisions and critical habitat designations where necessary for over 250 species before the end of the agency's 2017 fiscal year, 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 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

In August 2012, the EPA issued final rules that subject oil and natural gas production, processing, transmission and storage operations to regulation under the NSPS and National Emission Standards for Hazardous Air Pollutants ("NESHAP") programs. The EPA rules include NSPS standards for completions of hydraulically fractured natural gas wells. These standards require operators to capture the gas from natural gas well completions and make it available for use or sale, which can be done through the use of green completions. The standards are applicable to newly fractured wells and existing wells that are refractured. Further, the finalized regulations also establish specific new requirements for emissions from compressors, controllers, dehydrators, storage tanks, gas processing plants and certain other equipment. The EPA amended these rules in December 2014 to specify requirements for different flowback stages and to expand the rules to cover more storage vessels, among other changes. These rules may require changes to the Company's operations, including the installation of new equipment to control emissions.

The Company's costs for environmental compliance may increase in the future based on new environmental regulations. In November 2016, the BLM issued final rules to reduce methane emissions from venting, flaring, and leaks during oil and gas operations on public lands. Several states are pursuing similar measures to regulate emissions of methane from new and existing sources within the oil and natural gas source category. In addition, in May 2016, the EPA finalized rules regarding criteria for aggregating multiple small surface sites into a single source for air-quality permitting purposes applicable to the oil and gas industry. This rule could cause small facilities, on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting requirements. The EPA has also adopted new rules under the CAA that require the reduction of volatile organic compound emissions from certain fractured and refractured natural gas wells for which well completion operations are conducted and further require that most wells use reduced emission completions, also known as “green completions.” These regulations also establish specific new requirements regarding emissions from production-

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related wet seal and reciprocating compressors, and from pneumatic controllers and storage vessels. 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 U.S., a term broadly defined to include, among other things, certain wetlands. Under the CWA, permits must be obtained for the discharge of pollutants into waters of the U.S. The CWA provides for administrative, civil and criminal penalties for unauthorized discharges, both routine and accidental, of pollutants and of oil and hazardous substances. It imposes substantial potential liability for the costs of removal or remediation associated with discharges of oil or hazardous substances. State laws governing discharges to water also provide varying civil, criminal and administrative penalties and impose liabilities in the case of a discharge of petroleum or its derivatives, or other hazardous substances, into state waters. In addition, the EPA has promulgated regulations that may require permits to discharge storm water runoff, including discharges associated with construction activities. The CWA also prohibits the discharge of fill materials to regulated waters including wetlands without a permit. In addition, the EPA and the Army Corps of Engineers ("Corps") released a rule to revise the definition of "waters of the United States" ("WOTUS") for all CWA programs, which went into effect in August 2015. In October 2015, the U.S. Court of Appeals for the Sixth Circuit stayed the WOTUS rule nationwide pending further action of the court. In response to this decision, the EPA and the Corps resumed nationwide use of the agencies' prior regulations defining the term "waters of the United States." Those regulations will be implemented as they were prior to the effective date of the new WOTUS rule. The WOTUS rule could significantly expand federal control of land and water resources across the U.S., triggering substantial additional permitting and regulatory requirements.

Also, in August 2016, the EPA finalized new wastewater pretreatment standards that prohibit onshore unconventional oil and natural gas extraction facilities from sending wastewater to publicly-owned treatment works, permitting several years until compliance will be enforced. This pending restriction of disposal options for hydraulic fracturing waste and other changes to CWA requirements may result in increased costs.

Natural Gas Sales and Transportation

Section 1(b) of the Natural Gas Act ("NGA") exempts natural gas gathering facilities from regulation by the Federal Energy Regulatory Commission ("FERC") as a natural gas company under the NGA. 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, but the status of these lines has never been challenged before FERC. The distinction between FERC-regulated transmission services and federally unregulated gathering services is subject to change based on future determinations by FERC, the courts, or Congress, and application of existing FERC policies to individual factual circumstances. Accordingly, the classification and regulation of some of the Company's natural gas gathering facilities may be subject to challenge before FERC or subject to change based on future determinations by FERC, the courts, or Congress. In the event the Company's gathering facilities are reclassified to FERC-regulated transmission services, it may be required to charge lower rates and its revenues could thereby be reduced.

FERC requires certain participants in the natural gas market, including natural gas gatherers and marketers which engage in a minimum level of natural gas sales or purchases, to submit annual reports regarding those transactions to FERC. Should the Company fail to comply with this requirement or any other applicable FERC-administered statute, rule, regulation or order, it could be subject to substantial penalties and fines.

Pipeline Safety Regulations

The U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration ("PHMSA") regulates safety of oil and natural gas pipelines, including, with some specific exceptions, oil and natural gas gathering lines. From time to time, PHMSA, the courts, or Congress may make determinations that affect PHMSA's regulations or their applicability to the Company's pipelines. These determinations may affect the costs the Company incurs in complying with applicable safety regulations.

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Item 1. Business - Continued

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. Failure to comply with OSHA requirements can lead to the imposition of penalties. In December 2015, the U.S. Departments of Justice and Labor announced a plan to more frequently and effectively prosecute worker health and safety violations, including enhanced penalties.

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, 2016, 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 2017 or that will otherwise have a material impact on its financial position, results of operations or cash flows.

Employees

As of December 31, 2016, the Company employed approximately 1,500 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, Houston, Texas 77002. The main telephone number is (281) 840-4000.

Available Information

The Company’s internet website is www.linnenergy.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 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 these reports at www.sec.gov. Any materials that the Company files with the SEC may be read or copied at the SEC’s Public Reference Room at 100 F Street, NE, Washington, DC 20549. Information concerning the operation of the Public Reference Room may be obtained by calling the SEC at (800) 732-0330.

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 strategy;
- financial strategy;
- new capital structure and the future adoption of fresh start accounting;
- uncertainty of the Company’s ability to improve its financial results and profitability following emergence from bankruptcy and other risks and uncertainties related to the Company’s emergence from bankruptcy;
- inability to maintain relationships with suppliers, customers, employees and other third parties following emergence from bankruptcy;

- failure to satisfy the Company's short- or long-term liquidity needs, including its inability to generate sufficient cash flow from operations or to obtain adequate financing to fund its capital expenditures and meet working capital needs following emergence from bankruptcy;
- large or multiple customer defaults on contractual obligations, including defaults resulting from actual or potential insolvencies;
- ability to comply with covenants under the Exit Facility;
- effects of legal proceedings;
- drilling locations;
- oil, natural gas and NGL reserves;
- realized oil, natural gas and NGL prices;
- production volumes;
- capital expenditures;
- economic and competitive advantages;
- credit and capital market conditions;
- regulatory changes;
- lease operating expenses, general and administrative expenses and development costs;
- future operating results, including results of acquired properties;
- plans, objectives, expectations and intentions; and
- taxes.

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

Risks Related to Emergence from Bankruptcy

We recently emerged from bankruptcy, which could adversely affect our business and relationships.

It is possible that our having filed for bankruptcy and our recent emergence from the bankruptcy could adversely affect our business and relationships with customers, vendors, royalty and working interest owners, employees, service providers and suppliers. Due to uncertainties, many risks exist, including the following:

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vendors or other contract counterparties could terminate their relationship or require financial assurances or enhanced performance;

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Item 1A. Risk Factors - Continued

- the ability to renew existing contracts and compete for new business may be adversely affected;
- the ability to attract, motivate and/or retain key executives and employees may be adversely affected;
- employees may be distracted from performance of their duties or more easily attracted to other employment opportunities; and
- competitors may take business away from us, and our ability to attract and retain customers may be negatively impacted.

The occurrence of one or more of these events could adversely affect our business, operations, financial condition and reputation. We cannot assure you that having been subject to bankruptcy protection will not adversely affect our operations in the future.

Our actual financial results after emergence from bankruptcy may not reflect historical trends.

In connection with the disclosure statement we filed with the Bankruptcy Court, and the hearing to consider confirmation of the LINN Plan, we prepared projected financial information to demonstrate to the Bankruptcy Court the feasibility of the LINN Plan and our ability to continue operations upon our emergence from bankruptcy. Those projections were prepared solely for the purpose of the bankruptcy proceedings and have not been, and will not be, updated on an ongoing basis. At the time they were prepared, the projections reflected numerous assumptions concerning our anticipated future performance with respect to prevailing and anticipated market and economic conditions that were and remain beyond our control and that may not materialize. Projections are inherently subject to substantial and numerous uncertainties and to a wide variety of significant business, economic and competitive risks and the assumptions underlying the projections and/or valuation estimates may prove to be wrong in material respects. Actual results will likely vary significantly from those contemplated by the projections. As a result, investors should not rely on those projections.

In addition, upon our emergence from bankruptcy, we will adopt fresh start accounting and, as a result, our assets and liabilities will be recorded at fair value as of the fresh start reporting date, which may differ materially from the recorded values of assets and liabilities on our historical consolidated balance sheets. Our financial results after the application of fresh start accounting also may be different from historical trends. The lack of comparable historical financial information may discourage investors from purchasing our common stock.

Upon our emergence from bankruptcy, the composition of the Board of Directors changed significantly.

Pursuant to the LINN Plan, the composition of the Board of Directors changed significantly. Upon emergence, our Board of Directors will consist of seven directors, none of which, except for Mark E. Ellis, our President and Chief Executive Officer, previously served on the Board of Directors of the Predecessor. The new directors have different backgrounds, experiences and perspectives from those individuals who previously served on the Board of Directors and, thus, may have different views on the issues that will determine the future of the Company. There is no guarantee that the new Board of Directors will pursue, or will pursue in the same manner, strategic plans consistent with those of the Predecessor. As a result, the future strategy and plans of the Company may differ materially from those of the past. The ability of the new directors to quickly expand their knowledge of our business plans, operations and strategies in a timely manner will be critical to their ability to make informed decisions about Company strategy and operations. If our Board of Directors is not sufficiently informed to make such decisions, our ability to compete effectively and profitably could be adversely affected.

The ability to attract and retain key personnel is critical to the success of our business and may be affected by our emergence from bankruptcy.

The success of our business depends on key personnel. The ability to attract and retain these key personnel may be difficult in light of our emergence from bankruptcy, the uncertainties currently facing the business and changes we may make to the organizational structure to adjust to changing circumstances. We may need to enter into retention or other arrangements that could be costly to maintain. If executives, managers or other key personnel resign, retire or are terminated, or their service is otherwise interrupted, we may not be able to replace them in a timely manner and we could experience significant declines in productivity.

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Item 1A. Risk Factors - Continued

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 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; 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.

The sustained oil, natural gas and NGL price declines have resulted in significant impairments of certain of our properties. Future declines in commodity prices, changes in expected capital development, increases in operating costs or adverse changes in well performance may result in additional 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. For the year ended December 31, 2016, we recorded noncash impairment charges of approximately $165 million. 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 additional 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.

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We may not be able to obtain funding under the Exit Facility because of a decrease in our borrowing base, or obtain new financing, which could adversely affect our operations and financial condition.
Historically, the Predecessor relied on borrowings under the Sixth Amended and Restated Credit Agreement (the "LINN Credit Facility") to meet a portion of its capital needs. Pursuant to the LINN Plan, the LINN Credit Facility was paid down in part and replaced by the Credit Agreement ("Exit Facility") entered into in connection with the reorganization, which consists of a new reserve-based revolving loan with up to $1.4 billion in borrowing commitments and a new term loan in an original principal amount of $300 million. The initial borrowing base is subject to redetermination on April 1, 2018, and semiannual borrowing base redeterminations thereafter and may also be subject to certain additional redeterminations triggered by certain asset sales, casualty events, acquisitions, debt issuances and hedge terminations. Any reduction in the borrowing base will reduce our available liquidity, and, if the reduction results in the outstanding amount under the Exit Facility exceeding the borrowing base, we will be required to repay the deficiency. We may not have the financial resources in the future to make any mandatory deficiency principal prepayments required under the Exit Facility, which could result in an event of default.
In the future, we may not be able to access adequate funding under the Exit Facility 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 Exit 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.
Our Exit Facility also restricts 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 our Exit Facility 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 financial maintenance or other covenants in the Exit Facility, which could result in an event of default under the Exit Facility that, if not cured or waived, would have a material adverse effect on our business and financial condition.
Under the Exit Facility, we are required to maintain certain financial covenants including the maintenance of (i) an asset coverage ratio of at least 1.1 to 1.0, tested on (a) the date of each scheduled borrowing base redetermination commencing with the first scheduled borrowing base redetermination and (b) the date of each additional borrowing base redetermination done in conjunction with an asset sale and (ii) a maximum total net debt to last twelve months EBITDAX ratio of 6.75 to 1.0 for March 31, 2018 through December 31, 2018, 6.5 to 1.0 for March 31, 2019 through March 31, 2020, and 4.5 to 1.0 thereafter.
If we were to violate any of the covenants under the Exit 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 Exit Facility, then the lenders may exercise certain remedies including, among others, declaring all outstanding borrowings 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 Exit Facility 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 Exit Facility impose significant operating and financial restrictions on us and our subsidiaries. These restrictions limit our ability to, among other things:
- incur additional indebtedness;
- incur additional liens;
- enter into sale and lease-back transactions;

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- make certain investments;
- make certain capital expenditures;
- consolidate, merge, sell, or otherwise dispose of all or substantially all of our assets;
- pay dividends or make other distributions or repurchase or redeem our stock;
- enter into transactions with our affiliates;
- engage or enter into any new lines of business;
- enter into certain marketing activities for hydrocarbons;
- create additional subsidiaries;
- prepay, redeem, or repurchase certain of our indebtedness; and
- amend or modify certain provisions of our organizational documents.

The Exit Facility also requires us to comply with certain financial maintenance covenants as discussed above. A breach of any of these covenants could result in a default under our Exit Facility. If a default occurs and remains uncured or unwaived, the administrative agent or majority lenders under the Exit Facility may elect to declare all borrowings outstanding thereunder, together with accrued interest and other fees, to be immediately due and payable. The administrative agent or majority lenders under the Exit Facility 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 administrative agent will also have the right to proceed against the collateral pledged to it to secure the indebtedness under the Exit 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 Exit Facility. The restrictions contained in the Exit Facility 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.

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 and natural gas, we have entered into commodity derivative contracts for a portion of our production. 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 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 for 2017, 2018 and 2019, our anticipated production 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 would be adversely affected.

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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 our Exit 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.

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Item 1A. Risk Factors - Continued

Our development 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.
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. 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; and
- our ability to acquire, locate and produce new reserves.

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;
- blowouts, craterings and explosions; and
- uncontrollable flows of oil, natural gas and NGL or well fluids.

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

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, 2016, nonoperated wells represented approximately 42% of our owned gross wells, or approximately 18% of our owned net wells. We have limited ability to influence or control the operation or future development of these nonoperated 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 depends on gathering and transportation facilities. Any limitation in the availability of those facilities would interfere with our ability to market the oil, natural gas and NGL we produce, which could adversely affect our business, results of operations and cash flows.

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.

Regulatory Risks

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

The operations of our wells, gathering systems, turbines, pipelines and other facilities are subject to stringent and complex federal, state and local environmental laws and regulations. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of orders enjoining future operations. There is an inherent risk that we may incur environmental costs and liabilities due to the nature of our business, the substances we handle and the ownership or operation of our properties. Certain environmental statutes, including the RCRA, CERCLA and analogous state laws and regulations, impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances have been disposed of or otherwise released. In addition, an accidental release from one of our wells or gathering pipelines could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage and fines or penalties for related violations of environmental laws or regulations. Moreover, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase our compliance costs and the cost of any remediation that may become necessary, and these costs may not be recoverable from insurance. For a more detailed discussion of environmental and regulatory matters impacting our business, see Item 1. "Business – Environmental Matters and Regulation."

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Item 1A. Risk Factors - Continued

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

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

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

We could also be affected by more stringent laws and regulations adopted in the future, including any related to climate change, engine emissions, greenhouse gases and hydraulic fracturing. Changes in environmental laws and regulations occur frequently, and any changes that result in delays or restrictions in permitting or development of projects or more stringent or costly construction, drilling, water management, or completion activities or waste handling, storage, transport, remediation or disposal, emission or discharge requirements could require significant expenditures by us or other operators of the properties to attain and maintain compliance and may otherwise have a material adverse effect on our results of operations or financial condition. Increased scrutiny of the oil and natural gas industry may occur as a result of the EPA’s FY2017 2019 National Enforcement Initiatives, through which the EPA will purportedly address incidences of noncompliance from natural gas extraction and production activities that may cause or contribute to significant harm to public health and/or the environment.

Legislation and regulation of hydraulic fracturing, including with respect to seismic activity allegedly related to hydraulic fracturing, could adversely affect our business.

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. For a description of the laws and regulations that affect us, including our hydraulic fracturing operations, see Item 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.

We use a significant amount of water in our hydraulic fracturing operations. 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.

Finally, 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 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. Future orders or regulations addressing concerns about seismic activity from well injection could affect us, either directly or indirectly, depending on the wells affected.

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Item 1A. Risk Factors - Continued

Legislation and regulation of greenhouse gases could adversely affect our business.
In December 2009, the 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 began adopting and implementing regulations to restrict emissions of GHGs under existing provisions of the Clean Air Act ("CAA"). The EPA has adopted three sets of rules regulating GHG emissions under the CAA, one that requires a reduction in emissions of GHGs from motor vehicles, a second that regulates emissions of GHGs from certain large stationary sources under the CAA's Prevention of Significant Deterioration and Title V permitting programs, and a third that regulates GHG emissions from fossil fuel-burning power plants. In September 2015, the EPA published a proposed rule that would update and expand the New Source Performance Standards by setting additional emissions limits for volatile organic compounds and regulating methane emissions from new and modified sources in the oil and gas industry. In May 2016, the EPA finalized rules that establish 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. 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. In addition, in 2015, the U.S. participated in the United Nations Conference on Climate Change, which led to the creation of the Paris Agreement. The Paris Agreement requires countries to review and "represent a progression" in their intended nationally determined contributions, which set GHG emission reduction goals, every five years beginning in 2020. Legislation has from time to time been introduced in Congress that would establish measures restricting GHG emissions in the U.S. At the state level, almost one half of the states, including California, have begun taking actions to control and/or reduce emissions of GHGs. For a description of the California "cap and trade" program, see Item 1. "Business – Environmental Matters and Regulation." 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.
Uncertainty regarding derivatives legislation could have an adverse impact on our ability to hedge risks associated with our business.
Title VII of the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"), enacted in 2010, expands federal oversight and regulation of the derivatives markets and entities, such as us, that participate in those markets. Those markets involve derivative transactions, which include certain instruments, such as interest rate swaps, forward contracts, option contracts, financial contracts and other contracts, used in our risk management activities. The Dodd-Frank Act requires that most swaps ultimately will be cleared through a registered clearing facility and that they be traded on a designated exchange or swap execution facility, with certain exceptions for entities that use swaps to hedge or mitigate commercial risk. The Dodd-Frank Act requirements relating to derivative transactions have not been fully implemented by the SEC and the Commodities Futures Trading Commission and the current presidential administration has indicated a desire to repeal and/or replace certain provisions of the Dodd-Frank Act. Uncertainty regarding the current law and any new regulations could increase the operational and transactional cost of derivatives contracts and affect the number and/or creditworthiness of available counterparties. 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.
Stockholder Risks
There is currently no established public trading market for shares of our Class A common stock and such shares of Class A common stock may never be publicly traded. Accordingly, the holders of our Class A common stock may have no ability to sell their shares.

Upon our emergence from bankruptcy, all units representing limited liability company interests of the Predecessor were canceled and the Reorganized LINN issued shares of Class A common stock. Our Class A common stock is not currently listed on any national or regional securities exchange or quoted on any over-the-counter market. There can be no assurance that a market for our Class A common stock will be established or that, if established, a market will be sustained. Therefore, holders of our Class A common stock may be unable to sell their shares.

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The market price of our Class A common stock could be subject to wide fluctuations in response to, and the level of trading that develops for our Class A common stock may be affected by numerous factors, many of which are beyond our control. These factors include, among other things, our new capital structure as a result of the transactions contemplated by the LINN Plan, our limited trading history subsequent to our emergence from bankruptcy, our limited trading volume, the concentration of holdings of our Class A common stock, the lack of comparable historical financial information, in certain material respects, given the adoption of fresh start accounting, actual or anticipated variations in our operating results and cash flows, the nature and content of our earnings releases, announcements or events that impact our assets, customers, competitors or markets, business conditions in our markets and the general state of the securities markets and the market for energy-related stocks, as well as general economic and market conditions and other factors that may affect our future results, including those described in this Annual Report on Form 10 K. No assurance can be given that an active market will develop for our Class A common stock or as to the liquidity of the trading market for our Class A common stock. Our Class A common stock may be traded only infrequently in transactions arranged through brokers or otherwise, and reliable market quotations may not be available. Holders of our Class A common stock may experience difficulty in reselling, or an inability to sell, their shares. In addition, if an active trading market does not develop or is not maintained, significant sales of our Class A common stock, or the expectation of these sales, could materially and adversely affect the market price of our Class A 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 Fir Tree Inc., York Capital Management Global Advisors, LLC and Elliott Management Corporation collectively owned approximately 49% of our outstanding Class A common stock as of March 13, 2017. Circumstances may arise in which these stockholders may have an interest in pursuing or preventing acquisitions, divestitures or other transactions, including the issuance of additional shares or debt, that, in their judgment, could enhance their investment in the Company. Such transactions might adversely affect us or other holders of our Class A common stock. In addition, our significant concentration of share ownership may adversely affect the trading price of our Class A common stock because investors may perceive disadvantages in owning shares in companies with significant stockholders.

The issuance of share-based awards may dilute your holding of shares of Class A common stock.

Pursuant to the LINN Plan, we issued 91,708,500 shares of Class A common stock in the Reorganized LINN. A total of 6,444,381 shares of Class A common stock of the Reorganized LINN were reserved for issuance (of which 2,478,608 shares were issued as of the Effective Date) under the 2017 Omnibus Incentive Plan ("2017 Incentive Plan") as equity-based awards to employees, directors and certain other persons. The exercise of equity awards, including any stock options that we may grant in the future, and warrants, and the sale of shares of our common stock underlying any such stock options could have an adverse effect on the market for our common stock, including the price that investors could obtain for their shares. Investors may experience dilution in the value of their investment upon the exercise of any stock options that may be granted or issued pursuant to the 2017 Incentive Plan in the future.

We do not expect to pay dividends in the near future.

We do not anticipate that cash dividends or other distributions will be paid with respect to our Class A common stock in the foreseeable future. In addition, restrictive covenants in certain debt instruments to which we are, or may be, a party, may limit our ability to pay dividends or for us to receive dividends from our operating companies, any of which may negatively impact the trading price of our Class A common stock.

Certain provisions of our Certificate of Incorporation and our Bylaws may make it difficult for stockholders to change the composition of our Board of Directors and may discourage, delay or prevent a merger or acquisition that some stockholders may consider beneficial.

Certain provisions of our Certificate of Incorporation and our Bylaws may have the effect of delaying or preventing changes in control if our Board of Directors determines that such changes in control are not in the best interests of the Company and our stockholders. The provisions in our Certificate of Incorporation and Bylaws include, among other things, those that:

- authorize our Board of Directors to issue preferred stock and to determine the price and other terms, including preferences and voting rights, of those shares without stockholder approval;
- establish advance notice procedures for nominating directors or presenting matters at stockholder meetings; and

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- limit the persons who may call special meetings of stockholders.

These provisions could enable the Board of Directors to delay or prevent a transaction that some, or a majority, of the 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.

We are a "smaller reporting company" and, as such, are allowed to provide less disclosure than larger public companies.

We are currently a "smaller reporting company," as defined by Rule 12b-2 of the Securities Exchange Act of 1934. As a "smaller reporting company," we have certain decreased disclosure obligations in our SEC filings, which may make it harder for investors to analyze our results of operations and financial prospects and may result in less investor confidence.

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 Exit Facility are secured by mortgages on substantially all of the Company's oil and natural gas properties. See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" for additional details about the Exit Facility.

Offices

The Company's principal corporate office is located at 600 Travis, Houston, Texas 77002. The Company maintains additional offices in California, Illinois, Kansas, Louisiana, Michigan, New Mexico, Oklahoma, Texas, Utah and Wyoming.

Item 3. Legal Proceedings

On May 11, 2016, the Debtors filed Bankruptcy Petitions for relief under Chapter 11 of the Bankruptcy Code in the Bankruptcy Court. The Debtors' Chapter 11 cases are being administered jointly under the caption In re Linn Energy, LLC., et al., Case No. 16 60040. On January 27, 2017, the Bankruptcy Court entered the Confirmation Order. Consummation of the LINN Plan was subject to certain conditions set forth in the LINN Plan. On the Effective Date, all of the conditions were satisfied or waived and the LINN Plan became effective and was implemented in accordance with its terms. The LINN Debtors Chapter 11 cases will remain pending until the final resolution of all outstanding claims.

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. For certain statewide class action royalty payment disputes, the Company filed notices advising that it had filed for bankruptcy protection and seeking a stay, which was granted. 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.

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

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Part II

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

From May 24, 2016 through February 28, 2017, the Predecessor’s units were listed on the OTC Markets Group Inc.’s Pink marketplace (“OTC”) under the trading symbol “LINEQ.” Prior to May 24, 2016, the Predecessor’s units were listed on the NASDAQ Global Select Market (“NASDAQ”).

In connection with the Company’s reorganization and emergence from bankruptcy, on the Effective Date, all units in the Predecessor outstanding prior to the emergence were canceled and ceased to be listed on the OTC Markets Group Inc.’s Pink marketplace. Simultaneous with the cancellation of the units, the Successor authorized for issuance 270,000,000 shares of Class A common stock and 30,000,000 shares of preferred stock, par value $0.001 per share, and issued 91,708,500 shares of Class A common stock primarily to holders of certain classes of claims in the Chapter 11 cases.

There is currently no established public trading market for the shares of Class A common stock and there has not been an established public trading market for the shares of Class A common stock since the Company emerged from bankruptcy on February 28, 2017. At the close of business on March 15, 2017, there were approximately two stockholders of record.

The following table sets forth the range of high and low last reported sales prices per unit of the Predecessor, as reported by the OTC or NASDAQ, for the quarters indicated. In addition, distributions declared during each quarter are presented.

Quarter	Unit Price Range High	Unit Price Range Low	Cash Distributions Declared Per Unit
2016:			
October 1 – December 31	$0.34	$0.05	$ —
July 1 – September 30	$0.10	$0.05	$ —
April 1 – June 30	$0.48	$0.08	$ —
January 1 – March 31	$1.95	$0.33	$ —
2015:			
October 1 – December 31	$3.41	$1.12	$ —
July 1 – September 30	$9.16	$2.11	$ 0.313
April 1 – June 30	$13.94	$8.91	$ 0.313
January 1 – March 31	$14.25	$9.22	$ 0.313

Distributions

Under the Predecessor’s limited liability company agreement, unitholders were entitled to receive a distribution of available cash, which included cash on hand plus borrowings less any reserves established by the Predecessor’s Board of Directors to provide for the proper conduct of the Predecessor’s business (including reserves for future capital expenditures, including drilling, acquisitions and anticipated future credit needs) or to fund distributions, if any, over the next four quarters. In October 2015, the Predecessor’s Board of Directors determined to suspend payment of the Predecessor’s distribution. The Successor currently has no intention of paying cash dividends and any future payment of cash dividends would be subject to the restrictions in the Exit Facility.

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.

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

Sales of Unregistered Securities

None

Issuer Purchases of Equity Securities

None

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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 rapid growth through acquisitions and development of properties, 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 results of operations of Berry are reported as discontinued operations for all periods presented (see Note 3).

	At or for the Year Ended December 31,				
	2016	2015	2014	2013	2012
	(in thousands, except per unit amounts)				
Statement of operations data:					
Oil, natural gas and natural gas liquids sales	$952,132	$1,151,240	$2,312,137	$2,022,916	$1,601,180
Gains (losses) on oil and natural gas derivatives	(164,330)	1,027,014	1,127,395	182,906	124,762
Depreciation, depletion and amortization	404,237	554,386	771,549	818,466	606,150
Interest expense, net of amounts capitalized	192,862	460,635	499,890	417,174	379,937
Loss from continuing operations	(385,697)	(3,744,634)	(474,405)	(671,364)	(386,616)
Income (loss) from discontinued operations	(1,786,159)	(1,015,177)	22,596	(19,973)	—
Net loss	(2,171,856)	(4,759,811)	(451,809)	(691,337)	(386,616)
Loss per unit – continuing operations:					
Basic	(1.10)	(10.91)	(1.47)	(2.86)	(1.92)
Diluted	(1.10)	(10.91)	(1.47)	(2.86)	(1.92)
Income (loss) per unit – discontinued operations:					
Basic	(5.06)	(2.96)	0.07	(0.08)	—
Diluted	(5.06)	(2.96)	0.07	(0.08)	—
Net loss per unit:					
Basic	(6.16)	(13.87)	(1.40)	(2.94)	(1.92)
Diluted	(6.16)	(13.87)	(1.40)	(2.94)	(1.92)
Distributions declared per unit	$—	$0.938	$2.90	$2.90	$2.87
Weighted average units outstanding	352,653	343,323	328,918	237,544	203,775
Cash flow data:					
Net cash provided by (used in):					
Operating activities [(1)]	$880,514	$1,249,457	$1,711,890	$1,166,212	$350,907
Investing activities	(235,840)	(310,417)	(2,021,025)	(818,317)	(3,684,829)
Financing activities	48,015	(938,681)	258,773	(296,967)	3,334,051
Balance sheet data:					
Total assets	$4,660,591	$9,936,880	$16,632,820	$16,436,499	$11,365,653
Current portion of long-term debt	1,937,729	2,841,518	—	—	—
Long-term debt, net	—	4,447,308	8,125,213	6,796,015	5,958,539
Liabilities subject to compromise	4,305,005	—	—	—	—
Unitholders’ capital (deficit)	(2,396,988)	(268,901)	4,543,605	5,891,427	4,427,180

(1) Net of payments made for commodity derivative premiums of approximately $583 million for the year ended December 31, 2012.

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Item 6. Selected Financial Data - Continued

	At or for the Year Ended December 31,				
	2016	2015	2014	2013	2012
Production data:					
Average daily production – continuing operations:					
Natural gas (MMcf/d)	511	549	492	440	349
Oil (MBbls/d)	27.5	32.4			