LINN ENERGY, LLC
Form 10-K
March 15, 2016

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, 2015

¨ 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, LLC
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	65-1177591 (I.R.S. Employer Identification No.)
600 Travis, Suite 5100 Houston, Texas (Address of principal executive offices)	77002 (Zip Code)

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

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Units Representing Limited Liability Company Interests	The NASDAQ Global Select Market

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 x No ¨

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No 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 x Accelerated filer ¨ Non-accelerated filer ¨ Smaller reporting company ¨
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 $2.0 billion on June 30, 2015, based on $8.91 per unit, the last reported sales price of the units on the NASDAQ Global Select Market on such date.
As of January 31, 2016, there were 355,241,631 units outstanding.
Documents Incorporated By Reference:
Certain information called for in Items 10, 11, 12, 13 and 14 of Part III are incorporated by reference to the registrant's definitive proxy statement for its annual meeting of unitholders, or 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.

Diatomite. A sedimentary rock composed primarily of siliceous, diatom shells.

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.

Enhanced oil recovery. A technique for increasing the amount of oil that can be extracted from a field.

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.

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Glossary of Terms - Continued

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

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Glossary of Terms - Continued

Unproved reserves. Reserves that are considered less certain to be recovered than proved reserves. Unproved reserves may be further sub-classified to denote progressively increasing uncertainty of recoverability and include probable reserves and possible reserves.
Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.
Workover. Maintenance on a producing well to restore or increase production.
Zone. A stratigraphic interval containing one or more reservoirs.

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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, LLC ("LINN Energy" or the "Company"), the intent is to refer to LINN Energy 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 is an indirect 100% wholly owned subsidiary of the Company.

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's mission is to acquire, develop and maximize cash flow from a growing portfolio of long-life oil and natural gas assets. LINN Energy is an independent oil and natural gas company that began operations in March 2003 and completed its initial public offering in January 2006. The Company's properties are located in the United States ("U.S."), in the Hugoton Basin, the Rockies, California, east Texas and north Louisiana ("TexLa"), the Mid-Continent, Michigan/Illinois, the Permian Basin and south Texas.

Proved reserves at December 31, 2015, were approximately 4,488 Bcfe, of which approximately 26% were oil, 59% were natural gas and 15% were natural gas liquids ("NGL"). All proved reserves were classified as proved developed, with a total standardized measure of discounted future net cash flows of approximately $3.0 billion. At December 31, 2015, the Company operated 19,294 or approximately 72% of its 26,808 gross productive wells and had an average proved reserve-life index of approximately 11 years, based on the December 31, 2015, reserve reports and year-end 2015 production.

Strategy

The Company is pursuing several strategies in the current low commodity price environment, as discussed below.

- Evaluate Strategic Alternatives. The Company's Board of Directors and management are in the process of evaluating strategic alternatives to help provide the Company with financial stability, but no assurance can be given as to the outcome or timing of this process. See below under "Recent Developments" for additional details.
- Live Within Cash Flow While Maximizing Liquidity and Financial Flexibility. The Company has taken the following steps to live within cash flow while maximizing liquidity and financial flexibility in the current low commodity price environment:
- In January 2015, the Company reduced its distribution to $1.25 per unit, from the previous level of $2.90 per unit, on an annualized basis. In October 2015, the Company suspended payment of its distribution;
- For 2015, the Company decreased its total capital expenditures approximately 67% compared to the amount spent in 2014. For 2016, the Company estimates its total capital expenditures will be approximately $340 million, representing a decrease of approximately 34% compared to the amount spent in 2015;
- During the year ended December 31, 2015, the Company repurchased at a discount, through privately negotiated transactions and on the open market, approximately $992 million of its outstanding senior notes, and in November 2015, the Company issued $1.0 billion in aggregate principal amount of new 12.00% senior secured second lien notes due December 2020 in exchange for approximately $2.0 billion in aggregate principal amount of certain of its outstanding senior notes (see below for additional details);

- The Company continues to implement cost reduction initiatives across its organization. During 2015, the Company took steps to reduce its lease operating expenses, general and administrative expenses, interest costs and capital costs; and
- The Company has a commodity hedge book with a fair value of approximately $1.8 billion as of December 31, 2015 (see Note 7).

As a result of these steps, the Company has reduced its spending levels with the goal of living within cash flow. For the year ended December 31, 2015, after discretionary adjustments considered by its Board of Directors, the Company had an excess of approximately $368 million of net cash provided by operating activities after funding its interest costs, total oil and natural gas development costs and its distributions to unitholders paid through September 2015 ("excess cash"). The excess cash was used primarily to reduce indebtedness.

Also, in June 2015, the Company formed strategic alliances with affiliates of private capital investor GSO Capital Partners LP ("GSO") and affiliates of private capital investor Quantum Energy Partners ("Quantum") which may give the Company access to additional capital. Funds managed by GSO have agreed to commit up to $500 million with 5-year availability to fund drilling programs while funds managed by Quantum have committed $1 billion to fund selected future oil and natural gas acquisitions. See below for additional details.

In addition, in February 2016, the Company borrowed approximately $919 million under the LINN Credit Facility, which represented the remaining undrawn amount that was available under the LINN Credit Facility, the proceeds of which were deposited in an unencumbered account with a bank that is not a lender under either the LINN or Berry Credit Facility. These funds are intended to be used for general corporate purposes. As of February 29, 2016, there was less than $1 million of available borrowing capacity under the Credit Facilities, as defined in Note 6.

- Efficiently Operate and Develop Properties. The Company has organized the operation of its properties into defined operating regions to minimize operating costs and maximize production and capital efficiency. The Company maintains a large inventory of drilling and optimization projects within each region to achieve organic growth from its capital development program. 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. The development program is focused on lower-risk, repeatable drilling opportunities to maintain and/or grow net cash provided by operating activities. Many of the Company's wells are completed in multiple producing zones with commingled production and long economic lives. In addition, the Company seeks to deliver attractive financial returns by leveraging its experienced workforce and scalable infrastructure.

Recent Developments

See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" for details about the Company's going concern uncertainty.

Process to Explore Strategic Alternatives Related to the Company's Capital Structure

In February 2016, the Company announced that it had initiated a process to explore strategic alternatives to strengthen its balance sheet and maximize the value of the Company. The Company's Board of Directors and management are in the process of evaluating strategic alternatives to help provide the Company with financial stability, but no assurance can be given as to the outcome or timing of this process. The Company has retained Lazard as its financial advisor and Kirkland & Ellis LLP as its legal advisor to assist the Board of Directors and management team with the strategic review process.

Reduction and Suspension of Distribution

In January 2015, the Company reduced its distribution to $1.25 per unit, from the previous level of $2.90 per unit, on an annualized basis. Monthly distributions were paid by the Company through September 2015. In October 2015, following the recommendation from management, the Company's Board of Directors determined to suspend payment of the Company's distribution and reserve any excess cash that would otherwise be available for distribution. The Company's Board of Directors and management believe the suspension to be in the best long-term interest of all Company stakeholders. The Company's Board of Directors will continue to evaluate the Company's ability to reinstate the distribution.

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2016 Oil and Natural Gas Capital Budget

For 2016, the Company estimates its total capital expenditures, excluding acquisitions, will be approximately $340 million, including approximately $250 million related to its oil and natural gas capital program and approximately $75 million related to its plant and pipeline capital. The 2016 budget contemplates continued low commodity prices and is under continuous review and subject to ongoing adjustments. The Company expects to fund its capital expenditures primarily from net cash provided by operating activities; however, there is uncertainty regarding the Company's liquidity as discussed in Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Alliance with GSO Capital Partners

The Company signed definitive agreements dated June 30, 2015, with GSO, the credit platform of The Blackstone Group L.P., to fund oil and natural gas development ("DrillCo"). Funds managed by GSO have agreed to commit up to $500 million with 5-year availability to fund drilling programs on locations provided by LINN Energy. Subject to adjustments depending on asset characteristics and return expectations of the selected drilling plan, GSO will fund 100% of the costs associated with new wells drilled under the DrillCo agreement and is expected to receive an 85% working interest in these wells until it achieves a 15% internal rate of return on annual groupings of wells, while LINN Energy is expected to receive a 15% carried working interest during this period. Upon reaching the internal rate of return target, GSO's interest will be reduced to 5%, while LINN Energy's interest will increase to 95%. As of December 31, 2015, no development activities had been funded under the agreement.

Alliance with Quantum Energy Partners

The Company signed definitive agreements dated June 30, 2015, with Quantum to fund selected future oil and natural gas acquisitions and the development of those acquired assets ("AcqCo"). See the Company's Current Report on Form 8-K filed on July 7, 2015, for additional details regarding these agreements.

Divestiture

On August 31, 2015, the Company, through certain of its wholly owned subsidiaries, completed the sale of its remaining position in Howard County in the Permian Basin. Cash proceeds received from the sale of these properties were approximately $276 million. The Company used the net proceeds from the sale to repay a portion of the outstanding indebtedness under the LINN Credit Facility.

Financing Activities

In November 2015, the Company entered into separate, privately-negotiated, exchange agreements ("Exchange Agreements") with certain holders of the Company's outstanding 6.50% senior notes due May 2019, 6.25% senior notes due November 2019, 8.625% senior notes due April 2020, 7.75% senior notes due February 2021 and 6.50% senior notes due September 2021 ("Exchanged Notes"). The Exchange Agreements provided that the Company issue $1.0 billion in aggregate principal amount of new 12.00% senior secured second lien notes due December 2020 in exchange for approximately $2.0 billion in aggregate principal amount of the Company's Exchanged Notes held by such holders. The indenture governing the second lien notes ("Second Lien Indenture") required the Company to deliver mortgages by February 18, 2016, subject to a 45 day grace period. The Company elected to exercise its right to the grace period and not deliver the mortgages, and as a result, the Company is currently in default under the Second Lien Indenture. See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations – Going Concern Uncertainty" for additional information.

In addition, during the year ended December 31, 2015, the Company repurchased at a discount, through privately negotiated transactions and on the open market, approximately $992 million of its outstanding senior notes.

The spring 2015 semi-annual borrowing base redeterminations of the Company's Credit Facilities were completed in May 2015, and as a result of lower commodity prices, the borrowing base under the LINN Credit Facility decreased from $4.5 billion to $4.05 billion and the borrowing base under the Berry Credit Facility decreased from $1.4 billion to $1.2 billion, including $250 million posted as restricted cash (discussed below). The fall 2015 semi-annual redeterminations were completed in October 2015 and the borrowing base under the LINN Credit Facility was reaffirmed at $4.05 billion, subject to certain conditions being met on or before January 1, 2016, and the borrowing base under the Berry Credit Facility decreased from $1.2 billion to $900 million, including the $250 million of restricted cash. In connection with the reduction in Berry’s

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borrowing base in October 2015, Berry repaid $300 million of borrowings outstanding under the Berry Credit Facility. The borrowing base under the LINN Credit Facility automatically decreased to $3.6 billion on January 1, 2016, since certain conditions were not met. Also, in October 2015, LINN Energy and Berry each entered into an amendment to its Credit Facility.

Continued low commodity prices, reductions in the Company's capital budget and the resulting reserve write-downs, along with the maturity schedule of the Company's hedges, are expected to adversely impact future redeterminations.

In connection with the reduction in Berry's borrowing base in May 2015, LINN Energy borrowed $250 million under the LINN Credit Facility and contributed it to Berry to post as restricted cash with Berry's lenders. As directed by LINN Energy, the $250 million was deposited on Berry's behalf in a security account with the administrative agent subject to a security control agreement. Berry's ability to withdraw funds from this account is subject to a concurrent reduction of the borrowing base under the Berry Credit Facility or lender's consent in connection with a redetermination of such borrowing base. The $250 million may be used to satisfy obligations under the Berry Credit Facility or, subject to restrictions in the indentures governing Berry's senior notes, may be returned to LINN Energy in the future.

See Note 6 for additional details about the Company's debt.

During the year ended December 31, 2015, the Company, under its equity distribution agreement, sold 3,621,983 units representing limited liability company interests at an average price of $12.37 per unit for net proceeds of approximately $44 million (net of approximately $448,000 in commissions). The Company used the net proceeds for general corporate purposes, including the open market repurchases of a portion of its senior notes (see Note 6). At December 31, 2015, units totaling approximately $455 million in aggregate offering price remained available to be sold under the agreement.

In May 2015, the Company sold 16,000,000 units representing limited liability company interests in an underwritten public offering at $11.79 per unit ($11.32 per unit, net of underwriting discount) for net proceeds of approximately $181 million (after underwriting discount and offering costs of approximately $8 million). The Company used the net proceeds from the sale of these units to repay a portion of the outstanding indebtedness under the LINN Credit Facility.

Commodity Derivatives

During the year ended December 31, 2015, the Company entered into commodity derivative contracts consisting of natural gas basis swaps for May 2015 through December 2017 to hedge exposure to differentials in certain producing areas and oil swaps for April 2015 through December 2015. In addition, the Company entered into natural gas basis swaps for May 2015 through December 2016 to hedge exposure to the differential in California, where it consumes natural gas in its heavy oil development operations.

During the fourth quarter of 2015, the Company canceled certain of its commodity derivative contracts, consisting of Permian basis swaps for 2016 and 2017, trade month roll swaps for 2016 and 2017, and positions representing oil swaps which could have been extended at counterparty election for 2017. The Company received net cash settlements of approximately $5 million from the cancellations.

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), North Dakota (Williston Basin) and Colorado (Piceance Basin);
- California, which includes properties located in the San Joaquin Valley and Los Angeles basins;
- TexLa, which includes properties located in east Texas and north Louisiana;
- Mid-Continent, which includes Oklahoma properties located in the Anadarko and Arkoma basins, as well as waterfloods in the Central Oklahoma Platform;
- Michigan/Illinois, which includes properties located in the Antrim Shale formation in north Michigan and oil properties in south Illinois;

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- 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 of approximately 3,200 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 operates two natural gas processing plants in southwest Kansas. The Company owns the Jayhawk natural gas processing plant with capacity of approximately 450 MMcf/d, and has a 51% operating interest in the Satanta natural gas processing plant with capacity of approximately 220 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 plants via a system of approximately 3,920 miles of pipeline and related facilities operated by the Company, of which approximately 2,065 miles of pipeline are owned by the Company.

Hugoton Basin proved reserves represented approximately 31% of total proved reserves at December 31, 2015, all of which were classified as proved developed. This region produced approximately 252 MMcfe/d or 21% of the Company's 2015 average daily production. During 2015, the Company invested approximately $9 million to develop the properties in this region. During 2016, the Company anticipates spending approximately 1% of its total oil and natural gas capital budget for development activities in the Hugoton Basin region.

Rockies

The Rockies region consists of properties located in Wyoming (Green River, Washakie and Powder River basins), northeast Utah (Uinta Basin), North Dakota (Bakken and Three Forks formations in the Williston Basin) and northwest Colorado (Piceance 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 8,000 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 5,000 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 and its properties in the Piceance Basin produce at depths ranging from 7,500 feet to 9,500 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 845 miles of pipeline and associated compression and metering facilities that connect to numerous sales outlets in the area. The Company also owns the Brundage Canyon natural gas processing plant with capacity of approximately 30 MMcf/d.

Rockies proved reserves represented approximately 22% of total proved reserves at December 31, 2015, all of which were classified as proved developed. This region produced approximately 426 MMcfe/d or 35% of the Company's 2015 average daily production. During 2015, the Company invested approximately $209 million to develop the properties in this region. During 2016, the Company anticipates spending approximately 30% of its total oil and natural gas capital budget for development activities in the Rockies region.

California

The California region consists of properties located in the Midway-Sunset, McKittrick, Poso Creek and South Belridge fields in the San Joaquin Valley Basin as well as the Brea Olinda and Placerita fields in the Los Angeles Basin. The properties in the Midway-Sunset, McKittrick, Placerita, Poso Creek and South Belridge fields produce using thermal enhanced oil

recovery methods at depths ranging from 800 feet to 2,000 feet. Thermal production in the San Joaquin Valley Basin is primarily from the Tulare, Potter, Monarch and Diatomite formations, and in the Los Angeles Basin, thermal production is from the upper and lower Kraft formations. 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 16% of total proved reserves at December 31, 2015, all of which were classified as proved developed. This region produced approximately 185 MMcfe/d or 16% of the Company's 2015 average daily production. During 2015, the Company invested approximately $138 million to develop the properties in this region. During 2016, the Company anticipates spending approximately 13% of its total oil and natural gas capital budget for development activities in the California region.

TexLa

The TexLa region consists of properties located in east Texas and north Louisiana and primarily produces natural gas from the Cotton Valley and Travis Peak formations at depths ranging from 7,000 feet to 11,500 feet. Proved reserves for these mature, low-decline producing properties represented approximately 10% of total proved reserves at December 31, 2015, all of which 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 630 miles of pipeline and associated compression and metering facilities that connect to numerous sales outlets in the area. This region produced approximately 82 MMcfe/d or 7% of the Company's 2015 average daily production. During 2015, the Company invested approximately $35 million to develop properties in this region and approximately $10 million in exploration activity. During 2016, the Company anticipates spending approximately 5% of its total oil and natural gas capital budget for development activities in the TexLa region.

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, 2015, the Company's properties in this region are primarily mature, low-decline oil and natural gas wells.

Mid-Continent proved reserves represented approximately 9% of total proved reserves at December 31, 2015, all of which were classified as proved developed. This region produced approximately 100 MMcfe/d or 8% of the Company's 2015 average daily production. During 2015, the Company invested approximately $10 million to develop the properties in this region and approximately $10 million in exploration activity. During 2016, the Company anticipates spending approximately 44% of its total oil and natural gas capital budget for development activities in the Mid-Continent 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 600 feet to 4,000 feet. Michigan/Illinois proved reserves represented approximately 7% of total proved reserves at December 31, 2015, 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 31 MMcfe/d or 3% of the Company's 2015 average daily production. During 2015, the Company invested approximately $2 million to develop properties in this region. During 2016, the Company anticipates spending approximately 1% of its total oil and natural gas capital budget for development activities in the Michigan/Illinois region.

Permian Basin

The Permian Basin is one of the largest and most prolific oil and natural gas basins in the U.S. During the second half of 2014, the Company completed divestitures of the majority of its Midland Basin properties, and in August 2015, the

Company completed an additional divestiture in this region. The Company’s properties are located in west Texas and southeast New

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Mexico and 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.

Permian Basin proved reserves represented approximately 3% of total proved reserves at December 31, 2015, all of which were classified as proved developed. This region produced approximately 80 MMcfe/d or 7% of the Company's 2015 average daily production. During 2015, the Company invested approximately $20 million to develop the properties in this region. During 2016, the Company anticipates spending approximately 2% of its total oil and natural gas capital budget for development activities in the Permian Basin 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, 2015, all of which were classified as proved developed. This region produced approximately 32 MMcfe/d or 3% of the Company's 2015 average daily production. During 2015, the Company invested approximately $7 million to develop properties in this region. During 2016, the Company anticipates spending approximately 4% of its total oil and natural gas capital budget for development activities in the South Texas region.

Drilling and Acreage

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

	Year Ended December 31,		
	2015	2014	2013
Gross wells:			
Productive	584	917	557
Dry	5	1	2
	589	918	559
Net development wells:			
Productive	302	698	304
Dry	1	1	1
	303	699	305
Net exploratory wells:			
Productive	1	—	1
Dry	1	—	—
	2	—	1

There were two lateral segments added to existing vertical wellbores during the year ended December 31, 2015. There were no lateral segments added to existing vertical wellbores during the years ended December 31, 2014, or December 31, 2013. As of December 31, 2015, the Company had 92 gross (7 net) wells in progress (53 gross and 4 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, 2015:

	Total [1]
Proved undeveloped	—
Other locations	5,631
Total drilling locations	5,631
Leasehold interests – net acres (in thousands)	3,575

[1] Does not include optimization projects.

As a result of the uncertainty regarding the Company's future commitment to capital, the Company reclassified all of its proved undeveloped reserves ("PUDs") to unproved as of December 31, 2015. See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" for details regarding the Company's going concern uncertainty. As of December 31, 2015, the Company had identified 5,631 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, 2015. 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 2,620 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]	11,949	10,662	7,345	7,000	19,294	17,662
Nonoperated [2]	4,872	1,892	2,642	307	7,514	2,199
	16,821	12,554	9,987	7,307	26,808	19,861

[1] The Company had 32 operated wells with multiple completions at December 31, 2015.

[2] The Company had 20 nonoperated wells with multiple completions at December 31, 2015.

Developed and Undeveloped Acreage

The following table sets forth information relating to leasehold acreage as of December 31, 2015:

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
	(in thousands)					
Leasehold acreage	4,608	3,212	584	363	5,192	3,575

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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:

	2016		2017		2018	
	Gross	Net	Gross	Net	Gross	Net
	(in thousands)					
Leasehold acreage	35	20	155	91	54	50

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. The Company currently has no plans to develop or extend the lease terms on the majority of the acreage related to leases that are due to expire in 2016.

Production, Price and Cost History
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 percentage-of-proceeds contracts, percentage-of-index contracts or spot price contracts. 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. Under percentage-of-index contracts, the Company receives a price for natural gas and NGL based on indexes published for the producing area. Although exact percentages vary daily, as of December 31, 2015, 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, 2015, the Company had natural gas delivery commitments under a long-term contract of approximately 15 Bcf to be delivered each year through 2018 and approximately 2 Bcf to be delivered in 2019. In addition, the Company had NGL delivery commitments under long-term contracts of approximately 5,279 MBbls and 4,180 MBbls to be delivered in 2016 and 2017, respectively, and approximately 1,000 MBbls to be delivered in each subsequent year through 2022.

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, 2015, approximately 90% of its oil production was sold under short-term contracts. As of December 31, 2015, the Company had oil delivery commitments under long-term contracts of approximately 3,400 MBbls to be delivered by June 2018.

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. In connection with the Berry acquisition, the Company assumed certain firm transportation contracts on interstate and intrastate pipelines entered into by Berry to assure the delivery of its natural gas to market. These commitments generally require a minimum monthly charge regardless of whether the contracted capacity is used or not. The Company is negatively impacted by the minimum monthly charge for the Rockies

Express, Wyoming Interstate Company and Ruby pipelines. The Company somewhat mitigates this impact through various marketing arrangements.

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The following table sets forth information about material long-term firm transportation contracts for pipeline capacity as of December 31, 2015:

Pipeline	From	To	Quantity	Term	Demand Charge per MMBtu		Remaining Contractual Obligations
			(Avg. MMBtu/d)				(in thousands)
Rockies Express Pipeline	Meeker, CO	Clarington, OH	25,000	2/2008 to 1/2018	$1.13	(1)	$21,558
Rockies Express Pipeline	Meeker, CO	Clarington, OH	10,000	6/2009 to 11/2019	1.09	(1)	15,427
Questar Pipeline	Chipeta Plant, UT	Various UT locations	6,200	2/2013 to 2/2021	0.17		1,559
Ruby Pipeline	Opal, WY	Malin, OR	37,857	8/2011 to 7/2021	0.95		73,292
Wyoming Interstate Company Pipeline	Meeker, CO	Opal, WY	37,857	8/2011 to 7/2021	0.31		23,662
Questar Pipeline	Chipeta Plant, UT	Goshen, UT	5,000	9/2003 to 10/2022	0.26		3,209
Questar Pipeline	Brundage Canyon, UT	Chipeta Plant, UT	15,640	9/2013 to 8/2023	0.17		8,274
Total							$146,981

(1) Based on weighted average cost.

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

	Year Ended December 31,		
	2015	2014	2013
Average daily production:			
Natural gas (MMcf/d)	642	572	443
Oil (MBbls/d)	62.4	72.9	33.5
NGL (MBbls/d)	28.6	33.5	29.7
Total (MMcfe/d)	1,188	1,210	822
Total production:			
Natural gas (MMcf)	234,340	208,608	161,550
Oil (MBbls)	22,782	26,606	12,239
NGL (MBbls)	10,426	12,240	10,839
Total (MMcfe)	433,586	441,684	300,015
Weighted average prices: (1)			
Natural gas (Mcf)	$2.57	$4.29	$3.62
Oil (Bbl)	$43.16	$86.28	$94.15
NGL (Bbl)	$13.45	$34.40	$30.96
Average NYMEX prices:			
Natural gas (MMBtu)	$2.66	$4.41	$3.65
Oil (Bbl)	$48.80	$93.00	$97.97
Costs per Mcfe of production:			
Lease operating expenses	$1.42	$1.82	$1.24
Transportation expenses	$0.51	$0.47	$0.43
General and administrative expenses (2)	$0.68	$0.66	$0.79
Depreciation, depletion and amortization	$1.86	$2.43	$2.76
Taxes, other than income taxes	$0.42	$0.61	$0.46

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

(2) General and administrative expenses for the years ended December 31, 2015, December 31, 2014, and December 31, 2013, include approximately $47 million, $45 million and $37 million, respectively, of noncash unit-based compensation expenses.

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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,		
	2015	2014	2013
Total production:			
Hugoton Basin Field:			
Natural gas (MMcf)	58,125	36,738	25,929
Oil (MBbls)	21	16	2
NGL (MBbls)	3,875	2,572	2,336
Total (MMcfe)	81,502	52,263	39,958
Green River Basin Field:			
Natural gas (MMcf)	*	*	42,531
Oil (MBbls)	*	*	364
NGL (MBbls)	*	*	1,124
Total (MMcfe)	*	*	51,458

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

Steaming Operations

Certain of the Company's California assets consist of heavy crude oil, which requires heat, supplied in the form of steam, injected into the oil producing formations to reduce the oil viscosity, thereby allowing the oil to flow to the wellbore for production. The Company utilizes cyclic steam and/or steam flood recovery methods on these assets. The Company's use of these oil recovery methods exposes it to certain annual greenhouse gas emissions obligations in California. The state provides for a certain number of free allowances to offset a portion of the projected emissions. The remainder of the allowances must be purchased at any of the California carbon allowance auctions held in February, May, August and November of each year or in over-the-counter transactions. The Company believes it has met its obligations for the year ended December 31, 2015.

Cogeneration Steam Supply

The Company believes one of the primary methods to keep steam costs low is through the ownership and efficient operation of three cogeneration facilities located on its properties. These cogeneration facilities include a 38 megawatt ("MW") facility and an 18 MW facility located in the Midway-Sunset Field and a 42 MW facility located in the Placerita Field. Cogeneration, also called combined heat and power, extracts energy from the exhaust of a turbine to produce steam and increases the efficiency of the combined process.

Conventional Steam Generation

The Company also owns 79 fully permitted conventional steam generators. The number of generators operated at any point in time is dependent on the steam volume required to achieve the Company's targeted production and the price of natural gas compared to the realized price of crude oil sold. Ownership of these varied steam generation facilities and sources allows for maximum operational control over the steam supply, location and, to some extent, the aggregated cost of steam generation. The Company's steam supply and flexibility are crucial for the maximization of California thermally enhanced heavy oil production, cost control and ultimate oil recovery. The natural gas the Company purchases to generate steam and electricity is primarily based on California price indexes. The Company pays distribution/transportation charges for the delivery of natural gas to its various locations where it uses the natural gas for steam generation purposes. In some cases, this transportation cost is embedded in the price of the natural gas the Company purchases.

Electricity

Generation

The total average electrical generation capacity of the Company's three cogeneration facilities, which are centrally located on certain of its oil producing properties, was approximately 90 MW for the year ended December 31, 2015. The steam

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generated by each facility is capable of being delivered to numerous wells that require steam for the enhanced oil recovery process. The sole purpose of the cogeneration facilities is to reduce the steam costs in the Company's heavy oil operations and secure operating control of the respective steam generation. Expenses of operating the cogeneration plants are analyzed regularly to determine whether they are advantageous versus conventional steam generators. Cogeneration costs are allocated between electricity generation and oil and natural gas operations based on the conversion efficiency (of fuel to electricity and steam) of each cogeneration facility and certain direct costs to produce steam. Cogeneration costs allocated to electricity will vary based on, among other factors, the thermal efficiency of the Company's cogeneration plants, the price of natural gas used for fuel in generating electricity and steam, and the terms of the Company's power contracts. The Company views any profit or loss from the generation of electricity as a decrease or increase, respectively, to its total cost of producing heavy oil in California.

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, 2015, based on reserve reports prepared by independent engineers, DeGolyer and MacNaughton:

Estimated proved developed reserves:		
Natural gas (Bcf)	2,619	
Oil (MMBbls)	197	
NGL (MMBbls)	114	
Total (Bcfe)	4,488	
Estimated proved undeveloped reserves:		
Natural gas (Bcf)	—	
Oil (MMBbls)	—	
NGL (MMBbls)	—	
Total (Bcfe)	—	
Estimated total proved reserves:		
Natural gas (Bcf)	2,619	
Oil (MMBbls)	197	
NGL (MMBbls)	114	
Total (Bcfe)	4,488	
Proved developed reserves as a percentage of total proved reserves	100	%
Standardized measure of discounted future net cash flows (in millions) (1)	$3,034	
Representative NYMEX prices: (2)		
Natural gas (MMBtu)	$2.59	
Oil (Bbl)	$50.16	

(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, 2015, the Company's PUDs decreased to zero from 1,486 Bcfe at December 31, 2014. The decrease was due to 1,359 Bcfe of negative revisions (728 Bcfe due to lower commodity prices, 349 Bcfe due to uncertainty regarding the Company's future commitment to capital and 302 Bcfe due to the SEC five-year development limitation on PUDs, partially offset by 20 Bcfe of positive revisions due to asset performance), 105 Bcfe of PUDs developed during 2015 and 22 Bcfe related to 2015 divestitures. During the year ended December 31, 2015, the Company incurred approximately $159 million in capital expenditures to convert the 105 Bcfe of reserves that were classified as PUDs at December 31, 2014, to proved developed reserves.

As a result of the uncertainty regarding the Company's future commitment to capital, the Company reclassified all of its PUDs to unproved as of December 31, 2015. See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" for details regarding the Company's going concern uncertainty.

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.

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.

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Principal Customers

For the year ended December 31, 2015, sales of oil, natural gas and NGL to Phillips 66 accounted for approximately 12% of the Company's sales. 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 available for acquisitions, development or distributions, 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.

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.

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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 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 and plugging of abandoned 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, 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");
- Energy Independence and Security Act of 2007, which prescribes new fuel economy standards and other energy saving measures;
- National Environmental Policy Act, which governs oil and natural gas production activities on federal lands;
- Resource Conservation and Recovery Act ("RCRA"), which governs the management of solid waste;
- Safe Drinking Water Act, which governs the underground injection and disposal of wastewater; and
- U.S. Department of Interior regulations, which impose liability for pollution cleanup and damages.

Various states regulate the drilling for, and the production, gathering and sale of, oil, natural gas and NGL, including imposing production taxes and requirements for obtaining drilling permits. States also regulate the method of developing new fields, the spacing and operation of wells and the prevention of waste of resources. States may regulate rates of production and may establish maximum daily production allowables from natural gas wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic 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.

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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 has begun 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 addition, 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 for new and modified sources in the oil and gas industry. 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 will be open for signing on April 22, 2016, and will require 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.

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 Company's cost of acquiring compliance instruments in 2015 was approximately $2.00 per barrel of its California production. In the future, 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 September 2015, a federal district judge in Wyoming, in litigation pursued by several states, industry associations and an Indian tribe, granted a preliminary injunction against BLM's enforcement of the new rule; the litigation remains pending. 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. President Obama created the Interagency Working Group on Unconventional Natural Gas and Oil by Executive Order on April 13, 2012, which is charged with coordinating and aligning federal agency research and scientific studies on unconventional natural gas and oil resources. 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, both Texas and Louisiana 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. 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 the Company, either directly or indirectly, depending on the wells affected.

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. 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

On August 15, 2012, the EPA issued final rules that subject oil and natural gas production, processing, transmission and storage operations to regulation under the New Source Performance Standards ("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. For example, in September 2015, the EPA published proposed rules that would "aggregate" certain oil and gas production facilities for purposes of determining the applicability of certain CAA regulatory requirements. In January 2016, the BLM proposed rules to require additional efforts by producers to reduce venting, flaring and leaking of natural gas produced on federal and Native American lands.

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.

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, 2015, 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 2016 or that will otherwise have a material impact on its financial position, results of operations or cash flows.

Employees

As of December 31, 2015, the Company employed approximately 1,760 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 limited liability company with headquarters in Houston, Texas. The principal executive offices are located at 600 Travis, Suite 5100, Houston, Texas 77002. The main telephone number is (281) 840-4000.

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Item 1. Business - Continued

Company Website
The Company's internet website is www.linnenergy.com. The Company makes available free of charge on or through its website Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and any amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after the Company electronically files such material with, or furnishes it 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;
- effects of legal proceedings;
- ability to resume payment of distributions in the future or maintain or grow them after such resumption;
- 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
- integration of acquired businesses and operations and commencement of activities in the Company's strategic alliances with GSO and Quantum, which may take longer than anticipated, may be more costly than anticipated as a result of unexpected factors or events and may have an unanticipated adverse effect on the Company's business.

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 units 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.

If we are unable to repay or refinance our existing and future debt as it becomes due, whether at maturity or as a result of acceleration, we may be unable to continue as a going concern.

We have significant indebtedness under our May 2019 senior notes, November 2019 senior notes, April 2020 senior notes, Berry November 2020 senior notes, December 2020 senior secured second lien notes, February 2021 senior notes, September 2021 senior notes and Berry September 2022 senior notes (collectively, "Notes") and our Credit Facilities. As of February 29, 2016, we had an aggregate amount of approximately $9.3 billion outstanding under our Notes and our Credit Facilities (with additional borrowing capacity of less than $1 million). As a result of our indebtedness, we use a significant portion of our cash flow to pay interest and principal (when due) on our Notes and Credit Facilities, which reduces the cash available to finance our operations and other business activities and limits our flexibility in planning for or reacting to changes in our business and the industry in which we operate.

Based on our current estimates and expectations for commodity prices in 2016, we do not expect to remain in compliance with all of the restrictive covenants contained in our Credit Facilities throughout 2016 unless those requirements are waived or amended. Additionally, the borrowing bases under our Credit Facilities are subject to redeterminations in April 2016. Because the Credit Facilities are effectively fully drawn, any reduction in the borrowing bases would require us to make mandatory prepayments to the extent existing indebtedness exceeds the new borrowing bases. We also have substantial interest payments due during the next twelve months on our Notes and our Credit Facilities. If we fail to satisfy our obligations with respect to our indebtedness or fail to comply with the financial and other restrictive covenants contained in our Credit Facilities or the indentures governing our Notes, an Event of Default (as defined in the applicable agreements) could result, which would permit acceleration of the indebtedness under certain circumstances and could result in an Event of Default and acceleration of our other debt and permit our secured lenders to foreclose on any of our assets securing such debt. Any accelerated debt would become immediately due and payable.

While we will attempt to take appropriate mitigating actions to refinance any indebtedness prior to its maturity or otherwise extend the maturity dates, and to cure any potential defaults, there is no assurance that any particular actions with respect to refinancing existing indebtedness, extending the maturity of existing indebtedness or curing potential defaults in our existing and future debt agreements will be sufficient. The uncertainty associated with our ability to meet our obligations as they become due raises substantial doubt about our ability to continue as a going concern. The report of the Company's independent registered public accounting firm that accompanies its audited consolidated financial statements in this Annual Report on Form 10-K contains an explanatory paragraph regarding the substantial doubt about the Company's ability to continue as a going concern.

We are currently in default under the LINN Credit Facility and the Second Lien Indenture.

Under the LINN Credit Facility, we are required to deliver audited consolidated financial statements without a going concern or like qualification or explanation. Because the audit report prepared by our auditors with respect to the consolidated financial statements includes such going concern explanation, we are currently in default under the LINN Credit Facility.

If we are unable to obtain a waiver or other suitable relief from the lenders under the LINN Credit Facility prior to the expiration of the 30 day grace period, an Event of Default will result and the lenders holding a majority of the commitments under the LINN Credit Facility could accelerate the outstanding indebtedness, which would make it immediately due and payable. If we are unable to obtain a waiver from or otherwise reach an agreement with the lenders under the LINN Credit Facility and the indebtedness under the LINN Credit Facility is accelerated, then an Event of Default under LINN Energy's senior notes and second lien notes would occur, which, if it continues beyond any applicable cure periods, would, to the extent the applicable lenders so elect, result in the acceleration of those obligations. Furthermore, an Event of Default under the LINN Credit Facility will also result in an Event of Default under the Berry Credit Facility, which in the absence of a waiver or other suitable relief and upon the election of the agent or lenders holding a majority of commitments under the Berry Credit Facility would result in the acceleration of indebtedness under the Berry Credit Facility. Such Event of Default would trigger an Event of Default under the Berry senior notes. If such Event of Default continues beyond any applicable cure periods, such Event of Default would result in an acceleration of the Berry senior notes. Additionally, the Second Lien Indenture required us to deliver mortgages by February 18, 2016, subject to a 45 day grace period. We elected to exercise our right to the grace period and not deliver the mortgages, and as a result, we are currently in default under the Second Lien Indenture. If we do not deliver the mortgages within the 45 day grace period or is otherwise unable to obtain a waiver or other suitable relief from the holders under the Second Lien Indenture prior to the expiration of the 45 day grace period, an Event of Default (as defined in the Second Lien Indenture) will result and if the trustee or noteholders holding at least 25% in the aggregate outstanding principal amount of the second lien notes so elect would accelerate the second lien notes causing them to be immediately due and payable.

An Event of Default under the Second Lien Indenture triggers a cross-default under the LINN Credit Facility and Berry Credit Facility and, as discussed above, if the applicable lenders so elect would result in acceleration under the LINN Credit Facility and Berry Credit Facility. In addition, as discussed above, an acceleration of the obligations under the Second Lien Indenture or LINN Credit Facility would trigger a cross-default to LINN Energy's senior notes and if the applicable lenders so elect would result in a cross-acceleration under LINN Energy's senior notes, and an acceleration of the Berry Credit Facility if the applicable lenders so elect would result in cross-acceleration under the Berry senior notes.

If lenders, and subsequently noteholders, accelerate our outstanding indebtedness, it will become immediately due and payable and we will not have sufficient liquidity to repay those amounts. We are currently in discussions with various stakeholders and are pursuing or considering a number of actions, but there can be no assurance that sufficient liquidity can be obtained from one or more of these actions or that these actions can be consummated within the period needed to meet certain obligations, and we could be required to immediately file for protection under Chapter 11 of the U.S. Bankruptcy Code.

In addition, we expect the audit report Berry will receive with respect to its financial statements to contain an explanatory paragraph expressing uncertainty as to its ability to continue as a going concern, which would constitute a default under the Berry Credit Facility. If Berry does not obtain a waiver or other suitable relief from the lenders under the Berry Credit Facility before the expiration of the 30 day grace period, there will be an Event of Default under the Berry Credit Facility. If an Event of Default occurs under the Berry Credit Facility, the lenders holding a majority of the commitments could accelerate the loans outstanding under the Berry Credit Facility, which would in turn trigger cross-acceleration rights under the LINN Credit Facility and the indentures governing the Notes.

We may seek the protection of the United States Bankruptcy Court ("Bankruptcy Court") which may harm our business and place equity holders at significant risk of losing all of their investment in us.

We have engaged financial and legal advisors to assist us in, among other things, analyzing various strategic alternatives to address our liquidity and capital structure, including strategic and refinancing alternatives through a private restructuring. However, a filing under Chapter 11 of the U.S. Bankruptcy Code ("Chapter 11") may be unavoidable. Seeking Bankruptcy Court protection could have a material adverse effect on our business, financial condition, results of operations and liquidity. As long as a Chapter 11 proceeding continues, our senior management would be required to spend a significant amount of time and effort dealing with the reorganization instead of focusing exclusively on our business operations. Bankruptcy Court protection also might make it more difficult to retain management and other key personnel necessary to the success and growth of our business. Also during the Chapter 11 proceedings, our ability to enter into new commodity derivatives covering additional estimated future production would be dependent upon either entering into unsecured hedges or obtaining Bankruptcy Court approval to enter into secured hedges. Furthermore, counterparties under our existing hedge transactions may elect to terminate those transactions in connection with a bankruptcy filing without our consent.

We have a significant amount of indebtedness that is senior to our units in our capital structure. As a result, we believe that seeking Bankruptcy Court protection under a Chapter 11 proceeding could cause our units to be canceled, result in a limited recovery for unitholders, if any, and place current equity holders at significant risk of losing all of their investment in us.

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Any reduction of the borrowing bases under our Credit Facilities will require us to repay that portion of indebtedness that exceeds the new borrowing bases under our Credit Facilities earlier than anticipated, which will adversely impact our liquidity.

As of February 29, 2016, total borrowings (including outstanding letters of credit) under the LINN Credit Facility were $3.6 billion with no remaining availability. Total borrowings under the Berry Credit Facility were approximately $899 million with less than $1 million available. Each of our Credit Facilities is subject to scheduled redeterminations of its borrowing base, semi-annually in April and October, based primarily on reserve reports using lender commodity price expectations at such time. Additionally, the lenders under the LINN Credit Facility have the ability to request an interim redetermination of the borrowing base once per calendar year and the lenders under the Berry Credit Facility have the ability to request an interim redetermination of the borrowing base once between scheduled redeterminations. Continued low commodity prices, reductions in our capital budget and the resulting reserve write-downs, along with the maturity schedule of our hedges, are expected to adversely impact future redeterminations.

Because the Credit Facilities are effectively fully drawn, any reduction in the Credit Facilities' borrowing bases will require us or Berry to make mandatory prepayments under the Credit Facilities to the extent existing indebtedness under the Credit Facilities exceeds the new borrowing bases. Although we are not required to, we may choose to contribute or otherwise provide cash to Berry or post restricted cash on Berry's behalf, which would reduce our liquidity position. We may have insufficient cash on hand to be able to make mandatory prepayments under the Credit Facilities. Any failure to repay indebtedness in excess of our borrowing bases in accordance with the terms of the Credit Facilities would constitute an Event of Default under the Credit Facilities. Such Event of Default would permit our lenders to accelerate the debt, which, if actually accelerated, would become immediately due and payable and could result in a cross-default and cross-acceleration under our other outstanding indebtedness, and could permit our secured lenders to foreclose on any of our assets securing such indebtedness.

Our ability to comply with financial covenants and ratios in our Credit Facilities and the indentures governing the Notes is affected by events beyond our control, including, among other things, continued low commodity prices. Absent a waiver or amendment, failure to meet these covenants and ratios could result in a default and potentially an acceleration of our existing indebtedness.

The Credit Facilities require us to maintain compliance with specified financial ratios and satisfy certain financial condition tests. Based on current estimates and expectations for commodity prices in 2016, we do not expect to remain in compliance with all of the financial covenants and ratios throughout 2016 unless those requirements are waived or amended. Our inability to comply with the required financial ratios will, if not amended or waived, result in a default under the Credit Facilities.

In addition, the LINN Credit Facility requires delivery of audited consolidated financial statements without a going concern or like qualification or explanation to the lenders no later than 90 days after the end of our fiscal year. Due to delivery of the audit report with such going concern explanation, we are in default under the LINN Credit Facility. While the audit opinion is as of December 31, 2015, the default under the LINN Credit Facility does not occur until we have failed to deliver an audit opinion without a going concern or like qualification or explanation, which is the filing date.

A default under the Credit Facilities, if not cured or waived, could result in an Event of Default which permits the acceleration of all indebtedness outstanding thereunder. The accelerated debt would become immediately due and payable, which would in turn trigger cross-acceleration under our other debt. In addition, if an Event of Default under the Credit Facilities occurs, the lenders could foreclose on the collateral and compel us to apply all of our available cash to repay our borrowings or they could prevent us from making payments on our Notes. If the amounts outstanding under the Credit Facilities, our Notes or any of our other indebtedness were to be accelerated, our assets may not be sufficient to repay in full the money owed to the lenders or to our other debt holders and we may be unable to borrow sufficient funds to refinance our debt. Even if new financing were available, any such financing may not be on terms that are acceptable to us and may impose financial restrictions and other covenants on us that may be more restrictive than the Credit Facilities or the indentures governing our Notes.

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

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

- make distributions to our unitholders or make other restricted payments;
- incur or guarantee additional indebtedness;
- refinance certain indebtedness;
- create or incur liens;
- engage in certain mergers or consolidations or otherwise dispose of all or substantially all of our assets;
- make certain investments or acquisitions;
- make certain sales, dispositions or transfers of assets;
- engage in specified transactions with subsidiaries and affiliates;
- repurchase, redeem or retire our units or Notes; and
- pursue other corporate activities.

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

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

We have a significant level of debt, which could have significant consequences for our business and future prospects.

As of February 29, 2016, we had an aggregate amount of approximately $9.3 billion outstanding under our Notes and our Credit Facilities (with additional borrowing capacity of less than $1 million). Our debt and the limitations imposed on us by our existing or future debt agreements could have significant consequences for our business and future prospects, including the following:

- we will be required to dedicate a significant portion of our cash flow to payments of interest and principal on our Credit Facilities and Notes when due;
- we may be limited in our flexibility to plan for or react to changes in our business and industry in which we operate;
- we may not be able to finance our operations and other business activities; and
- we may have a competitive disadvantage relative to our competitors that have less debt.

Our ability to make payments on and to refinance our indebtedness, including our Credit Facilities and Notes, and to fund planned capital expenditures will depend on our ability to generate cash flow in the future. We expect our earnings and cash flow to vary significantly from year to year due to the cyclical nature of our industry. As a result, the amount of debt that we can manage in some periods may not be appropriate for us in other periods. A range of economic, competitive, business and industry factors will affect our future financial performance, and, as a result, our ability to generate cash flow from operations and to pay our debt. Many of these factors, such as oil, natural gas and NGL prices, economic and financial conditions in our industry and the global economy, the impact of legislative or regulatory actions on how we conduct our business or competitive initiatives of our competitors, are beyond our control. Consequently, our future cash flow may be insufficient to meet our debt obligations and commitments. Any cash flow insufficiency could negatively impact our business, financial condition and results of operations. To the extent we are unable to make scheduled interest payments or repay our indebtedness as it becomes due or at maturity with cash on hand, we will need to refinance our debt, sell assets or seek additional debt or equity financing. Additional indebtedness and debt or equity financing may not be available to us in the future for the refinancing or repayment of existing indebtedness, and we may not be able to complete asset sales in a timely manner sufficient to make such repayments.

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Despite our and our subsidiaries' current level of indebtedness, we may still be able to incur more debt. This could further exacerbate the risks associated with our substantial indebtedness.

We and our subsidiaries may be able to incur additional indebtedness in the future. Although the credit agreements governing our Credit Facilities and the indentures that govern our Notes contain restrictions on the incurrence of additional indebtedness, these restrictions are subject to a number of qualifications and exceptions, and the additional indebtedness incurred in compliance with these restrictions could be substantial. Moreover, these restrictions will not prevent us from incurring obligations that do not constitute indebtedness, as defined in the applicable agreements governing our existing indebtedness.

If new debt is added to our current debt levels, the related risks that we and our subsidiaries now face could intensify. Our level of indebtedness could, for instance, prevent us from engaging in transactions that might otherwise be beneficial to us or from making desirable capital expenditures. This could put us at a competitive disadvantage relative to other less leveraged competitors that have more cash flow to devote to their operations. In addition, the incurrence of additional indebtedness could make it more difficult to satisfy our existing financial obligations.

Our debt rating has been downgraded and liquidity concerns could result in a further downgrade in our debt ratings which could restrict our access to, and negatively impact the terms of, current or future financings or trade credit.

Our ability to obtain financings and trade credit and the terms of any financings or trade credit are, in part, dependent on the credit ratings assigned to our debt by independent credit rating agencies. We cannot provide assurance that any of our current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances so warrant. Factors that may impact our credit ratings include debt levels, liquidity, asset quality, cost structure, product mix and commodity pricing levels. Further ratings downgrades could adversely impact our ability to access financings or trade credit, increase our borrowing costs and potentially require us to post letters of credit or other credit support for certain obligations.

Our substantial indebtedness, liquidity concerns and potential restructuring transactions may have a material adverse effect on our business and operations.

Our substantial indebtedness, liquidity concerns and potential restructuring transactions may result in uncertainty about our business and cause, among other things:

- our suppliers, vendors, derivatives counterparties and service providers to renegotiate the terms of our agreements, terminate their relationship with us or require financial assurances from us;
- third parties to lose confidence in our ability to produce oil, natural gas and NGL, resulting in a significant decline in our revenues, profitability and cash flow;
- difficulty retaining, attracting or replacing key employees; and
- employees to be distracted from performance of their duties or more easily attracted to other career opportunities.

These events, among others, may have a material adverse effect on our business and operations.

Failure to maintain the continued listing standards of the NASDAQ Global Select Market could result in delisting of our common units, which could negatively impact the market price and liquidity of our common units and our ability to access the capital markets.

Our common units are listed on the NASDAQ Global Select Market ("NASDAQ") and the continued listing of our common units on NASDAQ is subject to our ability to comply with NASDAQ's continued listing requirements, including, among other things, a minimum closing bid price requirement of $1.00 per common unit. If we fail to satisfy such requirement for a period of 30 consecutive business days, NASDAQ will send us a deficiency notice indicating that we have a compliance period of 180 calendar days from such notice to cure the deficiency by satisfying the minimum bid requirement for a minimum of ten consecutive business days. Failure to regain compliance with the minimum closing bid price requirement could result in delisting of our common units from NASDAQ.

To date in 2016, the bid price of our common units closed below the $1.00 per unit minimum bid price on several occasions. Any delisting from NASDAQ could have a negative impact on the market price and liquidity of our common units. In addition, delisting could harm our ability to access the capital markets and result in the potential loss of confidence by investors, increased employee turnover and fewer business development opportunities.

Disruptions in the capital and credit markets, continued low commodity prices, our debt level 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 as a result of our debt level or otherwise, refuse to refinance existing debt at maturity on favorable terms, or at all, 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, financial condition and results of operations.

Our Board of Directors has the ability to reserve any or all of our cash on hand at the end of a quarter for purposes other than distribution to unitholders, including reduction of indebtedness.

Although we may have generated sufficient net cash provided by operating activities during any particular quarter, our Board of Directors has the ability under our limited liability company agreement to establish a cash reserve, which could encompass all of the cash otherwise available for distribution, to provide for the proper conduct of our business in both the short and long term. To provide for the proper conduct of our business, the Board of Directors can determine to reserve cash to reduce indebtedness, among other things. For example, in October 2015, our Board of Directors approved a suspension of our distribution. Our decision to reserve all of our cash on hand for such allowed purposes and not distribute it may significantly impact our unitholders, as well as our business and operations. The market value of our units may remain depressed or further decrease unless and until we resume a distribution. In addition, refinancing or restructuring of our debt may require us to accept covenants that further restrict our ability to reinstate the distribution to our unitholders. External perceptions of the health of our business and our liquidity may also be impacted, which could further limit our ability to access capital markets, cause our vendors to tighten our credit terms and cause a strain in our relationship with landowners and other business partners.

Commodity prices are volatile, and prolonged depressed prices or a further decline in prices would reduce our revenues, net cash provided by operating activities and profitability 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.

During 2015, the prices of oil, natural gas and NGL were extremely volatile and declined significantly. Downward pressure on commodity prices has continued in 2016 and may continue for the foreseeable future. The speed and severity of the decline in oil prices from 2014 to 2016 has materially affected our results of operations. If commodity prices continue at current levels for a prolonged period or further decline, our net cash provided by operating activities will decline and our financial position, the quantities of oil and natural gas reserves that we can economically produce, our cash flow available for capital expenditures, our ability to service our debt obligations, our ability to generate free cash flow after capital expenditures and debt service and our ability to access funds under our Credit Facilities and through the capital markets may be materially and adversely affected.

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, 2015, we recorded noncash impairment charges (before and after tax) of approximately $5.8 billion. 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.

We may experience difficulties in fully utilizing our alliances with GSO and Quantum, which could cause us to fail to realize many of the anticipated potential benefits of those alliances.

As part of our plan to (i) create new sources of capital to allow us to acquire and develop assets without increasing capital intensity, (ii) enhance our long-term ability to live within cash flow and (iii) provide opportunities for dropdowns of stable production over time, we entered into strategic alliances with GSO Capital Partners LP (“GSO”), the credit platform of The Blackstone Group L.P., to fund oil and natural gas development (“DrillCo”) and Quantum Energy Partners (“Quantum”) to fund selected future oil and natural gas acquisitions and the development of those acquired assets through a new entity (“AcqCo”).

Achieving the anticipated benefits of DrillCo will depend in part on whether we and GSO are able to agree on a drilling plan during any of the five years of the term of DrillCo, as well as our ability to execute on that drilling plan. Achieving the anticipated benefits of AcqCo will depend in part on whether we are able to come to an agreement with Quantum and AcqCo regarding identification and acquisition of suitable assets for AcqCo, whether we are able to fund the acquisition of our required minimum working interest in such assets and ultimately whether we are able to purchase back assets from AcqCo after they have matured into conventional MLP assets. An inability to realize the full extent of the anticipated benefits of these alliances may affect our ability to accomplish the objectives identified above.

If we are unable to replace declines in production, proved developed producing reserves and cash flow, our net cash provided by operating activities could be reduced, which could adversely affect our ability to service debt or to resume payment of distributions to our unitholders.

In determining the amount of cash that we distribute to unitholders, if any, our Board of Directors establishes at the end of each year an amount of capital expenditures for the next year (which we refer to as discretionary reductions for a portion of oil and natural gas development costs) with the objective of replacing proved developed producing reserves, current production and cash flow, taking into consideration our overall commodity mix. Management evaluates all of these objectives as part of the decision-making process to determine the discretionary reductions for a portion of oil and natural gas development costs for the year, although every objective may not be met in each year. Furthermore, there may be certain years in which commodity prices and other economic conditions do not merit capital spending at a level sufficient to accomplish any of these objectives.

In determining this portion of oil and natural gas development costs (which may include estimated drilling and development costs associated with projects to convert a portion of non-producing reserves to producing status but does not include the historical cost of acquired properties as those amounts have already been spent in prior periods and were financed primarily with external sources of funding), management evaluates historical results of our drilling and development activities based on periodically revised and updated information from past years to assess the costs, adequacy and effectiveness of such activities and future assumptions regarding cost trends, production and decline rates and reserve recoveries. However, our management does not conduct an analysis to evaluate historical amounts of capital actually spent on such drilling and development activities. Our ability to pursue projects with the intent to replace proved developed producing reserves, current production and cash flow through drilling and development activities is limited to our inventory of development opportunities on our existing acreage position. Management's estimate of this discretionary portion of our oil and natural gas development costs does not include the historical acquisition cost of projects pursued during the year or the acquisition of new oil and natural gas reserves. Moreover, our assumptions regarding costs, production and decline rates and reserve recoveries may prove to be incorrect. After establishing the amount of discretionary reductions for a portion of oil and natural gas development costs, if we do not fully replace proved developed producing reserves, current production and cash flow, our net cash provided by operating activities could be reduced, which could adversely affect our ability to service debt or to resume payment of distributions to our unitholders. Furthermore, our existing reserves, inventory of drilling locations and production levels will decline over time as a result of development and production activities. Consequently, if we were to limit our total capital expenditures to this discretionary portion of our oil and natural gas development costs and not complete acquisitions of new reserves, total reserves would decrease over time, resulting in an inability to sustain production at current levels, which could also adversely affect our ability to service debt and to resume payment of distributions to our unitholders.

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 additional 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.

Although LINN Energy has hedged a significant portion of its natural gas production through 2017, its oil production is hedged to a lesser extent for 2016 and beyond, and its NGL production is completely unhedged. In addition, Berry's oil production is completed unhedged. Based on current expectations for continued low 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 additional 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.

Derivatives legislation and implementing rules 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 market and entities, such as us, that participate in that market. 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 requirements relating to derivative transactions have not been fully implemented by the SEC and the Commodities Futures Trading Commission. When fully implemented, the 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, like the U.S., 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.

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 can 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 our significant level of indebtedness, current market conditions and restrictive covenants under our debt agreements, we may be unable to finance such 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. We may not be successful in exploring for, developing or acquiring additional reserves. We also may not be successful in raising funds to acquire additional reserves.

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;

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

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

Our development operations require substantial capital expenditures, which will reduce our cash available to service debt. We may be unable to obtain needed capital or financing on satisfactory terms, which 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 to service debt or to resume payment of distributions to our unitholders. We intend to finance our future capital expenditures primarily with net cash provided by operating activities. 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 or the borrowing bases under our Credit Facilities decrease, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. In addition, as noted previously, our Credit Facilities are effectively fully drawn, precluding our ability to utilize our Credit Facilities to fund our operations. Our Credit Facilities also restrict our ability to obtain new financing. If additional capital is needed, we may not be able to obtain debt or equity financing on terms favorable to us, or at all. If net cash provided by operating activities or cash available under our Credit Facilities is not sufficient to meet our capital requirements, the failure to obtain such additional debt or equity financing could result in a curtailment of our development operations, which in turn could lead to a decline in our reserves.

We may 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.

The SEC’s reserve reporting rules include a general requirement that, subject to limited exceptions, proved undeveloped reserves may only be recorded if they relate to wells scheduled to be drilled within five years. As a result of the uncertainty regarding our future commitment to capital, we reclassified all of our proved undeveloped reserves to unproved as of December 31, 2015. See Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations” for details regarding our going concern uncertainty.

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, and could reduce our cash available to

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service debt or to resume payment of distributions to our unitholders and adversely impact expected increases in oil, natural gas and NGL production from our drilling program.

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 reduce our cash available to service debt or to resume payment of distributions to our unitholders and adversely impact expected increases in oil, natural gas and NGL production from our drilling program.

We depend on certain key customers for sales of our oil, natural gas and NGL. To the extent these and other customers reduce the volumes they purchase from us or delay payment, our revenues and cash available to service debt or to resume payment of distributions to our unitholders could decline. Further, a general increase in nonpayment could have an adverse impact on our financial position and results of operations.

For the year ended December 31, 2015, sales of oil, natural gas and NGL to Phillips 66 accounted for approximately 12% of our sales. To the extent this and other customers reduce the volumes of oil, natural gas or NGL that they purchase from us, our revenues and cash available to service debt or to resume payment of distributions to our unitholders could decline.

We may be unable to retain key employees.

Our future success will depend in part on our ability to retain key employees. Since the fourth quarter of 2014, the prices of oil, natural gas and NGL have been extremely volatile, have declined significantly and downward pressure on commodity prices may continue for the foreseeable future. Key employees may depart because of issues relating to the uncertainty during times of commodity price volatility. Accordingly, no assurance can be given that we will be able to retain key employees to the same extent as in the past.

Many of our leases are in areas that have been partially depleted or drained by offset wells.

Many of our leases are in areas that have already been partially depleted or drained by earlier offset drilling. This may inhibit our ability to find economically recoverable quantities of reserves in these areas. Our identified drilling location inventories are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling, which could have a material 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 and, as a result, our ability to service debt or to resume payment of distributions to our unitholders.

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 impact our financial position, results of operations and cash flows, and as a result, our ability to service debt or to resume payment of distributions to our unitholders.

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, 2015, nonoperated wells represented approximately 28% of our owned gross wells, or approximately 11% 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.

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 and the substances we handle. Certain environmental statutes, including the RCRA, CERCLA and analogous state laws and regulations, impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances have been disposed of or otherwise released. In addition, an accidental release from one of our wells or gathering pipelines could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage and fines or penalties for related violations of environmental laws or regulations.

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

We are subject to complex 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.

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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, as well as our ability to service debt or to resume payment of distributions to our unitholders. For a description of the laws and regulations that affect us, see Item 1. "Business - Environmental Matters and Regulation."

Legislation and regulation of 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 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. 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.

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 has begun 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 addition, 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. 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 will be open for signing on April 22, 2016, and will require 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.

Recent regulatory changes in California have and may continue to adversely affect our production and operating costs related to our Diatomite assets.

Recent regulatory changes in California have impacted production from our Diatomite assets. In 2010, Diatomite production decreased significantly due to the inability to drill new wells pending the receipt of permits from the California Division of Oil, Gas and Geothermal Resources (“DOGGR”). Berry received a new full-field development approval in late July 2011 from DOGGR, which contained stringent operating requirements. Revisions to the July 2011 project approval letter were received in February 2012. Implementation of these new operating requirements negatively impacted the pace of drilling and steam injection and increased Berry’s operating costs for its Diatomite assets. The requirements continued to affect Berry’s operations through 2015, and we may not be successful in streamlining the review process with DOGGR or in taking additional steps to more efficiently manage our operations to avoid additional delays. In addition, DOGGR may impose additional operational restrictions or requirements. For example, currently DOGGR is developing new regulations for shallow, thermal Diatomite. In such case, we may experience additional delays in production and increased operating costs related to our Diatomite assets, which could adversely affect our business, financial position, results of operations and net cash provided by operating activities.

We may issue additional units without unitholder approval, which would dilute existing ownership interests.

We may issue an unlimited number of limited liability company interests of any type, including units, without the approval of our unitholders.

The issuance of additional units or other equity securities may have the following effects:

- an individual unitholder’s proportionate ownership interest in us may decrease;
- the relative voting strength of each previously outstanding unit may be reduced;
- the amount of cash available for distribution per unit may decrease; and
- the market price of the units may decline.

Our management may have conflicts of interest with the unitholders. Our limited liability company agreement limits the remedies available to our unitholders in the event unitholders have a claim relating to conflicts of interest.

Conflicts of interest may arise between our management on one hand, and the Company and our unitholders on the other hand, related to the divergent interests of our management. Situations in which the interests of our management may differ from interests of our nonaffiliated unitholders include, among others, the following situations:

- our limited liability company agreement gives our Board of Directors broad discretion in establishing cash reserves for the proper conduct of our business, which will affect the amount of cash available for distributions to our unitholders. For example, our management will use its reasonable discretion to establish and maintain cash reserves sufficient to fund our drilling program, and may also determine to reduce indebtedness;
- our management team, subject to oversight from our Board of Directors, determines the timing and extent of our drilling program and related capital expenditures, asset purchases and sales, borrowings, issuances of additional units and reserve adjustments, all of which will affect the amount of cash available to service debt or to resume payment of distributions to our unitholders; and
- affiliates of our directors are not prohibited from investing or engaging in other businesses or activities that compete with the Company.

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Your units are subject to limited call rights that could result in your having to involuntarily sell your units at a time or price that may be undesirable.

If at any time a person owns more than 90% of our outstanding units, such person may elect to purchase all, but not less than all, of our remaining outstanding units at a price equal to the higher of the current market price (as defined in our limited liability company agreement) and the highest price paid by such person or any of its affiliates for any of our units purchased during the 90-day period preceding the date notice was mailed to the our unitholders informing them of such election. In this case, you will be required to tender all of your outstanding units and you may receive a payment that is effectively less than the price at which you would prefer to sell your units.

Unitholders who are not “Eligible Holders” will be subject to redemption of their units.

In order to comply with U.S. laws with respect to the ownership of interests in oil and natural gas leases on federal lands, we have adopted certain requirements regarding those investors who may own our units. As used herein, an Eligible Holder means a person or entity qualified to hold an interest in oil and natural gas leases on federal lands. Unitholders who are not persons or entities who meet the requirements to be an Eligible Holder will not be entitled to receive distributions in kind on their units in a liquidation and they run the risk of having their units redeemed by us at the then-current market price.

Tax Risks

We are exploring strategic alternatives to strengthen our balance sheet and maximize our value. We may consider alternatives that could have significant adverse tax consequences to our unitholders.

We are exploring strategic alternatives to strengthen our balance sheet and maximize our value. We may consider alternatives that could have significant adverse tax consequences to our unitholders. For example, we may engage in additional transactions that result in significant cancellation of debt (“COD”) income to our unitholders. As described below, any COD income may cause a unitholder to be allocated income with respect to our units with no corresponding distribution of cash to fund the payment of the resulting tax liability to the unitholder. In addition, we may engage in transactions that trigger a unitholder’s tax gain or loss with respect to our units. A transaction that triggers a unitholder’s gain may not be accompanied by any receipt of cash to fund the payment of the resulting tax liability to the unitholder. Under certain circumstances, a unitholder’s loss upon any such transaction may be permanently disallowed.

We urge our unitholders to consult their tax advisors regarding the potential adverse effects of the various strategic alternatives that may be available to us.

Unitholders are required to pay taxes on their share of our taxable income, including their share of ordinary income and capital gain upon dispositions of properties by us or cancellation of debt, even if they do not receive any cash distributions from us to fund any resulting tax liability. A unitholder’s share of our taxable income, gain, loss and deduction, or specific items thereof, may be substantially different than the unitholder’s interest in our economic profits.

Our unitholders are required to pay federal income taxes and, in some cases, state and local income taxes on their share of our taxable income, whether or not they receive any cash distributions from us. Even if our distributions are reinstated, our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from their share of our taxable income.

For example, a unitholder’s share of our taxable income will include any COD income recognized upon the satisfaction of our outstanding indebtedness for total consideration less than the adjusted issue price (and any accrued but unpaid interest) of such indebtedness. During 2015, we repurchased and exchanged approximately $3.0 billion of our outstanding senior notes at a significant discount, resulting in substantial COD income. We may engage in other transactions that result in COD income in the future. Depending upon the net amount of other items related to our loss (or income) allocable to a unitholder, any COD income may cause a unitholder to be allocated income with respect to our units with no corresponding distribution of cash to fund the payment of the resulting tax liability to the unitholder. Furthermore, such COD income event may not be fully offset, either now or in the future, by capital losses, which are subject to significant limitations, or other losses. Accordingly, a COD income event could cause a unitholder to realize taxable income without corresponding future economic benefits or offsetting tax deductions.

In addition, we may sell a portion of our properties and use the proceeds to pay down debt or acquire other properties rather than distributing the proceeds to our unitholders, and some or all of our unitholders may be allocated substantial taxable income or loss with respect to that sale. A unitholder's share of our taxable income upon a disposition of property by us may be ordinary income or capital gain or some combination thereof. Even where we dispose of properties that are capital assets, what otherwise would be capital gains may be recharacterized as ordinary income in order to "recapture" ordinary deductions that were previously allocated to that unitholder related to the same properties. A unitholder's share of our taxable income and gain (or specific items thereof) may be substantially greater than, or our tax losses and deductions (or specific items thereof) may be substantially less than, the unitholder's interest in our economic profits. This may occur, for example, in the case of a unitholder who purchases units at a time when the value of our units or of one or more of our properties is relatively low or a unitholder who acquires units directly from us in exchange for property whose fair market value exceeds its tax basis at the time of the exchange. Cash distributions from us decrease a unitholder's tax basis in its units, and the amount, if any, of excess distributions over a unitholder's tax basis in its units will, in effect, become taxable income to the unitholder, above and beyond the unitholder's share of our taxable income and gain (or specific items thereof).

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of additional entity level taxation by individual states. If the Internal Revenue Service ("IRS") were to treat us as a corporation for federal income tax purposes or we were to become subject to material additional entity level taxation for state tax purposes, taxes paid, if any, would reduce the amount of cash available to service debt or to resume payment of distributions to our unitholders.

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

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rates, currently at a maximum rate of 35%. Distributions, if any, would generally be taxed again as corporate distributions, and no income, gain, loss, deduction or credit would flow through to unitholders. Because a tax may be imposed on us as a corporation, our cash available to service debt or to resume payment of distributions to our unitholders could be reduced.

Current law or our business may change and cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity level taxation. Any modification to current law or interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible to meet the requirements for partnership status, affect or cause us to change our business activities, affect the tax considerations of an investment in us, change the character or treatment of portions of our income and adversely affect an investment in our units.

In addition, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships and limited liability companies to entity level taxation through the imposition of state income, franchise or other forms of taxation. For example, we may be required to pay Texas franchise tax on our total revenue apportioned to Texas at a maximum effective rate of approximately 0.5%. Imposition of a similar entity-level tax on our income or receipts by any other state would reduce the amount of cash available to service debt or to resume payment of distributions to our unitholders.

A successful IRS contest of the federal income tax positions we take may adversely affect the market for our units, and the cost of an IRS contest will reduce our cash available to service debt or to resume payment of distributions to our unitholders.

The IRS may adopt tax positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS may materially and adversely impact the market for our units and the price at which they trade, as well as reduce our cash available to service debt or to resume payment of distributions to our unitholders.

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Item 1A. Risk Factors - Continued

If the IRS makes audit adjustments to our income tax returns for tax years beginning after 2017, it (and some states) may collect any resulting taxes (including any applicable penalties and interest) directly from us, in which case our cash available to service debt or to pay distributions to our unitholders, if and when resumed, might be substantially reduced.

Pursuant to the Bipartisan Budget Act of 2015, if the IRS makes audit adjustments to our income tax returns for tax years beginning after 2017, it may collect any resulting taxes (including any applicable penalties and interest) directly from us. We will generally have the ability to shift any such tax liability to our unitholders in accordance with their interests in us during the year under audit, but there can be no assurance that we will be able to do so (and will choose to do so) under all circumstances, or that we will be able to (or choose to) effect corresponding shifts in state income or similar tax liability resulting from the IRS adjustment in states in which we do business in the year under audit or in the adjustment year. If we make payments of taxes, penalties and interest resulting from audit adjustments, our cash available to service debt or to resume payment of distributions to our unitholders could be reduced.

A unitholder’s taxable gain or loss on the disposition of our units could be more or less than expected.

If unitholders sell their units, they will recognize a gain or loss equal to the difference between the amount realized and their tax basis in those units. Prior distributions to our unitholders in excess of the total net taxable income they were allocated for a unit, which decreases their tax basis, will become taxable income to our unitholders if the unit is sold at a price greater than their tax basis in that unit, even if the price received is less than their original cost.

A substantial portion of the amount realized, whether or not representing gain, may be ordinary income. In addition, if unitholders sell their units, they may incur a tax liability in excess of the amount of cash they receive from the sale. If the IRS successfully contests some positions we take, unitholders could recognize more gain on the sale of units than would be the case under those positions, without the benefit of decreased income in prior years.

Tax-exempt entities and non-U.S. persons face unique tax issues from owning our units that may result in adverse tax consequences to them.

Investment in units by tax-exempt entities, such as individual retirement accounts (known as IRAs) and other retirement plans, and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file U.S. federal tax returns and pay tax on their share of our taxable income.

We treat each purchaser of units as having the same economic and tax characteristics without regard to the units purchased. The IRS may challenge this treatment, which could adversely affect the value of the units.

Because we cannot match transferors and transferees of units, we must maintain uniformity of the economic and tax characteristics of our units to a purchaser of units. We take depletion, depreciation and amortization and other positions that are intended to maintain such uniformity. These positions may not conform with all aspects of existing Treasury regulations and may affect the amount or timing of income, gain, loss or deduction allocable to a unitholder or the amount of gain from a unitholder’s sale of units. A successful IRS challenge to those positions could also adversely affect the amount or timing of income, gain, loss or deduction allocable to a unitholder, or the amount of gain from a unitholder’s sale of units and could have a negative impact on the value of our units or result in audit adjustments to unitholders tax returns.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month (or in some cases for periods shorter than a month) based upon the ownership of our units on the first day of each month (or shorter period), instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month (or in some cases for periods shorter than a month) based upon the ownership of our units on the first day of each month (or shorter period), instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be

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permitted under existing Treasury regulations. If the IRS were to challenge this method or new Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

The sale or exchange of 50% or more of our capital and profits interests within a 12-month period will result in the deemed termination of our tax partnership for federal income tax purposes.

We will be considered to have terminated for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a 12-month period. Our termination would, among other things, result in the closing of our taxable year for all unitholders and could result in a deferral of depreciation deductions allowable in computing our taxable income. If this occurs, our unitholders will be allocated an increased amount of federal taxable income for the year in which we are considered to be terminated as a percentage of the cash distributed to the unitholders with respect to that period.

A unitholder whose units are loaned to a “short seller” to cover a short sale of units may be considered as having disposed of those units. If so, the unitholder would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition.

Because a unitholder whose units are loaned to a “short seller” to cover a short sale of units may be considered as having disposed of the loaned units, the unitholder may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss, or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

Unitholders may be subject to state and local taxes and return filing requirements in states and jurisdictions where they do not live as a result of investing in our units.

In addition to federal income taxes, our unitholders will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property now or in the future, even if they do not reside in any of those jurisdictions. Our unitholders will likely be required to file foreign, state and local income tax returns and pay state and local income taxes in some or all of these jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. In 2015, we have been registered to do business or have owned assets in Alabama, Arkansas, California, Colorado, Illinois, Indiana, Kansas, Louisiana, Michigan, Mississippi, Montana, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, Utah and Wyoming. As we make acquisitions or expand our business, we may do business or own assets in other states in the future. It is the responsibility of each unitholder to file all U.S. federal, state and local tax returns that may be required of such unitholder.

Changes to current federal tax laws may affect the tax treatment of publicly traded partnerships or unitholders’ ability to take certain tax deductions, possibly on a retroactive basis.

Substantive changes to the existing federal income tax laws have been proposed that, if adopted, would affect, among other things, the ability to take certain operations-related deductions, including deductions for intangible drilling and deductions for U.S. production activities. Other proposed changes may affect our ability to remain taxable as a partnership for federal income tax purposes or tax publicly traded partnerships with qualifying income from fossil fuels activities as a corporation. Additionally, in May 2015, the IRS and the U.S. Department of the Treasury published proposed regulations that provide industry-specific guidance regarding whether income earned from certain activities will constitute qualifying income. We are unable to predict whether any changes, or other proposals to such laws, ultimately will be enacted or, if enacted, will be applied retroactively, or whether proposed regulations, once issued in final form, will materially change interpretations of the current law. Any such changes could negatively impact the value of an investment in our units.

Item 1B. Unresolved Staff Comments

None

Item 2. Properties

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

The Company's obligations under its Credit Facilities and senior secured second lien notes are secured by mortgages on a substantial majority of its oil and natural gas properties. See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 6 for additional details about the Credit Facilities and senior secured second lien notes.

Offices

The Company's principal corporate office is located at 600 Travis, Suite 5100, Houston, Texas 77002. The Company maintains additional offices in California, Colorado, Illinois, Kansas, Louisiana, Michigan, New Mexico, Oklahoma, Texas, Utah and Wyoming.

Item 3. Legal Proceedings

For certain statewide class action royalty payment disputes where a reserve has not yet been established, the Company has denied that it has any liability on the claims and has raised arguments and defenses that, if accepted by the courts, will result in no loss to the Company. In addition, the Company is involved in various other disputes arising in the ordinary course of business. 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

The Company's units are listed on the NASDAQ Global Select Market ("NASDAQ") under the symbol "LINE." At the close of business on January 31, 2016, there were approximately 143 unitholders of record.

The following table sets forth the range of high and low last reported sales prices per unit, as reported by 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
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
2014:			
October 1 – December 31	$29.58	$9.83	$0.725
July 1 – September 30	$32.57	$29.81	$0.725
April 1 – June 30	$32.35	$27.96	$0.725
January 1 – March 31	$33.72	$27.18	$0.725

Distributions

Under the Company's limited liability company agreement, unitholders are entitled to receive a distribution of available cash, which includes cash on hand plus borrowings less any reserves established by the Company's Board of Directors to provide for the proper conduct of the Company'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 January 2015, the Company reduced its distribution to $1.25 per unit, from the previous level of $2.90 per unit, on an annualized basis. Monthly distributions were paid by the Company through September 2015.

In October 2015, the Company's Board of Directors determined to suspend payment of the Company's distribution. The Company's Board of Directors will continue to evaluate the Company's ability to reinstate the distribution. For additional information, see "Distribution Practices" in Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations."

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

Unitholder Return Performance Presentation

The performance graph below compares the total unitholder return on the Company's units with the total return of the Standard & Poor's 500 Index ("S&P 500 Index") and the Alerian MLP Index, a weighted composite of certain prominent energy master limited partnerships. Total return includes the change in the market price, adjusted for reinvested dividends or distributions, for the period shown on the performance graph and assumes that $100 was invested in the Company, the S&P 500 Index and the Alerian MLP Index on December 31, 2010. The results shown in the graph below are not necessarily indicative of future performance.

	December 31, 2010	December 31, 2011	December 31, 2012	December 31, 2013	December 31, 2014	December 31, 2015
LINN Energy	$100	$108	$108	$104	$38	$5
Alerian MLP Index	$100	$114	$119	$152	$160	$108
S&P 500 Index	$100	$102	$118	$157	$178	$181

Notwithstanding anything to the contrary set forth in any of the Company's previous or future filings under the Securities Act of 1933 or the Securities Exchange Act of 1934 that might incorporate this Annual Report on Form 10-K or future filings with the Securities and Exchange Commission ("SEC"), in whole or in part, the preceding performance information shall not be deemed to be "soliciting material" or to be "filed" with the SEC or incorporated by reference into any filing except to the extent this performance presentation is specifically incorporated by reference therein.

Securities Authorized for Issuance Under Equity Compensation Plans

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

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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

In conjunction with LinnCo, LLC's ("LinnCo") contribution of Berry Petroleum Company, now Berry Petroleum Company, LLC ("Berry") to LINN Energy (see Note 2), on December 16, 2013, LINN Energy issued 93,756,674 units to LinnCo, which were not and will not be registered under the Securities Act of 1933, as amended, and the rules and regulations promulgated thereunder ("Securities Act"), or any state securities laws, in reliance on Section 4(2) of the Securities Act as these transactions were by an issuer not involving a public offering. Total units issued to LinnCo included 40,938 (approximately $1 million) of Berry equity awards that vested and were converted to LinnCo common shares on the Berry acquisition date and included in total consideration. These shares were issued in 2014 due to six month deferred issuance provisions in the original Berry award agreements.

Issuer Purchases of Equity Securities

The Company's Board of Directors has authorized the repurchase of up to $250 million of the Company's outstanding units from time to time on the open market or in negotiated purchases. The timing and amounts of any such repurchases are at the discretion of management, subject to market conditions and other factors, and in accordance with applicable securities laws and other legal requirements. The repurchase plan does not obligate the Company to acquire any specific number of units and may be discontinued at any time. The Company did not repurchase any units during the year ended December 31, 2015, and as of December 31, 2015, the entire amount remained available for unit repurchase under the program.

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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.

	At or for the Year Ended December 31,				
	2015	2014	2013	2012	2011
	(in thousands, except per unit amounts)				
Statement of operations data:					
Oil, natural gas and natural gas liquids sales	$1,726,271	$3,610,539	$2,073,240	$1,601,180	$1,162,037
Gains on oil and natural gas derivatives	1,056,189	1,206,179	177,857	124,762	449,940
Depreciation, depletion and amortization	805,757	1,073,902	829,311	606,150	334,084
Interest expense, net of amounts capitalized	546,453	587,838	421,137	379,937	259,725
Net income (loss)	(4,759,811)	(451,809)	(691,337)	(386,616)	438,439
Net income (loss) per unit:					
Basic	(13.87)	(1.40)	(2.94)	(1.92)	2.52
Diluted	(13.87)	(1.40)	(2.94)	(1.92)	2.51
Distributions declared per unit	0.938	2.90	2.90	2.87	2.70
Weighted average units outstanding	343,323	328,918	237,544	203,775	172,004
Cash flow data:					
Net cash provided by (used in):					
Operating activities [1]	$1,249,457	$1,711,890	$1,166,212	$350,907	$518,706
Investing activities	(307,302)	(1,920,104)	(1,253,317)	(3,684,829)	(2,130,360)
Financing activities	(941,796)	157,852	138,033	3,334,051	1,376,767
Balance sheet data:					
Total assets	$9,976,946	$16,423,509	$16,504,964	$11,451,238	$7,928,854
Current portion of long-term debt	3,716,508	—	211,558	—	—
Long-term debt, net	5,328,235	10,295,809	8,958,658	6,037,817	3,993,657
Unitholders' capital (deficit)	(268,901)	4,543,605	5,891,427	4,427,180	3,428,910

(1) Net of payments made for commodity derivative premiums of approximately $583 million and $134 million for the years ended December 31, 2012, and December 31, 2011, respectively.

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Item 6. Selected Financial Data - Continued

	At or for the Year Ended December 31,				
	2015	2014	2013	2012	2011
Production data:					
Average daily production:					
Natural gas (MMcf/d)	642	572	443	349	175
Oil (MBbls/d)	62.4	72.9	33.5	29.2	21.5
NGL (MBbls/d)	28.6	33.5	29.7	24.5	10.8
Total (MMcfe/d)	1,188	1,210	822	671	369
Estimated proved reserves: (1)					
Natural gas (Bcf)	2,619	4,255	3,010	2,571	1,675
Oil (MMBbls)	197	342	366	191	189
NGL (MMBbls)	114	166	200	179	94
Total (Bcfe)	4,488	7,304	6,403	4,796	3,370

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

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

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

When referring to Linn Energy, LLC ("LINN Energy" or the "Company"), the intent is to refer to LINN Energy 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 a "Note" herein refers to the accompanying Notes to Consolidated Financial Statements contained in Item 8. "Financial Statements and Supplementary Data."

Executive Overview

LINN Energy's mission is to acquire, develop and maximize cash flow from a growing portfolio of long-life oil and natural gas assets. LINN Energy is an independent oil and natural gas company that began operations in March 2003 and completed its initial public offering in January 2006. The Company's properties are located in eight operating regions in the United States ("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), North Dakota (Williston Basin) and Colorado (Piceance Basin);
- California, which includes properties located in the San Joaquin Valley and Los Angeles basins;
- TexLa, which includes properties located in east Texas and north Louisiana;
- Mid-Continent, which includes Oklahoma properties located in the Anadarko and Arkoma basins, as well as waterfloods in the Central Oklahoma Platform;
- Michigan/Illinois, which includes properties located in the Antrim Shale formation in north Michigan and oil properties in south Illinois;
- Permian Basin, which includes properties located in west Texas and southeast New Mexico; and
- South Texas.

For a discussion of the Company's eight operating regions, see Item 1 "Business."

Results for the year ended December 31, 2015, included the following:

- oil, natural gas and NGL sales of approximately $1.7 billion compared to $3.6 billion for 2014;
- average daily production of approximately 1,188 MMcfe/d compared to 1,210 MMcfe/d for 2014;
- net loss of approximately $4.8 billion compared to $452 million for 2014;
- net cash provided by operating activities of approximately $1.2 billion compared to $1.7 billion for 2014;
- capital expenditures, excluding acquisitions, of approximately $518 million compared to $1.6 billion for 2014; and
- 589 wells drilled (584 successful) compared to 918 wells drilled (917 successful) for 2014.

Process to Explore Strategic Alternatives Related to the Company's Capital Structure

In February 2016, the Company announced that it had initiated a process to explore strategic alternatives to strengthen its balance sheet and maximize the value of the Company. The Company's Board of Directors and management are in the process of evaluating strategic alternatives to help provide the Company with financial stability, but no assurance can be given as to the outcome or timing of this process. The Company has retained Lazard as its financial advisor and Kirkland & Ellis LLP as its legal advisor to assist the Board of Directors and management team with the strategic review process.

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Going Concern Uncertainty

The Company's liquidity outlook has changed since the third quarter of 2015 due to continued low commodity prices, which are expected to result in significantly lower levels of cash flow from operating activities in the future as the Company's current commodity derivative contracts expire, and have limited the Company's ability to access the capital markets. In addition, each of the Company's Credit Facilities is subject to scheduled redeterminations of its borrowing base, semi-annually in April and October, based primarily on reserve reports using lender commodity price expectations at such time. Continued low commodity prices, reductions in the Company's capital budget and the resulting reserve write-downs, along with the maturity schedule of the Company's hedges, are expected to adversely impact the upcoming April redeterminations and will likely have a significant negative impact on the Company's liquidity.

As a result of these and other factors, the following issues have adversely impacted the Company's ability to continue as a going concern:

- the Company's ability to comply with financial covenants and ratios in its Credit Facilities and indentures has been affected by continued low commodity prices. Absent a waiver or amendment, failure to meet these covenants and ratios would result in a default and, to the extent the applicable lenders so elect, an acceleration of the Company's existing indebtedness, causing such debt of approximately $3.6 billion to be immediately due and payable. Based on the Company's current estimates and expectations for commodity prices in 2016, the Company does not expect to remain in compliance with all of the restrictive covenants contained in its Credit Facilities throughout 2016 unless those requirements are waived or amended. The Company does not currently have adequate liquidity to repay all of its outstanding debt in full if such debt were accelerated;
- because the Credit Facilities are effectively fully drawn, any reduction of the borrowing bases under the Company's Credit Facilities would require mandatory prepayments to the extent existing indebtedness exceeds the new borrowing bases. The Company may not have sufficient cash on hand to be able to make any such mandatory prepayments; and
- the Company's ability to make interest payments as they become due and repay indebtedness upon maturities (whether under existing terms or as a result of acceleration) is impacted by the Company's liquidity. As of February 29, 2016, there was less than $1 million of available borrowing capacity under the Credit Facilities.

The Company's Board of Directors and management are in the process of evaluating strategic alternatives to help provide the Company with financial stability, but no assurance can be given as to the outcome or timing of this process.

The report of the Company's independent registered public accounting firm that accompanies its audited consolidated financial statements in this Annual Report on Form 10-K contains an explanatory paragraph regarding the substantial doubt about the Company's ability to continue as a going concern. The consolidated financial statements do not include any adjustments that might result from the outcome of the going concern uncertainty.

The Company's Credit Facilities contain the requirement to deliver audited consolidated financial statements without a going concern or like qualification or exception. Consequently, as of the filing date, March 15, 2016, the Company is in default under the LINN Credit Facility. If the Company is unable to obtain a waiver or other suitable relief from the lenders under the LINN Credit Facility prior to the expiration of the 30 day grace period, an Event of Default (as defined in the applicable agreements) will result and the lenders holding a majority of the commitments under the LINN Credit Facility could accelerate the outstanding indebtedness, which would make it immediately due and payable. If the Company is unable to obtain a waiver from or otherwise reach an agreement with the lenders under the LINN Credit Facility and the indebtedness under the LINN Credit Facility is accelerated, then an Event of Default under LINN Energy's senior notes and second lien notes would occur, which, if it continues beyond any applicable cure periods, would, to the extent the applicable lenders so elect, result in the acceleration of those obligations. Furthermore, an Event of Default under the LINN Credit Facility will also result in an Event of Default under the Berry Credit Facility, which in the absence of a waiver or other suitable relief and upon the election of the agent or lenders holding a majority of commitments under the Berry Credit Facility would result in the acceleration of indebtedness under the Berry Credit Facility. Such Event of Default would trigger an Event of Default under the Berry senior notes. If such Event of Default continues beyond any applicable cure periods, such Event of Default would result in an acceleration of the Berry senior notes.

Additionally, the indenture governing the second lien notes ("Second Lien Indenture") required the Company to deliver mortgages by February 18, 2016, subject to a 45 day grace period. The Company elected to exercise its right to the grace period and not deliver the mortgages, and as a result, the Company is currently in default under the Second Lien Indenture. If the Company does not deliver the mortgages within the 45 day grace period or is otherwise unable to obtain a waiver or other suitable relief from the holders under the Second Lien Indenture prior to the expiration of the 45 day grace period, an Event of Default (as defined in the Second Lien Indenture) will result and if the trustee or noteholders holding at least 25% in the aggregate outstanding principal amount of the second lien notes so elect would accelerate the second lien notes causing them to be immediately due and payable.

Furthermore, the Company has decided to defer making interest payments totaling approximately $60 million due March 15, 2016, including approximately $30 million on LINN Energy's 7.75% senior notes due February 2021, approximately $12 million on LINN Energy's 6.50% senior notes due September 2021 and approximately $18 million on Berry's senior notes due September 2022, which will result in the Company being in default under these senior notes. The indentures governing each of the applicable series of notes permit the Company a 30 day grace period to make the interest payments. If the Company fails to make the interest payments within the grace period, or is otherwise unable to obtain a waiver or suitable relief from the holders of these senior notes, an Event of Default will result and if the trustee or noteholders holding at least 25% in the aggregate outstanding principal amount of each series of notes so elect would accelerate the notes causing them to be immediately due and payable.

An Event of Default under the Second Lien Indenture or any of the indentures governing the senior notes triggers a cross-default under the LINN Credit Facility and Berry Credit Facility and, as discussed above, if the applicable lenders so elect would result in acceleration under the LINN Credit Facility and Berry Credit Facility. In addition, as discussed above, an acceleration of the obligations under the Second Lien Indenture or LINN Credit Facility would trigger a cross-default to LINN Energy's senior notes and if the applicable lenders so elect would result in a cross-acceleration under LINN Energy's senior notes, and an acceleration of the Berry Credit Facility if the applicable lenders so elect would result in cross-acceleration under the Berry senior notes.

If lenders, and subsequently noteholders, accelerate the Company's outstanding indebtedness, it will become immediately due and payable and the Company will not have sufficient liquidity to repay those amounts. If the Company is unable to reach an agreement with its creditors prior to any of the above described accelerations, the Company could be required to immediately file for protection under Chapter 11 of the U.S. Bankruptcy Code.

The Company is currently in discussions with various stakeholders and is pursuing or considering a number of actions including: (i) obtaining additional sources of capital from asset sales, private issuances of equity or equity-linked securities, debt for equity swaps, or any combination thereof; (ii) pursuing in- and out-of-court restructuring transactions; (iii) obtaining waivers or amendments from its lenders; and (iv) continuing to minimize its capital expenditures, reduce costs and maximize cash flows from operations. There can be no assurance that sufficient liquidity can be obtained from one or more of these actions or that these actions can be consummated within the period needed.

Reduction and Suspension of Distribution

In January 2015, the Company reduced its distribution to $1.25 per unit, from the previous level of $2.90 per unit, on an annualized basis. Monthly distributions were paid by the Company through September 2015. In October 2015, following the recommendation from management, the Company's Board of Directors determined to suspend payment of the Company's distribution and reserve any excess cash that would otherwise be available for distribution. The Company's Board of Directors and management believe the suspension to be in the best long-term interest of all Company stakeholders. The Company's Board of Directors will continue to evaluate the Company's ability to reinstate the distribution. For additional information, see "Distribution Practices" below.

2016 Oil and Natural Gas Capital Budget

For 2016, the Company estimates its total capital expenditures, excluding acquisitions, will be approximately $340 million, including approximately $250 million related to its oil and natural gas capital program and approximately $75 million related to its plant and pipeline capital. The 2016 budget contemplates continued low commodity prices and is under continuous review and subject to ongoing adjustments. The Company expects to fund its capital expenditures primarily from net cash

provided by operating activities; however, there is uncertainty regarding the Company’s liquidity as discussed above. In addition, at this level of capital spending, the Company expects its total reserves to decline.

Alliance with GSO Capital Partners

The Company signed definitive agreements dated June 30, 2015, with affiliates of private capital investor GSO Capital Partners LP (“GSO”), the credit platform of The Blackstone Group L.P., to fund oil and natural gas development (“DrillCo”). Funds managed by GSO have agreed to commit up to $500 million with 5-year availability to fund drilling programs on locations provided by LINN Energy. Subject to adjustments depending on asset characteristics and return expectations of the selected drilling plan, GSO will fund 100% of the costs associated with new wells drilled under the DrillCo agreement and is expected to receive an 85% working interest in these wells until it achieves a 15% internal rate of return on annual groupings of wells, while LINN Energy is expected to receive a 15% carried working interest during this period. Upon reaching the internal rate of return target, GSO’s interest will be reduced to 5%, while LINN Energy’s interest will increase to 95%. As of December 31, 2015, no development activities had been funded under the agreement.

Alliance with Quantum Energy Partners

The Company signed definitive agreements dated June 30, 2015, with affiliates of private capital investor Quantum Energy Partners to fund selected future oil and natural gas acquisitions and the development of those acquired assets (“AcqCo”). See the Company’s Current Report on Form 8-K filed on July 7, 2015, for additional details regarding these agreements.

Divestiture

On August 31, 2015, the Company, through certain of its wholly owned subsidiaries, completed the sale of its remaining position in Howard County in the Permian Basin (“Howard County Assets Sale”). Cash proceeds received from the sale of these properties were approximately $276 million. The Company used the net proceeds from the sale to repay a portion of the outstanding indebtedness under the LINN Credit Facility.

Financing Activities

In February 2016, the Company borrowed approximately $919 million under the LINN Credit Facility, which represented the remaining undrawn amount that was available under the LINN Credit Facility, the proceeds of which were deposited in an unencumbered account with a bank that is not a lender under either the LINN or Berry Credit Facility. These funds are intended to be used for general corporate purposes. As of February 29, 2016, total borrowings (including outstanding letters of credit) under the LINN Credit Facility were $3.6 billion with no remaining availability. Total borrowings under the Berry Credit Facility were approximately $899 million with less than $1 million available.

In November 2015, the Company entered into separate, privately-negotiated, exchange agreements (“Exchange Agreements”) with certain holders of the Company’s outstanding 6.50% senior notes due May 2019, 6.25% senior notes due November 2019, 8.625% senior notes due April 2020, 7.75% senior notes due February 2021 and 6.50% senior notes due September 2021 (“Exchanged Notes”). The Exchange Agreements provided that the Company issue $1.0 billion in aggregate principal amount of new 12.00% senior secured second lien notes due December 2020 (“Second Lien Notes”) in exchange for approximately $2.0 billion in aggregate principal amount of the Company’s Exchanged Notes held by such holders.

In addition, during the year ended December 31, 2015, the Company repurchased at a discount, through privately negotiated transactions and on the open market, approximately $992 million of its outstanding senior notes.

The spring 2015 semi-annual borrowing base redeterminations of the Company’s Credit Facilities, as defined in Note 6, were completed in May 2015 and, as a result of lower commodity prices, the borrowing base under the LINN Credit Facility decreased from $4.5 billion to $4.05 billion and the borrowing base under the Berry Credit Facility decreased from $1.4 billion to $1.2 billion, including $250 million posted as restricted cash (discussed below). The fall 2015 semi-annual redeterminations were completed in October 2015 and the borrowing base under the LINN Credit Facility was reaffirmed at $4.05 billion, subject to certain conditions being met on or before January 1, 2016, and the borrowing base under the Berry Credit Facility decreased from $1.2 billion to $900 million, including the $250 million of restricted cash. In connection with the reduction in Berry’s borrowing base in October 2015, Berry repaid $300 million of borrowings outstanding under the

Berry Credit Facility. The borrowing base under the LINN Credit Facility automatically decreased to $3.6 billion on January 1, 2016, since certain conditions were not met. Also, in October 2015, LINN Energy and Berry each entered into an amendment to its Credit Facility.

Continued low commodity prices, reductions in the Company’s capital budget and the resulting reserve write-downs, along with the maturity schedule of the Company’s hedges, are expected to adversely impact future redeterminations.

In connection with the reduction in Berry’s borrowing base in May 2015, LINN Energy borrowed $250 million under the LINN Credit Facility and contributed it to Berry to post as restricted cash with Berry’s lenders. As directed by LINN Energy, the $250 million was deposited on Berry’s behalf in a security account with the administrative agent subject to a security control agreement. Berry’s ability to withdraw funds from this account is subject to a concurrent reduction of the borrowing base under the Berry Credit Facility or lender’s consent in connection with a redetermination of such borrowing base. The $250 million may be used to satisfy obligations under the Berry Credit Facility or, subject to restrictions in the indentures governing Berry’s senior notes, may be returned to LINN Energy in the future.

See Note 6 for additional details about the Company’s debt.

During the year ended December 31, 2015, the Company, under its equity distribution agreement, sold 3,621,983 units representing limited liability company interests at an average price of $12.37 per unit for net proceeds of approximately $44 million (net of approximately $448,000 in commissions). The Company used the net proceeds for general corporate purposes, including the open market repurchases of a portion of its senior notes (see Note 6). At December 31, 2015, units totaling approximately $455 million in aggregate offering price remained available to be sold under the agreement.

In May 2015, the Company sold 16,000,000 units representing limited liability company interests in an underwritten public offering at $11.79 per unit ($11.32 per unit, net of underwriting discount) for net proceeds of approximately $181 million (after underwriting discount and offering costs of approximately $8 million). The Company used the net proceeds from the sale of these units to repay a portion of the outstanding indebtedness under the LINN Credit Facility.

Commodity Derivatives

During the year ended December 31, 2015, the Company entered into commodity derivative contracts consisting of natural gas basis swaps for May 2015 through December 2017 to hedge exposure to differentials in certain producing areas and oil swaps for April 2015 through December 2015. In addition, the Company entered into natural gas basis swaps for May 2015 through December 2016 to hedge exposure to the differential in California, where it consumes natural gas in its heavy oil development operations.

During the fourth quarter of 2015, the Company canceled certain of its commodity derivative contracts, consisting of Permian basis swaps for 2016 and 2017, trade month roll swaps for 2016 and 2017, and positions representing oil swaps which could have been extended at counterparty election for 2017. The Company received net cash settlements of approximately $5 million from the cancellations.

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

Results of Operations

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

	Year Ended December 31,		
	2015	2014	Variance
	(in thousands)		
Revenues and other:			
Natural gas sales	$602,688	$894,043	$(291,355)
Oil sales	983,337	2,295,491	(1,312,154)
NGL sales	140,246	421,005	(280,759)
Total oil, natural gas and NGL sales	1,726,271	3,610,539	(1,884,268)
Gains on oil and natural gas derivatives	1,056,189	1,206,179	(149,990)
Marketing and other revenues	100,874	166,585	(65,711)
	2,883,334	4,983,303	(2,099,969)
Expenses:			
Lease operating expenses	617,764	805,164	(187,400)
Transportation expenses	219,721	207,331	12,390
Marketing expenses	57,144	117,465	(60,321)
General and administrative expenses (1)	296,887	293,073	3,814
Exploration costs	9,473	125,037	(115,564)
Depreciation, depletion and amortization	805,757	1,073,902	(268,145)
Impairment of long-lived assets	5,813,954	2,303,749	3,510,205
Taxes, other than income taxes	181,895	267,403	(85,508)
Gains on sale of assets and other, net	(197,409)	(366,500)	169,091
	7,805,186	4,826,624	2,978,562
Other income and (expenses)	155,580	(604,051)	759,631
Loss before income taxes	(4,766,272)	(447,372)	(4,318,900)
Income tax expense (benefit)	(6,461)	4,437	(10,898)
Net loss	$(4,759,811)	$(451,809)	$(4,308,002)

(1) General and administrative expenses for the years ended December 31, 2015, and December 31, 2014, include approximately $47 million and $45 million, respectively, of noncash unit-based compensation expenses.

	Year Ended December 31,			
	2015	2014	Variance	
Average daily production:				
Natural gas (MMcf/d)	642	572	12	%
Oil (MBbls/d)	62.4	72.9	(14	)%
NGL (MBbls/d)	28.6	33.5	(15	)%
Total (MMcfe/d)	1,188	1,210	(2	)%
Weighted average prices: (1)				
Natural gas (Mcf)	$2.57	$4.29	(40	)%
Oil (Bbl)	$43.16	$86.28	(50	)%
NGL (Bbl)	$13.45	$34.40	(61	)%
Average NYMEX prices:				
Natural gas (MMBtu)	$2.66	$4.41	(40	)%
Oil (Bbl)	$48.80	$93.00	(48	)%
Costs per Mcfe of production:				
Lease operating expenses	$1.42	$1.82	(22	)%
Transportation expenses	$0.51	$0.47	9	%
General and administrative expenses (2)	$0.68	$0.66	3	%
Depreciation, depletion and amortization	$1.86	$2.43	(23	)%
Taxes, other than income taxes	$0.42	$0.61	(31	)%

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

(2) General and administrative expenses for the years ended December 31, 2015, and December 31, 2014, include approximately $47 million and $45 million, respectively, of noncash unit-based compensation expenses.

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

Revenues and Other

Oil, Natural Gas and NGL Sales

Oil, natural gas and NGL sales decreased by approximately $1.9 billion or 52% to approximately $1.7 billion for the year ended December 31, 2015, from approximately $3.6 billion for the year ended December 31, 2014, due to lower oil, natural gas and NGL prices and lower production volumes. Lower oil, natural gas and NGL prices resulted in a decrease in revenues of approximately $982 million, $402 million and $218 million, respectively.

Average daily production volumes decreased to approximately 1,188 MMcfe/d for the year ended December 31, 2015, from approximately 1,210 MMcfe/d for the year ended December 31, 2014. Lower oil and NGL production volumes resulted in a decrease in revenues of approximately $330 million and $62 million, respectively. Higher natural gas production volumes resulted in an increase in revenues of approximately $110 million.

The following table sets forth average daily production by region:

	Year Ended December 31,					
	2015	2014	Variance			
Average daily production (MMcfe/d):						
Rockies	426	318	108		34	%
Hugoton Basin	252	188	64		35	%
California	185	171	14		8	%
Mid-Continent	100	287	(187	)	(65	)%
TexLa	82	48	34		70	%
Permian Basin	80	153	(73	)	(48	)%
South Texas	32	12	20		172	%
Michigan/Illinois	31	33	(2	)	(5	)%
	1,188	1,210	(22	)	(2	)%

The increase in average daily production volumes in the Rockies region primarily reflects the impact of the acquisition of properties from subsidiaries of Devon Energy Corporation ("Devon" and the acquisition, the "Devon Assets Acquisition") on August 29, 2014, and development capital spending. The increase in average daily production volumes in the Hugoton Basin region primarily reflects the impact of the properties received in the exchange with Exxon Mobil Corporation and its affiliates, including its wholly owned subsidiary XTO Energy Inc. ("Exxon XTO") on August 15, 2014, and the acquisition of properties from Pioneer Natural Resources Company ("Pioneer" and the acquisition, the "Pioneer Assets Acquisition") on September 11, 2014. The increase in average daily production volumes in the California region primarily reflects the impact of the properties received in the exchange with Exxon Mobil Corporation ("ExxonMobil") on November 21, 2014, and development capital spending. The decrease in average daily production volumes in the Mid-Continent region primarily reflects lower production volumes as a result of the properties sold to privately held institutional affiliates of EnerVest, Ltd. and its joint venture partner FourPoint Energy, LLC ("Granite Wash Assets Sale") on December 15, 2014, partially offset by the impact of the Devon Assets Acquisition. The increase in average daily production volumes in the TexLa region primarily reflects the impact of the Devon Assets Acquisition. The decrease in average daily production volumes in the Permian Basin region primarily reflects lower production volumes as a result of the properties relinquished in the two exchanges with Exxon XTO and ExxonMobil, the properties sold to Fleur de Lis Energy, LLC ("Permian Basin Assets Sale") on November 14, 2014, and the Howard County Assets Sale on August 31, 2015. The increase in average daily production volumes in the South Texas region reflects the full year impact of the Devon Assets Acquisition. The decrease in average daily production volumes in the Michigan/Illinois region primarily reflects a low-decline asset base with minimal development capital spending.

Gains (Losses) on Oil and Natural Gas Derivatives

Gains on oil and natural gas derivatives were approximately $1.1 billion and $1.2 billion for the years ended December 31, 2015, and December 31, 2014, respectively, representing a decrease of approximately $150 million. Gains on oil and natural gas derivatives decreased primarily due to changes in fair value of the derivative contracts. The results for 2015 and 2014 also include cash settlements of approximately $5 million and $12 million, respectively, related to canceled derivatives

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contracts. In addition, the results for 2015 and 2014 include gains of approximately $4 million and $7 million, respectively, related to the recoveries of a bankruptcy claim (see Note 11). The fair value on unsettled derivatives contracts changes as future commodity price expectations change compared to the contract prices on the derivatives. If the expected future commodity prices increase compared to the contract prices on the derivatives, losses are recognized; and if the expected future commodity prices decrease compared to the contract prices on the derivatives, gains are recognized.

During the year ended December 31, 2015, the Company had commodity derivative contracts for approximately 81% of its natural gas production and 83% of its oil production. During the year ended December 31, 2014, the Company had commodity derivative contracts for approximately 85% of its natural gas production and 94% of its oil production. The Company does not hedge the portion of natural gas production used to economically offset natural gas consumption related to its heavy oil development operations in California.

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

Marketing and Other Revenues

Marketing revenues represent third-party activities associated with company-owned gathering systems, plants and facilities. Marketing and other revenues decreased by approximately $66 million or 39% to approximately $101 million for the year ended December 31, 2015, from approximately $167 million for the year ended December 31, 2014. The decrease was primarily due to lower revenues generated by the Jayhawk natural gas processing plant in Kansas, principally driven by a change in contract terms, lower electricity sales revenues generated by the Company's California cogeneration facilities and the impact of properties sold during the fourth quarter of 2014, partially offset by higher helium sales revenue in the Hugoton Basin.

Expenses

Lease Operating Expenses

Lease operating expenses include expenses such as labor, field office, vehicle, supervision, maintenance, tools and supplies, and workover expenses. Lease operating expenses decreased by approximately $187 million or 23% to approximately $618 million for the year ended December 31, 2015, from approximately $805 million for the year ended December 31, 2014. The decrease was primarily due to cost savings initiatives, lower costs as a result of the properties sold during the fourth quarter of 2014 and a decrease in steam costs caused by lower prices for natural gas used in steam generation, partially offset by costs associated with properties acquired during the third quarter of 2014. Lease operating expenses per Mcfe also decreased to $1.42 per Mcfe for the year ended December 31, 2015, from $1.82 per Mcfe for the year ended December 31, 2014.

Transportation Expenses

Transportation expenses increased by approximately $13 million or 6% to approximately $220 million for the year ended December 31, 2015, from approximately $207 million for the year ended December 31, 2014. The increase was primarily due to costs associated with properties acquired during the third quarter of 2014 partially offset by lower costs as a result of the properties sold during the fourth quarter of 2014. Transportation expenses per Mcfe also increased to $0.51 per Mcfe for the year ended December 31, 2015, from $0.47 per Mcfe for the year ended December 31, 2014.

Marketing Expenses

Marketing expenses represent third-party activities associated with company-owned gathering systems, plants and facilities. Marketing expenses decreased by approximately $60 million or 51% to approximately $57 million for the year ended December 31, 2015, from approximately $117 million for the year ended December 31, 2014. The decrease was primarily due to lower expenses associated with the Jayhawk natural gas processing plant in Kansas, principally driven by a change in contract terms, and lower electricity generation expenses incurred by the Company's California cogeneration facilities.

General and Administrative Expenses

General and administrative expenses are costs not directly associated with field operations and reflect the costs of employees including executive officers, related benefits, office leases and professional fees. General and administrative expenses increased by approximately $4 million or 1% to approximately $297 million for the year ended December 31, 2015, from approximately $293 million for the year ended December 31, 2014. The increase was primarily due to higher advisory fees related to the alliance agreements partially offset by lower acquisition expenses. General and administrative expenses per Mcfe also increased to $0.68 per Mcfe for the year ended December 31, 2015, from $0.66 per Mcfe for the year ended December 31, 2014.

Exploration Costs

Exploration costs decreased by approximately $116 million to approximately $9 million for the year ended December 31, 2015, from approximately $125 million for the year ended December 31, 2014. The decrease was primarily due to lower leasehold impairment expenses on unproved properties.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization decreased by approximately $268 million or 25% to approximately $806 million for the year ended December 31, 2015, from approximately $1.1 billion for the year ended December 31, 2014. The decrease was primarily due to the divestitures of properties in 2014 with higher rates compared to the rates of properties acquired in 2014, lower rates as a result of the impairments recorded in the prior year and the first and third quarters of 2015, and lower total production volumes. Depreciation, depletion and amortization per Mcfe also decreased to $1.86 per Mcfe for the year ended December 31, 2015, from $2.43 per Mcfe for the year ended December 31, 2014. As a result of the uncertainty regarding the Company's future commitment to capital, the Company reclassified all of its proved undeveloped reserves to unproved as of December 31, 2015, which may impact depletion in the future.

Impairment of Long-Lived Assets

The Company recorded the following noncash impairment charges (before and after tax) associated with proved and unproved oil and natural gas properties:

	Year Ended December 31,	
	2015	2014
	(in thousands)	
Rockies region	$1,758,939	$585,705
Hugoton Basin region	1,667,768	—
California region	537,511	22
TexLa region	430,859	4,836
Mid-Continent region	405,370	244,413
Permian Basin region	71,990	1,337,444
South Texas region	42,433	131,329
Proved oil and natural gas properties	4,914,870	2,303,749
TexLa region	416,846	—
Permian Basin region	226,922	—
Rockies region	184,137	—
California region	71,179	—
Unproved oil and natural gas properties	899,084	—
Impairment of long-lived assets	$5,813,954	$2,303,749

The impairment charges in 2015 were due to a decline in commodity prices, changes in expected capital development and a decline in the Company's estimates of proved reserves. The impairment charges in 2014 include approximately $1.7 billion due to a steep decline in commodity prices during the fourth quarter of 2014 and approximately $603 million due to the divestiture of certain high valued unproved properties in the Midland Basin in which the expected cash flows were previously included in the impairment assessment for proved oil and natural gas properties.

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

Subsequent to December 31, 2015, the prices of oil, natural gas and NGL have continued to be volatile. In the future, if forward price curves continue to decline, the Company may have additional impairments which could have a material impact on its results of operations.

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

During the year ended December 31, 2015, the Company recorded a net gain of approximately $177 million, including costs to sell of approximately $1 million, on the Howard County Assets Sale. During the year ended December 31, 2014, the Company recorded the following net gains and losses on divestitures and exchanges of properties:

- Net gain of approximately $294 million, including costs to sell of approximately $10 million, on the Granite Wash Assets Sale;
- Net loss of approximately $28 million, including costs to sell of approximately $2 million, on the Permian Basin Assets Sale;
- Net gain of approximately $20 million, including costs to sell of approximately $3 million, on the noncash exchange of a portion of its Permian Basin properties to ExxonMobil for properties in California’s South Belridge Field;
- Net gain of approximately $65 million, including costs to sell of approximately $3 million, on the noncash exchange of a portion of its Permian Basin properties to Exxon XTO, for properties in the Hugoton Basin; and
- Net gain of approximately $36 million on the sale of the Company’s interests in certain non-producing oil and natural gas properties located in the Mid-Continent region.

See Note 2 for additional details of divestitures and exchanges of properties.

Taxes, Other Than Income Taxes

	Year Ended December 31,		
	2015	2014	Variance
	(in thousands)		
Severance taxes	$62,000	$133,933	$(71,933)
Ad valorem taxes	99,368	114,955	(15,587)
California carbon allowances	20,573	18,212	2,361
Other	(46)	303	(349)
	$181,895	$267,403	$(85,508)

Taxes, other than income taxes decreased by approximately $86 million or 32% for the year ended December 31, 2015, compared to the year ended December 31, 2014. Severance taxes, which are a function of revenues generated from production, decreased primarily due to lower oil, natural gas and NGL prices and lower production volumes. Ad valorem taxes, which are based on the value of reserves and production equipment and vary by location, decreased primarily due to a lower estimated valuation on certain of the Company’s properties, partially offset by acquisitions completed during the third quarter of 2014. California carbon allowances increased primarily due to an increase in estimated emissions for which credits are needed and higher costs for acquired allowances.

Other Income and (Expenses)

	Year Ended December 31,		
	2015	2014	Variance
	(in thousands)		
Interest expense, net of amounts capitalized	$(546,453)	$(587,838)	$41,385
Gain on extinguishment of debt	719,259	—	719,259
Other, net	(17,226)	(16,213)	(1,013)
	$155,580	$(604,051)	$759,631

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Other income and (expenses) decreased by approximately $760 million for the year ended December 31, 2015, compared to the year ended December 31, 2014. Interest expense decreased primarily due to lower outstanding debt during the period and lower amortization of financing fees and expenses primarily related to the bridge loan and term loan that were repaid during 2014 and senior notes that were repurchased during 2015, partially offset by a decrease in capitalized interest. In addition, for the year ended December 31, 2015, the Company recorded a gain on extinguishment of debt of approximately $719 million as a result of the repurchases of a portion of its senior notes and the exchange of Exchanged Notes for the Second Lien Notes. See "Debt" under "Liquidity and Capital Resources" below for additional details. Other expenses increased during 2015 primarily due to write-offs of deferred financing fees related to the Credit Facilities.

Income Tax Expense (Benefit)

The Company is a limited liability company treated as a partnership for federal and state income tax purposes, with the exception of the state of Texas, in which income tax liabilities and/or benefits of the Company are passed through to its unitholders. Limited liability companies are subject to Texas margin tax. In addition, certain of the Company's subsidiaries are Subchapter C-corporations subject to federal and state income taxes. The Company recognized an income tax benefit of approximately $6 million for the year ended December 31, 2015, compared to income tax expense of approximately $4 million for the year ended December 31, 2014. The income tax benefit was primarily due to lower income from the Company's taxable subsidiaries in 2015 compared to 2014.

Net Loss

Net loss increased by approximately $4.3 billion to approximately $4.8 billion for the year ended December 31, 2015, from approximately $452 million for the year ended December 31, 2014. The increase was primarily due to higher impairment charges, lower production revenues and lower gains on oil and natural gas derivatives, partially offset by the gain on extinguishment of debt and lower expenses, including interest. See discussion above for explanations of variances.

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

Results of Operations
Year Ended December 31, 2014, Compared to Year Ended December 31, 2013

	Year Ended December 31,		
	2014	2013	Variance
	(in thousands)		
Revenues and other:			
Natural gas sales	$894,043	$585,501	$308,542
Oil sales	2,295,491	1,152,213	1,143,278
NGL sales	421,005	335,526	85,479
Total oil, natural gas and NGL sales	3,610,539	2,073,240	1,537,299
Gains on oil and natural gas derivatives	1,206,179	177,857	1,028,322
Marketing and other revenues	166,585	80,558	86,027
	4,983,303	2,331,655	2,651,648
Expenses:			
Lease operating expenses	805,164	372,523	432,641
Transportation expenses	207,331	128,440	78,891
Marketing expenses	117,465	37,892	79,573
General and administrative expenses (1)	293,073	236,271	56,802
Exploration costs	125,037	5,251	119,786
Depreciation, depletion and amortization	1,073,902	829,311	244,591
Impairment of long-lived assets	2,303,749	828,317	1,475,432
Taxes, other than income taxes	267,403	138,631	128,772
(Gains) losses on sale of assets and other, net	(366,500)	13,637	(380,137)
	4,826,624	2,590,273	2,236,351
Other income and (expenses)	(604,051)	(434,918)	(169,133)
Loss before income taxes	(447,372)	(693,536)	246,164
Income tax expense (benefit)	4,437	(2,199)	6,636
Net loss	$(451,809)	$(691,337)	$239,528

(1) General and administrative expenses for the years ended December 31, 2014, and December 31, 2013, include approximately $45 million and $37 million, respectively, of noncash unit-based compensation expenses.

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

	Year Ended December 31,			
	2014	2013	Variance	
Average daily production:				
Natural gas (MMcf/d)	572	443	29	%
Oil (MBbls/d)	72.9	33.5	118	%
NGL (MBbls/d)	33.5	29.7	13	%
Total (MMcfe/d)	1,210	822	47	%
Weighted average prices: (1)				
Natural gas (Mcf)	$4.29	$3.62	19	%
Oil (Bbl)	$86.28	$94.15	(8	)%
NGL (Bbl)	$34.40	$30.96	11	%
Average NYMEX prices:				
Natural gas (MMBtu)	$4.41	$3.65	21	%
Oil (Bbl)	$93.00	$97.97	(5	)%
Costs per Mcfe of production:				
Lease operating expenses	$1.82	$1.24	47	%
Transportation expenses	$0.47	$0.43	9	%
General and administrative expenses (2)	$0.66	$0.79	(16	)%
Depreciation, depletion and amortization	$2.43	$2.76	(12	)%
Taxes, other than income taxes	$0.61	$0.46	33	%

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

(2) General and administrative expenses for the years ended December 31, 2014, and December 31, 2013, include approximately $45 million and $37 million, respectively, of noncash unit-based compensation expenses.

Revenues and Other

Oil, Natural Gas and NGL Sales

Oil, natural gas and NGL sales increased by approximately $1.5 billion or 74% to approximately $3.6 billion for the year ended December 31, 2014, from approximately $2.1 billion for the year ended December 31, 2013, due to higher production volumes and higher natural gas and NGL prices partially offset by lower oil prices. Higher natural gas and NGL prices resulted in an increase in revenues of approximately $138 million and $42 million, respectively. Lower oil prices resulted in a decrease in revenues of approximately $209 million.

Average daily production volumes increased to approximately 1,210 MMcfe/d for the year ended December 31, 2014, from approximately 822 MMcfe/d for the year ended December 31, 2013. Higher oil, natural gas and NGL production volumes resulted in an increase in revenues of approximately $1.4 billion, $171 million and $43 million, respectively.

The following table sets forth average daily production by region:

	Year Ended December 31,			
	2014	2013	Variance	
Average daily production (MMcfe/d):				
Rockies	318	187	131	71 %
Mid-Continent	287	330	(43)	(13)%
Hugoton Basin	188	143	45	31 %
California	171	19	152	824 %
Permian Basin	153	87	66	76 %
TexLa	48	22	26	122 %
Michigan/Illinois	33	34	(1)	(3)%
South Texas	12	—	12	—
	1,210	822	388	47 %

The increase in average daily production volumes in the Rockies region primarily reflects the impact of the Berry acquisition in December 2013, the Devon Assets Acquisition on August 29, 2014, and development capital spending. The decrease in average daily production volumes in the Mid-Continent region primarily reflects lower development capital spending in the Granite Wash and lower production volumes as a result of the properties sold in the Granite Wash Assets Sale on December 15, 2014, partially offset by the impact of the Devon Assets Acquisition. The increase in average daily production volumes in the Hugoton Basin region primarily reflects the impact of the properties received in the exchange with Exxon XTO on August 15, 2014, the Pioneer Assets Acquisition on September 11, 2014, and development capital spending. The increase in average daily production volumes in the California region primarily reflects the impact of the Berry acquisition and the impact of the properties received in the exchange with ExxonMobil on November 21, 2014. The increase in average daily production volumes in the Permian Basin region primarily reflects the impact of an acquisition in October 2013, the Berry acquisition and development capital spending, partially offset by lower production volumes as a result of the properties relinquished in the two exchanges with Exxon XTO and ExxonMobil and the Permian Basin Assets Sale on November 14, 2014. The increase in average daily production volumes in the TexLa region primarily reflects the impact of the Berry acquisition and the Devon Assets Acquisition. The Michigan/Illinois region consists of a low-decline asset base and continues to produce at consistent levels. Average daily production volumes in the South Texas region reflect the impact of the Devon Assets Acquisition.

Gains (Losses) on Oil and Natural Gas Derivatives

Gains on oil and natural gas derivatives were approximately $1.2 billion and $178 million for the years ended December 31, 2014, and December 31, 2013, respectively, representing an increase of $1.0 billion. Gains on oil and natural gas derivatives increased primarily due to changes in fair value on unsettled derivative contracts. The results for 2014 also include cash settlements of approximately $12 million related to canceled derivatives contracts. In addition, the results for 2014 and 2013 include gains of approximately $7 million and $11 million, respectively, related to the recoveries of a bankruptcy claim (see Note 11). The fair value on unsettled derivatives contracts changes as future commodity price expectations change compared to the contract prices on the derivatives. If the expected future commodity prices increase compared to the contract prices on the derivatives, losses are recognized; and if the expected future commodity prices decrease compared to the contract prices on the derivatives, gains are recognized.

During the year ended December 31, 2014, the Company had commodity derivative contracts for approximately 85% of its natural gas production and 94% of its oil production. During the year ended December 31, 2013, the Company had commodity derivative contracts for approximately 107% of its natural gas production and 127% of its oil production. The Company does not hedge the portion of natural gas production used to economically offset natural gas consumption related to its heavy oil development operations in California.

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

Marketing and Other Revenues

Marketing revenues represent third-party activities associated with company-owned gathering systems, plants and facilities. Marketing and other revenues increased by approximately $86 million or 107% to approximately $167 million for the year ended December 31, 2014, from approximately $81 million for the year ended December 31, 2013. The increase was primarily due to electricity sales revenues generated by the Company's California cogeneration facilities acquired and certain contracts assumed in the Berry acquisition in December 2013, as well as higher revenues generated by the Jayhawk natural gas processing plant.

Expenses

Lease Operating Expenses

Lease operating expenses include expenses such as labor, field office, vehicle, supervision, maintenance, tools and supplies, and workover expenses. Lease operating expenses increased by approximately $432 million or 116% to approximately $805 million for the year ended December 31, 2014, from approximately $373 million for the year ended December 31, 2013. Lease operating expenses increased primarily due to costs associated with properties acquired in the Berry acquisition and acquisitions completed during the third quarter of 2014 (see Note 2). Lease operating expenses per Mcfe also increased to $1.82 per Mcfe for the year ended December 31, 2014, from $1.24 per Mcfe for the year ended December 31, 2013, primarily due to higher unit rates on newly acquired oil properties.

Transportation Expenses

Transportation expenses increased by approximately $79 million or 61% to approximately $207 million for the year ended December 31, 2014, from approximately $128 million for the year ended December 31, 2013. The increase was primarily due to costs associated with properties acquired in the Berry acquisition and acquisitions during the third quarter of 2014. Transportation expenses per Mcfe also increased to $0.47 per Mcfe for the year ended December 31, 2014, from $0.43 per Mcfe for the year ended December 31, 2013, primarily due to higher rates on Berry properties acquired in the Rockies region.

Marketing Expenses

Marketing expenses represent third-party activities associated with company-owned gathering systems, plants and facilities. Marketing expenses increased by approximately $79 million or 210% to approximately $117 million for the year ended December 31, 2014, from approximately $38 million for the year ended December 31, 2013. The increase was primarily due to electricity generation expenses incurred by the Company's California cogeneration facilities acquired and certain contracts assumed in the Berry acquisition, as well as higher expenses associated with the Jayhawk natural gas processing plant.

General and Administrative Expenses

General and administrative expenses are costs not directly associated with field operations and reflect the costs of employees including executive officers, related benefits, office leases and professional fees. General and administrative expenses increased by approximately $57 million or 24% to approximately $293 million for the year ended December 31, 2014, from approximately $236 million for the year ended December 31, 2013. The increase was primarily due to higher salaries and benefits related expenses, primarily driven by increased employee headcount and unit-based compensation, higher professional services expenses and higher various other administrative expenses, partially offset by lower non-payroll related

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acquisition expenses. Although general and administrative expenses increased, the unit rate decreased to $0.66 per Mcfe for the year ended December 31, 2014, from $0.79 per Mcfe for the year ended December 31, 2013.

Exploration Costs

Exploration costs increased by approximately $120 million to approximately $125 million for the year ended December 31, 2014, from approximately $5 million for the year ended December 31, 2013. The increase was due to higher leasehold impairment expenses on unproved properties, primarily in Michigan, the Mid-Continent and the Powder River Basin.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization increased by approximately $245 million or 29% to approximately $1.1 billion for the year ended December 31, 2014, from approximately $829 million for the year ended December 31, 2013. Higher total production volumes were the primary reason for the increased expense. Depreciation, depletion and amortization per Mcfe decreased to $2.43 per Mcfe for the year ended December 31, 2014, from $2.76 per Mcfe for the year ended December 31, 2013, primarily due to a lower rate in the Granite Wash formation as a result of the impairment recorded in the prior year and properties held for sale at September 30, 2014, that were divested on December 15, 2014.

Impairment of Long-Lived Assets

The Company recorded the following noncash impairment charges (before and after tax) associated with proved oil and natural gas properties:

	Year Ended December 31,	
	2014	2013