LINN ENERGY, LLC
Form 10-K
February 19, 2015

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, 2014

¨ 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<br>(State or other jurisdiction of<br>incorporation or organization) | 65-1177591<br>(I.R.S. Employer<br>Identification No.) |
| 600 Travis, Suite 5100<br>Houston, Texas<br>(Address of principal executive offices) | 77002<br>(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 Exchange 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 is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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 $6.5 billion on June 30, 2014, based on $32.35 per unit, the last reported sales price of the units on the NASDAQ Global Select Market on such date.

As of January 31, 2015, there were 335,562,043 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 from the registrant's definitive proxy statement for the annual meeting of unitholders to be held on April 21, 2015.

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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 a 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 crude oil that can be extracted from an oil 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 a 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 a 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. Additional reserves expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included in “proved developed reserves” only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.
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 a ratio of six Mcf of natural gas to one Bbl of oil, condensate or natural gas liquids.

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Glossary of Terms - Continued

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil, natural gas and NGL regardless of whether such acreage contains proved reserves.
Unproved reserves. Reserves that are considered less certain to be recovered than proved reserves. Unproved reserves may be further sub-classified to denote progressively increasing uncertainty of recoverability and include probable reserves and possible reserves.
Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.
Workover. Maintenance on a producing well to restore or increase production.
Zone. A stratigraphic interval containing one or more reservoirs.

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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 projections as of the date of this filing. These statements by their nature are subject to risks, uncertainties and assumptions and are influenced by various factors. As a consequence, actual results may differ materially from those expressed 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 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 (“IPO”) in January 2006. The Company’s properties are located in the United States (“U.S.”), in the Rockies, the Hugoton Basin, California, east Texas and north Louisiana (“TexLa”), the Mid-Continent, the Permian Basin, Michigan/Illinois and south Texas.

Proved reserves at December 31, 2014, were approximately 7,304 Bcfe, of which approximately 28% were oil, 58% were natural gas and 14% were natural gas liquids (“NGL”). Approximately 80% were classified as proved developed, with a total standardized measure of discounted future net cash flows of approximately $12.5 billion. At December 31, 2014, the Company operated 19,591 or approximately 71% of its 27,738 gross productive wells and had an average proved reserve-life index of approximately 17 years, based on the December 31, 2014, reserve reports and year-end 2014 production.

Strategy

The Company’s primary goal is to provide stability and growth of distributions for the long-term benefit of its unitholders. The following is a summary of the key elements of the Company’s business strategy:

- grow through acquisition of long-life, high quality properties;
- efficiently operate and develop acquired properties; and
- reduce cash flow volatility through hedging.

The Company’s business strategy is discussed in more detail below.

Grow Through Acquisition of Long-Life, High Quality Properties

The Company’s acquisition program targets oil and natural gas properties that it believes will be financially accretive and offer stable, long-life, high quality production with relatively predictable decline curves, as well as lower-risk development opportunities. The Company evaluates acquisitions based on rate of return, field cash flow, operational efficiency, reserve life, development costs and decline profile. As part of this strategy, the Company continually seeks to optimize its asset portfolio, which may include the divestiture of noncore assets. This allows the Company to redeploy capital into projects to develop lower-risk, long-life and low-decline properties that are better suited to its business strategy.

Since January 1, 2010, the Company has completed 37 acquisitions of working and royalty interests in oil and natural gas properties and related gathering and pipeline assets. Total acquired proved reserves as of the acquisition dates were approximately 7.2 Tcfe with acquisition costs of approximately $1.66 per Mcfe. Estimates of proved reserves as of the acquisition dates were primarily prepared by the independent engineering firm, DeGolyer and MacNaughton. The Company finances acquisitions with a combination of funds from equity and debt offerings, bank borrowings and net cash provided by operating activities. In addition, the Company completed two exchanges of properties during the year ended December 31, 2014. See Note 2 for additional details about the Company's acquisitions.

Efficiently Operate and Develop Acquired Properties

The Company has organized the operation of its acquired 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. For 2015, the Company estimates its total capital expenditures, excluding acquisitions, will be approximately $600 million, including approximately $520 million related to its oil and natural gas capital program and approximately $40 million related to its plant and pipeline capital. This estimate is under continuous review and is subject to ongoing adjustments. The Company expects to fund these capital expenditures primarily with net cash provided by operating activities.

Reduce Cash Flow Volatility Through Hedging

An important part of the Company's business strategy includes hedging a significant portion of its forecasted production to reduce exposure to fluctuations in the prices of oil and natural gas and provide long-term cash flow predictability to manage its business, service debt and pay distributions. The current direct NGL hedging market is constrained in terms of price, volume, duration and number of counterparties, which limits the Company's ability to effectively hedge its NGL production. As a result, currently, the Company directly hedges only its oil and natural gas production. The Company also hedges its exposure to natural gas differentials in certain operating areas but does not currently hedge exposure to oil differentials. By removing a significant portion of the price volatility associated with future production, the Company expects to mitigate, but not eliminate, the potential effects of variability in net cash provided by operating activities due to fluctuations in commodity prices.

Commodity hedging transactions are entered into with respect to a portion of the Company's projected production to provide an economic hedge of the risk related to the future commodity prices received. The Company does not enter into derivative contracts for trading purposes. The Company enters into commodity hedging transactions primarily in the form of swap contracts that are designed to provide a fixed price and, from time to time, put options that are designed to provide a fixed price floor with the opportunity for upside. In addition, as part of the 2013 acquisition of Berry Petroleum Company, now Berry Petroleum Company, LLC ("Berry") (see Note 2), the Company assumed certain derivative contracts that Berry had entered into prior to the acquisition date, including swap contracts, collars and three-way collars.

The Company maintains a substantial portion of its hedges in the form of swap contracts. From time to time, the Company has chosen to purchase put option contracts primarily in connection with acquisition activity to hedge volumes in excess of those already hedged with swap contracts. Put options require the payment of a premium, which the Company pays in cash at the time of execution and no additional amounts are payable in the future under the contracts. The appropriate level of production to be hedged is an ongoing consideration and is based on a variety of factors, including current and future expected commodity market prices, cost and availability of put option contracts, the level of acquisition activity and the Company's overall risk profile, including leverage and size and scale considerations. As a result, the appropriate percentage of production volumes to be hedged may change over time.

In certain historical periods, the Company paid an incremental premium to increase the fixed price floors on existing put options because the Company typically hedges multiple years in advance and in some cases commodity prices had increased significantly beyond the initial hedge prices. As a result, the Company determined that the existing put option strike prices did not provide reasonable downside protection in the context of the current market.

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For additional details about the Company's commodity derivatives, see Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Item 7A. "Quantitative and Qualitative Disclosures About Market Risk." See also Note 7 and Note 8.

In addition, the Company may from time to time enter into derivative contracts in the form of interest rate swaps to minimize the effects of fluctuations in interest rates. Currently, the Company has no outstanding interest rate swaps.

## Recent Developments

### Reduction of 2015 Capital Budget and Distribution

In February 2015, the Company's Board of Directors approved a revised 2015 budget which includes a 61% reduction in capital expenditures to approximately $600 million, from approximately $1.6 billion spent in 2014. The 2015 budget contemplates a significantly lower oil price than in 2014. 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. The reduction of the 2015 budget and the distribution are intended to solidify the Company's financial position and regain a useful cost of capital.

### Alliance with GSO Capital Partners

In January 2015, the Company also announced that it has signed a non-binding letter of intent with private capital investor GSO Capital Partners LP ("GSO") to fund oil and natural gas development (the "DrillCo Agreement"). Subject to final documentation, funds managed by GSO and its affiliates have agreed to commit up to $500 million with 5-year availability to fund drilling programs on locations provided by the Company. Subject to certain conditions, 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 the Company 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 Company's interest will increase to 95%.

This initiative is expected to allow the Company to develop oil and natural gas assets without increasing capital intensity, provide the potential to add a steady and growing cash flow stream without a capital requirement, increase the Company's long-term ability to fund capital expenditures and the distribution with internally generated cash flow, mitigate drilling risk for the Company and, upon meeting the return hurdle, provide incremental low-decline production growth for the Company. The DrillCo Agreement is subject to final negotiations and approval by the Company and GSO, and as such there can be no assurance that an agreement will be reached on the terms set forth in the letter of intent or at all.

### Exchanges of Properties

On November 21, 2014, the Company, through two of its wholly owned subsidiaries, completed the trade of a portion of its Permian Basin properties to Exxon Mobil Corporation in exchange for properties in California's South Belridge Field. As of the exchange date, the Company received approximately 185 Bcfe of proved reserves while Exxon Mobil Corporation received approximately 17,000 net acres prospective for horizontal Wolfcamp drilling in the Midland Basin, approximately 800 acres in the New Mexico Delaware Basin and approximately 100 Bcfe of proved reserves.

On August 15, 2014, the Company, through two of its wholly owned subsidiaries, completed the trade of a portion of its Permian Basin properties to Exxon Mobil Corporation and its affiliates, including its wholly owned subsidiary XTO Energy Inc. (collectively, "ExxonMobil"), in exchange for properties in the Hugoton Basin. As of the exchange date, the Company received approximately 659 Bcfe of proved reserves while ExxonMobil received approximately 25,000 net acres in the Midland Basin, which are located primarily in Midland, Martin, Upton and Glasscock counties, and approximately 162 Bcfe of proved reserves.

### Acquisitions

On September 11, 2014, the Company completed the acquisition of certain oil and natural gas properties located in the Hugoton Basin from Pioneer Natural Resources Company ("Pioneer" and the acquisition, the "Pioneer Assets Acquisition") for total consideration of approximately $328 million. The acquisition included approximately 303 Bcfe of proved reserves as of the acquisition date.

On August 29, 2014, the Company completed the acquisition of certain oil and natural gas properties located in five operating regions in the U.S. from subsidiaries of Devon Energy Corporation ("Devon" and the acquisition, the "Devon Assets Acquisition") for total consideration of approximately $2.1 billion. The acquisition included approximately 1,344 Bcfe of proved reserves as of the acquisition date.

During the year ended December 31, 2014, the Company also completed other smaller acquisitions of oil and natural gas properties located in its various operating regions. The Company, in the aggregate, paid approximately $5 million in total consideration for these properties.

Divestitures

On December 15, 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 to privately held institutional affiliates of EnerVest, Ltd. and its joint venture partner FourPoint Energy, LLC (the "Granite Wash Assets Sale"). Cash proceeds received from the sale of these properties were approximately $1.8 billion, net of costs to sell of approximately $10 million.

On November 14, 2014, the Company completed the sale of certain of its Wolfberry properties in Ector and Midland counties in the Permian Basin to Fleur de Lis Energy, LLC (the "Permian Basin Assets Sale"). Cash proceeds received from the sale of these properties were approximately $351 million, net of costs to sell of approximately $2 million.

On October 30, 2014, the Company completed the sale of its interests in certain non-producing oil and natural gas properties located in the Mid-Continent region. Cash proceeds received from the sale of these properties were approximately $44 million.

The Company used the net cash proceeds received from these sales to repay in full the VIE Term Loan, as defined in Note 6, as well as repay a portion of the borrowings outstanding under the LINN Credit Facility, also defined in Note 6.

Distributions

On January 2, 2015, the Company's Board of Directors declared a cash distribution of $0.3125 per unit with respect to the fourth quarter of 2014, to be paid in three equal monthly installments of $0.1042 per unit. The current distribution represents an approximate 57% decrease from the distribution of $0.725 paid for the previous quarter. The first monthly distribution with respect to the fourth quarter of 2014, totaling approximately $35 million, was paid on January 15, 2015, to unitholders of record as of the close of business on January 12, 2015, and the second monthly distribution, totaling approximately $35 million, was paid on February 17, 2015, to unitholders of record as of the close of business on February 10, 2015.

Operating Regions

The Company's properties are located in eight operating regions in the U.S.:

- 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);
- Hugoton Basin, which includes properties located in Kansas, the Oklahoma Panhandle and the Shallow Texas Panhandle;
- 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;
- Permian Basin, which includes properties located in west Texas and southeast New Mexico;
- Michigan/Illinois, which includes properties located in the Antrim Shale formation in north Michigan and oil properties in south Illinois; and
- South Texas.

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 14,000 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 14,000 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 $CO_2$ flood operated by Anadarko Petroleum Corporation 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 29% of total proved reserves at December 31, 2014, of which 65% were classified as proved developed. This region produced approximately 318 MMcfe/d or 26% of the Company's 2014 average daily production. During 2014, the Company invested approximately $590 million to develop the properties in this region. During 2015, the Company anticipates spending approximately 40% of its total oil and natural gas capital budget for development activities in the Rockies region.

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 extract 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 3,900 miles of pipeline and related facilities operated by the Company, of which approximately 2,050 miles of pipeline are owned by the Company.

Hugoton Basin proved reserves represented approximately 28% of total proved reserves at December 31, 2014, of which 83% were classified as proved developed. This region produced approximately 188 MMcfe/d or 15% of the Company's 2014 average daily production. During 2014, the Company invested approximately $52 million to develop the properties in this region. During 2015, the Company anticipates spending approximately 2% of its total oil and natural gas capital budget for development activities in the Hugoton Basin 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 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.

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California proved reserves represented approximately 15% of total proved reserves at December 31, 2014, of which 74% were classified as proved developed. This region produced approximately 171 MMcfe/d or 14% of the Company's 2014 average daily production. During 2014, the Company invested approximately $236 million to develop the properties in this region. During 2015, the Company anticipates spending approximately 29% 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 9% of total proved reserves at December 31, 2014, 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 48 MMcfe/d or 4% of the Company's 2014 average daily production. During 2014, the Company invested approximately $6 million to develop properties in this region. During 2015, the Company anticipates spending approximately 11% 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. Wells in this diverse region produce from both oil and natural gas reservoirs at depths ranging from 1,500 feet to 11,000 feet, and as of December 31, 2014, the Company's remaining 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, 2014, of which 99% were classified as proved developed. This region produced approximately 287 MMcfe/d or 24% of the Company's 2014 average daily production. During 2014, the Company invested approximately $245 million to develop the properties in this region. During 2015, the Company anticipates spending approximately 7% of its total oil and natural gas capital budget for development activities in the Mid-Continent 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. The Company's properties are located in west Texas and southeast New Mexico and primarily produce at depths ranging from 2,000 feet to 12,000 feet, and as of December 31, 2014, the Company's remaining properties in this region are primarily mature, low-decline oil and natural gas wells including several waterflood properties located across the basin.

Permian Basin proved reserves represented approximately 5% of total proved reserves at December 31, 2014, of which 70% were classified as proved developed. This region produced approximately 153 MMcfe/d or 13% of the Company's 2014 average daily production. During 2014, the Company invested approximately $355 million to develop the properties in this region. During 2015, the Company anticipates spending approximately 8% of its total oil and natural gas capital budget for development activities in the Permian Basin region.

Michigan/Illinois

The Michigan/Illinois region consists primarily of natural gas properties in the Antrim Shale formation in north Michigan and also includes oil properties in south Illinois. These wells produce at depths ranging from 600 feet to 4,000 feet. Michigan/Illinois proved reserves represented approximately 4% of total proved reserves at December 31, 2014, all of which were classified as proved developed. This region produced approximately 33 MMcfe/d or 3% of the Company's 2014 average daily production. During 2014, the Company invested approximately $3 million to develop properties in this region. During 2015, the Company anticipates spending approximately 1% of its total oil and natural gas capital budget for development activities in the Michigan/Illinois region.

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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 4,000 feet to 14,000 feet. Proved reserves for these mature properties, the majority of which are natural gas with associated NGL, represented approximately 1% of total proved reserves at December 31, 2014, all of which were classified as proved developed. This region produced approximately 12 MMcfe/d or 2% of the Company's 2014 average daily production. During 2015, the Company anticipates spending approximately 2% of its total oil and natural gas capital budget for development activities in the South Texas region.
Drilling and Acreage
The following sets forth the wells drilled during the periods indicated ("gross" refers to the total wells in which the Company had a working interest and "net" refers to gross wells multiplied by the Company's working interest):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| Gross wells: | | | |
| Productive | 917 | 557 | 436 |
| Dry | 1 | 2 | 4 |
| | 918 | 559 | 440 |
| Net development wells: | | | |
| Productive | 698 | 304 | 223 |
| Dry | 1 | 1 | 2 |
| | 699 | 305 | 225 |
| Net exploratory wells: | | | |
| Productive | — | 1 | — |
| Dry | — | — | — |
| | — | 1 | — |

There were no lateral segments added to existing vertical wellbores during the years ended December 31, 2014, December 31, 2013, or December 31, 2012. As of December 31, 2014, the Company had 97 gross (96 net) wells in progress (no wells were temporarily suspended).
This information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled and the quantities or economic value of reserves found. Productive wells are those that produce commercial quantities of oil, natural gas or NGL, regardless of whether they generate a reasonable rate of return.
The following sets forth information about the Company's drilling locations and net acres of leasehold interests as of December 31, 2014:

| | Total [1] |
|---|---|
| Proved undeveloped | 2,778 |
| Other locations | 8,107 |
| Total drilling locations | 10,885 |
| | |
| Leasehold interests – net acres (in thousands) | 3,406 |

[1] Does not include optimization projects.

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As shown in the table above, as of December 31, 2014, the Company had 2,778 proved undeveloped drilling locations (specific drilling locations as to which the independent engineering firm, DeGolyer and MacNaughton, assigned proved undeveloped reserves as of such date) and the Company had identified 8,107 additional unproved drilling locations (specific drilling locations as to which DeGolyer and MacNaughton has not assigned any proved reserves) on acreage that the Company has under existing leases. As successful development wells frequently result in the reclassification of adjacent lease acreage from unproved to proved, the Company expects that a significant number of its unproved drilling locations will be reclassified as proved drilling locations prior to the actual drilling of these locations.

Productive Wells

The following sets forth information relating to the productive wells in which the Company owned a working interest as of December 31, 2014. Productive wells consist of producing wells and wells capable of production, including wells awaiting pipeline or other connections to commence deliveries. Gross wells refer to the total number of producing wells in which the Company has a working interest and net wells refer to the sum of its fractional working interests owned in gross wells. The number of wells below does not include approximately 2,640 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)] | 12,144 | 10,305 | 7,447 | 6,741 | 19,591 | 17,046 |
| Nonoperated [(2)] | 5,477 | 1,659 | 2,670 | 336 | 8,147 | 1,995 |
| | 17,621 | 11,964 | 10,117 | 7,077 | 27,738 | 19,041 |

(1) The Company had 11 operated wells with multiple completions at December 31, 2014.

(2) The Company had 1 nonoperated well with multiple completions at December 31, 2014.

Developed and Undeveloped Acreage

The following sets forth information relating to leasehold acreage as of December 31, 2014:

| | Developed Acreage | | Undeveloped Acreage | | Total Acreage | |
|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net |
| | (in thousands) | | | | | |
| Leasehold acreage | 4,328 | 3,144 | 405 | 262 | 4,733 | 3,406 |

Production, Price and Cost History

The Company’s natural gas production is primarily sold under market-sensitive contracts which 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 based on indexes published for the producing area. Although exact percentages vary daily, as of December 31, 2014, 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, 2014, 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

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approximately 5,356 MBbls, 5,279 MBbls and 4,180 MBbls to be delivered in 2015, 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 which 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, 2014, approximately 90% of its oil production was sold under short-term contracts. As of December 31, 2014, the Company had oil delivery commitments under long-term contracts of approximately 5,840 MBbls to be delivered by June 2018.

As discussed in the "Strategy" section above, the Company enters into derivative contracts primarily in the form of swap contracts, collars, three-way collars and put options to reduce the impact of commodity price volatility on its net cash provided by operating activities. By removing a significant portion of the price volatility associated with future production, the Company expects to mitigate, but not eliminate, the potential effects of variability in net cash provided by operating activities due to fluctuations in commodity prices.

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

The following table sets forth information about material long-term firm transportation contracts for pipeline capacity as of December 31, 2014:

| 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) | $31,906 |
| Rockies Express Pipeline | Meeker, CO | Clarington, OH | 10,000 | 6/2009 to 11/2019 | 1.09 | (1) | 19,420 |
| Questar Pipeline | Chipeta Plant, UT | Various UT locations | 6,200 | 2/2013 to 2/2021 | 0.17 | | 2,039 |
| Ruby Pipeline | Opal, WY | Malin, OR | 37,857 | 8/2011 to 7/2021 | 0.95 | | 86,419 |
| Wyoming Interstate Company Pipeline | Meeker, CO | Opal, WY | 37,857 | 8/2011 to 7/2021 | 0.31 | | 27,900 |
| Questar Pipeline | Chipeta Plant, UT | Goshen, UT | 5,000 | 9/2003 to 10/2022 | 0.26 | | 3,679 |
| Questar Pipeline | Brundage Canyon, UT | Chipeta Plant, UT | 15,640 | 9/2013 to 8/2023 | 0.17 | | 9,036 |
| Total | | | | | | | $180,399 |

(1) Based on weighted average cost.

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

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| Average daily production: | | | |
| Natural gas (MMcf/d) | 572 | 443 | 349 |
| Oil (MBbls/d) | 72.9 | 33.5 | 29.2 |
| NGL (MBbls/d) | 33.5 | 29.7 | 24.5 |
| Total (MMcfe/d) | 1,210 | 822 | 671 |
| | | | |
| Weighted average prices: (1) | | | |
| Natural gas (Mcf) | $4.29 | $3.62 | $2.87 |
| Oil (Bbl) | $86.28 | $94.15 | $88.59 |
| NGL (Bbl) | $34.40 | $30.96 | $32.10 |
| | | | |
| Average NYMEX prices: | | | |
| Natural gas (MMBtu) | $4.41 | $3.65 | $2.79 |
| Oil (Bbl) | $93.00 | $97.97 | $94.20 |
| | | | |
| Costs per Mcfe of production: | | | |
| Lease operating expenses | $1.82 | $1.24 | $1.29 |
| Transportation expenses | $0.47 | $0.43 | $0.31 |
| General and administrative expenses (2) | $0.66 | $0.79 | $0.71 |
| Depreciation, depletion and amortization | $2.43 | $2.76 | $2.47 |
| Taxes, other than income taxes | $0.61 | $0.46 | $0.54 |

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

(2) General and administrative expenses for the years ended December 31, 2014, December 31, 2013, and December 31, 2012, include approximately $45 million, $37 million and $28 million, respectively, of noncash unit-based compensation expenses.

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, 2014.

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 consuming less fuel.

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Conventional Steam Generation

The Company also owns 68 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 the Company 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 net electrical generation capacity of the Company's three cogeneration facilities, which are centrally located on certain of the Company's oil producing properties, was approximately 91 MW as of December 31, 2014. The steam 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.

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Reserve Data

Proved Reserves

The following sets forth estimated proved oil, natural gas and NGL reserves and the standardized measure of discounted future net cash flows at December 31, 2014, based on reserve reports prepared by independent engineers, DeGolyer and MacNaughton:

| | | |
|---|---|---|
| Estimated proved developed reserves: | | |
| Natural gas (Bcf) | 3,549 | |
| Oil (MMBbls) | 246 | |
| NGL (MMBbls) | 132 | |
| Total (Bcfe) | 5,818 | |
| | | |
| Estimated proved undeveloped reserves: | | |
| Natural gas (Bcf) | 706 | |
| Oil (MMBbls) | 96 | |
| NGL (MMBbls) | 34 | |
| Total (Bcfe) | 1,486 | |
| | | |
| Estimated total proved reserves (Bcfe) | 7,304 | |
| Proved developed reserves as a percentage of total proved reserves | 80 | % |
| Standardized measure of discounted future net cash flows (in millions) (1) | $12,512 | |
| | | |
| Representative NYMEX prices: (2) | | |
| Natural gas (MMBtu) | $4.35 | |
| Oil (Bbl) | $95.27 | |

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

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

During the year ended December 31, 2014, the Company's proved undeveloped reserves ("PUDs") decreased to 1,486 Bcfe from 2,063 Bcfe at December 31, 2013, representing a decrease of 577 Bcfe. The decrease was due to 446 Bcfe of PUDs developed during 2014, 411 Bcfe related to the 2014 divestitures and properties relinquished in the two exchanges with Exxon Mobil Corporation and 229 Bcfe of revisions due primarily to asset performance and the SEC five-year development limitation, partially offset by 383 Bcfe added primarily as a result of the acquisitions from Devon and Pioneer and properties acquired in the two exchanges with Exxon Mobil Corporation and 126 Bcfe added as a result of the Company's drilling activities.

During the year ended December 31, 2014, the Company incurred approximately $820 million in capital expenditures to convert 446 Bcfe of reserves that were classified as PUDs at December 31, 2013, to proved developed reserves. Based on the December 31, 2014 reserve reports, the amounts of capital expenditures estimated to be incurred in 2015, 2016 and 2017 to develop the Company's PUDs are approximately $405 million, $923 million and $837 million, respectively. The amount and timing of these expenditures will depend on a number of factors, including actual drilling results, service costs and product prices. None of the 1,486 Bcfe of PUDs at December 31, 2014, has remained undeveloped for five years or more. All PUD properties are included in the Company's current five-year development plan.

Reserve engineering is inherently a subjective process of estimating underground accumulations of oil, natural gas and NGL that cannot be measured exactly. The accuracy of any reserve estimate is a function of the quality of available data and engineering and geological interpretation and judgment. Accordingly, reserve estimates may vary from the quantities of oil,

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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, is 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 that not only replace production, but add value through reserve and production growth and future operational synergies. Many of the Company’s wells are completed in multiple producing zones with commingled production and long economic lives.

### Principal Customers

For the year ended December 31, 2014, sales of oil, natural gas and NGL to Enbridge Energy Partners, L.P. accounted for approximately 13% of the Company’s total production volumes. 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 these 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 volume of oil and natural gas 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 and results of operations. 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. Oil and natural gas properties are subject to customary royalty and other interests, liens for current taxes and other burdens which do not materially interfere with the use of or affect the carrying value of the properties.

### Seasonal Nature of Business

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

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

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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 lying 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.

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.

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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 two sets of rules regulating GHG emissions under the CAA, one that requires a reduction in emissions of GHGs from motor vehicles and the other that regulates emissions of GHGs from certain large stationary sources under the CAA's Prevention of Significant Deterioration and Title V permitting programs. 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. 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 thereafter 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 ("CCAs") 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 continues to assess the impact of these regulations on its operations, including the cost to acquire allowances and to reduce emissions. The Company's cost of acquiring compliance instruments in 2014 was in the range of \$1.50 to \$2.50 per barrel of 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, on May 16, 2013, the Department of the Interior's Bureau of Land Management ("BLM") issued a proposed rule that, if adopted, would require 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 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 adopted, these 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 entire state of New York and certain communities in Colorado and Texas have enacted bans or moratoria on hydraulic fracturing, to which legal challenges are 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 and results of operations.

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 as a result of flawed well design or operation. This has resulted in stricter regulatory requirements in some jurisdictions relating to the location and operation of underground injection wells. The Company does not expect these developments to have a material adverse effect on its business, financial condition, results or operations or cash flows.

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 as well as existing wells that are refractured. Further, the finalized regulations also establish specific new requirements for emissions from compressors, controllers, dehydrators, storage tanks, gas processing plants and certain other equipment. The EPA amended these rules in December 2014 to specify requirements for different flowback stages and to expand the rules to cover more storage vessels, among other changes. These rules may require changes to the Company’s operations, including the installation of new equipment to control emissions.

The Company’s costs for environmental compliance may increase in the future based on new environmental regulations. In January 2015, the EPA announced plans to issue a proposed rule in summer 2015 governing methane emissions from the oil and natural gas industry. The BLM is also expected to address methane emissions from the oil and natural gas industry on federal 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. Under the Energy Policy Act of 2005, FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1 million per day for each violation and disgorgement of profits associated with any violation.

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, 2014, the Company did not incur any material capital expenditures for installation of remediation or pollution control equipment at any of the Company's facilities. The Company is not aware of any environmental issues or claims that will require material capital expenditures during 2015 or that will otherwise have a material impact on its financial position or results of operations.

Employees

As of December 31, 2014, the Company employed approximately 1,800 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.

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.

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Item 1. Business - Continued

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 maintain or grow distributions;
- 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, 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 listed in the "Risk Factors" section 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.

We may not have sufficient net cash provided by operating activities to pay our distribution at the current distribution level, or at all, and as a result, future distributions to our unitholders may be reduced, suspended or eliminated.
While our Board of Directors makes discretionary adjustments to net cash provided by operating activities when declaring a distribution for the current period, if we generate insufficient net cash provided by operating activities for a sustained period of time and/or forecasts demonstrate expectations of continued future insufficiencies, our Board of Directors may determine to reduce, suspend or eliminate our distribution to unitholders. Any such reduction, suspension or elimination in distributions may cause the trading price of our units to decline. Factors that may cause us to generate net cash provided by operating activities that is insufficient to pay our current distribution to unitholders include, among other things, the following:

- Unhedged oil production: Our expected oil production for 2015 is approximately 70% hedged at approximately $94 per Bbl and 2016 is approximately 65% hedged at approximately $90 per Bbl. As a result, a meaningful portion of our expected oil production for 2015 and 2016 remains unhedged and subject to fluctuating market prices. If we are ultimately unable to hedge additional expected oil production volumes for 2015 and beyond, we will be subject to further potential commodity price volatility, which may result in lower than expected net cash provided by operating activities. Consequently, our Board of Directors may determine to reduce, suspend or eliminate future distributions to our unitholders.
- Reduced capital expenditures: As previously announced, we have approved a 2015 budget which includes a 61% reduction in capital expenditures to approximately $600 million, from approximately $1.6 billion spent in 2014. If our capital program continues to be limited or is further reduced in the future, our production volumes and revenues may be lower than expected, net cash provided by operating activities could be insufficient to pay our current distribution to unitholders, and our Board of Directors may determine to reduce, suspend or eliminate future distributions to our unitholders.
- Liquidity position: Our liquidity is dependent on many factors, including availability under our Credit Facilities, as defined in Note 6, and cost and access to capital and credit markets, which are affected by the price and performance of our equity and debt securities. If the borrowing bases under our Credit Facilities are reduced and we are otherwise unable to maintain our current liquidity position, we may no longer have the financial flexibility to manage our business, including funding our planned capital expenditures, and our Board of Directors may determine to reduce, suspend or eliminate future distributions to our unitholders.
- Ability to consummate accretive acquisitions: Accretive acquisitions are an integral component of our business strategy. When cash flows are expected to be lower as a result of weak commodity prices on unhedged volumes, under-performance of assets, or declining contract prices on hedged volumes, we seek to make accretive acquisitions of oil and natural gas properties to cover potential shortfalls in net cash provided by operating activities in order to maintain our distribution level. As a result of the effect of weakened commodity prices on the price of our equity and debt securities, we may be limited in our ability to access the capital markets at an acceptable cost or at all; thus, our ability to make accretive acquisitions may be limited, in which case our Board of Directors may determine to reduce, suspend or eliminate future distributions to our unitholders.

As a result of these and other factors, the amount of cash we distribute to our unitholders in the future may be significantly less than the current distribution level, and future distributions to our unitholders may be reduced, suspended or eliminated.
The borrowing bases under our Credit Facilities are subject to redetermination and any reduction in either borrowing base may result in our having to repay indebtedness under our Credit Facilities earlier than anticipated, potentially causing future distributions to our unitholders to be reduced, suspended or eliminated.
Each of our Credit Facilities is subject to scheduled redeterminations of its borrowing base, based primarily on reserve reports using lender commodity price expectations at such time, semi-annually in April and October. 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. If current low commodity prices continue through such redetermination events, the borrowing base under either Credit Facility may be reduced. Upon

any such potential reduction, any outstanding

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indebtedness in excess of the new borrowing base may become due within a short time span or we must pledge other properties as additional collateral. We currently have limited unpledged properties.

In particular, because the Berry Credit Facility is effectively fully drawn, any such reduction in the Berry Credit Facility's borrowing base may require Berry and us to make mandatory prepayments under the Berry Credit Facility to the extent existing indebtedness under the Berry Credit Facility exceeds the new borrowing base, or we may choose to post restricted cash on Berry's behalf, reducing our liquidity position. If we are required to repay indebtedness under either of our Credit Facilities earlier than anticipated due to a borrowing base redetermination, it may be necessary to use cash that would otherwise be available for capital expenditures or distributions to our unitholders to repay such indebtedness. As a result of this, future distributions to our unitholders may be reduced, suspended or eliminated. In addition, any failure to repay indebtedness in excess of our borrowing bases would constitute an event of default under the Credit Facilities, and could cause a cross-default under our other outstanding indebtedness.

Commodity prices are volatile, and a significant decline in commodity prices for a prolonged period would reduce our revenues, net cash provided by operating activities and profitability and we may have to lower our distribution or may not be able to pay distributions at all.

Our revenues, profitability and cash flow depend on the prices of and demand for oil, natural gas and NGL. The oil, natural gas and NGL market is very volatile and a drop in prices can 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. 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.

In the fourth quarter of 2014 and subsequent to December 31, 2014, the prices of oil, natural gas and NGLs have been extremely volatile and declined significantly. Downward pressure on commodity prices has continued in 2015 and may continue for the foreseeable future. If commodity prices continue at current levels for a prolonged period or further decline, our net cash provided by operating activities will decline, and we may have to reduce our distribution, which we did at the beginning of 2015, or future distributions to our unitholders may be suspended or eliminated.

We may not have sufficient net cash provided by operating activities to pay our distribution at the current distribution level, or at all, and future distributions to our unitholders may fluctuate from quarter to quarter.

We may not have sufficient net cash provided by operating activities each quarter to pay our distribution at the current distribution level or at all. Under the terms of our limited liability company agreement, the amount of cash otherwise available for distribution will be reduced by our operating expenses and any cash reserve amounts that our Board of Directors establishes to provide for future operations, future capital expenditures, future debt service requirements and future cash

distributions to our unitholders. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- produced volumes of oil, natural gas and NGL;
- prices at which oil, natural gas and NGL production is sold;
- level of our operating costs;
- payment of interest, which depends on the amount of our indebtedness and the interest payable thereon; and
- level of our capital expenditures.

For example, in response to significantly lower oil prices beginning in the fourth quarter of 2014, and in order to solidify our financial position and regain a useful cost of capital, we reduced our oil and natural gas capital budget and distribution to unitholders. In addition, the actual amount of cash we will have available for distribution will depend on other factors, some of which are beyond our control, including:

- availability of borrowings on acceptable terms under the LINN Credit Facility, as defined in Note 6, to pay distributions;
- the costs of acquisitions, if any;
- fluctuations in our working capital needs;
- timing and collectability of receivables;
- restrictions on distributions contained in our Credit Facilities and the indentures governing our May 2019 Senior Notes, November 2019 Senior Notes, 2010 Issued Senior Notes, Berry November 2020 Senior Notes and Berry September 2022 Senior Notes, as defined in Note 6;
- prevailing economic conditions;
- access to credit or capital markets; and
- the amount of cash reserves established by our Board of Directors for the proper conduct of our business.

As a result of these and other factors, the amount of cash we distribute to our unitholders may fluctuate significantly from quarter to quarter and may be significantly less than the current distribution level, or the distribution may be reduced, suspended or eliminated.

We actively seek to acquire oil and natural gas properties. Acquisitions involve potential risks that could adversely impact our future growth and our ability to increase or pay distributions at the current level, or at all.

Any acquisition involves potential risks, including, among other things:

- the risk that reserves expected to support the acquired assets may not be of the anticipated magnitude or may not be developed as anticipated;
- the risk of title defects discovered after closing;
- inaccurate assumptions about revenues and costs, including synergies;
- significant increases in our indebtedness and working capital requirements;
- an inability to transition and integrate successfully or timely the businesses we acquire;
- the cost of transition and integration of data systems and processes;
- the potential environmental problems and costs;
- the assumption of unknown liabilities;
- limitations on rights to indemnity from the seller;
- the diversion of management’s attention from other business concerns;
- increased demands on existing personnel and on our corporate structure;
- disputes arising out of acquisitions;
- customer or key employee losses of the acquired businesses; and
- the failure to realize expected growth or profitability.

The scope and cost of these risks may ultimately be materially greater than estimated at the time of the acquisition. Further, our future acquisition costs may be higher than those we have achieved historically. Any of these factors could adversely impact our future growth and our ability to increase or pay distributions.

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If we do not make future acquisitions on economically acceptable terms, then our growth and ability to pay or increase distributions will be limited.

Our ability to grow and to pay or increase distributions to our unitholders is partially dependent on our ability to make acquisitions that result in an increase in net cash provided by operating activities. We may be unable to make such acquisitions because we are:

- unable to identify attractive acquisition candidates or negotiate acceptable purchase agreements with them;
- unable to obtain financing for these acquisitions on economically acceptable terms; or
- outbid by competitors.

In any such case, our future growth and ability to pay or increase distributions will be limited. Furthermore, even if we do make acquisitions that we believe will increase net cash provided by operating activities, these acquisitions may nevertheless result in a decrease in available cash flow per unit and future distributions to our unitholders may be reduced, suspended or eliminated.

If we are unable to replace declines in production, proved developed producing reserves and cash flow from discretionary reductions for a portion of our oil and natural gas development costs, our net cash provided by operating activities could be reduced, which could adversely affect our ability to pay a distribution at the current level or at all.

In determining the amount of cash that we distribute to unitholders, 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 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 pay a distribution at the current level or at all. 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 adversely affect our ability to pay a distribution at the current level or at all.

We have significant indebtedness under our May 2019 Senior Notes, November 2019 Senior Notes, 2010 Issued Senior Notes, Berry November 2020 Senior Notes and Berry September 2022 Senior Notes (collectively, “Senior Notes”) and, from time to time, our Credit Facilities. For a discussion of our debt, see Note 6. Our Credit Facilities and the indentures governing our Senior Notes have substantial restrictions and financial covenants and we may have difficulty obtaining additional credit, which could adversely affect our operations, our ability to make acquisitions and our ability to pay distributions to our unitholders.

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As of January 31, 2015, we had an aggregate of approximately $10.3 billion outstanding under Senior Notes and our Credit Facilities (with additional borrowing capacity of approximately $2.2 billion under the LINN Credit Facility). As a result of our indebtedness, we will use a portion of our cash flow to pay interest and principal when due, which will reduce the cash available to finance our operations and other business activities and could limit our flexibility in planning for or reacting to changes in our business and the industry in which we operate.
The Credit Facilities restrict our ability to obtain additional financing, make investments, lease equipment, sell assets, enter into commodity and interest rate derivative contracts and engage in business combinations. We are also required to comply with certain financial covenants and ratios under our Credit Facilities and the indentures governing our Senior Notes. Our ability to comply with these restrictions and covenants in the future is uncertain and will be affected by the levels of cash flow from our operations and events or circumstances beyond our control. Our failure to comply with any of the restrictions and covenants could result in an event of default, which, if it continues beyond any applicable cure periods, could cause all of our existing indebtedness to be immediately due and payable.
We depend, in part, on our Credit Facilities for future capital needs; however, at December 31, 2014, there was no remaining borrowing capacity available under the Berry Credit Facility. We have drawn on the LINN Credit Facility to fund or partially fund cash distribution payments. Absent such borrowing, we would have at times experienced a shortfall in cash available to pay our declared cash distribution amount. If there is a default by us under our Credit Facilities that continues beyond any applicable cure period, we would be unable to make borrowings to fund distributions. In addition, we may finance acquisitions through borrowings under our Credit Facilities or the incurrence of additional debt. To the extent that we are unable to incur additional debt under our Credit Facilities or otherwise because we are not in compliance with the financial covenants in the Credit Facilities, we may not be able to complete acquisitions, which could adversely affect our ability to pay or increase distributions to our unitholders. Furthermore, to the extent we are unable to refinance our Credit Facilities on terms that are as favorable as those in our existing Credit Facilities, or at all, our ability to fund our operations and our ability to pay distributions could be affected.
The borrowing bases under our Credit Facilities are determined semi-annually at the discretion of the lenders and are based in part on oil, natural gas and NGL prices. Significant declines in oil, natural gas or NGL prices may result in a decrease in our borrowing base. The lenders can unilaterally adjust the borrowing base and therefore the borrowings permitted to be outstanding under the Credit Facilities. Any increase in the borrowing base requires the consent of all the lenders. Outstanding borrowings in excess of the borrowing base must be repaid immediately, or we must pledge other properties as additional collateral. We currently have limited unpledged properties, and we may not have the financial resources in the future to make any mandatory principal prepayments if required under the Credit Facilities. Significant declines in our production or significant declines in realized oil, natural gas or NGL prices for prolonged periods and resulting decreases in our borrowing base may force us to reduce, suspend or eliminate future distributions to our unitholders.
Our ability to access the capital and credit markets to raise capital and borrow on favorable terms will be affected by disruptions in the capital and credit markets, which could adversely affect our operations, our ability to make acquisitions and our ability to pay distributions to our unitholders.
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. Recent decreases in commodity prices, among other things, may cause some lenders to increase interest rates, enact tighter lending standards, refuse to refinance existing debt at maturity on favorable terms or at all and may reduce or cease to provide funding to borrowers. If we are unable to access the capital and credit markets on favorable terms, our ability to make acquisitions and pay distributions could be affected and future distributions to our unitholders may be reduced, suspended or eliminated.
Our variable rate indebtedness subjects us to interest rate risk, which could cause our debt service obligations to increase significantly.
Borrowings under our Credit Facilities bear interest at variable rates and expose us to interest rate risk. If interest rates increase and we are unable to effectively hedge our interest rate risk, our debt service obligations on the variable rate

indebtedness would increase even though the amount borrowed remained the same, and our net income and cash available for servicing our indebtedness would decrease.

Increases in interest rates could adversely affect the demand for our units.

An increase in interest rates may cause a corresponding decline in demand for equity investments, in particular for yield-based equity investments such as our units. Any such reduction in demand for our units resulting from other more attractive investment opportunities may cause the trading price of our units to decline.

The terms of Berry's senior notes restrict Berry's ability to make distributions to us, which may limit the cash available to pay distributions to our unitholders.

The indentures governing Berry's senior notes contain, and any future indebtedness may also contain, a number of restrictive covenants that impose financial restrictions on Berry, including restrictions on Berry's ability to make cash distributions to us. These restrictions on Berry's ability to make cash distributions to us may adversely affect our ability to pay distributions to our unitholders at the current level or at all.

Our commodity derivative activities could result in financial losses or could reduce our income, which may adversely affect our ability to pay distributions to our unitholders.

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 enter into commodity derivative contracts for a significant 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 cash flow from our sale of the underlying physical commodity, resulting in a substantial reduction of our liquidity, which may adversely affect our ability to pay distributions to our unitholders and future distributions to our unitholders may be reduced, suspended or eliminated.

Our limited ability to hedge our NGL production and commodity basis differentials could adversely impact our net cash provided by operating activities and results of operations.

A liquid, readily available and commercially viable market for hedging NGL and commodity basis differentials has not developed in the same way that exists for crude oil and natural gas priced at WTI and Henry Hub, respectively. The current direct NGL and commodity basis differential hedging market is constrained in terms of price, volume, duration and number of counterparties. This limits both our ability to hedge our NGL production and price difference based on point of sale effectively or at all. As a result, currently, we directly hedge only our oil and natural gas production priced at WTI and Henry Hub, respectively. If the current price levels for NGL continue or decrease in the future or the commodity basis differentials versus WTI or Henry Hub negatively increase, our revenues and results of operations would be affected, net cash provided by operating activities could be insufficient to pay our current distribution to unitholders and future distributions to our unitholders may be reduced, suspended or eliminated.

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 could be insufficient to pay our current distribution to unitholders and future distributions to our unitholders may be reduced, suspended or eliminated.

The swaps regulatory provisions of the Dodd-Frank Act and the rules adopted thereunder could have an adverse impact on our ability to hedge risks associated with our business and on our results of operations and cash flows.

Title VII of the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") establishes federal oversight and regulation of the over-the-counter ("OTC") derivatives market and entities, such as us, that participate in that market. The provisions of that title of the Dodd-Frank Act and the rules of the Commodity Future Trading Commission ("CFTC") and the SEC adopted and proposed to be adopted thereunder, regulate certain swaps entities, require clearing of certain swaps by clearing organizations and execution of certain swaps on contract markets or swap execution facilities, and require certain reporting and recordkeeping of swaps. They also give the CFTC the authority to establish limits on the positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities held by market

participants, with exceptions for certain bona fide hedging transactions. The CFTC's rules establishing position limits were vacated by a federal district court in September 2012. However, on November 5, 2013, the CFTC proposed new position limits rules that would modify and expand the applicability of position limits on certain core futures and equivalent swaps contracts for or linked to certain physical commodities that market participants could hold with exceptions for certain bona fide hedging transactions.

The CFTC has designated certain interest rate swaps and certain credit default swaps for mandatory clearing and set compliance dates for three different categories of market participants who are parties to such swaps, the earliest of which was March 11, 2013, and the latest of which was September 9, 2013. The CFTC has not yet proposed rules designating any other classes of swaps, including physical commodity swaps, for mandatory clearing. Although we expect to qualify for the end-user exception from the mandatory clearing and trade execution requirements for our swaps entered to hedge our commercial risks, the application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. In addition, for uncleared swaps, the CFTC or federal banking regulators may require our counterparties to require that we enter into credit support documentation and/or post initial and variation margin; however, the proposed margin rules are not yet final, and therefore the application of those provisions to us is uncertain at this time. Provisions of the Dodd-Frank Act may also cause our derivatives counterparties to spin off some or all of their derivatives activities to a separate entity, which could be our counterparty in future swaps and which entity may not be as creditworthy as the current counterparty.

The Dodd-Frank Act's swaps regulatory provisions and the related rules could significantly increase the cost of derivatives contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivatives contracts, reduce the availability of derivatives to protect against risks that we encounter, reduce our ability to monetize or restructure our existing derivatives contracts, and increase our exposure to less creditworthy counterparties. If, as a result of the swaps regulatory regime discussed above, we were to reduce our use of swaps to hedge our risks, such as commodity price risks that we encounter in our operations, our results of operations and cash flows may become more volatile and could be otherwise adversely affected.

In addition to the Dodd-Frank Act, in 2012, the European Market Infrastructure Regulation ("EMIR") became effective. EMIR includes regulations related to the trading, reporting and clearing of derivatives and the regulations thereunder may impact our ability to maintain or enter into derivatives with certain of our European counterparties.

Unless we replace our reserves, our reserves and production will decline, which would adversely affect our revenues, net cash provided by operating activities from operations and our ability to make distributions to our unitholders.

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 revenues, net cash provided by operating activities and our ability to make distributions to our unitholders.

Future price declines or downward reserve revisions may result in a write-down of our asset carrying values, which could adversely affect our results of operations.

Declines in oil, natural gas and NGL prices may result in our having to make substantial downward adjustments to our estimated proved reserves. If this occurs, or if our estimates of development costs increase, production data factors change or drilling results deteriorate, accounting rules may require us to write-down, as a noncash charge to earnings, the carrying value of our properties for impairments. We capitalize costs to acquire, find and develop our oil and natural gas properties under the successful efforts accounting method. We are required to perform impairment tests on our assets periodically and whenever events or changes in circumstances warrant a review of our assets. To the extent such tests indicate a reduction of the estimated useful life or estimated future cash flows of our assets, the carrying value may not be recoverable and therefore would require a write-down. We have incurred impairment charges in the past and may do so in the future. Any impairment could be substantial and have a material adverse effect on our results of operations in the period incurred.

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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. Independent petroleum engineering firms prepare estimates of our proved reserves. Some of our reserve estimates are made without the benefit of a lengthy production history, which are less reliable than estimates based on a lengthy production history. Also, we make certain assumptions regarding future oil, natural gas and NGL prices, production levels and operating and development costs that may prove incorrect. Any significant variance from these assumptions by actual amounts could greatly affect our estimates of reserves, the economically recoverable quantities of oil, natural gas and NGL attributable to any particular group of properties, the classifications of reserves based on risk of recovery and estimates of the future net cash flows. Decreases in commodity prices can result in a reduction of our estimated reserves if development of those reserves would not be economic at those lower prices. Numerous changes over time to the assumptions on which our reserve estimates are based, as described above, often result in the actual quantities of oil, natural gas and NGL we ultimately recover being different from our reserve estimates.

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

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

Although proved reserves were estimated in accordance with SEC regulations, 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, there was a steep decline in commodity prices during the fourth quarter of 2014. From September 30, 2014 to December 31, 2014, NYMEX oil and natural gas prices decreased approximately 42% and 30%, respectively, to $53.27 per Bbl for oil and $2.89 per MMBtu for natural gas at December 31, 2014.

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 for distribution. 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 for distribution. We intend to finance our future capital expenditures with net cash provided by operating activities and to the extent necessary, with equity and debt offerings or bank borrowings. 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 revenues or the borrowing bases under our Credit Facilities decrease as a result of lower oil, natural gas and NGL prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. Our Credit Facilities 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 additional financing could result in a curtailment of our development operations, which in turn could lead to a possible 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. 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 our ability to pay distributions. In addition, the SEC's reserve reporting rules include a general requirement that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. At December 31, 2014, we had 2,778 proved undeveloped drilling locations. To the extent that we do not drill these locations within five years of initial booking, they may not continue to qualify for classification as proved reserves, and we may be required to reclassify such reserves as unproved reserves. The reclassification of such reserves could also have a negative effect on the borrowing bases under our Credit Facilities.

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. In the future, if we drill wells that we identify as dry holes, our drilling success rate would decline, which could have an adverse effect on our business, financial condition, results of operations and cash flows.

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 for distribution 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 and pipeline systems. 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 or eliminate our cash available for distribution 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 for distribution 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, 2014, sales of oil, natural gas and NGL to Enbridge Energy Partners, L.P. accounted for approximately 13% of our total production volumes. For the year ended December 31, 2013, sales of oil, natural gas and

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NGL to Enbridge Energy Partners, L.P. accounted for approximately 20% of our total production volumes. 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 for distribution could decline.

We may experience difficulties in integrating assets we acquire from third parties, which could cause us to fail to realize many of the anticipated potential benefits of those acquisitions.

As part of our previously announced plan to divest certain of our higher decline, capital intensive properties for more mature, long-life oil and natural gas properties with lower decline rates, we acquired oil and natural gas properties throughout our various operating regions. Achieving the anticipated benefits of these acquisitions will depend in part on whether we are able to integrate these assets in an efficient and effective manner. We may not be able to accomplish this integration process smoothly or successfully. The difficulties of integrating these assets with our business potentially will include, among other things, the necessity of coordinating geographically separated assets and addressing possible differences incorporating cultures and management philosophies of employees associated with these assets, and the integration of certain operations, data systems and processes, which may require the dedication of significant management resources and which may temporarily distract management's attention from our day-to-day business.

An inability to realize the full extent of the anticipated benefits of these acquisitions, as well as any delays encountered in the transition process, could have an adverse effect on our revenues, level of expenses and operating results, which may affect our cash available for distribution.

We may be unable to retain key employees.

Our future success will depend in part on our ability to retain key employees. During 2014, we acquired several new properties and hired employees associated with those properties. Additionally, in the fourth quarter of 2014, commodity prices decreased significantly. Key employees may depart because of issues relating to the uncertainty and difficulty of integration or 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.

Our key project areas are located in some of the most active drilling areas of the producing basins in the U.S. As a result, 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, resulting in temporarily lower net cash provided by operating activities, which may impact our ability to pay distributions.

Our management has specifically identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. As of December 31, 2014, we had identified 10,885 drilling locations, of which 2,778 were proved undeveloped locations and 8,107 were other locations. These identified drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of factors, including the availability of capital, seasonal conditions, regulatory approvals, oil, natural gas and NGL prices, costs and drilling results. In addition, DeGolyer and MacNaughton has not estimated proved reserves for the 8,107 other drilling locations we have identified and scheduled for drilling, and therefore there may be greater uncertainty with respect to the success of drilling wells at these drilling locations. Our final determination on whether to drill any of these drilling locations will be dependent upon the factors described above as well as, to some degree, the results of our drilling activities with respect to our proved drilling locations. Because of these uncertainties, we do not know if the numerous drilling locations we have identified will be drilled within our expected timeframe or will ever be drilled or if we will be able to produce oil, natural gas and NGL from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

Drilling for and producing oil, natural gas and NGL are high risk activities with many uncertainties that could adversely affect our financial position or results of operations and, as a result, our ability to pay distributions to our unitholders.

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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 ability to generate sufficient net cash provided by operating activities to pay distributions to our unitholders at the current distribution level or at all. Increased costs could include losses from personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination, loss of wells and regulatory penalties. We ordinarily maintain insurance against certain losses and liabilities arising from our operations. However, it is impossible to insure against all operational risks in the course of our business. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. Losses could therefore occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business activities, financial position and results of operations.

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, 2014, nonoperated wells represented approximately 29% of our owned gross wells, or approximately 10% 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. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence or control the operation and future development of these properties could materially adversely affect the realization of our targeted returns on capital in drilling or acquisition activities 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

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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.

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 ability to pay distributions to our unitholders. For a description of the laws and regulations that affect us, see Item 1. "Business – Environmental Matters and Regulation."

Federal and state legislation and regulatory initiatives related to hydraulic fracturing could result in increased costs and operating restrictions or delays.

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 Environmental Protection Agency ("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, on May 16, 2013, the Department of the Interior's Bureau of Land Management ("BLM") issued a proposed rule that, if adopted, would require 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 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 adopted, these 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 entire state of New York and certain communities in Colorado and Texas have enacted bans or moratoria on hydraulic fracturing, to which legal challenges are pending. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us 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 our revenues and results of operations.

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 as a result of flawed well design or operation. This has resulted in stricter regulatory requirements in some jurisdictions relating to the location and operation of underground injection wells.

Legislation and regulation of greenhouse gases could adversely affect our business.

In December 2009, the 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 two sets of rules regulating GHG emissions under the CAA, one that requires a reduction in emissions of GHGs from motor vehicles and the other that regulates emissions of GHGs from certain large stationary sources under the CAA’s Prevention of Significant Deterioration and Title V permitting programs. 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. 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.

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 we are a part, as our California operations emit GHGs. The cap will decline annually thereafter through 2020. We are required to remit compliance instruments for each metric ton of GHG that we emit, 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, we will be granted a certain number of California Carbon Allowances (“CCAs”) and we will need to purchase CCAs and/or offset credits to cover the remaining amount of our emissions. Compliance with Assembly Bill 32 could significantly increase our capital, compliance and operating costs and could also reduce demand for the oil and natural gas we produce. We continue to assess the impact of these regulations on our operations, including the cost to acquire allowances and to reduce emissions. Our cost of acquiring compliance instruments in 2014 was in the range of $1.50 to $2.50 per barrel of 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 our ability to limit our 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.

Recent regulatory changes in California have and may continue to materially and adversely impact our production and operating costs related to our Diatomite assets acquired in the Berry acquisition.

Recent regulatory changes in California have impacted production from our Diatomite assets acquired in the Berry acquisition. 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 2014, 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. In such case, we may experience additional delays in production and increased operating costs related to our Diatomite assets, which could 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 distribution. For example, our management will use its reasonable discretion to establish and maintain cash reserves sufficient to fund our drilling program;
- 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 that we distribute 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.

We do not have the same flexibility as other types of organizations to accumulate cash and equity to protect against illiquidity in the future.

Unlike a corporation, our limited liability company agreement requires us to make distributions to our unitholders of all available cash reduced by any amounts of reserves for commitments and contingencies, including capital and operating costs and debt service requirements. The value of our units may decrease in direct correlation with decreases in the amount we distribute per unit. Accordingly, if we experience a liquidity problem in the future, we may have difficulty issuing more equity to recapitalize.

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Item 1A. Risk Factors - Continued

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 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 entity level taxation for state tax purposes, taxes paid, if any, would reduce the amount of cash available for distribution.

The anticipated after-tax economic benefit of an investment in our units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this or any other tax matter 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 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 for distribution to our unitholders could be reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to our unitholders, likely causing a substantial reduction in the value of our units.

Current law or our business may change so as to 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 0.7%. Imposition of a tax on us by any other state would reduce the amount of cash available for distribution 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 for distribution 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.

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, even if they do not receive any cash distributions from us. 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. 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, 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 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 property. 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

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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 their units, and the amount, if any, of excess distributions over a unitholder's tax basis in their 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).

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 unitholder 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 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 2014, we have been registered to do business or have owned assets in Arkansas, California, Colorado, Illinois, Indiana, Kansas, Louisiana, Michigan, Mississippi, Montana, New Mexico, North Dakota, Oklahoma, Pennsylvania, 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 unitholders' ability to take certain tax deductions.
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. We are unable to predict whether any changes, or other proposals to such laws, ultimately will be enacted. Any such changes could negatively impact the value of an investment in our units.
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. Unitholders who are not "Eligible Holders" will be subject to redemption of their units.
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.

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. As of the date hereof, Eligible Holder means: (1) a citizen of the U.S.; (2) a corporation organized under the laws of the U.S. or of any state thereof; or (3) an association of U.S. citizens, such as a partnership or limited liability company, organized under the laws of the U.S. or of any state thereof, but only if such association does not have any direct or indirect foreign ownership, other than foreign ownership of stock in a parent corporation organized under the laws of the U.S. or of any state thereof. For the avoidance of doubt, onshore mineral leases or any direct or indirect interest therein may be acquired and held by aliens only through stock ownership, holding or control in a corporation organized under the laws of the U.S. or of any state thereof and only for so long as the alien is not from a country that the U.S. federal government regards as denying similar privileges to citizens or corporations of the U.S. 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.

## Item 1B. Unresolved Staff Comments

None

## Item 2. Properties

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

The Company’s obligations under its Credit Facilities are secured by mortgages on 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 information concerning the Credit Facilities.

### 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

The Company has been named as a defendant in a number of lawsuits, including claims from royalty owners related to disputed royalty payments and royalty valuations. With respect to a certain statewide class action case, the Company has filed a motion to dismiss the case for failure to state a claim on which relief may be granted, and that motion has not yet been ruled on by the Court. While that motion has remained pending, the parties have agreed on a scheduling order, which provides for briefing on the class certification issues in late 2015 and first part of 2016. The Company has denied that it has liability on the claims asserted in the case and has denied that class certification is proper. If the Court accepts the Company’s arguments, there will be no liability to the Company in the case. For another statewide class action royalty payment dispute, briefing on class certification issues is expected to be completed during the summer of 2015. The Company has denied that it has any liability on the claims and has denied that class certification is proper. If the Court accepts the Company’s arguments, there will be no liability to the Company in the case. The Company is unable to estimate a possible loss, or range of possible loss, if any, in these cases. 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.

Prior to the Company’s acquisition of Berry Petroleum Company, now Berry Petroleum Company, LLC (“Berry”), Berry became a defendant in a certain statewide royalty class action case. The parties entered into a settlement agreement to settle past claims for approximately $2.4 million, which the Court approved on October 29, 2014. On December 17, 2014, Berry made a one-time lump sum payment of $2.4 million for damages related to production through April 30, 2014. On December 29, 2014, the Court issued an Order dismissing the matter with prejudice. Per the parties’ settlement agreement, Berry has agreed to a new methodology for calculating royalty payments beginning May 1, 2014.

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Item 3. Legal Proceedings - Continued

In 2013, several class action complaints were filed and ultimately consolidated in the United States District Court, Southern District of New York (the “Federal Actions”) against LINN Energy, LinnCo, certain of their officers and directors and the various underwriters for LinnCo’s initial public offering. These cases collectively asserted claims based on allegations that LINN Energy made false or misleading statements relating to its (i) hedging strategy, (ii) the cash flow available for distribution to unitholders, and (iii) LINN Energy’s energy production in its Exchange Act filings; and additional claims based on alleged misstatements relating to these issues in the prospectus and registration statement for LinnCo’s initial public offering. Several derivative actions were also filed in federal and state court in Texas, and in the Delaware Court of Chancery (the “Derivative Actions”) asserting derivative claims on behalf of LINN Energy against the individual officers and directors for alleged breaches of fiduciary duty, waste of corporate assets, mismanagement, abuse of control, and unjust enrichment based on factual allegations similar to those in the Federal Actions.

In July 2014, the Court dismissed the claims of the plaintiffs in the Federal Actions with prejudice, concluding that the plaintiffs failed to demonstrate any material misstatement or omission by LINN Energy or LinnCo, or their officers and directors. The plaintiffs in the Federal Actions did not appeal the Court’s dismissal, and the appeals deadline has now passed. The plaintiffs in the Derivative Actions subsequently have dismissed their claims without prejudice.

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, 2015, there were approximately 159 unitholders of record.
The following 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 [(1)] |
|---|---|---|---|
| 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 |
| 2013: | | | |
| October 1 – December 31 | $31.80 | $26.01 | $0.725 |
| July 1 – September 30 | $33.29 | $22.79 | $0.725 |
| April 1 – June 30 | $39.15 | $30.52 | $0.725 |
| January 1 – March 31 | $39.33 | $35.93 | $0.725 |

(1) In April 2013, the Company's Board of Directors approved a change in the distribution policy that provides a distribution with respect to any quarter may be made, at the discretion of the Board of Directors, (i) within 45 days following the end of each quarter or (ii) in three equal installments within 15, 45 and 75 days following the end of each quarter. The first monthly distribution was paid in July 2013.

### 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 over the next four quarters.

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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 (the "S&P 500 Index") and the Alerian MLP Index, a weighted composite of 50 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 on December 31, 2009, and the S&P 500 Index and the Alerian MLP Index on the same date. The results shown in the graph below are not necessarily indicative of future performance.

| | December 31, 2009 | December 31, 2010 | December 31, 2011 | December 31, 2012 | December 31, 2013 | December 31, 2014 |
|---|---|---|---|---|---|---|
| LINN Energy | $100 | $147 | $159 | $159 | $153 | $56 |
| Alerian MLP Index | $100 | $136 | $155 | $162 | $207 | $217 |
| S&P 500 Index | $100 | $115 | $117 | $136 | $180 | $205 |

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 under 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 registered 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 (see LINN Energy and LinnCo’s joint proxy statement/prospectus for their 2014 annual meetings for additional information). Total units issued as consideration to LinnCo includes 40,938 (approximately $1 million) of Berry equity awards that vested and converted to LinnCo common shares on the Berry acquisition date and included in total consideration but such shares were issued in 2014 due to six month deferred issuance provisions in the original Berry award agreements.

Issuer Purchases of Equity Securities

In August 2014, the Board of Directors of the Company 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, 2014, and as of December 31, 2014, 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 these results and certain other financial data may not be meaningful or indicative of future results.

| | At or for the Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2014 | 2013 | 2012 | 2011 | 2010 |
| | (in thousands, except per unit amounts) | | | | |
| Statement of operations data: | | | | | |
| Oil, natural gas and natural gas liquids sales | $3,610,539 | $2,073,240 | $1,601,180 | $1,162,037 | $690,054 |
| Gains on oil and natural gas derivatives | 1,206,179 | 177,857 | 124,762 | 449,940 | 75,211 |
| Depreciation, depletion and amortization | 1,073,902 | 829,311 | 606,150 | 334,084 | 238,532 |
| Interest expense, net of amounts capitalized | 587,838 | 421,137 | 379,937 | 259,725 | 193,510 |
| Net income (loss) | (451,809) | (691,337) | (386,616) | 438,439 | (114,288) |
| Net income (loss) per unit: | | | | | |
| Basic | (1.40) | (2.94) | (1.92) | 2.52 | (0.80) |
| Diluted | (1.40) | (2.94) | (1.92) | 2.51 | (0.80) |
| Distributions declared per unit | 2.90 | 2.90 | 2.87 | 2.70 | 2.55 |
| Weighted average units outstanding | 328,918 | 237,544 | 203,775 | 172,004 | 142,535 |
| | | | | | |
| Cash flow data: | | | | | |
| Net cash provided by (used in): | | | | | |
| Operating activities [1] | $1,711,890 | $1,166,212 | $350,907 | $518,706 | $270,918 |
| Investing activities | (1,920,104) | (1,253,317) | (3,684,829) | (2,130,360) | (1,581,408) |
| Financing activities | 157,852 | 138,033 | 3,334,051 | 1,376,767 | 1,524,260 |
| | | | | | |
| Balance sheet data: | | | | | |
| Total assets | $16,423,509 | $16,504,964 | $11,451,238 | $7,928,854 | $5,933,148 |
| Long-term debt | 10,295,809 | 8,958,658 | 6,037,817 | 3,993,657 | 2,742,902 |
| Unitholders' capital | 4,543,605 | 5,891,427 | 4,427,180 | 3,428,910 | 2,788,216 |

(1) Net of payments made for commodity derivative premiums of approximately $583 million, $134 million and $120 million for the years ended December 31, 2012, December 31, 2011, and December 31, 2010, respectively.

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Item 6. Selected Financial Data - Continued

| | At or for the Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2014 | 2013 | 2012 | 2011 | 2010 |
| Production data: | | | | | |
| Average daily production: | | | | | |
| Natural gas (MMcf/d) | 572 | 443 | 349 | 175 | 137 |
| Oil (MBbls/d) | 72.9 | 33.5 | 29.2 | 21.5 | 13.1 |
| NGL (MBbls/d) | 33.5 | 29.7 | 24.5 | 10.8 | 8.3 |
| Total (MMcfe/d) | 1,210 | 822 | 671 | 369 | 265 |
| | | | | | |
| Estimated proved reserves: [1] | | | | | |
| Natural gas (Bcf) | 4,255 | 3,010 | 2,571 | 1,675 | 1,233 |
| Oil (MMBbls) | 342 | 366 | 191 | 189 | 156 |
| NGL (MMBbls) | 166 | 200 | 179 | 94 | 71 |
| Total (Bcfe) | 7,304 | 6,403 | 4,796 | 3,370 | 2,597 |

(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 "Consolidated Financial Statements" and "Notes to Consolidated Financial Statements," 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 that reflect the Company's future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside the Company's control. The Company's actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, market prices for oil, 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 discussed below and elsewhere in this Annual Report on Form 10-K, particularly in Item 1A. "Risk Factors." In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur.

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."):

- 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);
- Hugoton Basin, which includes properties located in Kansas, the Oklahoma Panhandle and the Shallow Texas Panhandle;
- 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;
- Permian Basin, which includes properties located in west Texas and southeast New Mexico;
- Michigan/Illinois, which includes properties located in the Antrim Shale formation in north Michigan and oil properties in south Illinois; and
- South Texas.

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

Results for the year ended December 31, 2014, included the following:

- oil, natural gas and NGL sales of approximately \$3.6 billion compared to \$2.1 billion in 2013;
- average daily production of 1,210 MMcfe/d compared to 822 MMcfe/d in 2013;
- net loss of approximately \$452 million compared to \$691 million in 2013;
- net cash provided by operating activities of approximately \$1.7 billion compared to \$1.2 billion in 2013;
- capital expenditures, excluding acquisitions, of approximately \$1.6 billion compared to \$1.3 billion in 2013; and
- 918 wells drilled (917 successful) compared to 559 wells drilled (557 successful) in 2013.

Reduction of 2015 Oil and Natural Gas Capital Budget and Distribution

In February 2015, the Company's Board of Directors approved a revised 2015 budget which includes a 61% reduction in capital expenditures to approximately \$600 million, from approximately \$1.6 billion spent in 2014. The 2015 budget contemplates a significantly lower oil price than in 2014. In January 2015, the Company reduced its distribution to \$1.25 per

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unit, from the previous level of $2.90 per unit, on an annualized basis. The reduction of the 2015 budget and the distribution are intended to solidify the Company's financial position and regain a useful cost of capital.

Alliance with GSO Capital Partners

In January 2015, the Company also announced that it has signed a non-binding letter of intent with private capital investor GSO Capital Partners LP ("GSO") to fund oil and natural gas development (the "DrillCo Agreement"). Subject to final documentation, funds managed by GSO and its affiliates have agreed to commit up to $500 million with 5-year availability to fund drilling programs on locations provided by the Company. Subject to certain conditions, 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 the Company 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 Company's interest will increase to 95%.

This initiative is expected to allow the Company to develop oil and natural gas assets without increasing capital intensity, provide the potential to add a steady and growing cash flow stream without a capital requirement, increase the Company's long-term ability to fund capital expenditures and the distribution with internally generated cash flow, mitigate drilling risk for the Company and, upon meeting the return hurdle, provide incremental low-decline production growth for the Company. The DrillCo Agreement is subject to final negotiations and approval by the Company and GSO, and as such there can be no assurance that an agreement will be reached on the terms set forth in the letter of intent or at all.

Exchanges of Properties

On November 21, 2014, the Company, through two of its wholly owned subsidiaries, completed the trade of a portion of its Permian Basin properties to Exxon Mobil Corporation in exchange for properties in California's South Belridge Field. As of the exchange date, the Company received approximately 185 Bcfe of proved reserves while Exxon Mobil Corporation received approximately 17,000 net acres prospective for horizontal Wolfcamp drilling in the Midland Basin, approximately 800 acres in the New Mexico Delaware Basin and approximately 100 Bcfe of proved reserves.

On August 15, 2014, the Company, through two of its wholly owned subsidiaries, completed the trade of a portion of its Permian Basin properties to Exxon Mobil Corporation and its affiliates, including its wholly owned subsidiary XTO Energy Inc. (collectively, "ExxonMobil"), in exchange for properties in the Hugoton Basin. As of the exchange date, the Company received approximately 659 Bcfe of proved reserves while ExxonMobil received approximately 25,000 net acres in the Midland Basin, which are located primarily in Midland, Martin, Upton and Glasscock counties, and approximately 162 Bcfe of proved reserves.

Acquisitions

On September 11, 2014, the Company completed the acquisition of certain oil and natural gas properties located in the Hugoton Basin from Pioneer Natural Resources Company ("Pioneer" and the acquisition, the "Pioneer Assets Acquisition") for total consideration of approximately $328 million. The acquisition included approximately 303 Bcfe of proved reserves as of the acquisition date.

On August 29, 2014, the Company completed the acquisition of certain oil and natural gas properties located in five operating regions in the U.S. from subsidiaries of Devon Energy Corporation ("Devon" and the acquisition, the "Devon Assets Acquisition") for total consideration of approximately $2.1 billion. The acquisition included approximately 1,344 Bcfe of proved reserves as of the acquisition date.

During the year ended December 31, 2014, the Company also completed other smaller acquisitions of oil and natural gas properties located in its various operating regions. The Company, in the aggregate, paid approximately $5 million in total consideration for these properties.

Divestitures

On December 15, 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 to privately held institutional affiliates of EnerVest, Ltd. and its joint

venture partner FourPoint Energy, LLC (the "Granite Wash Assets Sale"). Cash proceeds received from the sale of these properties were approximately $1.8 billion, net of costs to sell of approximately $10 million.

On November 14, 2014, the Company completed the sale of certain of its Wolfberry properties in Ector and Midland counties in the Permian Basin to Fleur de Lis Energy, LLC (the "Permian Basin Assets Sale"). Cash proceeds received from the sale of these properties were approximately $351 million, net of costs to sell of approximately $2 million.

On October 30, 2014, the Company completed the sale of its interests in certain non-producing oil and natural gas properties located in the Mid-Continent region. Cash proceeds received from the sale of these properties were approximately $44 million.

The Company used the net cash proceeds received from these sales to repay in full the VIE Term Loan, as defined below, as well as repay a portion of the borrowings outstanding under the LINN Credit Facility, also defined below.

Financing Activities

The Company's Sixth Amended and Restated Credit Agreement ("LINN Credit Facility") provides for (1) a senior secured revolving credit facility and (2) a $500 million senior secured term loan, in aggregate subject to the then-effective borrowing base. Borrowing capacity under the revolving credit facility is limited to the lesser of (i) the then-effective borrowing base reduced by the $500 million term loan and (ii) the maximum commitment amount of $4.0 billion, and is currently $4.0 billion. At January 31, 2015, the borrowing base under the LINN Credit Facility was $4.5 billion and availability under the revolving credit facility was approximately $2.2 billion, which includes a $5 million reduction for outstanding letters of credit.

In April 2014, the Company entered into an amendment to the LINN Credit Facility to extend the maturity date from April 2018 to April 2019, among other items. In August 2014 and September 2014, the Company entered into amendments to the LINN Credit Facility to permit the Devon Assets Acquisition and the Pioneer Assets Acquisition, respectively, and the related Reverse 1031 Exchanges (see Note 2). As a result of the debt incurred under the Bridge Loan, as defined below, the borrowing base was reduced by 25% of the gross proceeds from the Bridge Loan, or $250 million, from $4.5 billion to $4.25 billion, resulting in a reduction of availability under the revolving credit facility of $250 million. Additionally, upon the issuance of an aggregate $1.1 billion of senior notes in the September 2014 offering (see below), the borrowing base was further reduced by $25 million to $4.225 billion, resulting in a further reduction of availability under the revolving credit facility of $25 million. The fall 2014 semi-annual redetermination occurred in December 2014 in order to coincide with the completion of the Reverse 1031 Exchanges, and as part of that redetermination, the borrowing base was restored to $4.5 billion with a maximum commitment amount of $4.0 billion.

The next semi-annual redetermination of the borrowing base is scheduled to occur in April 2015. Continued lower commodity prices may result in a decrease in the borrowing base at that time. In the event Berry's borrowing base is reduced below the amount of borrowings outstanding, LINN Energy will either make principal repayments or post restricted cash on Berry's behalf to address the shortfall, subject to the LINN Credit Facility.

In August 2014, the Company entered into a bridge loan agreement (the "Bridge Loan") pursuant to which the Company borrowed an aggregate principal amount of $1.0 billion of term loans. The proceeds from the Bridge Loan were used to partially fund the Devon Assets Acquisition (see Note 2).

In August 2014, an entity formed to facilitate the Reverse 1031 Exchange for the Devon Assets Acquisition (see Note 2) entered into a 364-day term loan agreement (the "VIE Term Loan") pursuant to which it borrowed an aggregate principal amount of $1.3 billion of term loans. The proceeds from the VIE Term Loan were used to partially fund the Devon Assets Acquisition. In December 2014, the outstanding indebtedness under the VIE Term Loan was paid in full using a portion of the net cash proceeds received from the Granite Wash Assets Sale and the Permian Basin Assets Sale. See Note 2 for additional information.

In September 2014, the Company issued $1.1 billion in aggregate principal amount of senior notes consisting of $450 million of 6.50% senior notes due May 2019 (the "New May 2019 Senior Notes") and $650 million of 6.50% senior notes due September 2021 (the "September 2021 Senior Notes") (see Note 6). The Company used the net proceeds of approximately

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$1.1 billion to repay all indebtedness outstanding under its Bridge Loan as well as repay a portion of the borrowings outstanding under the LINN Credit Facility.

On May 30, 2014, in accordance with the provisions of the indenture related to Berry Petroleum Company, LLC's ("Berry") 10.25% senior notes due June 2014 (the "Berry June 2014 Senior Notes"), the Company paid in full the remaining outstanding principal amount of approximately $205 million.

On March 22, 2013, the Company filed a registration statement on Form S-4 to register exchange notes that are substantially similar to the 6.25% senior notes due November 2019 (the "November 2019 Senior Notes"), except that the transfer restrictions, registration rights and additional interest provisions related to the outstanding November 2019 Senior Notes do not apply to the new November 2019 Senior Notes. On June 2, 2014, the registration statement was declared effective and the Company commenced an offer to exchange any and all of its $1.8 billion outstanding principal amount of November 2019 Senior Notes for an equal amount of new November 2019 Senior Notes. The exchange offer expired on June 28, 2014.

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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.

| | 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.

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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 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 ExxonMobil 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 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 increased by approximately $1 billion to gains of approximately $1.2 billion for the year ended December 31, 2014, from gains of approximately $178 million for the year ended December 31, 2013. Gains on oil and natural gas derivatives increased primarily due to changes in fair value on unsettled derivative contracts partially offset by lower cash settlements during the year. 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

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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 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 information 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 from 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, primarily due to 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 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.

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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

During the fourth quarter of 2014, the Company recorded noncash impairment charges, before and after tax, of approximately $1.7 billion associated with proved oil and natural gas properties throughout its various operating regions. The impairment was due to a steep decline in commodity prices. From September 30, 2014 to December 31, 2014, NYMEX oil and natural gas forward price curves decreased approximately 24% and 12%, respectively. The impairment charges were determined using the average five-year NYMEX forward price curves of approximately $64.76 per BBl for oil and $3.66 per MMBtu for natural gas and, thereafter, the prices were held flat at $69.77 per Bbl for oil and $4.12 per MMBtu for natural gas. Following are the impairment charges recorded by operating region:

- Permian Basin – $735 million;
- Rockies – $586 million (in the Powder River Basin and Uinta Basin);
- Mid-Continent – $244 million;
- South Texas – $131 million; and
- TexLa – $5 million.

In addition, during the third quarter of 2014, the Company recorded noncash impairment charges, before and after tax, of approximately $603 million associated with proved oil and natural gas properties in the Permian Basin region. The impairment was 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 the proved oil and natural gas properties. During the year ended December 31, 2013, the Company recorded noncash impairment charges, before and after tax, of approximately $828 million. Impairment charges for the year ended December 31, 2013, consist of approximately $791 million associated with proved oil and natural gas properties in the Granite Wash formation related to asset performance resulting in reserve revisions and a decline in commodity prices as well as approximately $37 million associated with the write-down of the carrying value of the Panther Operated Cleveland Properties sold in May 2013 (see Note 2).

Subsequent to December 31, 2014, 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, 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 Exxon Mobil Corporation for properties in California’s South Belridge

Field;

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

- 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 Mobil Corporation and its affiliates, including its wholly owned subsidiary XTO Energy Inc., 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, | | |
|---|---|---|---|
| | 2014 | 2013 | Variance |
| | (in thousands) | | |
| Severance taxes | $133,933 | $90,655 | $43,278 |
| Ad valorem taxes | 114,955 | 48,547 | 66,408 |
| California carbon allowances | 18,212 | 355 | 17,857 |
| Other | 303 | (926) | 1,229 |
| | $267,403 | $138,631 | $128,772 |

Taxes, other than income taxes increased by approximately $129 million or 93% for the year ended December 31, 2014, compared to the year ended December 31, 2013. Severance taxes, which are a function of revenues generated from production, increased primarily due to higher production volumes and higher natural gas and NGL prices partially offset by lower oil prices. Ad valorem taxes, which are primarily based on the value of reserves and production equipment and vary by location, increased primarily due to the Berry acquisition and acquisitions completed during the third quarter of 2014. California carbon allowances increased primarily due to the California properties acquired in the Berry acquisition.

Other Income and (Expenses)

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | Variance |
| | (in thousands) | | |
| Interest expense, net of amounts capitalized | $(587,838) | $(421,137) | $(166,701) |
| Loss on extinguishment of debt | — | (5,304) | 5,304 |
| Other, net | (16,213) | (8,477) | (7,736) |
| | $(604,051) | $(434,918) | $(169,133) |

Other income and (expenses) increased by approximately $169 million for the year ended December 31, 2014, compared to the year ended December 31, 2013. Interest expense increased primarily due to higher outstanding debt during the period and higher amortization of financing fees and expenses associated with the Bridge Loan, the VIE Term Loan, the senior notes issued in September 2014 and amendments made to the Company’s Credit Facilities during 2014 and 2013. For the year ended December 31, 2013, the Company recorded a loss on extinguishment of debt of approximately $5 million as a result of the redemption of the remaining outstanding 2017 and 2018 Senior Notes. See “Debt” under “Liquidity and Capital Resources” below for additional details. Other expenses increased primarily due to write-offs of deferred financing fees related to the VIE Term Loan and LINN Credit Facility during 2014, compared to no such write-offs during 2013.

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 income tax expense of

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approximately $4 million for the year ended December 31, 2014, compared to an income tax benefit of approximately $2 million for the year ended December 31, 2013. Income tax expense increased primarily due to higher income from the Company's taxable subsidiaries during the year ended December 31, 2014, compared to the year ended December 31, 2013.

Net Loss

Net loss decreased by approximately $239 million or 35% to approximately $452 million for the year ended December 31, 2014, from approximately $691 million for the year ended December 31, 2013. The decrease was primarily due to higher production revenues and higher gains on oil and natural gas derivatives, partially offset by higher impairment charges and other expenses, including interest. See discussions 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, 2013, Compared to Year Ended December 31, 2012

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2013 | 2012 | Variance |
| | (in thousands) | | |
| Revenues and other: | | | |
| Natural gas sales | $585,501 | $367,550 | $217,951 |
| Oil sales | 1,152,213 | 946,304 | 205,909 |
| NGL sales | 335,526 | 287,326 | 48,200 |
| Total oil, natural gas and NGL sales | 2,073,240 | 1,601,180 | 472,060 |
| Gains on oil and natural gas derivatives | 177,857 | 124,762 | 53,095 |
| Marketing and other revenues | 80,558 | 48,298 | 32,260 |
| | 2,331,655 | 1,774,240 | 557,415 |
| Expenses: | | | |
| Lease operating expenses | 372,523 | 317,699 | 54,824 |
| Transportation expenses | 128,440 | 77,322 | 51,118 |
| Marketing expenses | 37,892 | 31,821 | 6,071 |
| General and administrative expenses (1) | 236,271 | 173,206 | 63,065 |
| Exploration costs | 5,251 | 1,915 | 3,336 |
| Depreciation, depletion and amortization | 829,311 | 606,150 | 223,161 |
| Impairment of long-lived assets | 828,317 | 422,499 | 405,818 |
| Taxes, other than income taxes | 138,631 | 131,679 | 6,952 |
| Losses on sale of assets and other, net | 13,637 | 1,539 | 12,098 |
| | 2,590,273 | 1,763,830 | 826,443 |
| Other income and (expenses) | (434,918) | (394,236) | (40,682) |
| Loss before income taxes | (693,536) | (383,826) | (309,710) |
| Income tax expense (benefit) | (2,199) | 2,790 | (4,989) |
| Net loss | $(691,337) | $(386,616) | $(304,721) |

(1) General and administrative expenses for the years ended December 31, 2013, and December 31, 2012, include approximately $37 million and $28 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, | | | |
|---|---|---|---|---|
| | 2013 | 2012 | Variance | |
| Average daily production: | | | | |
| Natural gas (MMcf/d) | 443 | 349 | 27 | % |
| Oil (MBbls/d) | 33.5 | 29.2 | 15 | % |
| NGL (MBbls/d) | 29.7 | 24.5 | 21 | % |
| Total (MMcfe/d) | 822 | 671 | 23 | % |
| | | | | |
| Weighted average prices: (1) | | | | |
| Natural gas (Mcf) | $3.62 | $2.87 | 26 | % |
| Oil (Bbl) | $94.15 | $88.59 | 6 | % |
| NGL (Bbl) | $30.96 | $32.10 | (4 | )% |
| | | | | |
| Average NYMEX prices: | | | | |
| Natural gas (MMBtu) | $3.65 | $2.79 | 31 | % |
| Oil (Bbl) | $97.97 | $94.20 | 4 | % |
| | | | | |
| Costs per Mcfe of production: | | | | |
| Lease operating expenses | $1.24 | $1.29 | (4 | )% |
| Transportation expenses | $0.43 | $0.31 | 39 | % |
| General and administrative expenses (2) | $0.79 | $0.71 | 11 | % |
| Depreciation, depletion and amortization | $2.76 | $2.47 | 12 | % |
| Taxes, other than income taxes | $0.46 | $0.54 | (15 | )% |

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

(2) General and administrative expenses for the years ended December 31, 2013, and December 31, 2012, include approximately $37 million and $28 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 increased by approximately $472 million or 29% to approximately $2.1 billion for the year ended December 31, 2013, from approximately $1.6 billion for the year ended December 31, 2012, due to higher production volumes and higher natural gas and oil prices partially offset by lower NGL prices. Higher natural gas and oil prices resulted in an increase in revenues of approximately $121 million and $68 million, respectively. Lower NGL prices resulted in a decrease in revenues of approximately $12 million.

Average daily production volumes increased to approximately 822 MMcfe/d for the year ended December 31, 2013, from approximately 671 MMcfe/d for the year ended December 31, 2012. Higher oil, natural gas and NGL production volumes resulted in an increase in revenues of approximately $137 million, $97 million and $61 million, respectively.

The following table sets forth average daily production by region:

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2013 | 2012 | Variance | | |
| Average daily production (MMcfe/d): | | | | | |
| Mid-Continent | 330 | 313 | 17 | 6 | % |
| Rockies | 187 | 91 | 96 | 105 | % |
| Hugoton Basin | 143 | 120 | 23 | 19 | % |
| Permian Basin | 87 | 83 | 4 | 5 | % |
| Michigan/Illinois | 34 | 35 | (1) | (4 | )% |
| East Texas | 22 | 16 | 6 | 37 | % |
| California | 19 | 13 | 6 | 42 | % |
| | 822 | 671 | 151 | 22 | % |

The increase in average daily production volumes in the Mid-Continent region primarily reflects the Company’s 2012 and 2013 capital drilling programs in the Granite Wash formation, partially offset by a decrease of approximately 11 MMcfe/d of production volumes related to the production of the Panther Operated Cleveland Properties sold on May 31, 2013. The increase in average daily production volumes in the Rockies region primarily reflects the impact of the acquisition from BP America Production Company (“BP”) on July 31, 2012, the joint-venture agreement entered into with Anadarko in April 2012 and development capital spending in the Williston Basin, partially offset by a reduction caused by ethane rejection in the region. The increase in average daily production volumes in the Hugoton Basin region primarily reflects the impact of the acquisition from BP on March 30, 2012. The increase in average daily production volumes in the Permian Basin region primarily reflects the impact of the acquisition on October 31, 2013, as well as development capital spending, partially offset by downtime from third parties’ infrastructure. The Michigan/Illinois region consists of a low-decline asset base and continues to produce at consistent levels. Average daily production volumes in the East Texas region reflect the impact of the acquisition on May 1, 2012. The increase in average daily production volumes in the California region primarily reflects the impact of the acquisition of Berry on December 16, 2013.

Gains on Oil and Natural Gas Derivatives

Gains on oil and natural gas derivatives increased by approximately $53 million to gains of approximately $178 million for the year ended December 31, 2013, from gains of approximately $125 million for the year ended December 31, 2012. Gains on oil and natural gas derivatives increased primarily due to the changes in fair value on unsettled derivative contracts partially offset by lower cash settlements during the year. The results for 2013 and 2012 also include gains of approximately $11 million and $22 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, 2013, the Company had commodity derivative contracts for approximately 107% of its natural gas production and 127% of its oil production. During the year ended December 31, 2012, the Company had commodity derivative contracts for approximately 110% of its natural gas production and 106% of its oil production.

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 information 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 $33 million or 67% to approximately $81 million for the year ended December 31, 2013, from approximately $48 million for the year ended December 31, 2012, primarily due to higher revenues generated from the Jayhawk natural gas processing plant acquired from BP in March 2012.

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 $55 million or 17% to approximately $373 million for the year ended December 31, 2013, from approximately $318 million for the year ended December 31, 2012. Lease operating expenses increased primarily due to costs associated with the Berry acquisition in December 2013 and properties acquired during 2012 (see Note 2). Lease operating expenses per Mcfe decreased to $1.24 per Mcfe for the year ended December 31, 2013, from $1.29 per Mcfe for the year ended December 31, 2012, primarily due to lower rates on newly acquired properties and cost saving initiatives.

Transportation Expenses

Transportation expenses increased by approximately $51 million or 66% to approximately $128 million for the year ended December 31, 2013, from approximately $77 million for the year ended December 31, 2012, primarily due to the BP acquisitions in 2012.

Marketing Expenses

Marketing expenses represent third-party activities associated with company-owned gathering systems, plants and facilities. Marketing expenses increased by approximately $6 million or 19% to approximately $38 million for the year ended December 31, 2013, from approximately $32 million for the year ended December 31, 2012, primarily due to higher expenses associated with the Jayhawk natural gas processing plant acquired from BP in March 2012.

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 $63 million or 36% to approximately $236 million for the year ended December 31, 2013, from approximately $173 million for the year ended December 31, 2012. The increase was primarily due to an increase in salaries and benefits related expenses of approximately $40 million, driven primarily by severance associated with the Berry acquisition and increased employee headcount, an increase in acquisition related expenses of approximately $11 million, also primarily associated with the Berry acquisition, an increase in professional services expenses of approximately $8 million and an increase in various other expenses of approximately $4 million. General and administrative expenses per Mcfe also increased to $0.79 per Mcfe for the year ended December 31, 2013, from $0.71 per Mcfe for the year ended December 31, 2012.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization increased by approximately $223 million or 37% to approximately $829 million for the year ended December 31, 2013, from approximately $606 million for the year ended December 31, 2012. Higher depletion rates and higher total production volumes were the primary reasons for the increased expense.

Depreciation, depletion and amortization per Mcfe also increased to $2.76 per Mcfe for the year ended December 31, 2013, from $2.47 per Mcfe for the

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year ended December 31, 2012, primarily due to negative reserve revisions from the prior year, partially offset by lower rates on properties acquired in 2012.

Impairment of Long-Lived Assets

During the year ended December 31, 2013, the Company recorded noncash impairment charges, before and after tax, of approximately $828 million. Impairment charges consist of approximately $791 million associated with proved oil and natural gas properties in the Granite Wash formation related to asset performance resulting in reserve revisions and a decline in commodity prices as well as approximately $37 million associated with the write-down of the carrying value of the Panther Operated Cleveland Properties sold in May 2013 (see Note 2). During the year ended December 31, 2012, the Company recorded noncash impairment charges, before and after tax, of approximately $422 million associated with proved oil and natural gas properties in the Mississippi Shelf and Mayfield related to the Securities and Exchange Commission ("SEC") five-year development limitation on PUDs and a decline in commodity prices.

Taxes, Other Than Income Taxes

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2013 | 2012 | Variance |
| | (in thousands) | | |
| Severance taxes | $90,655 | $82,868 | $7,787 |
| Ad valorem taxes | 48,547 | 47,937 | 610 |
| California carbon allowances | 355 | — | 355 |
| Other | (926) | 874 | (1,800) |
| | $138,631 | $131,679 | $6,952 |

Taxes, other than income taxes increased by approximately $7 million or 5% for the year ended December 31, 2013, compared to the year ended December 31, 2012. Severance taxes, which are a function of revenues generated from production, increased primarily due to higher production volumes and higher natural gas and oil prices partially offset by lower NGL prices. Ad valorem taxes, which are primarily based on the value of reserves and production equipment and vary by location, increased primarily due to property acquisitions in 2012.

Other Income and (Expenses)

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2013 | 2012 | Variance |
| | (in thousands) | | |
| Interest expense, net of amounts capitalized | $(421,137) | $(379,937) | $(41,200) |
| Loss on extinguishment of debt | (5,304) | — | (5,304) |
| Other, net | (8,477) | (14,299) | 5,822 |
| | $(434,918) | $(394,236) | $(40,682) |

Other income and (expenses) increased by approximately $41 million for the year ended December 31, 2013, compared to the year ended December 31, 2012. Interest expense increased primarily due to higher outstanding debt during the period and higher amortization of financing fees and expenses associated with the November 2019 Senior Notes, as defined in Note 6, and amendments made to the LINN Credit Facility during 2012 and 2013. For the year ended December 31, 2013, the Company recorded a loss on extinguishment of debt of approximately $5 million as a result of the redemption of the remaining outstanding Original Senior Notes (see Note 6). See "Debt" under "Liquidity and Capital Resources" below for additional details. Other expenses decreased primarily due to no write-offs of deferred financing fees related to the amendment of the LINN Credit Facility during 2013, compared to approximately $8 million of write-offs during 2012.

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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 $2 million for the year ended December 31, 2013, compared to income tax expense of approximately $3 million for the year ended December 31, 2012. Income tax expense decreased primarily due to lower income from the Company's taxable subsidiaries during the year ended December 31, 2013, compared to the year ended December 31, 2012.

Net Loss

Net loss increased by approximately $304 million or 79% to approximately $691 million for the year ended December 31, 2013, from approximately $387 million for the year ended December 31, 2012. The increase was primarily due to higher impairment charges and other expenses, including interest, partially offset by higher production revenues and higher gains on oil and natural gas derivatives. See discussions above for explanations of variances.

Liquidity and Capital Resources

The Company utilizes funds from debt and equity offerings, borrowings under its Credit Facilities and net cash provided by operating activities for capital resources and liquidity. To date, the primary use of capital has been for acquisitions and the development of oil and natural gas properties. For the year ended December 31, 2014, the Company's total capital expenditures, excluding acquisitions, were approximately $1.6 billion. In order to solidify the Company's financial position and regain a useful cost of capital while also balancing cash flow and spending, the Company reduced its 2015 capital budget and estimates its total capital expenditures, excluding acquisitions, will be approximately $600 million, including approximately $520 million related to its oil and natural gas capital program and approximately $40 million related to its plant and pipeline capital. This estimate, which represents an approximate 61% reduction from the 2014 capital expenditures, reflects amounts for the development of properties associated with acquisitions (see Note 2), is under continuous review and subject to ongoing adjustments. The Company expects to fund the capital expenditures primarily with net cash provided by operating activities. In addition to reducing estimated capital spending, the Company also reduced its distribution and expects the distribution payout to decrease by approximately $548 million in 2015. At January 31, 2015, there was approximately $2.2 billion of available borrowing capacity under the LINN Credit Facility but less than $1 million available under the Berry Credit Facility, as defined in Note 6.

The next semi-annual redetermination of the borrowing base is scheduled to occur in April 2015. Continued lower commodity prices may result in a decrease in the borrowing base at that time, which may reduce the Company's liquidity. In the event Berry's borrowing base is reduced below the amount of borrowings outstanding, LINN Energy will either make principal repayments or post restricted cash on Berry's behalf to address the shortfall, subject to the LINN Credit Facility.

As the Company pursues growth, it continually monitors the capital resources available to meet future financial obligations and planned capital expenditures. The Company's future success in growing reserves and production volumes will be highly dependent on the capital resources available and its success in drilling for or acquiring additional reserves. The Company actively reviews acquisition opportunities on an ongoing basis. If the Company were to make significant additional acquisitions for cash, it would need to borrow additional amounts under its Credit Facilities, if available, or obtain additional debt or equity financing. The Company's Credit Facilities and indentures governing its senior notes impose certain restrictions on the Company's ability to obtain additional debt financing. Based upon current expectations, the Company believes its liquidity and capital resources will be sufficient to conduct its business and operations. For additional information about the risk that the Company may not have sufficient net cash provided by operating activities to maintain its distribution and other risk factors that could affect the Company, see Item 1A. "Risk Factors."

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

Statements of Cash Flows

The following is a comparative cash flow summary:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| | (in thousands) | | |
| Net cash: | | | |
| Provided by operating activities [1] | $1,711,890 | $1,166,212 | $350,907 |
| Used in investing activities | (1,920,104) | (1,253,317) | (3,684,829) |
| Provided by financing activities | 157,852 | 138,033 | 3,334,051 |
| Net increase (decrease) in cash and cash equivalents | $(50,362) | $50,928 | $129 |

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

Operating Activities

Cash provided by operating activities for the year ended December 31, 2014, was approximately $1.7 billion, compared to approximately $1.2 billion for the year ended December 31, 2013. The increase was primarily due to higher production related revenues principally due to increased production volumes and higher natural gas and NGL prices, partially offset by higher expenses and lower cash settlements on derivatives.

Cash provided by operating activities for the year ended December 31, 2013, was approximately $1.2 billion, compared to approximately $351 million for the year ended December 31, 2012. The increase was primarily due to no premiums paid for derivatives during the year ended December 31, 2013, compared to $583 million in premiums paid during the year ended December 31, 2012. Lower premiums and higher revenues primarily due to increased production volumes were partially offset by higher expenses.

During the year ended December 31, 2012, premiums paid were for commodity derivative contracts that hedge future production. The Company hedges a substantial portion of its production to reduce exposure to fluctuations in the prices of oil and natural gas and provide long-term cash flow predictability to manage its business, service debt and pay distributions. The majority of the Company's hedges are in the form of fixed price swaps, which are entered into on market terms and without cost. The Company's ability to enter into swaps is governed by covenants under its Credit Facilities which limit the maximum percentage of forecasted future production that may be hedged using swaps to 80% for the current calendar year and the following four calendar years and 70% thereafter. In prior years, the Company has chosen to purchase put options, primarily in connection with acquisitions, to hedge certain volumes in excess of volumes already hedged with swaps to achieve greater downside commodity price protection. Put options require the payment of a premium, which the Company pays in cash at the time of execution and no additional amounts are payable in the future under the contracts.

When the Company evaluates new hedging plans, it considers a variety of factors, including general characteristics of the asset to be hedged, such as commodity type and expectations for production growth, general availability of a liquid market to enter into new hedges, volumes, prices and duration of swaps that comply with the Credit Facilities covenants, and attributes associated with put options, such as time value, volatility and premiums for various strike prices relative to swap reference prices. Specifically, for acquisitions which it chose to hedge in part with put options, the Company typically set a budget of approximately 10% of the acquisition contract price to purchase put options covering associated production volumes for multiple years into the future.

The appropriate level of production to be hedged is an ongoing consideration and is based on a variety of factors, including current and future expected commodity market prices, cost and availability of put option contracts, the level of acquisition activity and the Company's overall risk profile, including leverage and size and scale considerations. As a result, the appropriate percentage of production volumes to be hedged may change over time. See Note 7 and Note 8 for additional details about the Company's commodity derivatives.

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

Investing Activities

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

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| | (in thousands) | | |
| Cash flow from investing activities: | | | |
| Acquisition of oil and natural gas properties and joint-venture funding, net of cash acquired | $(2,479,252) | $(279,213) | $(2,640,475) |
| Capital expenditures | (1,644,417) | (1,170,377) | (1,045,079) |
| Proceeds from sale of properties and equipment and other | 2,203,565 | 196,273 | 725 |
| | $(1,920,104) | $(1,253,317) | $(3,684,829) |

The primary use of cash in investing activities is for capital spending, including acquisitions and the development of the Company's oil and natural gas properties. The increase in 2014 was primarily due to two significant cash acquisitions of properties from Pioneer and Devon consummated during the year, compared to one significant cash acquisition of properties in the Permian Basin region consummated during 2013. The amount reported for the year ended December 31, 2013, includes approximately $451 million of cash acquired in the Berry acquisition. See Note 2 for additional details of acquisitions. Capital expenditures were higher during 2014 primarily due to increased development activities of properties in the Rockies, California and Permian Basin regions, partially offset by decreased development activities of properties in the Mid-Continent region. Proceeds from sale of properties and equipment and other for the year ended December 31, 2014, include approximately $1.8 billion and $351 million in net cash proceeds received from the Granite Wash Assets Sale and the Permian Basin Assets Sale, respectively, compared to $218 million in net cash proceeds received from the sale of the Panther Operated Cleveland Properties in 2013 (see Note 2).

Cash used in investing activities for the year ended December 31, 2012, primarily relates to four cash acquisitions of properties in the Rockies, Hugoton Basin and TexLa regions.

Financing Activities

Cash provided by financing activities for the year ended December 31, 2014, was approximately $158 million compared to approximately $138 million for the year ended December 31, 2013. The increase in financing cash flow needs was primarily attributable to increased cash acquisition activity during the year ended December 31, 2014. Cash provided by financing activities was approximately $3.3 billion for the year ended December 31, 2012.

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

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| | (in thousands) | | |
| Proceeds from borrowings: | | | |
| LINN Credit Facility | $2,540,000 | $1,730,000 | $3,640,000 |
| Senior notes | 1,100,024 | — | 1,799,802 |
| Bridge Loan and term loans | 2,300,000 | 500,000 | — |
| | $5,940,024 | $2,230,000 | $5,439,802 |
| Repayments of debt: | | | |
| LINN Credit Facility | $(2,305,000) | $(1,350,000) | $(3,400,000) |
| Senior notes | (206,124) | (54,898) | — |
| Bridge Loan and VIE Term Loan | (2,300,000) | — | — |
| | $(4,811,124) | $(1,404,898) | $(3,400,000) |

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

Debt
The following summarizes the Company's outstanding debt:

| | December 31, 2014 | 2013 |
|---|---|---|
| | (in thousands, except percentages) | |
| LINN Credit Facility | $1,795,000 | $1,560,000 |
| Berry Credit Facility | 1,173,175 | 1,173,175 |
| Term loan | 500,000 | 500,000 |
| 10.25% Berry senior notes due June 2014 | — | 205,257 |
| 6.50% senior notes due May 2019 [(1)] | 1,200,000 | 750,000 |
| 6.25% senior notes due November 2019 | 1,800,000 | 1,800,000 |
| 8.625% senior notes due April 2020 | 1,300,000 | 1,300,000 |
| 6.75% Berry senior notes due November 2020 | 299,970 | 300,000 |
| 7.75% senior notes due February 2021 | 1,000,000 | 1,000,000 |
| 6.50% senior notes due September 2021 [(1)] | 650,000 | — |
| 6.375% Berry senior notes due September 2022 | 599,163 | 600,000 |
| Net unamortized discounts and premiums | (21,499) | (18,216) |
| Total debt, net | 10,295,809 | 9,170,216 |
| Less current maturities | — | (211,558) |
| Total long-term debt, net | $10,295,809 | $8,958,658 |

(1) $450 million of senior notes due May 2019 and $650 million of senior notes due September 2021 were issued on September 9, 2014.

For additional information related to the Company's outstanding debt, see Note 6. The Company plans to file Berry's stand-alone financial statements with the Securities and Exchange Commission at a later date.

The Company is in compliance with all financial and other covenants of its Credit Facilities and senior notes. If an event of default would occur and were continuing, the Company would be unable to make borrowings and its financial condition and liquidity would be adversely affected.

The Company depends, in part, on its Credit Facilities for future capital needs. At January 31, 2015, there was approximately $2.2 billion of available borrowing capacity under the LINN Credit Facility but less than $1 million available under the Berry Credit Facility. In addition, the Company has drawn on the LINN Credit Facility to fund or partially fund cash distribution payments. Absent such borrowings, the Company would have at times experienced a shortfall in cash available to pay the declared cash distribution amount. For additional information, see "Distribution Practices" below. If an event of default would occur and were continuing under the Credit Facilities, the Company would be unable to make borrowings to fund distributions. For additional information about this matter and other risk factors that could affect the Company, see Item 1A. "Risk Factors."

Contingencies

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

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

Commitments and Contractual Obligations

The following is a summary of the Company's commitments and contractual obligations as of December 31, 2014:

| | Payments Due | | | | |
|---|---|---|---|---|---|
| Contractual Obligations | Total | 2015 | 2016 – 2017 | 2018 – 2019 | 2020 and Beyond |
| | (in thousands) | | | | |
| Long-term debt obligations: | | | | | |
| Credit facilities | $2,968,175 | $— | $— | $2,968,175 | $— |
| Term loan | 500,000 | — | — | 500,000 | — |
| Senior notes | 6,849,133 | — | — | 3,000,000 | 3,849,133 |
| Interest (1) | 3,029,399 | 562,372 | 1,119,815 | 965,249 | 381,963 |
| Operating lease obligations: | | | | | |
| Office, property and equipment leases | 46,436 | 13,265 | 18,503 | 13,622 | 1,046 |
| Other: | | | | | |
| Commodity derivatives | 684 | — | 530 | 154 | — |
| Asset retirement obligations | 497,570 | 16,187 | 18,293 | 19,095 | 443,995 |
| Firm natural gas transportation contracts (2) | 180,399 | 33,418 | 66,863 | 46,499 | 33,619 |
| Purchase obligations and other (3) | 5,294 | 2,852 | 2,442 | — | — |
| | $14,077,090 | $628,094 | $1,226,446 | $7,512,794 | $4,709,756 |

(1) Represents interest on the LINN Credit Facility, Berry Credit Facility and term loan computed at 1.92%, 2.67% and 2.66%, respectively, through maturities in April 2019. Interest on the May 2019 Senior Notes, November 2019 Senior Notes, April 2020 Senior Notes, Berry November 2020 Senior Notes, February 2021 Senior Notes, September 2021 Senior Notes and Berry September 2022 Senior Notes, as defined in Note 6, computed at fixed rates of 6.50%, 6.25%, 8.625%, 6.75%, 7.75%, 6.50% and 6.375%, respectively.

(2) In connection with the Berry acquisition, the Company assumed certain firm commitments to transport natural gas production to market and to transport natural gas for use in its cogeneration and conventional steam generation facilities. The remaining terms of these contracts range from three to nine years and require a minimum monthly charge regardless of whether the contracted capacity is used or not.

(3) Primarily represents cogeneration facility management services and equipment purchase obligations.

Counterparty Credit Risk

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

Issuance of Units for Berry Acquisition

On December 16, 2013, the Company completed the transactions contemplated by the merger agreement under which LinnCo, an affiliate of LINN Energy, acquired all of the outstanding common shares of Berry and the contribution agreement between LinnCo and the Company, under which LinnCo contributed Berry to the Company in exchange for LINN Energy units. Under the merger agreement, as amended, Berry's shareholders received 1.68 LinnCo common shares for each Berry common share

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they owned, totaling 93,756,674 LinnCo common shares. Under the contribution agreement, LinnCo contributed Berry to LINN Energy in exchange for 93,756,674 newly issued LINN Energy units with a value of approximately $2.8 billion. See Note 2 for additional information.

LinnCo Initial Public Offering

In October 2012, LinnCo completed its initial public offering (the "LinnCo IPO") of 34,787,500 common shares representing limited liability company interests to the public at a price of $36.50 per share ($34.858 per share, net of underwriting discount and structuring fee) for net proceeds of approximately $1.2 billion (after underwriting discount and structuring fee of approximately $57 million). The net proceeds LinnCo received from the offering were used to acquire 34,787,500 LINN Energy units which are equal to the number of LinnCo shares sold in the offering. The Company used the proceeds from the sale of the units to LinnCo to pay the expenses of the offering and repay a portion of the borrowings outstanding under the LINN Credit Facility.

Public Offering of Units

In January 2012, the Company sold 19,550,000 units representing limited liability company interests at $35.95 per unit ($34.512 per unit, net of underwriting discount) for net proceeds of approximately $674 million (after underwriting discount and offering expenses of approximately $28 million). The Company used the net proceeds from the sale of these units to repay a portion of the borrowings outstanding under the LINN Credit Facility.

At-the-Market Offering Program

In January 2012, the Company, under an equity distribution agreement pursuant to which it may from time to time issue and sell units representing limited liability company interests, issued and sold 1,539,651 units representing limited liability company interests at an average unit price of $38.02 for net proceeds of approximately $57 million (net of approximately $1 million in commissions). In connection with the issuance and sale of these units, the Company also incurred professional service expenses of approximately $700,000. The Company used the net proceeds for general corporate purposes, including the repayment of a portion of the borrowings outstanding under the LINN Credit Facility.

In August 2014, the Board of Directors increased the authority under the existing at-the-market offering program to $500 million, and as of December 31, 2014, no units had been sold under the increased authority. Sales of units, if any, will be made through a sales agent by means of ordinary brokers' transactions, in block transactions, or as otherwise agreed with the agent. The Company expects to use the net proceeds from any sale of the units for general corporate purposes, which may include, among other things, capital expenditures, acquisitions and the repayment of debt.

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

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 over the next four quarters. The following provides a summary of distributions paid by the Company during the year ended December 31, 2014:

| Date Paid | Distributions Per Unit | Total Distributions (in millions) |
|---|---|---|
| December 2014 | $0.2416 | $80 |
| November 2014 | $0.2416 | $80 |
| October 2014 | $0.2416 | $80 |
| September 2014 | $0.2416 | $80 |
| August 2014 | $0.2416 | $80 |
| July 2014 | $0.2416 | $80 |
| June 2014 | $0.2416 | $80 |
| May 2014 | $0.2416 | $80 |
| April 2014 | $0.2416 | $80 |
| March 2014 | $0.2416 | $80 |
| February 2014 | $0.2416 | $80 |
| January 2014 | $0.2416 | $80 |

On January 2, 2015, the Company’s Board of Directors declared a cash distribution of $0.3125 per unit with respect to the fourth quarter of 2014, to be paid in three equal monthly installments of $0.1042 per unit. The current distribution represents an approximate 57% decrease from the distribution of $0.725 paid for the previous quarter. The first monthly distribution with respect to the fourth quarter of 2014, totaling approximately $35 million, was paid on January 15, 2015, to unitholders of record as of the close of business on January 12, 2015, and the second monthly distribution, totaling approximately $35 million, was paid on February 17, 2015, to unitholders of record as of the close of business on February 10, 2015.

Distribution Practices

The Company’s Board of Directors determines the appropriate level of distributions on a periodic basis in accordance with the provisions of the Company’s limited liability company agreement. Management considers the timing and size of planned capital expenditures and long-term views about expected results in determining the amount of its distributions. Capital spending and resulting production and net cash provided by operating activities do not typically occur evenly throughout the year due to a variety of factors which are difficult to predict, including rig availability, weather, well performance, the timing of completions and the commodity price environment. Consistent with practices common to publicly traded partnerships, the Company’s Board of Directors historically has not varied the distribution it declares from period to period based on uneven net cash provided by operating activities. The Company’s Board of Directors reviews historical financial results and forecasts for future periods, including development activities, as well as considers the impact of significant acquisitions in making a determination to increase, decrease or maintain the current level of distribution. For example, in the year ended December 31, 2012, following acquisitions and development activities during the year, the Company’s Board of Directors reviewed the excess of net cash provided by operating activities after distributions and discretionary adjustments in then-current periods, as well as forecasts of expected future net cash provided by operating activities and determined to increase the distribution during the year. In each of the years ending December 31, 2014, and December 31, 2013, the Company’s Board of Directors considered shortfalls and excesses of net cash provided by operating activities after distributions and discretionary adjustments as well as forecasts of expected future net cash provided by operating activities and decided to maintain the distribution at the same level. If shortfalls are sustained over time and forecasts demonstrate expectations for continued future shortfalls, the Company’s Board of Directors may determine to reduce, suspend or discontinue paying distributions. Please read “Risk Factors – If we are unable to replace declines in production, proved developed producing reserves and cash flow from discretionary reductions for

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a portion of our oil and natural gas development costs, our net cash provided by operating activities could be reduced, which could adversely affect our ability to pay a distribution at the current level or at all" and "We may not have sufficient net cash provided by operating activities to pay our distribution at the current distribution level, or at all, and as a result, future distributions to our unitholders may be reduced, suspended or eliminated."

In January 2015, the Company's Board of Directors approved a reduction of the Company's distribution to $1.25 per unit, from the previous level of $2.90 per unit, on an annualized basis. The reduction of the distribution is intended to solidify the Company's financial position and regain a useful cost of capital, and was primarily driven by the contemplation of a significantly lower oil price in 2015 than in 2014.

The Company intends to fund interest expense, a portion of its oil and natural gas development costs and distributions to unitholders from net cash provided by operating activities. The Company funds premiums paid for derivatives, acquisitions and other capital expenditures primarily with proceeds from debt or equity offerings, borrowings under the LINN Credit Facility or other external sources of funding. Although it is the Company's practice to acquire or modify derivative instruments with external sources of funding, any cash settlements on derivatives are reported as net cash provided by operating activities and may be used to fund distributions. See below for details regarding the discretionary adjustments considered by the Company's Board of Directors in assessing the appropriate distribution amount for each period, as well as the extent to which sources of funding have been sufficient for the periods presented:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| | (in thousands) | | |
| Net cash provided by operating activities | $1,711,890 | $1,166,212 | $350,907 |
| Distributions to unitholders | (962,048) | (682,241) | (596,935) |
| Excess (shortfall) of net cash provided by operating activities after distributions to unitholders | 749,842 | 483,971 | (246,028) |
| Discretionary adjustments considered by the Board of Directors: | | | |
| Discretionary reductions for a portion of oil and natural gas development costs [(1)] | (823,562) | (476,507) | (362,430) |
| Premiums paid for derivatives [(2)] | — | — | 583,434 |
| Cash settlements on canceled derivatives [(3)] | (12,281) | — | — |
| Cash recoveries of bankruptcy claim [(4)] | (6,639) | (11,222) | (21,503) |
| Cash received (paid) for acquisitions or divestitures – revenues less operating expenses [(5)] | 91,890 | 7,144 | 80,502 |
| Provision for legal matters [(6)] | 1,598 | 1,000 | 414 |
| Changes in operating assets and liabilities and other, net [(7)] | 23,228 | (9,030) | 47,951 |
| Excess (shortfall) of net cash provided by operating activities after distributions to unitholders and discretionary adjustments considered by the Board of Directors [(8)] | $24,076 | $(4,644) | $82,340 |

(1) Represent discretionary reductions for a portion of oil and natural gas development costs, an estimated component of total development costs, which are amounts established by the Board of Directors at the end of each year for the following year, allocated across four quarters, that are intended to fully offset declines in production and proved developed producing reserves during the year as compared to the prior year. The portion of oil and natural gas development costs includes estimated drilling and development costs associated with projects to convert a portion of non-producing reserves to producing status. However, the amounts do not include the historical cost of acquired properties as those amounts have already been spent in prior periods, were financed primarily with external sources of funding and do not affect the Company's ability to pay distributions in the current period. The Company's existing reserves, inventory of drilling locations and production levels will decline over time as a result of

development and production activities. Consequently, if the Company were to limit its total capital expenditures to this portion of oil and natural gas development costs and not acquire new reserves, total reserves would decrease over time, resulting in an inability to maintain production at current levels, which could adversely affect the Company’s ability to pay a distribution at the current level or at all. However, the Company’s current total reserves do not include reserve additions that may result from converting existing probable and possible resources to additional proved reserves, potential additional discoveries or technological advancements on the Company’s existing acreage position. For additional information, including the risks associated with the process for determining this amount, please also see “Risk Factors – If we are unable to replace declines in production, proved developed producing reserves and cash flow from discretionary reductions for a portion of our oil and natural gas development costs, our net cash provided by operating activities could be reduced, which could adversely affect our ability to pay a distribution at the current level or at all.”

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

For 2015, the Board of Directors established the discretionary reductions with the objective of replacing proved developed producing reserves, current production and cash flow, taking into consideration the Company's 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.
Following is the total development of oil and natural gas properties as presented in the statements of cash flows:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| | (in thousands) | | |
| Total development of oil and natural gas properties | $1,569,877 | $1,078,025 | $984,530 |

Following are the disclosures for the last three years regarding (i) discretionary reductions for a portion of oil and natural gas development costs and (ii) the portion of reserves estimated to be converted from non-producing to producing status through the capital expenditures that are discretionary reductions for a portion of oil and natural gas development costs.

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| Discretionary reductions for a portion of oil and natural gas development costs (in thousands) [(a)] | $823,562 | $476,507 | $362,430 |
| Portion of non-producing reserves estimated to be converted to producing status through discretionary reductions (Bcfe) [(b)] | 447 | 313 | 265 |

(a) Represents the estimated costs to convert non-producing reserves to producing status on the Company's most efficient projects, with the intent to fully offset declines in production and proved developed producing reserves through drilling and development activities. Includes not only the conversion of reserves from proved undeveloped to producing status but also includes converting reserves that are non-proved to producing status and converting reserves from activities such as recompletions and workovers to producing status. Such estimated costs and quantities do not represent actual costs or reserve conversions or additions. See Item 1. "Business" and "Supplemental Oil and Natural Gas Data (Unaudited)" in Item 8. "Financial Statements and Supplementary Data" for information regarding historical reserve conversions or additions and the related costs of such conversions or additions.

(b) Represents the reserves estimated to be converted from the Company's most efficient projects, with the intent to fully offset declines in production and proved developed producing reserves through drilling and development activities. Includes not only the conversion of reserves from proved undeveloped to producing status but also includes converting reserves that are non-proved to producing status and converting reserves from activities such as recompletions and workovers to producing status.

(2) Represent premiums paid for derivatives during the period. The Company considers the cost of premiums paid for derivatives as an investment related to its underlying oil and natural gas properties. The Company's statements of cash flows, prepared in accordance with GAAP, present cash settlements on derivatives and premiums paid for derivatives as operating activities. However, for purposes of determining the amount available for distribution to unitholders, the Company considers premiums paid for derivatives as investing activities, similar to the way the initial acquisition or development costs of the Company's oil and natural gas properties are presented as investing activities while the cash flows generated from these assets are included in net cash provided by operating activities. The consideration of premiums paid for derivatives as investing activities for purposes of determining the amount available for distribution differs from the presentation of derivatives activities, including premiums paid, as operating activities in the Company's financial statements prepared in accordance with GAAP.

(3) Represent derivatives canceled prior to the contract settlement date.

(4)

Represent the recoveries of a bankruptcy claim against Lehman Brothers which was not a transaction occurring in the ordinary course of the Company's business.

(5) Represents adjustments to the purchase price of acquisitions and divestitures, based on the Company's contractual right to revenues less operating expenses for periods from the effective date of a transaction to the closing date of a transaction. In 2013, the Company also began deducting discretionary reductions for a portion of oil and natural gas development costs. When the Company is the buyer, it is legally entitled to revenues less operating expenses generated during this period, and the Company's Board of Directors has historically made a discretionary adjustment to include this cash in the amount available for distribution. Conversely, when the Company is the seller, the Company's Board of Directors has historically made a discretionary adjustment to reduce this cash from the amount available for distribution during the period.

(6) Represents reserves and settlements related to legal matters.

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

(7) Represents primarily working capital adjustments. These adjustments may or may not impact cash provided by (used in) operating activities during the respective period, but are included as discretionary adjustments considered by the Company's Board of Directors as the Board historically has not varied the distribution it declares period to period based on uneven cash flows. The Company's Board of Directors, when determining the appropriate level of cash distributions, excluded the impact of the timing of cash receipts and payments; as such, this adjustment is necessary to show the historical amounts considered by the Company's Board of Directors in assessing the appropriate distribution amount for each period.

(8) Represents the excess (shortfall) of net operating cash flow after distributions to unitholders and discretionary adjustments. Any excess was retained by the Company for future operations, future capital expenditures, future debt service or other future obligations. Any shortfall was funded with cash on hand and/or borrowings under the LINN Credit Facility.

Any cash generated by Berry is currently being used by Berry to fund its activities and is not currently being distributed to LINN Energy. To the extent that Berry generates cash in excess of its needs, the indentures governing Berry's senior notes limit the amount it may distribute to LINN Energy to the amount available under a "restricted payments basket," and Berry may not distribute any such amounts unless it is permitted by the indentures to incur additional debt pursuant to the consolidated coverage ratio test set forth in the Berry indentures. Berry's restricted payments basket was approximately $275 million at December 31, 2014, and may be increased in accordance with the terms of the Berry indentures by, among other things, 50% of Berry's future net income, reductions in its indebtedness and restricted investments, and future capital contributions.

A summary of the significant sources and uses of funding for the respective periods is presented below:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| | (in thousands) | | |
| Net cash provided by operating activities | $1,711,890 | $1,166,212 | $350,907 |
| Distributions to unitholders | (962,048) | (682,241) | (596,935) |
| Excess (shortfall) of net cash provided by operating activities after distributions to unitholders | 749,842 | 483,971 | (246,028) |
| Plus (less): | | | |
| Net cash provided by financing activities (excluding distributions to unitholders) | 1,119,900 | 820,274 | 3,930,986 |
| Acquisition of oil and natural gas properties and joint-venture funding, net of cash acquired | (2,479,252) | (279,213) | (2,640,475) |
| Development of oil and natural gas properties | (1,569,877) | (1,078,025) | (984,530) |
| Purchases of other property and equipment | (74,540) | (92,352) | (60,549) |
| Proceeds from sale of properties and equipment and other | 2,203,565 | 196,273 | 725 |
| Net increase (decrease) in cash and cash equivalents | $(50,362) | $50,928 | $129 |

## Critical Accounting Policies and Estimates

The discussion and analysis of the Company's financial condition and results of operations is based on the consolidated financial statements, which have been prepared in accordance with GAAP. The preparation of these financial statements requires the Company to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosures of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is a reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. The Company evaluates its estimates and assumptions on a regular basis. The Company bases estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in the preparation of financial statements.

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

Recently Issued Accounting Standards

For a discussion of recently issued accounting standards, see Note 1 of Notes to Consolidated Financial Statements.

Oil and Natural Gas Reserves

Proved reserves are based on the quantities of oil, natural gas and NGL that by analysis of geoscience and engineering data can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain. The independent engineering firm, DeGolyer and MacNaughton, prepared a reserve and economic evaluation of all of the Company properties on a well-by-well basis as of December 31, 2014, and the reserve estimates reported herein were prepared by DeGolyer and MacNaughton. The reserve estimates were reviewed and approved by the Company's senior engineering staff and management, with final approval by its Executive Vice President and Chief Operating Officer. Reserves and their relation to estimated future net cash flows impact the Company's depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. The process performed by the independent engineers to prepare reserve amounts included their estimation of reserve quantities, future production rates, future net revenue and the present value of such future net revenue, based in part on data provided by the Company. The estimates of reserves conform to the guidelines of the SEC, including the criteria of "reasonable certainty," as it pertains to expectations about the recoverability of reserves in future years.

The accuracy of reserve estimates is a function of many factors including the following: the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions and the judgments of the individuals preparing the estimates. In addition, reserve estimates are a function of many assumptions, all of which could deviate significantly from actual results. As such, reserve estimates may materially vary from the ultimate quantities of oil, natural gas and NGL eventually recovered. For additional information regarding estimates of reserves, including the standardized measure of discounted future net cash flows, see "Supplemental Oil and Natural Gas Data (Unaudited)" in Item 8. "Financial Statements and Supplementary Data" and see also Item 1. "Business."

Oil and Natural Gas Properties

Proved Properties

The Company accounts for oil and natural gas properties in accordance with the successful efforts method. In accordance with this method, all leasehold and development costs of proved properties are capitalized and amortized on a unit-of-production basis over the remaining life of the proved reserves and proved developed reserves, respectively.

The Company evaluates the impairment of its proved oil and natural gas properties on a field-by-field basis whenever events or changes in circumstances indicate that the carrying value may not be recoverable. The carrying values of proved properties are reduced to fair value when the expected undiscounted future cash flows of proved and risk-adjusted probable and possible reserves are less than net book value. The fair values of proved properties are measured using valuation techniques consistent with the income approach, converting future cash flows to a single discounted amount. Significant inputs used to determine the fair values of proved properties include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; and (iv) a market-based weighted average cost of capital rate. The underlying commodity prices embedded in the Company's estimated cash flows are the product of a process that begins with New York Mercantile Exchange ("NYMEX") forward curve pricing, adjusted for estimated location and quality differentials, as well as other factors that Company management believes will impact realizable prices. Costs of retired, sold or abandoned properties that constitute a part of an amortization base are charged or credited, net of proceeds, to accumulated depreciation, depletion and amortization unless doing so significantly affects the unit-of-production amortization rate, in which case a gain or loss is recognized currently. Gains or losses from the disposal of other properties are recognized currently. Expenditures for maintenance and repairs necessary to maintain properties in operating condition are expensed as incurred. Estimated dismantlement and abandonment costs are capitalized, net of salvage, at their estimated net present value and amortized on a unit-of-production basis over the remaining life of the related proved developed reserves. The Company capitalizes interest on borrowed funds related to its share of costs associated with the drilling and completion of new oil and natural gas wells. Interest is capitalized only during the periods in which these assets are brought to their intended use. The Company capitalized interest costs of

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approximately $9 million for the year ended December 31, 2014, and $2 million for each of the years ended December 31, 2013, and December 31, 2012.

Impairment of Proved Properties

Based on the analysis described above, for the years ended December 31, 2014, December 31, 2013, and December 31, 2012, the Company recorded noncash impairment charges, before and after tax, of approximately $2.3 billion, $791 million and $422 million, respectively, associated with proved oil and natural gas properties. The carrying values of the impaired proved properties were reduced to fair value, estimated using inputs characteristic of a Level 3 fair value measurement. The impairment charges are included in "impairment of long-lived assets" on the consolidated statements of operations.

Unproved Properties

Costs related to unproved properties include costs incurred to acquire unproved reserves. Because these reserves do not meet the definition of proved reserves, the related costs are not classified as proved properties. Unproved leasehold costs are capitalized and amortized on a composite basis if individually insignificant, based on past success, experience and average lease-term lives. Individually significant leases are reclassified to proved properties if successful and expensed on a lease by lease basis if unsuccessful or the lease term expires. Unamortized leasehold costs related to successful exploratory drilling are reclassified to proved properties and depleted on a unit-of-production basis. The Company assesses unproved properties for impairment quarterly on the basis of its experience in similar situations and other factors such as the primary lease terms of the properties, the average holding period of unproved properties and the relative proportion of such properties on which proved reserves have been found in the past.

Exploration Costs

Geological and geophysical costs, delay rentals, amortization and impairment of unproved leasehold costs and costs to drill exploratory wells that do not find proved reserves are expensed as exploration costs. The costs of any exploratory wells are carried as an asset if the well finds a sufficient quantity of reserves to justify its capitalization as a producing well and as long as the Company is making sufficient progress towards assessing the reserves and the economic and operating viability of the project. The Company recorded noncash leasehold impairment expenses related to unproved properties of approximately $125 million, $5 million and $2 million for the years ended December 31, 2014, December 31, 2013, and December 31, 2012, respectively, which are included in "exploration costs" on the consolidated statements of operations.

Revenue Recognition

Sales of oil, natural gas and NGL are recognized when the product has been delivered to a custody transfer point, persuasive evidence of a sales arrangement exists, the rights and responsibility of ownership pass to the purchaser upon delivery, collection of revenue from the sale is reasonably assured and the sales price is fixed or determinable. In addition, the Company engages in the purchase, gathering and transportation of third-party natural gas and subsequently markets such natural gas to independent purchasers under separate arrangements. As such, the Company separately reports third-party marketing revenues and marketing expenses.

Derivative Instruments

The Company uses derivative financial instruments to reduce exposure to fluctuations in the prices of oil and natural gas. By removing a significant portion of the price volatility associated with future production, the Company expects to mitigate, but not eliminate, the potential effects of variability in net cash provided by operating activities due to fluctuations in commodity prices.

The Company enters into commodity hedging transactions primarily in the form of swap contracts that are designed to provide a fixed price and, from time to time, put options that are designed to provide a fixed price floor with the opportunity for upside. A swap contract specifies a fixed price that the Company will receive from the counterparty as compared to floating market prices, and on the settlement date the Company will receive or pay the difference between the swap price and the market price. A put option requires the Company to pay the counterparty a premium equal to the fair value of the option at the purchase date and receive from the counterparty the excess, if any, of the fixed price floor over the market price at the settlement date. Also, the Company may from time to time enter into derivative contracts in the form of interest rate swaps to minimize the effects of fluctuations in interest rates. At December 31, 2014, the Company had no outstanding derivative contracts in the form of interest rate swaps.

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In addition, as part of the 2013 acquisition of Berry (see Note 2), the Company assumed certain derivative contracts that Berry had entered into prior to the acquisition date, including swap contracts, collars and three-way collars. Collar contracts specify floor and ceiling prices to be received as compared to floating market prices. Three-way collar contracts combine a short put (the lower price), a long put (the middle price) and a short call (the higher price) to provide a higher ceiling price as compared to a regular collar and limit downside risk to the market price plus the difference between the middle price and the lower price if the market price drops below the lower price.

Derivative instruments (including certain derivative instruments embedded in other contracts that require bifurcation) are recorded at fair value and included on the consolidated balance sheets as assets or liabilities. The Company did not designate these contracts as cash flow hedges; therefore, the changes in fair value of these instruments are recorded in current earnings. The Company uses certain pricing models to determine the fair value of its derivative financial instruments. Inputs to the pricing models include publicly available prices and forward price curves generated from a compilation of data gathered from third parties. Company management validates the data provided by third parties by understanding the pricing models used, obtaining market values from other pricing sources, analyzing pricing data in certain situations and confirming that those instruments trade in active markets. See Note 7 and Note 8 for additional details about the Company’s derivative financial instruments. See Item 7A. “Quantitative and Qualitative Disclosures About Market Risk” for sensitivity analysis regarding the Company’s derivative financial instruments.

Acquisition Accounting

The Company accounts for business combinations under the acquisition method of accounting (see Note 2). Accordingly, the Company recognizes amounts for identifiable assets acquired and liabilities assumed equal to their estimated acquisition date fair values. Transaction and integration costs associated with business combinations are expensed as incurred. Any excess of the acquisition price over the estimated fair value of net assets acquired is recorded as goodwill while any excess of the estimated fair value of net assets acquired over the acquisition price is recorded in current earnings as a gain.

The Company makes various assumptions in estimating the fair values of assets acquired and liabilities assumed. As fair value is a market-based measurement, it is determined based on the assumptions that market participants would use. The most significant assumptions relate to the estimated fair values of proved and unproved oil and natural gas properties. The fair values of these properties are measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; and (iv) a market-based weighted average cost of capital rate. The market-based weighted average cost of capital rate is subjected to additional project-specific risking factors. To compensate for the inherent risk of estimating and valuing unproved properties, the discounted future net revenues of probable and possible reserves are reduced by additional risk-weighting factors. In addition, when appropriate, the Company reviews comparable purchases and sales of oil and natural gas properties within the same regions, and uses that data as a proxy for fair market value; i.e., the amount a willing buyer and seller would enter into in exchange for such properties.

While the estimated fair values of the assets acquired and liabilities assumed have no effect on cash flow, they can have an effect on future results of operations. Generally, higher fair values assigned to oil and natural gas properties result in higher future depreciation, depletion and amortization expense, which results in decreased future net earnings. Also, a higher fair value assigned to oil and natural gas properties, based on higher future estimates of commodity prices, could increase the likelihood of impairment in the event of lower commodity prices or higher operating costs than those originally used to determine fair value. The recording of impairment expense has no effect on cash flow but results in a decrease in net income for the period in which the impairment is recorded.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about potential exposure to market risks. The term “market risk” refers to the risk of loss arising from adverse changes in commodity prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how the Company views and manages its ongoing market risk exposures. All of the Company’s market risk sensitive instruments were entered into for purposes other than trading.

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Item 7A. Quantitative and Qualitative Disclosures About Market Risk - Continued

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

Commodity Price Risk

An important part of the Company’s business strategy includes hedging a significant portion of its forecasted production to reduce exposure to fluctuations in the prices of oil and natural gas and provide long-term cash flow predictability to manage its business, service debt and pay distributions. The current direct NGL hedging market is constrained in terms of price, volume, duration and number of counterparties, which limits the Company’s ability to effectively hedge its NGL production. As a result, currently, the Company directly hedges only its oil and natural gas production. The Company also hedges its exposure to natural gas differentials in certain operating areas but does not currently hedge exposure to oil differentials. By removing a significant portion of the price volatility associated with future production, the Company expects to mitigate, but not eliminate, the potential effects of variability in net cash provided by operating activities due to fluctuations in commodity prices.

Commodity hedging transactions are entered into with respect to a portion of the Company’s projected production to provide an economic hedge of the risk related to the future commodity prices received. The Company does not enter into derivative contracts for trading purposes. The Company enters into commodity hedging transactions primarily in the form of swap contracts that are designed to provide a fixed price and, from time to time, put options that are designed to provide a fixed price floor with the opportunity for upside. A swap contract specifies a fixed price that the Company will receive from the counterparty as compared to floating market prices, and on the settlement date the Company will receive or pay the difference between the swap price and the market price. A put option requires the Company to pay the counterparty a premium equal to the fair value of the option at the purchase date and receive from the counterparty the excess, if any, of the fixed price floor over the market price at the settlement date.

In addition, as part of the 2013 acquisition of Berry Petroleum Company, now Berry Petroleum Company, LLC (“Berry”) (see Note 2), the Company assumed certain derivative contracts that Berry had entered into prior to the acquisition date, including swap contracts, collars and three-way collars. Collar contracts specify floor and ceiling prices to be received as compared to floating market prices. Three-way collar contracts combine a short put (the lower price), a long put (the middle price) and a short call (the higher price) to provide a higher ceiling price as compared to a regular collar and limit downside risk to the market price plus the difference between the middle price and the lower price if the market price drops below the lower price.

The Company maintains a substantial portion of its hedges in the form of swap contracts. From time to time, the Company has chosen to purchase put option contracts primarily in connection with acquisition activity to hedge volumes in excess of those already hedged with swap contracts. The appropriate level of production to be hedged is an ongoing consideration and is based on a variety of factors, including current and future expected commodity market prices, cost and availability of put option contracts, the level of acquisition activity and the Company’s overall risk profile, including leverage and size and scale considerations. As a result, the appropriate percentage of production volumes to be hedged may change over time. The Company did not enter into any new commodity derivative positions in 2014, and did not purchase any put options in 2014 or 2013.

In certain historical periods, the Company paid an incremental premium to increase the fixed price floors on existing put options because the Company typically hedges multiple years in advance and in some cases commodity prices had increased significantly beyond the initial hedge prices. As a result, the Company determined that the existing put option strike prices did not provide reasonable downside protection in the context of the current market.

At December 31, 2014, the fair value of fixed price swaps, put option contracts, collars and three-way collars was a net asset of approximately $1.8 billion. A 10% increase in the index oil and natural gas prices above December 31, 2014, prices would result in a net asset of approximately $1.4 billion, which represents a decrease in the fair value of approximately $423 million; conversely, a 10% decrease in the index oil and natural gas prices below December 31, 2014, prices would result in a net asset of approximately $2.2 billion, which represents an increase in the fair value of approximately $421 million.

At December 31, 2013, the fair value of fixed price swaps, put option contracts, collars and three-way collars was a net asset of approximately $751 million. A 10% increase in the index oil and natural gas prices above December 31, 2013, prices would result in a net liability of approximately $15 million, which represents a decrease in the fair value of approximately $766

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million; conversely, a 10% decrease in the index oil and natural gas prices below December 31, 2013, prices would result in a net asset of approximately $1.5 billion, which represents an increase in the fair value of approximately $781 million.

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. Inputs to the pricing models include publicly available prices and forward price curves generated from a compilation of data gathered from third parties. Company management validates the data provided by third parties by understanding the pricing models used, obtaining market values from other pricing sources, analyzing pricing data in certain situations and confirming that those instruments trade in active markets.

The prices of oil, natural gas and NGL have been extremely volatile, and the Company expects this volatility to continue. Prices for these commodities may fluctuate widely in response to relatively minor changes in the supply of and demand for such commodities, market uncertainty and a variety of additional factors that are beyond its control. Actual gains or losses recognized related to the Company's derivative contracts will likely differ from those estimated at December 31, 2014, and will depend exclusively on the price of the commodities on the specified settlement dates provided by the derivative contracts.

The Company cannot be assured that its counterparties will be able to perform under its derivative contracts. If a counterparty fails to perform and the derivative arrangement is terminated, the Company's cash flows and ability to pay distributions could be impacted.

Interest Rate Risk

At December 31, 2014, the Company had long-term debt outstanding under its Credit Facilities and term loan of approximately $3.5 billion which incurred interest at floating rates (see Note 6). A 1% increase in the London Interbank Offered Rate ("LIBOR") would result in an estimated $35 million increase in annual interest expense.

At December 31, 2013, the Company had long-term debt outstanding under its Credit Facilities and term loan of approximately $3.2 billion which incurred interest at floating rates (see Note 6). A 1% increase in the LIBOR would result in an estimated $32 million increase in annual interest expense.

Counterparty Credit Risk

The Company accounts for its commodity derivatives at fair value on a recurring basis (see Note 8). The fair value of these derivative financial instruments includes the impact of assumed credit risk adjustments, which are based on the Company's and counterparties' published credit ratings, public bond yield spreads and credit default swap spreads, as applicable.

At December 31, 2014, the average public bond yield spread utilized to estimate the impact of the Company's credit risk on derivative liabilities was approximately 1.85%. A 1% increase in the average public bond yield spread would result in an estimated $18,000 increase in net income for the year ended December 31, 2014. At December 31, 2014, the credit default swap spreads utilized to estimate the impact of counterparties' credit risk on derivative assets ranged between 0% and 2.15%. A 1% increase in each of the counterparties' credit default swap spreads would result in an estimated $20 million decrease in net income for the year ended December 31, 2014.

At December 31, 2013, the average public bond yield spread utilized to estimate the impact of the Company's credit risk on derivative liabilities was approximately 1.21%. A 1% increase in the average public bond yield spread would result in an estimated $188,000 increase in net income for the year ended December 31, 2013. At December 31, 2013, the credit default swap spreads utilized to estimate the impact of counterparties' credit risk on derivative assets ranged between 0% and 2.68%. A 1% increase in each of the counterparties' credit default swap spreads would result in an estimated $16 million decrease in net income for the year ended December 31, 2013.

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Item 8. Financial Statements and Supplementary Data

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

As of December 31, 2014, our management assessed the effectiveness of the Company's internal control over financial reporting based on the criteria for effective internal control over financial reporting established in Internal Control – Integrated Framework (1992) by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on the assessment, management determined that we maintained effective internal control over financial reporting as of December 31, 2014, based on those criteria.

KPMG LLP, the independent registered public accounting firm that audited the consolidated financial statements of the Company included in this Annual Report on Form 10-K, has issued an attestation report on the effectiveness of the Company's internal control over financial reporting as of December 31, 2014, which is included herein.

/s/ Linn Energy, LLC

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Unitholders
Linn Energy, LLC:

We have audited the accompanying consolidated balance sheets of Linn Energy, LLC and subsidiaries as of December 31, 2014 and 2013, and the related consolidated statements of operations, unitholders' capital, and cash flows for each of the years in the three-year period ended December 31, 2014. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Linn Energy, LLC and subsidiaries as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2014, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Linn Energy, LLC's internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control – Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 19, 2015, expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

Houston, Texas
February 19, 2015

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## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Unitholders
Linn Energy, LLC:

We have audited Linn Energy, LLC's internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control – Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Linn Energy, LLC's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, Linn Energy, LLC maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control – Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Linn Energy, LLC and subsidiaries as of December 31, 2014 and 2013, and the related consolidated statements of operations, unitholders' capital, and cash flows for each of the years in the three-year period ended December 31, 2014, and our report dated February 19, 2015, expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Houston, Texas
February 19, 2015

LINN ENERGY, LLC
CONSOLIDATED BALANCE SHEETS

| | December 31, 2014 | 2013 |
|---|---|---|
| | (in thousands, except unit amounts) | |
| ASSETS | | |
| Current assets: | | |
| Cash and cash equivalents | $1,809 | $52,171 |
| Accounts receivable – trade, net | 471,684 | 488,202 |
| Derivative instruments | 1,077,142 | 176,130 |
| Other current assets | 155,955 | 99,437 |
| Total current assets | 1,706,590 | 815,940 |
| | | |
| Noncurrent assets: | | |
| Oil and natural gas properties (successful efforts method) | 18,068,900 | 17,888,559 |
| Less accumulated depletion and amortization | (4,867,682) | (3,546,284) |
| | 13,201,218 | 14,342,275 |
| | | |
| Other property and equipment | 669,149 | 647,882 |
| Less accumulated depreciation | (144,282) | (110,939) |
| | 524,867 | 536,943 |
| | | |
| Derivative instruments | 848,097 | 682,002 |
| Other noncurrent assets | 142,737 | 127,804 |
| | 990,834 | 809,806 |
| | | |
| Total noncurrent assets | 14,716,919 | 15,689,024 |
| Total assets | $16,423,509 | $16,504,964 |
| | | |
| LIABILITIES AND UNITHOLDERS’ CAPITAL | | |
| Current liabilities: | | |
| Accounts payable and accrued expenses | $814,809 | $849,624 |
| Derivative instruments | — | 28,176 |
| Other accrued liabilities | 167,736 | 163,375 |
| Current portion of long-term debt | — | 211,558 |
| Total current liabilities | 982,545 | 1,252,733 |
| | | |
| Noncurrent liabilities: | | |
| Credit facilities | 2,968,175 | 2,733,175 |
| Term loan | 500,000 | 500,000 |
| Senior notes, net | 6,827,634 | 5,725,483 |
| Derivative instruments | 684 | 4,649 |
| Other noncurrent liabilities | 600,866 | 397,497 |
| Total noncurrent liabilities | 10,897,359 | 9,360,804 |
| | | |
| Commitments and contingencies (Note 11) | | |
| | | |
| Unitholders’ capital: | | |
| | 5,395,811 | 6,291,824 |

| | | |
|---|---|---|
| 331,974,913 units and 329,661,161 units issued and outstanding at December 31, 2014, and December 31, 2013, respectively | | |
| Accumulated deficit | (852,206 ) | (400,397 ) |
| | 4,543,605 | 5,891,427 |
| Total liabilities and unitholders’ capital | $16,423,509 | $16,504,964 |

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

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LINN ENERGY, LLC
CONSOLIDATED STATEMENTS OF OPERATIONS

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| | (in thousands, except per unit amounts) | | |
| Revenues and other: | | | |
| Oil, natural gas and natural gas liquids sales | $3,610,539 | $2,073,240 | $1,601,180 |
| Gains on oil and natural gas derivatives | 1,206,179 | 177,857 | 124,762 |
| Marketing revenues | 135,260 | 54,171 | 37,393 |
| Other revenues | 31,325 | 26,387 | 10,905 |
| | 4,983,303 | 2,331,655 | 1,774,240 |
| Expenses: | | | |
| Lease operating expenses | 805,164 | 372,523 | 317,699 |
| Transportation expenses | 207,331 | 128,440 | 77,322 |
| Marketing expenses | 117,465 | 37,892 | 31,821 |
| General and administrative expenses | 293,073 | 236,271 | 173,206 |
| Exploration costs | 125,037 | 5,251 | 1,915 |
| Depreciation, depletion and amortization | 1,073,902 | 829,311 | 606,150 |
| Impairment of long-lived assets | 2,303,749 | 828,317 | 422,499 |
| Taxes, other than income taxes | 267,403 | 138,631 | 131,679 |
| (Gains) losses on sale of assets and other, net | (366,500) | 13,637 | 1,539 |
| | 4,826,624 | 2,590,273 | 1,763,830 |
| Other income and (expenses): | | | |
| Interest expense, net of amounts capitalized | (587,838) | (421,137) | (379,937) |
| Loss on extinguishment of debt | — | (5,304) | — |
| Other, net | (16,213) | (8,477) | (14,299) |
| | (604,051) | (434,918) | (394,236) |
| Loss before income taxes | (447,372) | (693,536) | (383,826) |
| Income tax expense (benefit) | 4,437 | (2,199) | 2,790 |
| Net loss | $(451,809) | $(691,337) | $(386,616) |
| | | | |
| Net loss per unit: | | | |
| Basic | $(1.40) | $(2.94) | $(1.92) |
| Diluted | $(1.40) | $(2.94) | $(1.92) |
| Weighted average units outstanding: | | | |
| Basic | 328,918 | 237,544 | 203,775 |
| Diluted | 328,918 | 237,544 | 203,775 |
| | | | |
| Distributions declared per unit | $2.90 | $2.90 | $2.87 |

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

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LINN ENERGY, LLC
CONSOLIDATED STATEMENTS OF UNITHOLDERS' CAPITAL

| | Units | Unitholders' Capital | Accumulated Income (Deficit) | Total Unitholders' Capital |
|---|---|---|---|---|
| | (in thousands) | | | |
| December 31, 2011 | 177,365 | $2,751,354 | $677,556 | $3,428,910 |
| Sale of units, net of underwriting discounts and expenses of $32,044 | 55,877 | 1,942,045 | — | 1,942,045 |
| Issuance of units | 1,271 | 7,061 | — | 7,061 |
| Distributions to unitholders | | (596,935) | — | (596,935) |
| Unit-based compensation expenses | | 29,533 | — | 29,533 |
| Reclassification of distributions paid on forfeited restricted units | | 92 | — | 92 |
| Excess tax benefit from unit-based compensation | | 3,090 | — | 3,090 |
| Net loss | | — | (386,616) | (386,616) |
| December 31, 2012 | 234,513 | 4,136,240 | 290,940 | 4,427,180 |
| Issuance of units | 95,148 | 2,783,907 | — | 2,783,907 |
| Distributions to unitholders | | (682,241) | — | (682,241) |
| Unit-based compensation expenses | | 42,703 | — | 42,703 |
| Reclassification of distributions paid on forfeited restricted units | | 176 | — | 176 |
| Excess tax benefit from unit-based compensation | | 160 | — | 160 |
| Deferred tax on capital contribution | | 10,879 | — | 10,879 |
| Net loss | | — | (691,337) | (691,337) |
| December 31, 2013 | 329,661 | 6,291,824 | (400,397) | 5,891,427 |
| Issuance of units | 2,314 | 13,354 | — | 13,354 |
| Distributions to unitholders | | (962,048) | — | (962,048) |
| Unit-based compensation expenses | | 53,284 | — | 53,284 |
| Reclassification of distributions paid on forfeited restricted units | | 602 | — | 602 |
| Excess tax benefit from unit-based compensation and other | | 347 | — | 347 |
| Deferred tax on capital contribution | | (1,552) | — | (1,552) |
| Net loss | | — | (451,809) | (451,809) |
| December 31, 2014 | 331,975 | $5,395,811 | $(852,206) | $4,543,605 |

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

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LINN ENERGY, LLC
CONSOLIDATED STATEMENTS OF CASH FLOWS

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| | (in thousands) | | |
| Cash flow from operating activities: | | | |
| Net loss | $(451,809) | $(691,337) | $(386,616) |
| Adjustments to reconcile net loss to net cash provided by operating activities: | | | |
| Depreciation, depletion and amortization | 1,073,902 | 829,311 | 606,150 |
| Impairment of long-lived assets | 2,303,749 | 828,317 | 422,499 |
| Unit-based compensation expenses | 53,284 | 42,703 | 29,533 |
| Loss on extinguishment of debt | — | 5,304 | — |
| Amortization and write-off of deferred financing fees | 50,926 | 21,507 | 25,598 |
| (Gains) losses on sale of assets and other, net | (261,571) | 37,232 | 92 |
| Deferred income taxes | 3,943 | (2,541) | (360) |
| Derivatives activities: | | | |
| Total gains | (1,206,179) | (177,857) | (124,762) |
| Cash settlements | 95,514 | 248,862 | 390,765 |
| Cash settlements on canceled derivatives | 12,281 | — | — |
| Premiums paid for derivatives | — | — | (583,434) |
| Changes in assets and liabilities: | | | |
| (Increase) decrease in accounts receivable – trade, net | 5,064 | 89,188 | (77,573) |
| (Increase) decrease in other assets | (17,824) | 16,179 | (5,451) |
| Increase (decrease) in accounts payable and accrued expenses | 99,029 | (76,993) | 26,372 |
| Increase (decrease) in other liabilities | (48,419) | (3,663) | 28,094 |
| Net cash provided by operating activities | 1,711,890 | 1,166,212 | 350,907 |
| | | | |
| Cash flow from investing activities: | | | |
| Acquisition of oil and natural gas properties and joint-venture funding, net of cash acquired | (2,479,252) | (279,213) | (2,640,475) |
| Development of oil and natural gas properties | (1,569,877) | (1,078,025) | (984,530) |
| Purchases of other property and equipment | (74,540) | (92,352) | (60,549) |
| Proceeds from sale of properties and equipment and other | 2,203,565 | 196,273 | 725 |
| Net cash used in investing activities | (1,920,104) | (1,253,317) | (3,684,829) |
| | | | |
| Cash flow from financing activities: | | | |
| Proceeds from sale of units | — | — | 1,973,989 |
| Proceeds from borrowings | 5,940,024 | 2,230,000 | 5,439,802 |
| Repayments of debt | (4,811,124) | (1,404,898) | (3,400,000) |
| Distributions to unitholders | (962,048) | (682,241) | (596,935) |
| Financing fees and offering expenses | (69,694) | (16,033) | (73,320) |
| Excess tax benefit from unit-based compensation | 766 | 160 | 3,090 |
| Other | 59,928 | 11,045 | (12,575) |
| Net cash provided by financing activities | 157,852 | 138,033 | 3,334,051 |
| | | | |
| Net increase (decrease) in cash and cash equivalents | (50,362) | 50,928 | 129 |
| Cash and cash equivalents: | | | |
| Beginning | 52,171 | 1,243 | 1,114 |

| | | | |
|---|---|---|---|
| Ending | $1,809 | $52,171 | $1,243 |

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

LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
Note 1 – Basis of Presentation and Significant Accounting Policies
Nature of Business
Linn Energy, LLC ("LINN Energy" or the "Company") is an independent oil and natural gas company that began operations in March 2003 and was formed as a Delaware limited liability company in April 2005. The Company completed its initial public offering ("IPO") in January 2006 and its units representing limited liability company interests ("units") are listed on the NASDAQ Global Select Market under the symbol "LINE." LINN Energy's mission is to acquire, develop and maximize cash flow from a growing portfolio of long-life oil and natural gas assets.
The Company's properties are located in eight operating regions in the United States ("U.S."): 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); Hugoton Basin, which includes properties located in Kansas, the Oklahoma Panhandle and the Shallow Texas Panhandle; 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 properties located in the Anadarko and Arkoma basins in Oklahoma, as well as waterfloods in the Central Oklahoma Platform; Permian Basin, which includes properties located in west Texas and southeast New Mexico; Michigan/Illinois, which includes properties located in the Antrim Shale formation in north Michigan and oil properties in south Illinois; and South Texas.
The operations of the Company are governed by the provisions of a limited liability company agreement executed by and among its members. The agreement includes specific provisions with respect to the maintenance of the capital accounts of each of the Company's unitholders. Pursuant to applicable provisions of the Delaware Limited Liability Company Act (the "Delaware Act") and the Third Amended and Restated Limited Liability Company Agreement of Linn Energy, LLC, as amended (the "LLC Agreement"), unitholders have no liability for the debts, obligations and liabilities of the Company, except as expressly required in the LLC Agreement or the Delaware Act. The Company will remain in existence unless and until dissolved in accordance with the terms of the LLC Agreement.
Principles of Consolidation and Reporting
The Company presents its financial statements in accordance with U.S. generally accepted accounting principles ("GAAP"). The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries. All significant intercompany transactions and balances have been eliminated upon consolidation. Investments in noncontrolled entities over which the Company exercises significant influence are accounted for under the equity method.
The consolidated financial statements for previous periods include certain reclassifications that were made to conform to current presentation. Such reclassifications have no impact on previously reported net income (loss), unitholders' capital or cash flows.
Use of Estimates
The preparation of the accompanying consolidated financial statements in conformity with GAAP requires management of the Company to make estimates and assumptions about future events. These estimates and the underlying assumptions affect the amount of assets and liabilities reported, disclosures about contingent assets and liabilities, and reported amounts of revenues and expenses. The estimates that are particularly significant to the financial statements include estimates of the Company's reserves of oil, natural gas and natural gas liquids ("NGL"), future cash flows from oil and natural gas properties, depreciation, depletion and amortization, asset retirement obligations, certain revenues and operating expenses, fair values of commodity derivatives and fair values of assets acquired and liabilities assumed. As fair value is a market-based measurement, it is determined based on the assumptions that market participants would use. These estimates and assumptions are based on management's best estimates and judgment. Management evaluates its estimates and assumptions on an ongoing basis using historical experience and other factors, including the current economic environment, which management believes to be reasonable under the circumstances. Such estimates and assumptions are adjusted when facts and circumstances dictate. As future events and their effects cannot be determined with precision, actual results could differ from

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these estimates. Any changes in estimates resulting from continuing changes in the economic environment will be reflected in the financial statements in future periods.

### Recently Issued Accounting Standards

In May 2014, the Financial Accounting Standards Board ("FASB") issued an Accounting Standards Update ("ASU") that is intended to improve and converge the financial reporting requirements for revenue from contracts with customers. This ASU will be applied either retrospectively or as a cumulative-effect adjustment as of the date of adoption and is effective for fiscal years beginning after December 15, 2016, and interim periods within those years (early adoption prohibited). The Company is currently evaluating the impact, if any, of the adoption of this ASU on its consolidated financial statements and related disclosures.

In April 2014, the FASB issued an ASU that changes the criteria for reporting discontinued operations and enhances disclosures in this area. This ASU is effective for annual and interim periods beginning after December 15, 2014, with early adoption permitted for disposals or for assets classified as held for sale that have not been reported in previously issued financial statements. The Company early adopted this ASU on a prospective basis beginning with the third quarter of 2014. The adoption had no effect on the Company's consolidated financial statements.

### Cash Equivalents

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

### Accounts Receivable – Trade, Net

Trade accounts receivable are recorded at the invoiced amount and do not bear interest. The Company maintains an allowance for doubtful accounts for estimated losses inherent in its accounts receivable portfolio. In establishing the required allowance, management considers historical losses, current receivables aging, and existing industry and national economic data. The Company reviews its allowance for doubtful accounts monthly. Past due balances over 90 days and over a specified amount are reviewed individually for collectibility. Account balances are charged off against the allowance after all means of collection have been exhausted and the potential recovery is remote. The balance in the Company's allowance for doubtful accounts related to trade accounts receivable was approximately $1 million at both December 31, 2014, and December 31, 2013.

### Inventories

Materials, supplies and commodity inventories are valued at the lower of average cost or market.

### Oil and Natural Gas Properties

#### Proved Properties

The Company accounts for oil and natural gas properties in accordance with the successful efforts method. In accordance with this method, all leasehold and development costs of proved properties are capitalized and amortized on a unit-of-production basis over the remaining life of the proved reserves and proved developed reserves, respectively.

The Company evaluates the impairment of its proved oil and natural gas properties on a field-by-field basis whenever events or changes in circumstances indicate that the carrying value may not be recoverable. The carrying values of proved properties are reduced to fair value when the expected undiscounted future cash flows of proved and risk-adjusted probable and possible reserves are less than net book value. The fair values of proved properties are measured using valuation techniques consistent with the income approach, converting future cash flows to a single discounted amount. Significant inputs used to determine the fair values of proved properties include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; and (iv) a market-based weighted average cost of capital rate. The underlying commodity prices embedded in the Company's estimated cash flows are the product of a process that begins with New York Mercantile Exchange ("NYMEX") forward curve pricing, adjusted for estimated location and quality differentials, as well as other factors that Company management believes will impact realizable prices. Costs of retired, sold or abandoned properties that constitute a part of an amortization base are charged or credited, net of proceeds, to accumulated depreciation, depletion and amortization unless doing so significantly affects the unit-of-production amortization rate, in which case a gain or loss is recognized currently. Gains or losses from the disposal of other properties are recognized currently. Expenditures for maintenance and repairs necessary to maintain properties in operating condition are expensed as incurred. Estimated dismantlement and abandonment costs are capitalized, net of salvage, at their estimated net present value and amortized on a unit-of-production basis over the remaining life of the related proved developed reserves. The Company capitalizes interest on borrowed funds related to its share of costs associated with the drilling and completion of new oil and natural gas wells. Interest is capitalized only during the periods in which these assets are brought to their intended use. The Company capitalized interest costs of approximately $9 million for the year ended December 31, 2014, and $2 million for each of the years ended December 31, 2013, and December 31, 2012.

Impairment of Proved Properties

Based on the analysis described above, for the years ended December 31, 2014, December 31, 2013, and December 31, 2012, the Company recorded noncash impairment charges, before and after tax, of approximately $2.3 billion, $791 million and $422 million, respectively, associated with proved oil and natural gas properties. The carrying values of the impaired proved properties were reduced to fair value, estimated using inputs characteristic of a Level 3 fair value measurement. The impairment charges are included in "impairment of long-lived assets" on the consolidated statements of operations.

During the fourth quarter of 2014, the Company recorded noncash impairment charges, before and after tax, of approximately $1.7 billion associated with proved oil and natural gas properties throughout its various operating regions. The impairment was due to a steep decline in commodity prices. From September 30, 2014 to December 31, 2014, NYMEX oil and natural gas forward price curves decreased approximately 24% and 12%, respectively.

Following are the impairment charges recorded by operating region:

- Permian Basin – $735 million;
- Rockies – $586 million (in the Powder River Basin and Uinta Basin);
- Mid-Continent – $244 million;
- South Texas – $131 million; and
- TexLa – $5 million.

In addition, during the third quarter of 2014, the Company recorded noncash impairment charges, before and after tax, of approximately $603 million associated with proved oil and natural gas properties in the Permian Basin region. The impairment was 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 the proved oil and natural gas properties.

During the year ended December 31, 2013, the Company recorded a noncash impairment charge, before and after tax, of approximately $791 million associated with proved oil and natural gas properties in the Granite Wash formation related to asset performance resulting in reserve revisions and a decline in commodity prices. During the year ended December 31, 2012, the Company recorded noncash impairment charges, before and after tax, of approximately $422 million associated with proved oil and natural gas properties in the Mississippi Shelf and Mayfield related to the SEC five-year development limitation on PUDs and a decline in commodity prices.

Subsequent to December 31, 2014, 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.

Unproved Properties

Costs related to unproved properties include costs incurred to acquire unproved reserves. Because these reserves do not meet the definition of proved reserves, the related costs are not classified as proved properties. Unproved leasehold costs are capitalized and amortized on a composite basis if individually insignificant, based on past success, experience and average lease-term lives. Individually significant leases are reclassified to proved properties if successful and expensed on a lease by lease basis if unsuccessful or the lease term expires. Unamortized leasehold costs related to successful exploratory drilling are reclassified to proved properties and depleted on a unit-of-production basis. The Company assesses unproved properties for impairment quarterly on the basis of its experience in similar situations and other factors such as the primary lease terms of the properties, the average holding period of unproved properties and the relative proportion of such properties on which proved reserves have been found in the past.

Exploration Costs

Geological and geophysical costs, delay rentals, amortization and impairment of unproved leasehold costs and costs to drill exploratory wells that do not find proved reserves are expensed as exploration costs. The costs of any exploratory wells are carried as an asset if the well finds a sufficient quantity of reserves to justify its capitalization as a producing well and as long as the Company is making sufficient progress towards assessing the reserves and the economic and operating viability of the project. The Company recorded noncash leasehold impairment expenses related to unproved properties of approximately $125 million, $5 million and $2 million for the years ended December 31, 2014, December 31, 2013, and December 31, 2012, respectively, which are included in “exploration costs” on the consolidated statements of operations.

Other Property and Equipment

Other property and equipment includes natural gas gathering systems, pipelines, buildings, software, data processing and telecommunications equipment, office furniture and equipment, and other fixed assets. These assets are recorded at cost and are depreciated using the straight-line method based on expected lives ranging from two to 39 years for the individual asset or group of assets.

Revenue Recognition

Revenues representative of the Company’s ownership interest in its properties are presented on a gross basis on the consolidated statements of operations. Sales of oil, natural gas and NGL are recognized when the product has been delivered to a custody transfer point, persuasive evidence of a sales arrangement exists, the rights and responsibility of ownership pass to the purchaser upon delivery, collection of revenue from the sale is reasonably assured and the sales price is fixed or determinable.

The Company has elected the entitlements method to account for natural gas production imbalances. Imbalances occur when the Company sells more or less than its entitled ownership percentage of total natural gas production. In accordance with the entitlements method, any amount received in excess of the Company’s share is treated as a liability. If the Company receives less than its entitled share, the underproduction is recorded as a receivable. Imbalance receivables and payables are valued at the lower of the price in effect at the time of production, the current market value or, if a contract is in hand, the contract price. At December 31, 2014, and December 31, 2013, the Company had natural gas production imbalance receivables of approximately $17 million and $27 million, respectively, which are included in “accounts receivable – trade, net” on the consolidated balance sheets and natural gas production imbalance payables of approximately $13 million and $16 million, respectively, which are included in “accounts payable and accrued expenses” on the consolidated balance sheets.

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

The Company generates electricity with excess natural gas, which it uses to serve certain of its operating facilities in California. Any excess electricity is sold to the California wholesale power market. The revenue from this activity is included in “other revenues” on the consolidated statements of operations.

Restricted Cash

Restricted cash of approximately $6 million is included in “other noncurrent assets” on the consolidated balance sheets at both December 31, 2014, and December 31, 2013, and primarily represents cash the Company has deposited into a separate account and designated for asset retirement obligations in accordance with contractual agreements.

Derivative Instruments

The Company uses derivative financial instruments to reduce exposure to fluctuations in the prices of oil and natural gas. By removing a significant portion of the price volatility associated with future production, the Company expects to mitigate, but not eliminate, the potential effects of variability in net cash provided by operating activities due to fluctuations in commodity prices.

The Company enters into commodity hedging transactions primarily in the form of swap contracts that are designed to provide a fixed price and, from time to time, put options that are designed to provide a fixed price floor with the opportunity for upside. A swap contract specifies a fixed price that the Company will receive from the counterparty as compared to floating market prices, and on the settlement date the Company will receive or pay the difference between the swap price and the market price. A put option requires the Company to pay the counterparty a premium equal to the fair value of the option at the purchase date and receive from the counterparty the excess, if any, of the fixed price floor over the market price at the settlement date. Also, the Company may from time to time enter into derivative contracts in the form of interest rate swaps to minimize the effects of fluctuations in interest rates. At December 31, 2014, the Company had no outstanding derivative contracts in the form of interest rate swaps.

In addition, as part of the 2013 acquisition of Berry Petroleum Company, now Berry Petroleum Company, LLC (“Berry”) (see Note 2), the Company assumed certain derivative contracts that Berry had entered into prior to the acquisition date, including swap contracts, collars and three-way collars. Collar contracts specify floor and ceiling prices to be received as compared to floating market prices. Three-way collar contracts combine a short put (the lower price), a long put (the middle price) and a short call (the higher price) to provide a higher ceiling price as compared to a regular collar and limit downside risk to the market price plus the difference between the middle price and the lower price if the market price drops below the lower price.

Derivative instruments (including certain derivative instruments embedded in other contracts that require bifurcation) are recorded at fair value and included on the consolidated balance sheets as assets or liabilities. The Company did not designate these contracts as cash flow hedges; therefore, the changes in fair value of these instruments are recorded in current earnings. The Company uses certain pricing models to determine the fair value of its derivative financial instruments. Inputs to the pricing models include publicly available prices and forward price curves generated from a compilation of data gathered from third parties. Company management validates the data provided by third parties by understanding the pricing models used, obtaining market values from other pricing sources, analyzing pricing data in certain situations and confirming that those instruments trade in active markets. See Note 7 and Note 8 for additional details about the Company’s derivative financial instruments.

Unit-Based Compensation

The Company recognizes expense for unit-based compensation over the requisite service period in an amount equal to the fair value of unit-based awards granted to employees and nonemployee directors. The fair value of unit-based awards, excluding liability awards, is computed at the date of grant and is not remeasured. The fair value of liability awards is remeasured at each reporting date through the settlement date with the change in fair value recognized as compensation expense over that period. The Company currently does not have any awards accounted for as liability awards.

The Company has made a policy decision to recognize compensation expense for service-based awards on a straight-line basis over the requisite service period for the entire award. See Note 5 for additional details about the Company’s accounting for unit-based compensation.

The benefit of tax deductions in excess of recognized compensation costs is required to be reported as financing cash flow rather than operating cash flow. This requirement reduces net operating cash flow and increases net financing cash flow in periods in which such tax benefit exists. The amount of the Company’s excess tax benefit is also reported in “excess tax benefit from unit-based compensation and other” on the consolidated statements of unitholders’ capital.

Deferred Financing Fees

The Company incurred legal and bank fees related to the issuance of debt. At December 31, 2014, and December 31, 2013, net deferred financing fees of approximately $129 million and $114 million, respectively, are included in "other noncurrent assets" on the consolidated balance sheets. These debt issuance costs are amortized over the life of the debt agreement. Upon early retirement or amendment to the debt agreement, certain fees are written off to expense. For the years ended December 31, 2014, December 31, 2013, and December 31, 2012, amortization expense of approximately $46 million, $18 million and $13 million, respectively, is included in "interest expense, net of amounts capitalized" on the consolidated statements of operations. For the year ended December 31, 2014, approximately $8 million were written off to expense and included in "other, net" on the consolidated statement of operations related to the VIE Term Loan (as defined in Note 6) and amendments to the Credit Facilities (as defined in Note 6). For the year ended December 31, 2012, approximately $8 million were written off to expense and included in "other, net" on the consolidated statement of operations related to amendments of the LINN Credit Facility (as defined in Note 6). No fees related to amendments of the Credit Facilities were written off to expense during the year ended December 31, 2013.

Fair Value of Financial Instruments

The carrying values of the Company's receivables, payables and Credit Facilities are estimated to be substantially the same as their fair values at December 31, 2014, and December 31, 2013. See Note 6 for fair value disclosures related to the Company's other outstanding debt. As noted above, the Company carries its derivative financial instruments at fair value. See Note 8 for details about the fair value of the Company's derivative financial instruments.

Income Taxes

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. As such, with the exception of the state of Texas, the Company is not a taxable entity, it does not directly pay federal and state income tax and recognition has not been given to federal and state income taxes for the operations of the Company except as described below.

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, which are accounted for using the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis and tax carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. See Note 14 for detail of amounts recorded in the consolidated financial statements.

Note 2 – Exchanges of Properties, Acquisitions, Divestitures and Joint-Venture Funding

Exchanges of Properties – 2014

On November 21, 2014, the Company, through two of its wholly owned subsidiaries, completed the trade of a portion of its Permian Basin properties to Exxon Mobil Corporation in exchange for properties in California's South Belridge Field. The noncash exchange was accounted for at fair value and the Company recognized a net gain of approximately $20 million, including costs to sell of approximately $3 million. The gain is equal to the difference between the carrying value and the fair value of the assets exchanged less costs to sell, and is included in "(gains) losses on sale of assets and other, net" on the consolidated statement of operations. The fair value measurements were based on inputs that are not observable and therefore represent Level 3 inputs under the fair value hierarchy.

On August 15, 2014, the Company, through two of its wholly owned subsidiaries, completed the trade of a portion of its Permian Basin properties to Exxon Mobil Corporation and its affiliates, including its wholly owned subsidiary XTO Energy Inc., in exchange for properties in the Hugoton Basin. The noncash exchange was accounted for at fair value and the

Company recognized a net gain of approximately $65 million, including costs to sell of approximately $3 million. The gain is equal to the difference between the carrying value and the fair value of the assets exchanged less costs to sell, and is included in "(gains) losses on sale of assets and other, net" on the consolidated statement of operations. The fair value measurements were based on inputs that are not observable in the market and therefore represent Level 3 inputs under the fair value hierarchy.

Acquisitions – 2014

On September 11, 2014, the Company completed the acquisition of certain oil and natural gas properties located in the Hugoton Basin from Pioneer Natural Resources Company ("Pioneer" and the acquisition, the "Pioneer Assets Acquisition") for total consideration of approximately $328 million.

On August 29, 2014, the Company completed the acquisition of certain oil and natural gas properties located in five operating regions in the U.S. from subsidiaries of Devon Energy Corporation ("Devon" and the acquisition, the "Devon Assets Acquisition") for total consideration of approximately $2.1 billion.

The Pioneer Assets Acquisition was initially financed with borrowings under the LINN Credit Facility, and the Devon Assets Acquisition was initially financed with proceeds from the Bridge Loan and borrowings under the VIE Term Loan (see Note 6). The Company used the net proceeds from the sales of its Granite Wash properties as well as certain of its Wolfberry properties (see below) to repay the VIE Term Loan in full as well as repay a portion of the borrowings outstanding under the LINN Credit Facility.

The Pioneer Assets Acquisition and the Devon Assets Acquisition were structured as reverse like-kind exchanges pursuant to Section 1031 of the Internal Revenue Code, as amended ("Reverse 1031 Exchanges"). In connection with the Reverse 1031 Exchanges, the Company, through a subsidiary, assigned the rights to acquire legal title to the oil and natural gas properties from Pioneer and Devon to a variable interest entity ("VIE") formed by an exchange accommodation titleholder. A subsidiary of LINN Energy operated the properties pursuant to management agreements with the VIE. Because the Company was the primary beneficiary of the VIE, the VIE was included in the consolidated financial statements from the time of its formation.

The assets acquired by the VIE in the Pioneer Assets Acquisition and the Devon Assets Acquisition were conveyed to LINN Energy and its subsidiaries, and the VIE structure was terminated, upon the completion of the Reverse 1031 Exchanges (which occurred in December 2014 and included the Granite Wash Assets Sale and the Permian Basin Assets Sale, each as defined below).

During the year ended December 31, 2014, the Company also completed other smaller acquisitions of oil and natural gas properties located in its various operating regions. The Company, in the aggregate, paid approximately $5 million in total consideration for these properties.

These acquisitions were accounted for under the acquisition method of accounting. Accordingly, the Company conducted assessments of net assets acquired and recognized amounts for identifiable assets acquired and liabilities assumed at their estimated fair values on the acquisition dates, while transaction and integration costs associated with the acquisitions were expensed as incurred. The initial accounting for the business combinations is not complete and adjustments to provisional amounts, or recognition of additional assets acquired or liabilities assumed, may occur as more detailed analyses are completed and additional information is obtained about the facts and circumstances that existed as of the acquisition dates. The results of operations of all acquisitions have been included in the consolidated financial statements since the acquisition dates.

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LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

The following presents the values assigned to the net assets acquired as of the acquisition dates (in thousands):

| | |
|---|---|
| Assets: | |
| Current | $26,007 |
| Oil and natural gas properties | 2,532,439 |
| Other property and equipment | 121,101 |
| Total assets acquired | 2,679,547 |
| | |
| Liabilities: | |
| Current | 21,976 |
| Asset retirement obligations, current and noncurrent | 171,057 |
| Noncurrent | 18,380 |
| Total liabilities assumed | 211,413 |
| | |
| Net assets acquired | $2,468,134 |

Current assets include receivables and inventory. Current liabilities include payables and environmental liabilities. Noncurrent liabilities include out-of-market contracts.

The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and therefore represent Level 3 inputs under the fair value hierarchy. The fair values of oil and natural gas properties and asset retirement obligations were measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation of oil and natural gas properties include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; (iv) estimated future cash flows; and (v) a market-based weighted average cost of capital rate. These inputs require significant judgments and estimates by the Company's management at the time of the valuation and are the most sensitive and subject to change.

The following unaudited pro forma financial information presents a summary of the Company's consolidated results of operations for the years ended December 31, 2014, and December 31, 2013, assuming the Devon Assets Acquisition and the 2013 acquisition of Berry (see below) had been completed as of January 1, 2013, including adjustments to reflect the values assigned to the net assets acquired. The pro forma financial information has been prepared for informational purposes only and does not purport to represent what the actual results of operations would have been had the transactions been completed as of the date assumed, nor is this information necessarily indicative of future consolidated results of operations. The pro forma financial information does not give effect to the costs of any integration activities or benefits that may result from the realization of future cost savings from operating efficiencies, or any other synergies that may result from the transactions and changes in commodity and share prices.

| | Year Ended December 31, | |
|---|---|---|
| | 2014 | 2013 |
| | (in thousands, except per unit amounts) | |
| Total revenues and other | $5,335,442 | $3,973,605 |
| Total operating expenses | $5,039,311 | $3,711,868 |
| Net loss | $(403,447) | $(397,070) |
| | | |
| Net loss per unit: | | |
| Basic | $(1.25) | $(1.22) |
| Diluted | $(1.25) | $(1.22) |

The pro forma condensed combined statements of operations include adjustments to:

- Reflect the results of the Devon Assets Acquisition and the Berry acquisition for all periods presented.
- Reflect incremental depreciation, depletion and amortization expense, using the unit-of-production method related to oil and natural gas properties acquired and an estimated useful life of 10 years and 20 years for other property and equipment acquired in the Devon Assets Acquisition and the Berry acquisition, respectively.
- Reflect incremental accretion expense related to asset retirement obligations on oil and natural gas properties acquired in the Devon Assets Acquisition.
- Reflect an increase in interest expense related to incremental debt of $2.3 billion incurred to fund the purchase price of the Devon Assets Acquisition and a reduction in interest expense related to the amortization of the adjustment to fair value of Berry's debt using the effective interest method.
- Reflect incremental amortization of deferred financing fees associated with debt incurred to fund the purchase price of the Devon Assets Acquisition.
- Exclude transaction costs related to the Devon Assets Acquisition and the Berry acquisition included in the historical statements of operations as they reflect nonrecurring charges not expected to have a continuing impact on the combined results.
- Reflect approximately 93.8 million LINN Energy units assumed to be issued on January 1, 2013, in conjunction with the Berry acquisition.

Divestitures – 2014

On December 15, 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 to privately held institutional affiliates of EnerVest, Ltd. and its joint venture partner FourPoint Energy, LLC (the "Granite Wash Assets Sale"). Cash proceeds received from the sale of these properties were approximately $1.8 billion, net of costs to sell of approximately $10 million, and the Company recognized a net gain of approximately $294 million.

On November 14, 2014, the Company completed the sale of certain of its Wolfberry properties in Ector and Midland counties in the Permian Basin to Fleur de Lis Energy, LLC (the "Permian Basin Assets Sale"). Cash proceeds received from the sale of these properties were approximately $351 million, net of costs to sell of approximately $2 million, and the Company recognized a net loss of approximately $28 million.

On October 30, 2014, the Company completed the sale of its interests in certain non-producing oil and natural gas properties located in the Mid-Continent region. Cash proceeds received from the sale of these properties were approximately $44 million, and the Company recognized a net gain of approximately $36 million.

The gains and losses on divestitures are included in "(gains) losses on sales of assets and other, net" on the consolidated statement of operations.

The Company used the net cash proceeds received from these sales to repay in full the VIE Term Loan, as defined below, as well as repay a portion of the borrowings outstanding under the LINN Credit Facility, also defined below.

Joint-Venture Funding

For the year ended December 31, 2014, the Company paid approximately $25 million, including interest, to fund the commitment related to the joint-venture agreement it entered into with an affiliate of Anadarko in April 2012. For the years ended December 31, 2013, and December 31, 2012, the Company paid approximately $173 million and $202 million, respectively, to fund the commitment. As of February 2014, the Company had fully funded the total commitment of $400 million.

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Berry Acquisition – 2013

On December 16, 2013, the Company completed the transactions contemplated by the merger agreement between the Company, LinnCo, LLC (“LinnCo”), an affiliate of LINN Energy, and Berry under which LinnCo acquired all of the outstanding common shares of Berry and the contribution agreement between LinnCo and the Company, under which LinnCo contributed Berry to the Company in exchange for LINN Energy units. Under the merger agreement, as amended, Berry’s shareholders received 1.68 LinnCo common shares for each Berry common share they owned, totaling 93,756,674 LinnCo common shares. Under the contribution agreement, LinnCo contributed Berry to LINN Energy in exchange for 93,756,674 newly issued LINN Energy units, after which Berry became an indirect wholly owned subsidiary of LINN Energy. The transaction was valued at approximately $4.6 billion, including the assumption of approximately $2.3 billion of Berry’s debt and net of cash acquired of approximately $451 million.

Other Acquisitions – 2013 and 2012

The following is a summary of significant acquisitions completed by the Company during the years ended December 31, 2013, and December 31, 2012:

- On October 31, 2013, the Company completed the acquisition of certain oil and natural gas properties located in the Permian Basin for approximately $528 million.
- On July 31, 2012, the Company completed the acquisition of certain oil and natural gas properties in the Jonah Field located in the Green River Basin of southwest Wyoming from BP for approximately $988 million.
- On May 1, 2012, the Company completed the acquisition of certain oil and natural gas properties located in east Texas for approximately $164 million.
- On April 3, 2012, the Company entered into a JV Agreement with an affiliate of Anadarko Petroleum Corporation (“Anadarko”) whereby the Company participates as a partner in the CO2 enhanced oil recovery development of the Salt Creek Field, located in the Powder River Basin of Wyoming. Anadarko assigned the Company 23% of its interest in the field in exchange for future funding of $400 million of Anadarko’s development costs. The Company assigned approximately $392 million to the net assets acquired as of the JV Agreement date, which reflects an imputed discount of approximately $8 million on the future funding of this transaction.
- On March 30, 2012, the Company completed the acquisition of certain oil and natural gas properties and the Jayhawk natural gas processing plant located in the Hugoton Basin in Kansas from BP for approximately $1.17 billion.

Divestiture – 2013

On May 31, 2013, the Company, through one of its wholly owned subsidiaries, together with the Company’s partners, Panther Energy, LLC and Red Willow Mid-Continent, LLC, completed the sale of its interests in certain oil and natural gas properties located in the Mid-Continent region (“Panther Operated Cleveland Properties”) to Midstates Petroleum Company, Inc. During the year ended December 31, 2013, the Company recorded a noncash impairment charge, before and after tax, of approximately $37 million associated with the write-down of the carrying value of the Panther Operated Cleveland Properties. Cash proceeds received from the sale of these properties were approximately $218 million, net of costs to sell of approximately $2 million. The Company used the net proceeds from the sale to repay borrowings under the LINN Credit Facility.

Note 3 – Unitholders’ Capital

Berry Acquisition

On December 16, 2013, the Company completed the transactions contemplated by the merger agreement under which LinnCo, an affiliate of LINN Energy, acquired all of the outstanding common shares of Berry and the contribution agreement between LinnCo and the Company, under which LinnCo contributed Berry to the Company in exchange for LINN Energy units. Under the merger agreement, as amended, Berry's shareholders received 1.68 LinnCo common shares for each Berry common share they owned, totaling 93,756,674 LinnCo common shares. Under the contribution agreement, LinnCo contributed Berry to LINN Energy in exchange for 93,756,674 newly issued LINN Energy units with a value of approximately $2.8 billion.

LinnCo Initial Public Offering

In October 2012, LinnCo completed its IPO of 34,787,500 common shares representing limited liability company interests to the public at a price of $36.50 per share ($34.858 per share, net of underwriting discount and structuring fee) for net proceeds of approximately $1.2 billion (after underwriting discount and structuring fee of approximately $57 million). The net proceeds LinnCo received from the offering were used to acquire 34,787,500 LINN Energy units which are equal to the number of LinnCo shares sold in the offering. The Company used the proceeds from the sale of these units to LinnCo to pay the expenses of the offering and repay a portion of the borrowings outstanding under the LINN Credit Facility.

Public Offering of Units

In January 2012, the Company sold 19,550,000 units representing limited liability company interests at $35.95 per unit ($34.512 per unit, net of underwriting discount) for net proceeds of approximately $674 million (after underwriting discount and offering expenses of approximately $28 million). The Company used the net proceeds from the sale of these units to repay a portion of the borrowings outstanding under the LINN Credit Facility.

At-the-Market Offering Program

In January 2012, the Company, under an equity distribution agreement pursuant to which it may from time to time issue and sell units representing limited liability company interests, issued and sold 1,539,651 units representing limited liability company interests at an average unit price of $38.02 for net proceeds of approximately $57 million (net of approximately $1 million in commissions). In connection with the issuance and sale of these units, the Company also incurred professional service expenses of approximately $700,000. The Company used the net proceeds for general corporate purposes, including the repayment of a portion of the borrowings outstanding under the LINN Credit Facility.

In August 2014, the Board of Directors increased the authority under the existing at-the-market offering program to $500 million, and as of December 31, 2014, no units had been sold under the increased authority. Sales of units, if any, will be made through a sales agent by means of ordinary brokers' transactions, in block transactions, or as otherwise agreed with the agent. The Company expects to use the net proceeds from any sale of the units for general corporate purposes, which may include, among other things, capital expenditures, acquisitions and the repayment of debt.

Unit Repurchase Plan

In August 2014, the Board of Directors of the Company 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. Units are repurchased at fair market value. The Company did not repurchase any units during the years ended December 31, 2014, December 31, 2013, and December 31, 2012, and as of December 31, 2014, the entire amount remained available for unit repurchase under the program.

Distributions

Under the Company's LLC 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 over the next four quarters. Distributions paid by the Company are presented on the consolidated statements of unitholders' capital and the consolidated statements of cash flows. In April 2013, the Company's Board of Directors approved a change in its distribution policy that provides a distribution with respect to any

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quarter may be made, at the discretion of the Board of Directors, (i) within 45 days following the end of each quarter or (ii) in three equal installments within 15, 45 and 75 days following the end of each quarter. On January 2, 2015, the Company's Board of Directors declared a cash distribution of $0.3125 per unit with respect to the fourth quarter of 2014, to be paid in three equal monthly installments of $0.1042 per unit. The current distribution represents an approximate 57% decrease from the distribution of $0.725 paid for the previous quarter. The first monthly distribution, totaling approximately $35 million, was paid on January 15, 2015, to unitholders of record as of the close of business on January 12, 2015, and the second monthly distribution, totaling approximately $35 million, was paid on February 17, 2015, to unitholders of record as of the close of business on February 10, 2015.

## Note 4 – Business and Credit Concentrations

### Cash

The Company maintains its cash in bank deposit accounts which at times may exceed federally insured amounts. The Company has not experienced any losses in such accounts. The Company believes it is not exposed to any significant credit risk on its cash.

### Revenue and Trade Receivables

The Company has a concentration of customers who are engaged in oil and natural gas purchasing, transportation and/or refining within the U.S. This concentration of customers may impact the Company's overall exposure to credit risk, either positively or negatively, in that the customers may be similarly affected by changes in economic or other conditions. The Company's customers consist primarily of major oil and natural gas purchasers and the Company generally does not require collateral since it has not experienced significant credit losses on such sales. The Company routinely assesses the recoverability of all material trade and other receivables to determine collectibility (see Note 1).

For the year ended December 31, 2014, the Company's largest customer represented approximately 14% of the Company's sales. For the year ended December 31, 2013, the Company's largest customer represented approximately 12% of the Company's sales. For the year ended December 31, 2012, the Company's two largest customers represented approximately 12% and 11%, respectively, of the Company's sales.

At December 31, 2014, trade accounts receivable from one customer represented approximately 11% of the Company's receivables. At December 31, 2013, trade accounts receivable from two customers represented approximately 19% and 14%, respectively, of the Company's receivables.

## Note 5 – Unit-Based Compensation and Other Benefit Plans

### Incentive Plan Summary

The Linn Energy, LLC Amended and Restated Long-Term Incentive Plan, as amended (the "Plan"), originally became effective in December 2005. The Plan, which is administered by the Compensation Committee of the Board of Directors ("Compensation Committee"), permits granting unrestricted units, restricted units, phantom units, unit options, performance units and unit appreciation rights to employees, consultants and nonemployee directors under the terms of the Plan. The restricted units, phantom units and unit options generally vest ratably over three years. The contractual life of unit options is 10 years. Performance units were granted for the first time in January 2014 to certain executive officers. The initial 2014 awards vest 50% in two years and 50% in three years from the award date. Performance units granted in January 2015 vest three years from the award date.

The Plan limits the number of units that may be delivered pursuant to awards to 21 million units. The Board of Directors and the Compensation Committee have the right to alter or amend the Plan or any part of the Plan from time to time, including increasing the number of units that may be granted, subject to unitholder approval as required by the exchange upon which the units are listed at that time. However, no change in any outstanding grant may be made that would materially reduce the benefits to the participant without the consent of the participant.

Units to be delivered as restricted units, upon the vesting of phantom units or performance units, or upon exercise of a unit option or unit appreciation right may be new units issued by the Company, units acquired by the Company in the open market, units acquired by the Company from any other person, units already owned by the Company, or any combination of the foregoing. If the Company issues new units upon the grant of restricted units, vesting of phantom units or performance units, or exercise of a unit option or unit appreciation right, the total number of units outstanding will increase. To date, the Company has issued awards of unrestricted units, restricted units, phantom units, performance units and unit options. The Plan provides for all of the following types of awards:

Unit Grants – A unit grant is the grant of an unrestricted unit that vests immediately upon issuance.

Restricted Units – A restricted unit is a unit that vests over a period of time and that during such time is subject to forfeiture. The Company intends the restricted units under the Plan to serve as a means of incentive compensation for performance. Therefore, Plan participants will not pay any consideration for the units they receive. If a grantee's employment, consulting relationship or membership on the Company's Board of Directors terminates for any reason, other than death, the grantee's restricted units will be automatically forfeited unless, and to the extent, the Compensation Committee or the terms of the award agreement provide otherwise. The restricted units will vest upon a change of control, unless provided otherwise by the Compensation Committee.

Phantom Units – A phantom unit entitles the grantee to receive a unit upon the vesting of the phantom unit or, in the discretion of the Compensation Committee, cash equivalent to the value of a unit. The Compensation Committee may grant tandem distribution equivalent rights with respect to phantom units that entitle the holder to receive cash equal to any cash distributions made on units while the phantom units are outstanding. The Compensation Committee will determine the period over which phantom units will vest, subject to applicable minimum vesting periods except with respect to phantom unit grants to nonemployee directors. The Company intends the phantom units under the Plan to serve as a means of incentive compensation for performance. Therefore, Plan participants will not pay any consideration for the units they receive. If a grantee's employment, consulting relationship or membership on the Company's Board of Directors terminates for any reason, other than death or retirement, the grantee's phantom units will be automatically forfeited unless, and to the extent, the Compensation Committee or the terms of the award agreement provide otherwise. The phantom units will vest upon a change of control, unless provided otherwise by the Compensation Committee.

Unit Options – A unit option is a right to purchase a unit at a specified price. Unit options will have an exercise price that will not be less than the fair market value of the units on the date of grant. If a grantee's employment, consulting relationship or membership on the Company's Board of Directors terminates for any reason, the grantee's unvested unit options will be automatically forfeited unless, and to the extent, the Compensation Committee or the terms of the award agreement provide otherwise. The unit options will become exercisable upon a change of control, unless provided otherwise by the Compensation Committee.

Performance Units – A performance unit is a unit that vests over a period of time in an amount based on certain comparative performance criteria. The Company intends the performance units under the Plan to serve as a means of incentive compensation for performance. Therefore, Plan participants will not pay any consideration for the units they receive. Upon termination of employment with the Company other than for "Cause" or with "Good Reason" (as those terms are defined in the employment agreement), the performance units vest on the originally scheduled vesting date at the performance level multiplier applicable on that date. If employment terminates by reason of death or "Disability" (as defined in the employment agreement), the performance units immediately vest at the target level. Additionally, the performance units vest upon a change of control and the number of units awarded is determined as if the vesting period ended on the change of control date instead of the originally scheduled date.

Unit Appreciation Rights – A unit appreciation right is an award that, upon exercise, entitles the participant to receive the excess of the fair market value of a unit on the exercise date over the exercise price established for the unit appreciation right. The excess may be paid in the Company's units, cash or a combination thereof, as determined by the Compensation Committee in its discretion. To date, the Company has not granted any unit appreciation rights.

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LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Securities Authorized for Issuance Under the Plan
As of December 31, 2014, approximately 8.3 million units were issuable under the Plan pursuant to outstanding award or other agreements, including unvested restricted units, phantom units and outstanding unit options, and 4.7 million additional units were reserved for future issuance under the Plan.
Accounting for Unit-Based Compensation
The Company recognizes as expense, beginning at the grant date, the fair value of equity-based compensation issued to employees and nonemployee directors. The value of the portion of the award that is ultimately expected to vest is recognized as expense over the requisite service period using the straight-line method in the Company’s consolidated statements of operations. A summary of unit-based compensation expenses included in the consolidated statements of operations is presented below:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| | (in thousands) | | |
| General and administrative expenses | $45,195 | $37,375 | $27,641 |
| Lease operating expenses | 8,089 | 5,328 | 1,892 |
| Total unit-based compensation expenses | $53,284 | $42,703 | $29,533 |
| Income tax benefit | $19,688 | $15,779 | $10,912 |

Restricted Units/Phantom Units/Unrestricted Units
The fair value of restricted units, phantom units and unrestricted unit grants issued is determined based on the fair market value of the Company units on the date of grant. A summary of the status of the nonvested units as of December 31, 2014, is presented below:

| | Number of Nonvested Units | Weighted Average Grant-Date Fair Value |
|---|---|---|
| Nonvested units at December 31, 2013 | 2,571,410 | $33.14 |
| Granted | 1,789,038 | $33.10 |
| Vested | (1,282,509) | $32.77 |
| Forfeited | (238,966) | $32.25 |
| Nonvested units at December 31, 2014 | 2,838,973 | $32.70 |

The weighted average grant-date fair value of restricted units, phantom units and unrestricted units granted was $30.71 and $37.42 during the years ended December 31, 2013, and December 31, 2012, respectively. The total fair value of units that vested was approximately $42 million, $31 million and $24 million for the years ended December 31, 2014, December 31, 2013, and December 31, 2012, respectively. As of December 31, 2014, there was approximately $40 million of unrecognized compensation cost related to nonvested restricted units and phantom units. The cost is expected to be recognized over a weighted average period of approximately 1.6 years.
In January 2015, the Company granted 3,468,245 restricted units and 697,120 phantom units as part of its annual review of its employees’, including executives, compensation. The Company also granted 283,660 performance units (the maximum number of units available to be earned) to certain executive officers.

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Unit Options
The following provides information related to unit option activity for the year ended December 31, 2014:

| | Number of Units Underlying Options | Weighted Average Exercise Price Per Unit | Weighted Average Remaining Contractual Life in Years | Aggregate Intrinsic Value in Millions |
|---|---|---|---|---|
| Outstanding at December 31, 2013 | 6,433,223 | $30.22 | 6.66 | $33 |
| Exercised | (813,806) | $16.56 | | |
| Forfeited or expired | (175,000) | $40.01 | | |
| Outstanding at December 31, 2014 | 5,444,417 | $31.95 | 5.12 | $— |
| Exercisable at December 31, 2014 | 2,510,457 | $22.57 | 5.50 | $— |

No unit options were granted during the year ended December 31, 2014. During the years ended December 31, 2013, and December 31, 2012, the weighted average grant-date fair value of unit options granted was $7.52 and $5.31, respectively. All unit options granted in 2013 were replacement awards issued in exchange for options assumed in the Berry acquisition. The total intrinsic value of unit options exercised was approximately $11 million, $2 million and $3 million, during the years ended December 31, 2014, December 31, 2013, and December 31, 2012, respectively. The Company received approximately $13 million from the exercise of unit options during the year ended December 31, 2014. As of December 31, 2014, total unrecognized compensation cost related to nonvested unit options was approximately $4 million. The cost is expected to be recognized over a weighted average period of approximately 1.1 years.

The fair value of unit-based compensation for unit options was estimated on the date of grant using a Black-Scholes pricing model based on certain assumptions. That value may not be indicative of the fair value observed in a willing buyer/willing seller market transaction. The Company’s determination of the fair value of unit-based awards is affected by the Company’s unit price as well as assumptions consisting of a number of complex and subjective variables. The Company’s employee unit options have various restrictions including vesting provisions and restrictions on transfers and hedging, among others, and often are expected to be exercised prior to their contractual maturity.

Expected volatilities used in the estimation of fair value of the unit option grants have been determined using available volatility data for the Company. Expected distributions are estimated based on the Company’s distribution rate at the date of grant. Forfeitures are estimated using historical Company data and are revised, if necessary, in subsequent periods if actual forfeitures differ from estimates. The risk-free rate for periods within the expected term of the unit option is based on the U.S. Treasury yield curve in effect at the time of grant. Historical data of the Company is used to estimate expected term. All employees granted awards have been determined to have similar behaviors for purposes of determining the expected term used to estimate fair value. The fair values of the Company’s unit option grants were based upon the following assumptions:

| | 2013 [(1)] | 2012 |
|---|---|---|
| Expected volatility | 29.65% – 50.88% | 34.10% |
| Expected distributions | 9.84% | 7.25% |
| Risk-free rate | 0.13% – 1.55% | 0.67% |
| Expected term | 0.68 years – 5 years | 5 years |

(1) All unit options granted in 2013 were replacement awards issued in exchange for options assumed in the Berry acquisition.

Berry Acquisition
On December 16, 2013, in connection with the Berry acquisition (see Note 2), certain Berry awards were exchanged for awards issued by the Company. Each unvested Berry restricted stock unit (“RSU”) (excluding any Berry RSUs held

by a

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former nonemployee director of Berry or by an employee of Berry whose employment was terminated in connection with the acquisition as agreed by the parties and any performance-based Berry RSUs) was converted into a restricted unit award in respect of the number of LINN Energy units. Each option to purchase shares of Berry common stock was converted into an option to purchase a number of LINN Energy units.

Under the acquisition method of accounting, Berry employee RSUs and options were measured and recorded at their fair values on the acquisition date, resulting in additional purchase price consideration of approximately $19 million. The portion of the replacement awards attributable to post-combination service was calculated as the difference between the fair value of the replacement awards and the amount attributed to pre-combination service, and is recognized as compensation expense over the vesting period.

Nonemployee Grants

At December 31, 2014, the Company had 15,000 outstanding unit warrants with an exercise price of $25.50 per unit warrant, which are fully exercisable and expire in 2017.

Defined Contribution Plan

The Company sponsors a 401(k) defined contribution plan for eligible employees. Company contributions to the 401(k) plan consist of a discretionary matching contribution equal to 100% of the first 6% of eligible compensation contributed by the employee on a before-tax basis. The Company contributed approximately $10 million, $7 million and $5 million during the years ended December 31, 2014, December 31, 2013, and December 31, 2012, respectively, to the 401(k) plan's trustee account. The 401(k) plan funds are held in a trustee account on behalf of the plan participants.

Note 6 – Debt

The following summarizes the Company's outstanding debt:

| | December 31, 2014 | December 31, 2013 |
|---|---|---|
| | (in thousands, except percentages) | |
| LINN credit facility [1] | $1,795,000 | $1,560,000 |
| Berry credit facility [2] | 1,173,175 | 1,173,175 |
| Term loan [3] | 500,000 | 500,000 |
| 10.25% Berry senior notes due June 2014 | — | 205,257 |
| 6.50% senior notes due May 2019 [4] | 1,200,000 | 750,000 |
| 6.25% senior notes due November 2019 | 1,800,000 | 1,800,000 |
| 8.625% senior notes due April 2020 | 1,300,000 | 1,300,000 |
| 6.75% Berry senior notes due November 2020 | 299,970 | 300,000 |
| 7.75% senior notes due February 2021 | 1,000,000 | 1,000,000 |
| 6.50% senior notes due September 2021 [4] | 650,000 | — |
| 6.375% Berry senior notes due September 2022 | 599,163 | 600,000 |
| Net unamortized discounts and premiums | (21,499) | (18,216) |
| Total debt, net | 10,295,809 | 9,170,216 |
| Less current maturities | — | (211,558) |
| Total long-term debt, net | $10,295,809 | $8,958,658 |

[1] Variable interest rate of 1.92% at both December 31, 2014, and December 31, 2013.

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(2) Variable interest rate of 2.67% at both December 31, 2014, and December 31, 2013.
(3) Variable interest rates of 2.66% and 2.67% at December 31, 2014 and December 31, 2013, respectively.
(4) $450 million of senior notes due May 2019 and $650 million of senior notes due September 2021 were issued on September 9, 2014.

Fair Value

The Company's debt is recorded at the carrying amount in the consolidated balance sheets. The carrying amounts of the Company's Credit Facilities and term loan approximate fair value because the interest rates are variable and reflective of market rates. The Company uses a market approach to determine the fair value of its senior notes using estimates based on prices quoted from third-party financial institutions, which is a Level 2 fair value measurement.

| | December 31, 2014 | | December 31, 2013 | |
|---|---|---|---|---|
| | Carrying Value | Fair Value | Carrying Value | Fair Value |
| | (in thousands) | | | |
| Credit facilities | $2,968,175 | $2,968,175 | $2,733,175 | $2,733,175 |
| Term loan | 500,000 | 500,000 | 500,000 | 500,000 |
| Senior notes, net | 6,827,634 | 5,703,649 | 5,937,041 | 6,162,402 |
| Total debt, net | $10,295,809 | $9,171,824 | $9,170,216 | $9,395,577 |

Credit Facilities

LINN Credit Facility

The Company's Sixth Amended and Restated Credit Agreement ("LINN Credit Facility") provides for (1) a senior secured revolving credit facility and (2) a $500 million senior secured term loan, in aggregate subject to the then-effective borrowing base. Borrowing capacity under the revolving credit facility is limited to the lesser of (i) the then-effective borrowing base reduced by the $500 million term loan and (ii) the maximum commitment amount of $4.0 billion, and is currently $4.0 billion. At December 31, 2014, the borrowing base under the LINN Credit Facility was $4.5 billion and availability under the revolving credit facility was approximately $2.2 billion, which includes a $5 million reduction for outstanding letters of credit.

In April 2014, the Company entered into an amendment to the LINN Credit Facility to extend the maturity date from April 2018 to April 2019, among other items. In August 2014 and September 2014, the Company entered into amendments to the LINN Credit Facility to permit the Devon Assets Acquisition and the Pioneer Assets Acquisition, respectively, and the related Reverse 1031 Exchanges (see Note 2). As a result of the debt incurred under the Bridge Loan, as defined below, the borrowing base was reduced by 25% of the gross proceeds from the Bridge Loan, or $250 million, from $4.5 billion to $4.25 billion, resulting in a reduction of availability under the revolving credit facility of $250 million. Additionally, upon the issuance of an aggregate $1.1 billion of senior notes in the September 2014 offering (see below), the borrowing base was further reduced by $25 million to $4.225 billion, resulting in a further reduction of availability under the revolving credit facility of $25 million. The fall 2014 semi-annual redetermination occurred in December 2014 in order to coincide with the completion of the Reverse 1031 Exchanges, and as part of that redetermination, the borrowing base was restored to $4.5 billion with a maximum commitment amount of $4.0 billion.

Redetermination of the borrowing base under the LINN Credit Facility, based primarily on reserve reports using lender commodity price expectations at such time, occurs semi-annually, in April and October. The administrative agent, at the direction of a super majority of certain of the lenders, has the right to request one interim borrowing base redetermination per year. The Company also has the right to request one interim borrowing base redetermination per year, as well as the right to an additional interim redetermination each year in connection with certain acquisitions. Significant declines in commodity prices may result in a decrease in the borrowing base. The Company's obligations under the LINN Credit Facility are secured by mortgages on certain of its material subsidiaries' oil and natural gas properties and other personal property as well as a pledge of all ownership interests in the Company's direct and indirect material subsidiaries. The Company is required to maintain either: 1) mortgages on properties representing at least 80% of the total value of oil and natural gas properties included on its most recent reserve report, or 2) a Collateral Coverage Ratio of at least 2.5 to 1. Collateral Coverage Ratio is defined as the ratio of the present value of future cash flows from proved reserves from the currently mortgaged properties to the lesser of: (i) the then-effective borrowing base and (ii) the maximum commitment amount. Additionally, the obligations under the LINN Credit Facility are guaranteed by all of the Company's material subsidiaries, other than Berry, and are required to be guaranteed by any future material subsidiaries. The Company is in compliance with all financial and other covenants of the LINN Credit Facility.

At the Company's election, interest on borrowings under the LINN Credit Facility is determined by reference to either the London Interbank Offered Rate ("LIBOR") plus an applicable margin between 1.5% and 2.5% per annum (depending on the then-current level of borrowings under the LINN Credit Facility) or the alternate base rate ("ABR") plus an applicable margin between 0.5% and 1.5% per annum (depending on the then-current level of borrowings under the LINN Credit Facility). Interest is generally payable quarterly for loans bearing interest based on the ABR and at the end of the applicable interest period for loans bearing interest at LIBOR. The Company is required to pay a commitment fee to the lenders under the LINN Credit Facility, which accrues at a rate per annum between 0.375% and 0.5% (depending on the then-current level of borrowings under the LINN Credit Facility) on the average daily unused amount of the maximum commitment amount of the lenders.

The $500 million term loan has a maturity date of April 2019 and incurs interest based on either the LIBOR plus a margin of 2.5% per annum or the ABR plus a margin of 1.5% per annum, at the Company's election. Interest is generally payable quarterly for loans bearing interest based on the ABR and at the end of the applicable interest period for loans bearing interest at LIBOR. The term loan may be repaid at the option of the Company without premium or penalty, subject to breakage costs. While the term loan is outstanding, the Company is required to maintain either: 1) mortgages on properties representing at least 80% of the total value of oil and natural gas properties included on its most recent reserve report, or 2) a Term Loan Collateral Coverage Ratio of at least 2.5 to 1. The Term Loan Collateral Coverage Ratio is defined as the ratio of the present value of future cash flows from proved reserves from the currently mortgaged properties to the lesser of: (i) the then-effective borrowing base and (ii) the maximum commitment amount and the aggregate amount of the term loan outstanding. The other terms and conditions of the LINN Credit Facility, including the financial and other restrictive covenants set forth therein, are applicable to the term loan.

Berry Credit Facility

Berry's Second Amended and Restated Credit Agreement ("Berry Credit Facility") has a borrowing base of $1.4 billion, subject to lender commitments. At December 31, 2014, lender commitments under the facility were $1.2 billion but there was less than $1 million of available borrowing capacity, including outstanding letters of credit. In February 2014, Berry entered into an amendment to the Berry Credit Facility to amend the terms of certain financial and reporting covenants, among other items. In April 2014, Berry entered into an amendment to the Berry Credit Facility to extend the maturity date from May 2016 to April 2019 and to amend the terms of certain financial covenants and definitions, among other items.

Redetermination of the borrowing base under the Berry Credit Facility, based primarily on reserve reports using lender commodity price expectations at such time, occurs semi-annually, in April and October. A super-majority of the lenders under the Berry Credit Facility and Berry also have the right to request interim borrowing base redeterminations once between scheduled redeterminations. Significant declines in commodity prices may result in a decrease in the borrowing base. Berry's obligations under the Berry Credit Facility are secured by mortgages on its oil and natural gas properties and other personal property. Berry is required to maintain mortgages on properties representing at least 80% of the present value of its oil and natural gas proved reserves. Berry is in compliance with all financial and other covenants of the Berry Credit Facility.

At Berry's election, interest on borrowings under the Berry Credit Facility is determined by reference to either the LIBOR plus an applicable margin between 1.5% and 2.5% per annum (depending on the then-current level of borrowings under the Berry Credit Facility) or a Base Rate (as defined in the Berry Credit Facility) plus an applicable margin between 0.5% and 1.5% per annum (depending on the then-current level of borrowings under the Berry Credit Facility). Interest is generally payable quarterly for loans bearing interest based on the Base Rate and at the end of the applicable interest period for loans bearing interest at LIBOR. Berry is required to pay a commitment fee to the lenders under the Berry Credit Facility, which accrues at a rate per annum between 0.375% and 0.5% (depending on the then-current level of utilization under the Berry Credit Facility) on the average daily unused amount of the maximum commitment amount of the lenders.

The Company refers to the LINN Credit Facility and the Berry Credit Facility, collectively, as the “Credit Facilities.”

Bridge Loan

On August 29, 2014, the Company entered into a bridge loan agreement (the “Bridge Loan”) pursuant to which the Company borrowed an aggregate principal amount of $1.0 billion of term loans. The proceeds from the Bridge Loan were advanced to the VIE and used to partially fund the Devon Assets Acquisition (see Note 2). The Bridge Loan agreement was unsecured and was guaranteed by all of the Company’s material domestic subsidiaries which guarantee the LINN Credit Facility.

The Bridge Loan had an initial maturity date of August 29, 2015, with interest on the initial term loans determined by reference to either (i) LIBOR plus 5.0% plus an applicable margin per annum or (ii) alternate base rate plus 4.0% plus an applicable margin per annum. The applicable margin would have been 0% for the first three months after the funding date and, thereafter, increased by 0.50% at the end of each subsequent three-month period.

On September 9, 2014, the Company paid in full the outstanding indebtedness under the Bridge Loan using proceeds from the issuance of the New May 2019 Senior Notes and the September 2021 Senior Notes, each as defined below.

VIE Term Loan

On August 29, 2014, a subsidiary of the VIE, formed to facilitate the Reverse 1031 Exchange for the Devon Assets Acquisition (see Note 2) entered into a 364-day term loan agreement (the “VIE Term Loan”) pursuant to which it borrowed an aggregate principal amount of $1.3 billion of term loans. The proceeds from the VIE Term Loan were used to partially fund the Devon Assets Acquisition. The obligations under the VIE Term Loan were required to be secured by certain of the oil and natural gas properties and personal property of the VIE’s subsidiary and its material subsidiaries (if any), as well as a pledge of 100% of the equity interests in the subsidiary. Specifically, the VIE’s subsidiary was required to maintain mortgages on properties representing at least 80% of the total value of oil and natural gas properties included on its most recent reserve report. Additionally, the obligations under the VIE Term Loan were to be guaranteed by all of the material subsidiaries of the VIE’s subsidiary (if any).

In December 2014, the outstanding indebtedness under the VIE Term Loan was paid in full using a portion of the net cash proceeds received from the Granite Wash Assets Sale and the Permian Basin Assets Sale (see Note 2).

Senior Notes Due May 2019 and Senior Notes Due September 2021

On September 9, 2014, the Company issued $1.1 billion in aggregate principal amount of senior notes consisting of $450 million aggregate principal amount of 6.50% senior notes due May 2019 (the “New May 2019 Senior Notes”) at a price of 102% of par and $650 million in aggregate principal amount of 6.50% senior notes due September 2021 (the “September 2021 Senior Notes”) at a price of 98.619% of par. The New May 2019 Senior Notes and the September 2021 Senior Notes were registered under the Securities Act of 1933, as amended (the “Securities Act”), pursuant to a shelf registration statement on Form S-3 filed on September 4, 2014, which was automatically effective upon filing.

The Company received net proceeds of approximately $450 million from the issuance of the New May 2019 Senior Notes (after adding the premium of $9 million and deducting offering expenses of approximately $9 million) and approximately $628 million from the issuance of the September 2021 Senior Notes (after deducting the discount of approximately $9 million and offering expenses of approximately $13 million). The Company used the net proceeds from the New May 2019 Senior Notes and the September 2021 Senior Notes to repay all indebtedness outstanding under the Company’s Bridge Loan (see above) as well as repay a portion of the borrowings outstanding under the LINN Credit Facility. The financing fees and expenses of approximately $22 million incurred in connection with the New May 2019 Senior Notes and the September 2021 Senior Notes will be amortized over the life of the notes. Such amortized expenses, premium and discount are recorded in “interest expense, net of amounts capitalized” on the consolidated statements of operations.

The New May 2019 Senior Notes were issued as additional notes to the original $750 million in aggregate principal amount issued under an indenture (the “May 2019 Indenture”), dated as of May 13, 2011, mature May 15, 2019, and bear interest at 6.50%. Interest is payable in cash semi-annually in arrears on each May 15 and November 15. Interest will be payable to holders of record on the May 1 and November 1 immediately preceding the related interest payment date, and will be

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computed on the basis of a 360-day year consisting of twelve 30-day months. The May 2019 Senior Notes are general unsecured senior obligations of the Company and are effectively junior in right of payment to any secured indebtedness of the Company to the extent of the collateral securing such indebtedness. Each of the Company's material subsidiaries, other than Berry, has guaranteed the May 2019 Senior Notes on a senior unsecured basis. The May 2019 Indenture provides that the Company may redeem: (i) prior to May 15, 2015, all or part of the May 2019 Senior Notes at a redemption price equal to the principal amount redeemed, plus a make-whole premium (as defined in the May 2019 Indenture) and accrued and unpaid interest; and (ii) on or after May 15, 2015, all or part of the May 2019 Senior Notes at a redemption price equal to 103.250%, and decreasing percentages thereafter, of the principal amount redeemed, plus accrued and unpaid interest. The May 2019 Indenture also provides that, if a change of control (as defined in the May 2019 Indenture) occurs, the holders have a right to require the Company to repurchase all or part of the May 2019 Senior Notes at a redemption price equal to 101%, plus accrued and unpaid interest.

The September 2021 Senior Notes were issued under an indenture dated September 9, 2014 (the "September 2021 Indenture"), mature September 15, 2021, and bear interest at 6.50%. Interest is payable in cash semi-annually in arrears on each March 15 and September 15, commencing March 15, 2015. Interest will be payable to holders of record on the March 1 and September 1 immediately preceding the related interest payment date, and will be computed on the basis of a 360-day year consisting of twelve 30-day months. The September 2021 Senior Notes are general unsecured senior obligations of the Company and are effectively junior in right of payment to any secured indebtedness of the Company to the extent of the collateral securing such indebtedness. Each of the Company's material subsidiaries, other than Berry, has guaranteed the September 2021 Senior Notes on a senior unsecured basis. The September 2021 Indenture provides that the Company may redeem: (i) prior to September 15, 2017, up to 35% of the aggregate principal amount of the September 2021 Senior Notes at a redemption price of 106.500% of the principal amount redeemed, plus accrued and unpaid interest, with the net cash proceeds of one or more equity offerings; (ii) prior to September 15, 2017, all or part of the September 2021 Senior Notes at a redemption price equal to the principal amount redeemed, plus a make-whole premium (as defined in the September 2021 Indenture) and accrued and unpaid interest; and (iii) on or after September 15, 2017, all or part of the September 2021 Senior Notes at a redemption price equal to 103.250%, and decreasing percentages thereafter, of the principal amount redeemed, plus accrued and unpaid interest. The September 2021 Indenture also provides that, if a change of control (as defined in the September 2021 Indenture) occurs, the holders have a right to require the Company to repurchase all or part of the September 2021 Senior Notes at a redemption price equal to 101%, plus accrued and unpaid interest.

The May 2019 Indenture and the September 2021 Indenture contain covenants that, among other things, limit the Company's ability and the ability of the Company's restricted subsidiaries to: (i) pay distributions on, purchase or redeem the Company's units or redeem its subordinated debt; (ii) make investments; (iii) incur or guarantee additional indebtedness or issue certain types of equity securities; (iv) create certain liens; (v) sell assets; (vi) consolidate, merge or transfer all or substantially all of the Company's assets; (vii) enter into agreements that restrict distributions or other payments from the Company's restricted subsidiaries to the Company; (viii) engage in transactions with affiliates; and (ix) create unrestricted subsidiaries.

Senior Notes Due November 2019

The Company has $1.8 billion in aggregate principal amount of 6.25% senior notes due November 2019 (the "November 2019 Senior Notes"). In connection with the issuance and sale of the November 2019 Senior Notes, the Company entered into a Registration Rights Agreement ("November 2019 Registration Rights Agreement") with the initial purchasers. Under the November 2019 Registration Rights Agreement, the Company agreed to use its reasonable efforts to file with the SEC and cause to become effective a registration statement relating to an offer to issue new notes having terms substantially similar to the November 2019 Senior Notes in exchange for outstanding November 2019 Senior Notes within 400 days after the notes were issued. On March 22, 2013, the Company filed a registration statement on Form S-4 to register exchange notes that are substantially similar to the November 2019 Senior Notes. On June 2, 2014, the registration statement was declared effective and the Company commenced an offer to exchange any and all of its $1.8 billion outstanding principal amount of November 2019 Senior Notes for an equal amount of new November 2019 Senior Notes.

The terms of the new November 2019 Senior Notes are substantially similar in all material respects to those of the outstanding November 2019 Senior Notes, except that the transfer restrictions, registration rights and additional interest provisions related to the outstanding November 2019 Senior Notes do not apply to the new November 2019 Senior Notes. The exchange offer expired on June 28, 2014. The effective date of the registration statement was past the deadline in the

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registration rights agreement, and therefore, the Company paid additional interest of approximately $15 million since the deadline.

Senior Notes Due April 2020 and Senior Notes Due February 2021

The Company has $1.3 billion in aggregate principal amount of 8.625% senior notes due April 2020 (the “April 2020 Senior Notes”) and $1.0 billion in aggregate principal amount of 7.75% senior notes due February 2021 (the “February 2021 Senior Notes,” and together with the April 2020 Senior Notes, the “2010 Issued Senior Notes”). The restrictive legends from each of the 2010 Issued Senior Notes have been removed making them freely tradable (other than with respect to persons that are affiliates of the Company), thereby terminating the Company’s obligations under each of the registration rights agreements entered into in connection with the issuance of the 2010 Issued Senior Notes.

Berry Senior Notes Due November 2020

Berry has $300 million in aggregate principal amount of 6.75% senior notes due November 2020 (the “Berry November 2020 Senior Notes”). The Berry November 2020 Senior Notes were recorded at their fair value of $310 million on the Berry acquisition date including a $10 million premium which is being amortized to interest expense over the life of the related notes.

Berry Senior Notes Due September 2022

Berry has $599 million in aggregate principal amount of 6.375% senior notes due September 2022 (the “Berry September 2022 Senior Notes”). The Berry September 2022 Senior Notes were recorded at their fair value of approximately $607 million on the Berry acquisition date including a $7 million premium which is being amortized to interest expense over the life of the related notes.

Payment of Berry June 2014 Senior Notes

On May 30, 2014, in accordance with the provisions of the indenture related to the Berry June 2014 Senior Notes, the Company paid in full the remaining outstanding principal amount of approximately $205 million.

Repurchases of Berry Senior Notes

In February 2014, in accordance with the indentures related to Berry’s senior notes, the Company repurchased through cash tender offers $321,000, $30,000 and $837,000 of Berry’s 10.25% senior notes due June 2014 (the “Berry June 2014 Senior Notes”), November 2020 Senior Notes and September 2022 Senior Notes, respectively.

Redemptions of Senior Notes Due May 2017 and Senior Notes Due July 2018

In accordance with the provisions of the indentures related to the Company’s 11.75% senior notes due May 2017 (the “May 2017 Senior Notes”) and 9.875% senior notes due July 2018 (the “July 2018 Senior Notes” and together with the May 2017 Senior Notes, the “Original Senior Notes”), in June 2013 and July 2013, the Company redeemed the remaining outstanding principal amounts of approximately $41 million and $14 million, respectively. In connection with the redemptions of the Original Senior Notes, the Company recorded a loss on extinguishment of debt of approximately $5 million for the year ended December 31, 2013.

Senior Notes Covenants

The Company’s senior notes contain covenants that, among other things, may limit its ability to: (i) pay distributions on, purchase or redeem the Company’s units or redeem its subordinated debt; (ii) make investments; (iii) incur or guarantee additional indebtedness or issue certain types of equity securities; (iv) create certain liens; (v) sell assets; (vi) consolidate, merge or transfer all or substantially all of the Company’s assets; (vii) enter into agreements that restrict distributions or other payments from the Company’s restricted subsidiaries to the Company; (viii) engage in transactions with affiliates; and (ix) create unrestricted subsidiaries. The Company is in compliance with all financial and other covenants of its senior notes.

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Berry's senior notes contain covenants that, among other things, may limit its ability to: (i) incur or guarantee additional indebtedness; (ii) pay distributions on Berry's equity or redeem its subordinated debt; (iii) create certain liens; (iv) enter into agreements that restrict distributions or other payments from Berry's restricted subsidiaries to Berry; (v) sell assets; (vi) engage in transactions with affiliates; and (vii) consolidate, merge or transfer all or substantially all of Berry's assets. Berry is in compliance with all financial and other covenants of its senior notes.

In addition, any cash generated by Berry is currently being used by Berry to fund its activities and is not currently being distributed to LINN Energy. To the extent that Berry generates cash in excess of its needs, the indentures governing Berry's senior notes limit the amount it may distribute to LINN Energy to the amount available under a "restricted payments basket," and Berry may not distribute any such amounts unless it is permitted by the indentures to incur additional debt pursuant to the consolidated coverage ratio test set forth in the Berry indentures. Berry's restricted payments basket may be increased in accordance with the terms of the Berry indentures by, among other things, 50% of Berry's future net income, reductions in its indebtedness and restricted investments, and future capital contributions.

## Note 7 – Derivatives

### Commodity Derivatives

The Company hedges a significant portion of its forecasted production to reduce exposure to fluctuations in the prices of oil and natural gas and provide long-term cash flow predictability to manage its business, service debt and pay distributions. The current direct NGL hedging market is constrained in terms of price, volume, duration and number of counterparties, which limits the Company's ability to effectively hedge its NGL production. As a result, currently, the Company directly hedges only its oil and natural gas production.

The Company enters into commodity hedging transactions primarily in the form of swap contracts that are designed to provide a fixed price and, from time to time, put options that are designed to provide a fixed price floor with the opportunity for upside. The Company enters into these transactions with respect to a portion of its projected production to provide an economic hedge of the risk related to the future commodity prices received. The Company does not enter into derivative contracts for trading purposes. In connection with the Berry acquisition (see Note 2), the Company assumed certain derivative contracts that Berry had entered into prior to the acquisition date, including swap contracts, collars and three-way collars. The Company did not designate any of its contracts as cash flow hedges; therefore, the changes in fair value of these instruments are recorded in current earnings. See Note 8 for fair value disclosures about oil and natural gas commodity derivatives.

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The following table summarizes derivative positions for the periods indicated as of December 31, 2014:

| | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|
| Natural gas positions: | | | | |
| Fixed price swaps (NYMEX Henry Hub): | | | | |
| Hedged volume (MMMBtu) | 118,041 | 121,841 | 120,122 | 36,500 |
| Average price ($/MMBtu) | $5.19 | $4.20 | $4.26 | $5.00 |
| Put options (NYMEX Henry Hub): | | | | |
| Hedged volume (MMMBtu) | 71,854 | 76,269 | 66,886 | — |
| Average price ($/MMBtu) | $5.00 | $5.00 | $4.88 | $— |
| Oil positions: | | | | |
| Fixed price swaps (NYMEX WTI): (1) | | | | |
| Hedged volume (MBbls) | 11,599 | 11,465 | 4,755 | — |
| Average price ($/Bbl) | $96.23 | $90.56 | $89.02 | $— |
| Three-way collars (NYMEX WTI): | | | | |
| Hedged volume (MBbls) | 1,095 | — | — | — |
| Short put ($/Bbl) | $70.00 | $— | $— | $— |
| Long put ($/Bbl) | $90.00 | $— | $— | $— |
| Short call ($/Bbl) | $101.62 | $— | $— | $— |
| Put options (NYMEX WTI): | | | | |
| Hedged volume (MBbls) | 3,426 | 3,271 | 384 | — |
| Average price ($/Bbl) | $90.00 | $90.00 | $90.00 | $— |
| Natural gas basis differential positions: (2) | | | | |
| Panhandle basis swaps: | | | | |
| Hedged volume (MMMBtu) | 87,162 | 59,954 | 59,138 | 16,425 |
| Hedged differential ($/MMBtu) | $(0.33) | $(0.32) | $(0.33) | $(0.33) |
| NWPL Rockies basis swaps: | | | | |
| Hedged volume (MMMBtu) | 43,292 | 46,294 | 38,880 | 10,804 |
| Hedged differential ($/MMBtu) | $(0.20) | $(0.20) | $(0.19) | $(0.19) |
| MichCon basis swaps: | | | | |
| Hedged volume (MMMBtu) | 9,344 | 7,768 | 7,437 | 2,044 |
| Hedged differential ($/MMBtu) | $0.06 | $0.05 | $0.05 | $0.05 |
| Houston Ship Channel basis swaps: | | | | |
| Hedged volume (MMMBtu) | 4,891 | 4,575 | 3,604 | 986 |
| Hedged differential ($/MMBtu) | $(0.10) | $(0.10) | $(0.08) | $(0.08) |
| Permian basis swaps: | | | | |
| Hedged volume (MMMBtu) | 5,074 | 4,219 | 4,819 | 1,314 |
| Hedged differential ($/MMBtu) | $(0.21) | $(0.20) | $(0.20) | $(0.20) |
| Oil timing differential positions: | | | | |
| Trade month roll swaps (NYMEX WTI): (3) | | | | |
| Hedged volume (MBbls) | 7,251 | 7,446 | 6,486 | — |
| Hedged differential ($/Bbl) | $0.24 | $0.25 | $0.25 | $— |

(1) Includes certain outstanding fixed price oil swaps of approximately 5,384 MBbls which may be extended annually at a price of $100.00 per Bbl for each of the years ending December 31, 2017, and December 31, 2018, and $90.00 per Bbl for the year ending December 31, 2019, if the counterparties determine that the strike prices are in-the-money on a designated date in each respective preceding year. The extension for each year is exercisable without respect to the other years.

(2) Settle on the respective pricing index to hedge basis differential to the NYMEX Henry Hub natural gas price.

(3) The Company hedges the timing risk associated with the sales price of oil in the Mid-Continent, Hugoton Basin and Permian Basin regions. In these regions, the Company generally sells oil for the delivery month at a sales price based on the average NYMEX WTI price during that month, plus an adjustment calculated as a spread between the weighted average prices of the delivery month, the next month and the following month during the period when the delivery month is prompt (the "trade month roll").

During the fourth quarter of 2014, the Company canceled all of its ICE Brent – NYMEX WTI basis swaps for 2015 and received cash settlements of approximately $12 million. Currently, the Company has no outstanding ICE Brent – NYMEX WTI basis swaps.

During the year ended December 31, 2013, the Company entered into commodity derivative contracts consisting of oil basis swaps for 2013 and natural gas basis swaps for 2013 through 2018. Also, in connection with the Berry acquisition (see Note 2), the Company assumed certain derivative contracts that Berry had entered into prior to the acquisition date, including oil swaps, oil trade month roll swaps and oil collars through 2014, and oil basis swaps and oil three-way collars through 2015.

During the year ended December 31, 2012, the Company entered into commodity derivative contracts consisting of oil swaps for 2012 through 2017, natural gas swaps for 2012 through 2018, and oil and natural gas puts for 2012 through 2017 and paid premiums for put options of approximately $583 million. The Company also entered into natural gas basis swaps for 2012 through 2016 and trade month roll swaps for 2012 through 2017.

Settled derivatives on natural gas production for the year ended December 31, 2014, included volumes of 177,029 MMMBtu at an average contract price of $5.14 per MMBtu. Settled derivatives on oil production for the year ended December 31, 2014, included volumes of 24,988 MBbls at an average contract price of $92.39 per Bbl. Settled derivatives on natural gas production for the year ended December 31, 2013, included volumes of 173,488 MMMBtu at an average contract price of $5.29 per MMBtu. Settled derivatives on oil production for the year ended December 31, 2013, included volumes of 15,590 MBbls at an average contract price of $95.35 per Bbl. Settled derivatives on natural gas production for the year ended December 31, 2012, included volumes of 140,884 MMMBtu at an average contract price of $5.41 per MMBtu. Settled derivatives on oil production for the year ended December 31, 2012, included volumes of 11,289 MBbls at an average contract price of $97.61 per Bbl.

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

Balance Sheet Presentation

The Company's commodity derivatives are presented on a net basis in "derivative instruments" on the consolidated balance sheets. The following summarizes the fair value of derivatives outstanding on a gross basis:

| | December 31, 2014 | 2013 |
|---|---|---|
| | (in thousands) | |
| Assets: | | |
| Commodity derivatives | $2,014,815 | $1,048,212 |
| Liabilities: | | |
| Commodity derivatives | $90,260 | $222,905 |

By using derivative instruments to economically hedge exposures to changes in commodity prices, the Company exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes the Company, which creates credit risk. The Company's counterparties are current participants or affiliates of participants in its Credit Facilities or were

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participants or affiliates of participants in its Credit Facilities at the time it originally entered into the derivatives. The Credit Facilities are secured by the Company’s oil, natural gas and NGL reserves; therefore, the Company is not required to post any collateral. The Company does not receive collateral from its counterparties. The maximum amount of loss due to credit risk that the Company would incur if its counterparties failed completely to perform according to the terms of the contracts, based on the gross fair value of financial instruments, was approximately $2.0 billion at December 31, 2014. The Company minimizes the credit risk in derivative instruments by: (i) limiting its exposure to any single counterparty; (ii) entering into derivative instruments only with counterparties that meet the Company’s minimum credit quality standard, or have a guarantee from an affiliate that meets the Company’s minimum credit quality standard; and (iii) monitoring the creditworthiness of the Company’s counterparties on an ongoing basis. In accordance with the Company’s standard practice, its commodity derivatives are subject to counterparty netting under agreements governing such derivatives and therefore the risk of loss due to counterparty nonperformance is somewhat mitigated.

Gains (Losses) on Derivatives

Gains and losses on derivatives were net gains of approximately $1.2 billion, $178 million and $125 million for the years ended December 31, 2014, December 31, 2013, and December 31, 2012, respectively, and are reported on the consolidated statements of operations in “gains on oil and natural gas derivatives.” For the years ended December 31, 2014, December 31, 2013, and December 31, 2012, the Company received cash settlements of approximately $108 million, $249 million and $391 million, respectively.

Note 8 – Fair Value Measurements on a Recurring Basis

The Company accounts for its commodity derivatives at fair value (see Note 7) on a recurring basis. The Company determines the fair value of its oil and natural gas derivatives utilizing pricing models that use a variety of techniques, including market quotes and pricing analysis. Inputs to the pricing models include publicly available prices and forward price curves generated from a compilation of data gathered from third parties. Company management validates the data provided by third parties by understanding the pricing models used, obtaining market values from other pricing sources, analyzing pricing data in certain situations and confirming that those instruments trade in active markets. Assumed credit risk adjustments, based on published credit ratings, public bond yield spreads and credit default swap spreads, are applied to the Company’s commodity derivatives.

Fair Value Hierarchy

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

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

| | |
|---|---|
| Level 1 | Financial assets and liabilities for which values are based on unadjusted quoted prices for identical assets or liabilities in an active market that management has the ability to access. |
| Level 2 | Financial assets and liabilities for which values are based on quoted prices in markets that are not active or model inputs that are observable either directly or indirectly for substantially the full term of the asset or liability (commodity derivatives). |
| Level 3 | Financial assets and liabilities for which values are based on prices or valuation techniques that require inputs that are both unobservable and significant to the overall fair value measurement. These inputs reflect management’s own assumptions about the assumptions a market participant would use in pricing the asset or liability. |

When the inputs used to measure fair value fall within different levels of the hierarchy in a liquid environment, the level within which the fair value measurement is categorized is based on the lowest level input that is significant to the fair value

measurement in its entirety. The Company conducts a review of fair value hierarchy classifications on a quarterly basis. Changes in the observability of valuation inputs may result in a reclassification for certain financial assets or liabilities.

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

| | December 31, 2014 | | |
|---|---|---|---|
| | Level 2 | Netting [1] | Total |
| | (in thousands) | | |
| Assets: | | | |
| Commodity derivatives | $2,014,815 | $(89,576) | $1,925,239 |
| Liabilities: | | | |
| Commodity derivatives | $90,260 | $(89,576) | $684 |

| | December 31, 2013 | | |
|---|---|---|---|
| | Level 2 | Netting [1] | Total |
| | (in thousands) | | |
| Assets: | | | |
| Commodity derivatives | $1,048,212 | $(190,080) | $858,132 |
| Liabilities: | | | |
| Commodity derivatives | $222,905 | $(190,080) | $32,825 |

[1] Represents counterparty netting under agreements governing such derivatives.

Note 9 – Other Property and Equipment

Other property and equipment consists of the following:

| | December 31, | |
|---|---|---|
| | 2014 | 2013 |
| | (in thousands) | |
| Natural gas plant and pipeline | $479,754 | $507,342 |
| Buildings and leasehold improvements | 49,046 | 32,658 |
| Vehicles | 36,534 | 27,964 |
| Drilling and other equipment | 6,994 | 8,618 |
| Furniture and office equipment | 88,893 | 65,909 |
| Land | 7,928 | 5,391 |
| | 669,149 | 647,882 |
| Less accumulated depreciation | (144,282) | (110,939) |
| | $524,867 | $536,943 |

Note 10 – Asset Retirement Obligations

The Company has the obligation to plug and abandon oil and natural gas wells and related equipment at the end of production operations. Estimated asset retirement costs are recognized as liabilities with an increase to the carrying amounts of the related long-lived assets when the obligation is incurred. The liabilities are included in “other accrued liabilities” and “other noncurrent liabilities” on the consolidated balance sheets. Accretion expense is included in “depreciation, depletion and amortization” on the consolidated statements of operations. The fair value of additions to the asset retirement obligations is estimated using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation include estimates of: (i) plug and abandon costs per well based on existing regulatory requirements; (ii) remaining life per well; (iii) future inflation factors (2% for each of the years in the three-year period ended December 31, 2014); and (iv) a credit-adjusted risk-free interest rate (average of 5.3%, 6.2% and 6.8% for the years ended December 31, 2014, December 31, 2013, and December 31, 2012, respectively). These inputs require significant judgments and estimates by the Company's management at the time of the valuation and are the most sensitive and subject to change.

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

| | December 31, 2014 | 2013 |
|---|---|---|
| | (in thousands) | |
| Asset retirement obligations at beginning of year | $289,321 | $151,974 |
| Liabilities added from acquisitions | 176,538 | 98,343 |
| Liabilities added from drilling | 10,476 | 4,048 |
| Liabilities associated with assets divested | (25,656) | (1,092) |
| Current year accretion expense | 22,164 | 11,938 |
| Settlements | (12,620) | (5,136) |
| Revision of estimates | 37,347 | 29,246 |
| Asset retirement obligations at end of year | $497,570 | $289,321 |

Note 11 – Commitments and Contingencies

The Company has been named as a defendant in a number of lawsuits, including claims from royalty owners related to disputed royalty payments and royalty valuations. With respect to a certain statewide class action case, the Company has filed a motion to dismiss the case for failure to state a claim on which relief may be granted, and that motion has not yet been ruled on by the Court. While that motion has remained pending, the parties have agreed on a scheduling order, which provides for briefing on the class certification issues in late 2015 and first part of 2016. The Company has denied that it has liability on the claims asserted in the case and has denied that class certification is proper. If the Court accepts the Company's arguments, there will be no liability to the Company in the case. For another statewide class action royalty payment dispute, briefing on class certification issues is expected to be completed during the summer of 2015. The Company has denied that it has any liability on the claims and has denied that class certification is proper. If the Court accepts the Company's arguments, there will be no liability to the Company in the case. The Company is unable to estimate a possible loss, or range of possible loss, if any, in these cases. 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.

Prior to the Company's acquisition of Berry, Berry became a defendant in a certain statewide royalty class action case. The parties entered into a settlement agreement to settle past claims for approximately $2.4 million, which the Court approved on October 29, 2014. On December 17, 2014, Berry made a one-time lump sum payment of $2.4 million for damages related to production through April 30, 2014. On December 29, 2014, the Court issued an Order dismissing the matter with prejudice. Per the parties' settlement agreement, Berry has agreed to a new methodology for calculating royalty payments beginning May 1, 2014.

In 2013, several class action complaints were filed and ultimately consolidated in the United States District Court, Southern District of New York (the "Federal Actions") against LINN Energy, LinnCo, certain of their officers and directors and the various underwriters for LinnCo's initial public offering. These cases collectively asserted claims based on allegations that LINN Energy made false or misleading statements relating to its (i) hedging strategy, (ii) the cash flow available for distribution to unitholders, and (iii) LINN Energy's energy production in its Exchange Act filings; and additional claims based on alleged misstatements relating to these issues in the prospectus and registration statement for LinnCo's initial public offering. Several derivative actions were also filed in federal and state court in Texas, and in the Delaware Court of Chancery (the “Derivative Actions”) asserting derivative claims on behalf of LINN Energy against the individual officers and directors for alleged breaches of fiduciary duty, waste of corporate assets, mismanagement, abuse of control, and unjust enrichment based on factual allegations similar to those in the Federal Actions.

In July 2014, the Court dismissed the claims of the plaintiffs in the Federal Actions with prejudice, concluding that the plaintiffs failed to demonstrate any material misstatement or omission by LINN Energy or LinnCo, or their officers and directors. The plaintiffs in the Federal Actions did not appeal the Court’s dismissal, and the appeals deadline has now passed. The plaintiffs in the Derivative Actions subsequently have dismissed their claims without prejudice.

During the years ended December 31, 2014, December 31, 2013, and December 31, 2012, the Company made no significant payments to settle any legal, environmental or tax proceedings. The Company regularly analyzes current information and accrues for probable liabilities on the disposition of certain matters as necessary. Liabilities for loss contingencies arising from claims, assessments, litigation or other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated.

In 2008, Lehman Brothers Holdings Inc. and Lehman Brothers Commodity Services Inc. (together “Lehman”), filed voluntary petitions for reorganization under Chapter 11 of the U.S. Bankruptcy Code with the U.S. Bankruptcy Court for the Southern District of New York. In March 2011, the Company and Lehman entered into Termination Agreements under which the Company was granted general unsecured claims against Lehman in the amount of $51 million (the “Company Claim”). In December 2011, a Chapter 11 Plan (“Lehman Plan”) was approved by the Bankruptcy Court. Based on the recovery estimates described in the approved disclosure statement relating to the Lehman Plan, the Company expects to ultimately receive a substantial portion of the Company Claim. In 2014 and 2013, the Company received approximately $7 million and $11 million, respectively, of the Company Claim of which both amounts are included in “gains on oil and natural gas derivatives” on the consolidated statements of operations. In 2012, the Company received approximately $28 million of the Company Claim resulting in a gain of approximately $22 million included in “gains on oil and natural gas derivatives” on the consolidated statements of operations. In the aggregate, the Company has received approximately $46 million of the Company Claim.

Note 12 – Earnings Per Unit

Basic earnings per unit is computed by dividing net earnings attributable to unitholders by the weighted average number of units outstanding during each period. Diluted earnings per unit is computed by adjusting the average number of units outstanding for the dilutive effect, if any, of unit equivalents. The Company uses the treasury stock method to determine the dilutive effect.

The following table provides a reconciliation of the numerators and denominators of the basic and diluted per unit computations for net loss:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| | (in thousands, except per unit data) | | |
| Net loss | $(451,809) | $(691,337) | $(386,616) |
| Allocated to participating securities | (7,117) | (5,935) | (4,575) |
| | $(458,926) | $(697,272) | $(391,191) |
| Basic net loss per unit | $(1.40) | $(2.94) | $(1.92) |
| Diluted net loss per unit | $(1.40) | $(2.94) | $(1.92) |
| Basic weighted average units outstanding | 328,918 | 237,544 | 203,775 |
| Dilutive effect of unit equivalents | — | — | — |
| Diluted weighted average units outstanding | 328,918 | 237,544 | 203,775 |

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Basic units outstanding excludes the effect of weighted average anti-dilutive unit equivalents related to approximately 6 million, 4 million and 2 million unit options and warrants for the years ended December 31, 2014, December 31, 2013, and December 31, 2012, respectively. All equivalent units were anti-dilutive for the years ended December 31, 2014, December 31, 2013, and December 31, 2012.

Note 13 – Operating Leases

The Company leases office space and other property and equipment under lease agreements expiring on various dates through 2034. The Company recognized expense under operating leases of approximately $14 million, $7 million and $7 million, for the years ended December 31, 2014, December 31, 2013, and December 31, 2012, respectively.

As of December 31, 2014, future minimum lease payments were as follows (in thousands):

| | |
|---|---|
| 2015 | $13,265 |
| 2016 | 10,288 |
| 2017 | 8,215 |
| 2018 | 7,130 |
| 2019 | 6,492 |
| Thereafter | 1,046 |
| | $46,436 |

Note 14 – Income Taxes

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. As such, with the exception of the state of Texas and certain subsidiaries, the Company is not a taxable entity, it does not directly pay federal and state income taxes and recognition has not been given to federal and state income taxes for the operations of the Company, except as set forth in the tables below. Amounts recognized for income taxes are reported in "income tax expense (benefit)" on the consolidated statements of operations.

The Company's taxable income or loss, which may vary substantially from the net income or net loss reported on the consolidated statements of operations, is includable in the federal and state income tax returns of each unitholder. The aggregate difference in the basis of net assets for financial and tax reporting purposes cannot be readily determined as the Company does not have access to information about each unitholder's tax attributes.

Certain of the Company's subsidiaries are Subchapter C-corporations subject to federal and state income taxes. Income tax expense (benefit) consisted of the following:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| | (in thousands) | | |
| Current taxes: | | | |
| Federal | $473 | $144 | $2,711 |
| State | 21 | 198 | 439 |
| Deferred taxes: | | | |
| Federal | (104) | (2,805) | 323 |
| State | 4,047 | 264 | (683) |
| | $4,437 | $(2,199) | $2,790 |

As of December 31, 2014, the Company's taxable entities had approximately $11 million of net operating loss carryforwards for federal income tax purposes which will begin expiring in 2031.

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

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| Federal statutory rate | 35.0 % | 35.0 % | 35.0 % |
| State, net of federal tax benefit | (0.9 ) | (0.1 ) | 0.1 |
| Loss excluded from nontaxable entities | (34.6 ) | (34.6 ) | (35.6 ) |
| Other items | (0.5 ) | — | (0.2 ) |
| Effective rate | (1.0 )% | 0.3 % | (0.7 )% |

Significant components of the deferred tax assets and liabilities were as follows:

| | December 31, | |
|---|---|---|
| | 2014 | 2013 |
| | (in thousands) | |
| Deferred tax assets: | | |
| Net operating loss carryforwards | $— | $1,129 |
| Unit-based compensation | 22,105 | 21,965 |
| Other | 6,857 | 7,759 |
| Total deferred tax assets | 28,962 | 30,853 |
| Deferred tax liabilities: | | |
| Property and equipment principally due to differences in depreciation | (10,991 ) | (12,525 ) |
| Other | (6,370 ) | (1,509 ) |
| Total deferred tax liabilities | (17,361 ) | (14,034 ) |
| Net deferred tax assets | $11,601 | $16,819 |

Net deferred tax assets and liabilities were classified on the consolidated balance sheets as follows:

| | December 31, | |
|---|---|---|
| | 2014 | 2013 |
| | (in thousands) | |
| Deferred tax assets | $28,442 | $29,204 |
| Deferred tax liabilities | (2,964 ) | (10 ) |
| Other current assets | $25,478 | $29,194 |
| | | |
| Deferred tax assets | $520 | $1,649 |
| Deferred tax liabilities | (14,397 ) | (14,024 ) |
| Other noncurrent liabilities | $(13,877 ) | $(12,375 ) |

In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment. At December 31, 2014, based on the level of historical taxable income and projections

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for future taxable income over the periods in which the deferred tax assets are deductible, management believes it is more likely than not that the Company will realize the benefits of these deductible differences. The amount of deferred tax assets considered realizable could be reduced in the future if estimates of future taxable income during the carryforward period are reduced.

In accordance with the applicable accounting standards, the Company recognizes only the impact of income tax positions that, based on their merits, are more likely than not to be sustained upon audit by a taxing authority. To evaluate its current tax positions in order to identify any material uncertain tax positions, the Company developed a policy of identifying and evaluating uncertain tax positions that considers support for each tax position, industry standards, tax return disclosures and schedules and the significance of each position. It is the Company’s policy to recognize interest and penalties, if any, related to unrecognized tax benefits in income tax expense. The Company had no material uncertain tax positions at December 31, 2014, and December 31, 2013. The tax years 2011 – 2013 remain open to examination for federal income tax purposes.

Note 15 – Supplemental Disclosures to the Consolidated Balance Sheets and Consolidated Statements of Cash Flows

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

| | December 31, 2014 | 2013 |
|---|---|---|
| | (in thousands) | |
| Accrued interest | $105,310 | $93,998 |
| Accrued compensation | 44,875 | 55,257 |
| Asset retirement obligations | 16,187 | 12,616 |
| Other | 1,364 | 1,504 |
| | $167,736 | $163,375 |

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

| | Year Ended December 31, 2014 | 2013 | 2012 |
|---|---|---|---|
| | (in thousands) | | |
| Cash payments for interest, net of amounts capitalized | $542,775 | $392,607 | $343,331 |
| Cash payments for income taxes | $— | $14 | $366 |
| Noncash investing and financing activities: | | | |
| In connection with the acquisition of oil and natural gas properties and joint-venture funding, assets were acquired and liabilities were assumed as follow: | | | |
| Fair value of assets acquired | $2,679,547 | $5,726,681 | $2,923,990 |
| Cash paid, net of cash acquired | (2,395,339) | (109,350) | (2,640,475) |
| Units issued in connection with the Berry acquisition | — | (2,781,888) | — |
| Noncash gains on exchanges of properties | (85,493) | — | — |
| Receivables from sellers | 16,213 | (93) | 2,132 |
| Payables to sellers | (3,515) | (6,854) | 443 |
| Liabilities assumed | $211,413 | $2,828,496 | $286,090 |
| Accrued capital expenditures | $240,331 | $334,542 | $203,229 |

Included in “acquisition of oil and natural gas properties and joint-venture funding, net of cash acquired” on the consolidated statements of cash flows for the years ended December 31, 2014, December 31, 2013, and December 31, 2012, is approximately $25 million, $170 million and $197 million, respectively, paid by the Company towards the future funding commitment related to the joint-venture agreement entered into with Anadarko (see Note 2).

On November 21, 2014, the Company, through two of its wholly owned subsidiaries, completed a noncash exchange of a portion of its Permian Basin properties to Exxon Mobil Corporation in exchange for properties in California’s South Belridge Field. On August 15, 2014, the Company, through two of its wholly owned subsidiaries, completed a noncash exchange of a portion of its Permian Basin properties to Exxon Mobil Corporation and its affiliates, including its wholly owned subsidiary XTO Energy Inc., for properties in the Hugoton Basin.

For purposes of the consolidated statements of cash flows, the Company considers all highly liquid short-term investments with original maturities of three months or less to be cash equivalents. Restricted cash of approximately $6 million is included in “other noncurrent assets” on the consolidated balance sheets at both December 31, 2014, and December 31, 2013, and primarily represents cash the Company has deposited into a separate account and designated for asset retirement obligations in accordance with contractual agreements.

The Company manages its working capital and cash requirements to borrow only as needed from its Credit Facilities. At December 31, 2014, and December 31, 2013, net outstanding checks of approximately $95 million and $48 million, respectively, were reclassified and included in “accounts payable and accrued expenses” on the consolidated balance sheets. Net outstanding checks are presented as cash flows from financing activities and included in “other” on the consolidated statements of cash flows.

## Note 16 – Related Party Transactions

### LinnCo

LinnCo, an affiliate of LINN Energy, was formed on April 30, 2012. LinnCo’s initial sole purpose was to own units in LINN Energy. In connection with the acquisition of Berry, LinnCo amended its limited liability company agreement to permit, among other things, the acquisition and subsequent contribution of assets to LINN Energy. All of LinnCo’s common shares are held by the public. As of December 31, 2014, LinnCo had no significant assets or operations other than those related to its interest in LINN Energy and owned approximately 39% of LINN Energy’s outstanding units.

On December 16, 2013, LinnCo and LINN Energy completed the transactions contemplated by the merger agreement, as amended, under which Berry’s shareholders received 1.68 LinnCo common shares for each Berry common share they owned, totaling 93,756,674 LinnCo common shares. Under the contribution agreement between LinnCo and LINN Energy, LinnCo contributed Berry to LINN Energy in exchange for 93,756,674 newly issued LINN Energy units valued at approximately $2.8 billion.

In October 2012, LinnCo completed its IPO and used the net proceeds of approximately $1.2 billion from the offering to acquire 34,787,500 of LINN Energy’s units.

LINN Energy has agreed to provide to LinnCo, or to pay on LinnCo’s behalf, any legal, accounting, tax advisory, financial advisory and engineering fees, printing costs or other administrative and out-of-pocket expenses incurred by LinnCo, along with any other expenses incurred in connection with any public offering of shares in LinnCo or incurred as a result of being a publicly traded entity. These expenses include costs associated with annual, quarterly and other reports to holders of LinnCo shares, tax return and Form 1099 preparation and distribution, NASDAQ listing fees, printing costs, independent auditor fees and expenses, legal counsel fees and expenses, limited liability company governance and compliance expenses and registrar and transfer agent fees. In addition, the Company has agreed to indemnify LinnCo and its officers and directors for damages suffered or costs incurred (other than income taxes payable by LinnCo) in connection with carrying out LinnCo’s activities. All expenses and costs paid by LINN Energy on LinnCo’s behalf are expensed by LINN Energy.

For the year ended December 31, 2014, LinnCo incurred total general and administrative expenses and certain offering costs of approximately $3 million, all of which had been paid by LINN Energy on LinnCo’s behalf as of December 31, 2014. The

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expenses for the year ended December 31, 2014, include approximately $2 million related to services provided by LINN Energy necessary for the conduct of LinnCo's business, such as accounting, legal, tax, information technology and other expenses. In addition, during the year ended December 31, 2014, LINN Energy paid approximately $11 million on LinnCo's behalf for general and administrative expenses incurred by LinnCo in 2013.

For the year ended December 31, 2013, LinnCo incurred total general and administrative expenses and certain offering costs of approximately $42 million. The expenses for the year ended December 31, 2013, include approximately $40 million of transaction costs related to the Berry acquisition (see Note 2), including approximately $9 million of noncash share-based compensation expense. The expenses for the year ended December 31, 2013, also include approximately $2 million related to services provided by LINN Energy necessary for the conduct of LinnCo's business, such as accounting, legal, tax, information technology and other expenses. The offering costs of approximately $388,000 were incurred in connection with LinnCo's registration statement on Form S-4 also related to the Berry acquisition.

During the years ended December 31, 2014, December 31, 2013, and December 31, 2012, the Company paid approximately $373 million, $101 million and $25 million, respectively, in distributions to LinnCo attributable to LinnCo's interest in LINN Energy.

Other

One of the Company's directors is the President and Chief Executive Officer of Superior Energy Services, Inc. ("Superior"), which provides oilfield services to the Company. For the years ended December 31, 2014, December 31, 2013, and December 31, 2012, the Company paid approximately $21 million, $26 million and $21 million, respectively, to Superior and its subsidiaries for services rendered to the Company. The transactions associated with these payments were consummated on terms equivalent to those that prevail in arm's-length transactions.

Note 17 – Subsidiary Guarantors

LINN Energy, LLC's May 2019 Senior Notes, November 2019 Senior Notes, September 2021 Senior Notes and 2010 Issued Senior Notes are guaranteed by all of the Company's material subsidiaries, other than Berry Petroleum Company, LLC, which is an indirect 100% wholly owned subsidiary of the Company.

The following condensed consolidating financial information presents the financial information of LINN Energy, LLC, the guarantor subsidiaries and the non-guarantor subsidiary in accordance with SEC Regulation S-X Rule 3-10. The condensed consolidating financial information for the co-issuer, Linn Energy Finance Corp., is not presented as it has no assets, operations or cash flows. The financial information may not necessarily be indicative of the financial position or results of operations had the guarantor subsidiaries or non-guarantor subsidiary operated as independent entities. Condensed consolidating financial information is not provided for 2012 since during that period, the Company was a holding company that had no independent assets or operations of its own, the guarantees under each series of notes were full and unconditional and joint and several, and any subsidiaries of the Company other than the subsidiary guarantors were minor. There are no restrictions on the Company's ability to obtain cash dividends or other distributions of funds from the guarantor subsidiaries.

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LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

CONDENSED CONSOLIDATING BALANCE SHEETS
December 31, 2014

| | LINN Energy, LLC | Guarantor Subsidiaries | Non-Guarantor Subsidiary | Eliminations | Consolidated |
|---|---|---|---|---|---|
| | (in thousands) | | | | |
| ASSETS | | | | | |
| Current assets: | | | | | |
| Cash and cash equivalents | $38 | $185 | $1,586 | $— | $1,809 |
| Accounts receivable – trade, net | — | 371,325 | 100,359 | — | 471,684 |
| Accounts receivable – affiliates | 4,028,890 | 13,205 | — | (4,042,095) | — |
| Derivative instruments | — | 1,033,448 | 43,694 | — | 1,077,142 |
| Other current assets | 18 | 96,678 | 59,259 | — | 155,955 |
| Total current assets | 4,028,946 | 1,514,841 | 204,898 | (4,042,095) | 1,706,590 |
| | | | | | |
| Noncurrent assets: | | | | | |
| Oil and natural gas properties (successful efforts method) | — | 13,196,841 | 4,872,059 | — | 18,068,900 |
| Less accumulated depletion and amortization | — | (4,342,675) | (525,007) | — | (4,867,682) |
| | — | 8,854,166 | 4,347,052 | — | 13,201,218 |
| | | | | | |
| Other property and equipment | — | 553,150 | 115,999 | — | 669,149 |
| Less accumulated depreciation | — | (135,830) | (8,452) | — | (144,282) |
| | — | 417,320 | 107,547 | — | 524,867 |
| | | | | | |
| Derivative instruments | — | 848,097 | — | — | 848,097 |
| Notes receivable – affiliates | 130,500 | — | — | (130,500) | — |
| Advance to affiliate | — | — | 293,627 | (293,627) | — |
| Investments in consolidated subsidiaries | 8,562,608 | — | — | (8,562,608) | — |
| Other noncurrent assets | 116,637 | 11,816 | 14,284 | — | 142,737 |
| | 8,809,745 | 859,913 | 307,911 | (8,986,735) | 990,834 |
| Total noncurrent assets | 8,809,745 | 10,131,399 | 4,762,510 | (8,986,735) | 14,716,919 |
| Total assets | $12,838,691 | $11,646,240 | $4,967,408 | $(13,028,830) | $16,423,509 |
| | | | | | |
| LIABILITIES AND UNITHOLDERS' CAPITAL | | | | | |
| Current liabilities: | | | | | |
| Accounts payable and accrued expenses | $3,784 | $581,880 | $229,145 | $— | $814,809 |
| Accounts payable – affiliates | — | 4,028,890 | 13,205 | (4,042,095) | — |
| Advance from affiliate | — | 293,627 | — | (293,627) | — |
| Derivative instruments | — | — | — | — | — |
| Other accrued liabilities | 89,507 | 59,142 | 19,087 | — | 167,736 |
| Total current liabilities | 93,291 | 4,963,539 | 261,437 | (4,335,722) | 982,545 |
| | | | | | |
| Noncurrent liabilities: | | | | | |
| Credit facilities | 1,795,000 | — | 1,173,175 | — | 2,968,175 |
| Term loan | 500,000 | — | — | — | 500,000 |

| | | | | | |
|---|---|---|---|---|---|
| Senior notes, net | 5,913,857 | — | 913,777 | — | 6,827,634 |
| Notes payable – affiliates | — | 130,500 | — | (130,500) | — |
| Derivative instruments | — | 684 | — | — | 684 |
| Other noncurrent liabilities | — | 400,851 | 200,015 | — | 600,866 |
| Total noncurrent liabilities | 8,208,857 | 532,035 | 2,286,967 | (130,500) | 10,897,359 |
| | | | | | |
| Unitholders' capital: | | | | | |
| Units issued and outstanding | 5,388,749 | 4,831,339 | 2,416,381 | (7,240,658) | 5,395,811 |
| Accumulated income (deficit) | (852,206) | 1,319,327 | 2,623 | (1,321,950) | (852,206) |
| | 4,536,543 | 6,150,666 | 2,419,004 | (8,562,608) | 4,543,605 |
| Total liabilities and unitholders' capital | $12,838,691 | $11,646,240 | $4,967,408 | $(13,028,830) | $16,423,509 |

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LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

CONDENSED CONSOLIDATING BALANCE SHEETS
December 31, 2013

| | LINN Energy, LLC | Guarantor Subsidiaries | Non-Guarantor Subsidiary | Eliminations | Consolidated |
|---|---|---|---|---|---|
| | (in thousands) | | | | |
| ASSETS | | | | | |
| Current assets: | | | | | |
| Cash and cash equivalents | $52 | $1,078 | $51,041 | $— | $52,171 |
| Accounts receivable – trade, net | — | 365,347 | 122,855 | — | 488,202 |
| Accounts receivable – affiliates | 4,212,348 | 16,950 | — | (4,229,298) | — |
| Derivative instruments | — | 170,534 | 5,596 | — | 176,130 |
| Other current assets | 330 | 68,274 | 30,833 | — | 99,437 |
| Total current assets | 4,212,730 | 622,183 | 210,325 | (4,229,298) | 815,940 |
| | | | | | |
| Noncurrent assets: | | | | | |
| Oil and natural gas properties (successful efforts method) | — | 13,074,900 | 4,813,659 | — | 17,888,559 |
| Less accumulated depletion and amortization | — | (3,535,890) | (10,394) | — | (3,546,284) |
| | — | 9,539,010 | 4,803,265 | — | 14,342,275 |
| | | | | | |
| Other property and equipment | — | 564,756 | 83,126 | — | 647,882 |
| Less accumulated depreciation | — | (110,706) | (233) | — | (110,939) |
| | — | 454,050 | 82,893 | — | 536,943 |
| | | | | | |
| Derivative instruments | — | 679,491 | 2,511 | — | 682,002 |
| Notes receivable – affiliates | 86,200 | — | — | (86,200) | — |
| Investments in consolidated subsidiaries | 8,433,290 | — | — | (8,433,290) | — |
| Other noncurrent assets | 108,785 | 10,968 | 8,051 | — | 127,804 |
| | 8,628,275 | 690,459 | 10,562 | (8,519,490) | 809,806 |
| Total noncurrent assets | 8,628,275 | 10,683,519 | 4,896,720 | (8,519,490) | 15,689,024 |
| Total assets | $12,841,005 | $11,305,702 | $5,107,045 | $(12,748,788) | $16,504,964 |
| | | | | | |
| LIABILITIES AND UNITHOLDERS' CAPITAL | | | | | |
| Current liabilities: | | | | | |
| Accounts payable and accrued expenses | $14,529 | $587,774 | $247,321 | $— | $849,624 |
| Accounts payable – affiliates | — | 4,212,348 | 16,950 | (4,229,298) | — |
| Derivative instruments | — | 7,783 | 20,393 | — | 28,176 |
| Other accrued liabilities | 75,071 | 59,311 | 28,993 | — | 163,375 |
| Current portion of long-term debt | — | — | 211,558 | — | 211,558 |
| Total current liabilities | 89,600 | 4,867,216 | 525,215 | (4,229,298) | 1,252,733 |
| | | | | | |
| Noncurrent liabilities: | | | | | |
| Credit facilities | 1,560,000 | — | 1,173,175 | — | 2,733,175 |
| Term loan | 500,000 | — | — | — | 500,000 |
| Senior notes, net | 4,809,055 | — | 916,428 | — | 5,725,483 |

| | | | | | |
|---|---|---|---|---|---|
| Notes payable – affiliates | — | 86,200 | — | (86,200) | — |
| Derivative instruments | — | — | 4,649 | — | 4,649 |
| Other noncurrent liabilities | — | 205,406 | 192,091 | — | 397,497 |
| Total noncurrent liabilities | 6,869,055 | 291,606 | 2,286,343 | (86,200) | 9,360,804 |
| | | | | | |
| Unitholders' capital: | | | | | |
| Units issued and outstanding | 6,282,747 | 4,833,354 | 2,315,460 | (7,139,737) | 6,291,824 |
| Accumulated income (deficit) | (400,397) | 1,313,526 | (19,973) | (1,293,553) | (400,397) |
| | 5,882,350 | 6,146,880 | 2,295,487 | (8,433,290) | 5,891,427 |
| Total liabilities and unitholders' capital | $12,841,005 | $11,305,702 | $5,107,045 | $(12,748,788) | $16,504,964 |

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CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
For the Year Ended December 31, 2014

| | LINN Energy, LLC | Guarantor Subsidiaries | Non-Guarantor Subsidiary | Eliminations | Consolidated |
|---|---|---|---|---|---|
| | (in thousands) | | | | |
| Revenues and other: | | | | | |
| Oil, natural gas and natural gas liquids sales | $— | $2,312,137 | $1,298,402 | $— | $3,610,539 |
| Gains on oil and natural gas derivatives | — | 1,127,395 | 78,784 | — | 1,206,179 |
| Marketing revenues | — | 84,349 | 50,911 | — | 135,260 |
| Other revenues | — | 28,133 | 3,192 | — | 31,325 |
| | — | 3,552,014 | 1,431,289 | — | 4,983,303 |
| Expenses: | | | | | |
| Lease operating expenses | — | 440,624 | 364,540 | — | 805,164 |
| Transportation expenses | — | 165,489 | 41,842 | — | 207,331 |
| Marketing expenses | — | 81,210 | 36,255 | — | 117,465 |
| General and administrative expenses | — | 190,286 | 102,787 | — | 293,073 |
| Exploration costs | — | 125,037 | — | — | 125,037 |
| Depreciation, depletion and amortization | — | 771,549 | 302,353 | — | 1,073,902 |
| Impairment of long-lived assets | — | 2,050,387 | 253,362 | — | 2,303,749 |
| Taxes, other than income taxes | 40 | 169,655 | 97,708 | — | 267,403 |
| (Gains) losses on sale of assets and other, net | — | (487,286) | 120,786 | — | (366,500) |
| | 40 | 3,506,951 | 1,319,633 | — | 4,826,624 |
| Other income and (expenses): | | | | | |
| Interest expense, net of amounts capitalized | (480,259) | (19,631) | (87,948) | — | (587,838) |
| Interest expense – affiliates | — | (7,954) | — | 7,954 | — |
| Interest income – affiliates | 7,954 | — | — | (7,954) | — |
| Equity in earnings from consolidated subsidiaries | 28,397 | — | — | (28,397) | — |
| Other, net | (7,861) | (7,309) | (1,043) | — | (16,213) |
| | (451,769) | (34,894) | (88,991) | (28,397) | (604,051) |
| Income (loss) before income taxes | (451,809) | 10,169 | 22,665 | (28,397) | (447,372) |
| Income tax expense | — | 4,368 | 69 | — | 4,437 |
| Net income (loss) | $(451,809) | $5,801 | $22,596 | $(28,397) | $(451,809) |

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LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
For the Year Ended December 31, 2013

| | LINN Energy, LLC | Guarantor Subsidiaries | Non-Guarantor Subsidiary | Eliminations | Consolidated |
|---|---|---|---|---|---|
| | (in thousands) | | | | |
| Revenues and other: | | | | | |
| Oil, natural gas and natural gas liquids sales | $— | $2,022,916 | $50,324 | $— | $2,073,240 |
| Gains (losses) on oil and natural gas derivatives | — | 182,906 | (5,049) | — | 177,857 |
| Marketing revenues | — | 52,328 | 1,843 | — | 54,171 |
| Other revenues | — | 26,387 | — | — | 26,387 |
| | — | 2,284,537 | 47,118 | — | 2,331,655 |
| Expenses: | | | | | |
| Lease operating expenses | — | 357,113 | 15,410 | — | 372,523 |
| Transportation expenses | — | 125,864 | 2,576 | — | 128,440 |
| Marketing expenses | — | 36,259 | 1,633 | — | 37,892 |
| General and administrative expenses | — | 215,973 | 20,298 | — | 236,271 |
| Exploration costs | — | 5,251 | — | — | 5,251 |
| Depreciation, depletion and amortization | — | 818,466 | 10,845 | — | 829,311 |
| Impairment of long-lived assets | — | 828,317 | — | — | 828,317 |
| Taxes, other than income taxes | — | 136,501 | 2,130 | — | 138,631 |
| Losses on sale of assets and other, net | 724 | 2,705 | 10,208 | — | 13,637 |
| | 724 | 2,526,449 | 63,100 | — | 2,590,273 |
| Other income and (expenses): | | | | | |
| Interest expense, net of amounts capitalized | (415,670) | (1,504) | (3,963) | — | (421,137) |
| Interest expense – affiliates | — | (5,543) | — | 5,543 | — |
| Interest income – affiliates | 5,543 | — | — | (5,543) | — |
| Loss on extinguishment of debt | (5,304) | — | — | — | (5,304) |
| Equity in losses from consolidated subsidiaries | (266,899) | — | — | 266,899 | — |
| Other, net | (8,283) | (166) | (28) | — | (8,477) |
| | (690,613) | (7,213) | (3,991) | 266,899 | (434,918) |
| Loss before income taxes | (691,337) | (249,125) | (19,973) | 266,899 | (693,536) |
| Income tax benefit | — | (2,199) | — | — | (2,199) |
| Net loss | $(691,337) | $(246,926) | $(19,973) | $266,899 | $(691,337) |

Table of Contents
LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
For the Year Ended December 31, 2014

| | LINN Energy, LLC | Guarantor Subsidiaries | Non-Guarantor Subsidiary | Eliminations | Consolidated |
|---|---|---|---|---|---|
| | (in thousands) | | | | |
| Cash flow from operating activities: | | | | | |
| Net income (loss) | $(451,809) | $5,801 | $22,596 | $(28,397) | $(451,809) |
| Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities: | | | | | |
| Depreciation, depletion and amortization | — | 771,549 | 302,353 | — | 1,073,902 |
| Impairment of long-lived assets | — | 2,050,387 | 253,362 | — | 2,303,749 |
| Unit-based compensation expenses | — | 53,284 | — | — | 53,284 |
| Amortization and write-off of deferred financing fees | 38,785 | 17,054 | (4,913) | — | 50,926 |
| (Gains) losses on sale of assets and other, net | — | (372,945) | 111,374 | — | (261,571) |
| Equity in earnings from consolidated subsidiaries | (28,397) | — | — | 28,397 | — |
| Deferred income tax | — | 3,874 | 69 | — | 3,943 |
| Derivatives activities: | | | | | |
| Total gains | — | (1,127,395) | (78,784) | — | (1,206,179) |
| Cash settlements | — | 88,776 | 6,738 | — | 95,514 |
| Cash settlements on canceled derivatives | — | — | 12,281 | — | 12,281 |
| Changes in assets and liabilities: | | | | | |
| (Increase) decrease in accounts receivable – trade, net | — | (11,419) | 16,483 | — | 5,064 |
| Decrease in accounts receivable – affiliates | 257,485 | 16,950 | — | (274,435) | — |
| (Increase) decrease in other assets | 312 | (2,187) | (15,949) | — | (17,824) |
| Increase in accounts payable and accrued expenses | — | 99,003 | 26 | — | 99,029 |
| Decrease in accounts payable and accrued expenses – affiliates | — | (270,690) | (3,745) | 274,435 | — |
| Increase (decrease) in other liabilities | 14,465 | (24,473) | (38,411) | — | (48,419) |
| Net cash provided by (used in) operating activities | (169,159) | 1,297,569 | 583,480 | — | 1,711,890 |
| | | | | | |
| Cash flow from investing activities: | | | | | |
| Acquisition of oil and natural gas properties and joint-venture funding, net of cash acquired | — | (2,475,315) | (3,937) | — | (2,479,252) |
| Development of oil and natural gas properties | — | (1,061,395) | (508,482) | — | (1,569,877) |
| Purchases of other property and equipment | — | (63,070) | (11,470) | — | (74,540) |
| Investment in affiliates | (100,921) | — | — | 100,921 | — |
| Change in notes receivable with affiliate | (44,300) | — | — | 44,300 | — |

| | | | | | |
|---|---|---|---|---|---|
| Proceeds from sale of properties and equipment and other | (14,117) | 2,210,015 | 7,667 | — | 2,203,565 |
| Net cash used in investing activities | (159,338) | (1,389,765) | (516,222) | 145,221 | (1,920,104) |

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LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

| | LINN Energy, LLC | Guarantor Subsidiaries | Non-Guarantor Subsidiary | Eliminations | Consolidated |
|---|---|---|---|---|---|
| | (in thousands) | | | | |
| Cash flow from financing activities: | | | | | |
| Proceeds from borrowings | 4,640,024 | 1,300,000 | — | — | 5,940,024 |
| Repayments of debt | (3,305,000) | (1,300,000) | (206,124) | — | (4,811,124) |
| Distributions to unitholders | (962,048) | — | — | — | (962,048) |
| Financing fees and offering expenses | (59,048) | — | (10,646) | — | (69,694) |
| Change in note payable with affiliate | — | 44,300 | — | (44,300) | — |
| Capital contribution – affiliates | — | — | 100,921 | (100,921) | — |
| Excess tax benefit from unit-based compensation | 810 | (44) | — | — | 766 |
| Other | 13,745 | 47,047 | (864) | — | 59,928 |
| Net cash provided by (used in) financing activities | 328,483 | 91,303 | (116,713) | (145,221) | 157,852 |
| Net decrease in cash and cash equivalents | (14) | (893) | (49,455) | — | (50,362) |
| Cash and cash equivalents: | | | | | |
| Beginning | 52 | 1,078 | 51,041 | — | 52,171 |
| Ending | $38 | $185 | $1,586 | $— | $1,809 |

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LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
For the Year Ended December 31, 2013

| | LINN Energy, LLC | Guarantor Subsidiaries | Non-Guarantor Subsidiary | Eliminations | Consolidated |
|---|---|---|---|---|---|
| | (in thousands) | | | | |
| Cash flow from operating activities: | | | | | |
| Net loss | $(691,337) | $(246,926) | $(19,973) | $266,899 | $(691,337) |
| Adjustments to reconcile net loss to net cash provided by (used in) operating activities: | | | | | |
| Depreciation, depletion and amortization | — | 818,466 | 10,845 | — | 829,311 |
| Impairment of long-lived assets | — | 828,317 | — | — | 828,317 |
| Unit-based compensation expenses | — | 42,703 | — | — | 42,703 |
| Loss on extinguishment of debt | 5,304 | — | — | — | 5,304 |
| Amortization and write-off of deferred financing fees | 22,122 | — | (615) | — | 21,507 |
| Losses on sale of assets and other, net | — | 37,232 | — | — | 37,232 |
| Equity in losses from consolidated subsidiaries | 266,899 | — | — | (266,899) | — |
| Deferred income taxes | — | (2,541) | — | — | (2,541) |
| Derivatives activities: | | | | | |
| Total (gains) losses | — | (182,906) | 5,049 | — | (177,857) |
| Cash settlements | — | 248,862 | — | — | 248,862 |
| Changes in assets and liabilities: | | | | | |
| Decrease in accounts receivable – trade, net | — | 17,754 | 71,434 | — | 89,188 |
| Increase in accounts receivable – affiliates | (120,967) | (16,950) | — | 137,917 | — |
| (Increase) decrease in other assets | (330) | 5,896 | 10,613 | — | 16,179 |
| Increase (decrease) in accounts payable and accrued expenses | 178 | (52,143) | (25,028) | — | (76,993) |
| Increase in accounts payable and accrued expenses – affiliates | — | 120,967 | 16,950 | (137,917) | — |
| Increase (decrease) in other liabilities | 2,092 | 6,842 | (12,597) | — | (3,663) |
| Net cash provided by (used in) operating activities | (516,039) | 1,625,573 | 56,678 | — | 1,166,212 |
| | | | | | |
| Cash flow from investing activities: | | | | | |
| Acquisition of oil and natural gas properties and joint-venture funding, net of cash acquired | — | (730,326) | 451,113 | — | (279,213) |
| Development of oil and natural gas properties | — | (1,060,547) | (17,478) | — | (1,078,025) |
| Purchases of other property and equipment | — | (92,352) | — | — | (92,352) |
| Investment in affiliates | 435,000 | — | — | (435,000) | — |
| Change in notes receivable with affiliate | (26,700) | — | — | 26,700 | — |
| Proceeds from sale of properties and equipment and other | (22,039) | 218,312 | — | — | 196,273 |

| | | | | | |
|---|---|---|---|---|---|
| Net cash provided by (used in) investing activities | 386,261 | (1,664,913) | 433,635 | (408,300) | (1,253,317) |

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LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

| | LINN Energy, LLC | Guarantor Subsidiaries | Non-Guarantor Subsidiary | Eliminations | Consolidated |
|---|---|---|---|---|---|
| | (in thousands) | | | | |
| Cash flow from financing activities: | | | | | |
| Proceeds from borrowings | 2,230,000 | — | — | — | 2,230,000 |
| Repayments of debt | (1,404,898) | — | — | — | (1,404,898) |
| Distributions to unitholders | (682,241) | — | — | — | (682,241) |
| Financing fees and offering expenses | (16,033) | — | — | — | (16,033) |
| Change in note payable with affiliate | — | 26,700 | — | (26,700) | — |
| Capital contribution – affiliates | — | — | (435,000) | 435,000 | — |
| Excess tax benefit from unit-based compensation | — | 160 | — | — | 160 |
| Other | 2,895 | 12,422 | (4,272) | — | 11,045 |
| Net cash provided by (used in) financing activities | 129,723 | 39,282 | (439,272) | 408,300 | 138,033 |
| Net increase (decrease) in cash and cash equivalents | (55) | (58) | 51,041 | — | 50,928 |
| Cash and cash equivalents: | | | | | |
| Beginning | 107 | 1,136 | — | — | 1,243 |
| Ending | $52 | $1,078 | $51,041 | $— | $52,171 |

Note 18 – SEC Inquiry

As disclosed on July 1, 2013, the Company and its affiliate, LinnCo, were notified by the staff of the SEC that its Fort Worth Regional Office had commenced an inquiry regarding LINN Energy and LinnCo. The SEC staff was investigating whether any violations of federal securities laws had occurred. Both LINN Energy and LinnCo cooperated fully with the SEC in this matter. The Company was notified on February 4, 2015, that the SEC has closed its inquiry regarding LINN Energy and LinnCo and does not intend to recommend any enforcement action.

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LINN ENERGY, LLC

SUPPLEMENTAL OIL AND NATURAL GAS DATA (Unaudited)

The following discussion and analysis should be read in conjunction with the “Consolidated Financial Statements” and “Notes to Consolidated Financial Statements,” which are included in this Annual Report on Form 10-K in Item 8. “Financial Statements and Supplementary Data.”

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

Costs incurred in oil and natural gas property acquisition, exploration and development, whether capitalized or expensed, are presented below:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| | (in thousands) | | |
| Property acquisition costs: [1] | | | |
| Proved | $2,784,852 | $3,740,379 | $2,531,419 |
| Unproved | 788,682 | 1,638,302 | 181,124 |
| Exploration costs | 792 | 13,096 | 452 |
| Development costs | 1,487,204 | 1,153,770 | 1,062,043 |
| Asset retirement costs | 20,919 | 7,351 | 4,675 |
| Total costs incurred | $5,082,449 | $6,552,898 | $3,779,713 |

[1] See Note 2 for details about the Company’s acquisitions.

Oil and Natural Gas Capitalized Costs

Aggregate capitalized costs related to oil, natural gas and NGL production activities with applicable accumulated depletion and amortization are presented below:

| | December 31, | |
|---|---|---|
| | 2014 | 2013 |
| | (in thousands) | |
| Proved properties: | | |
| Leasehold acquisition | $13,362,642 | $12,277,089 |
| Development | 2,830,841 | 3,660,277 |
| Unproved properties | 1,875,417 | 1,951,193 |
| | 18,068,900 | 17,888,559 |
| Less accumulated depletion and amortization | (4,867,682) | (3,546,284) |
| | $13,201,218 | $14,342,275 |

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LINN ENERGY, LLC
SUPPLEMENTAL OIL AND NATURAL GAS DATA (Unaudited) - Continued

Results of Oil and Natural Gas Producing Activities
The results of operations for oil, natural gas and NGL producing activities (excluding corporate overhead and interest costs) are presented below:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| | (in thousands) | | |
| Revenues and other: | | | |
| Oil, natural gas and natural gas liquid sales | $3,610,539 | $2,073,240 | $1,601,180 |
| Gains on oil and natural gas derivatives | 1,206,179 | 177,857 | 124,762 |
| | 4,816,718 | 2,251,097 | 1,725,942 |
| Production costs: | | | |
| Lease operating expenses | 805,164 | 372,523 | 317,699 |
| Transportation expenses | 207,331 | 128,440 | 77,322 |
| Severance taxes, ad valorem taxes and California carbon allowances | 267,100 | 139,202 | 130,805 |
| | 1,279,595 | 640,165 | 525,826 |
| Other costs: | | | |
| Exploration costs | 125,037 | 5,251 | 1,915 |
| Depletion and amortization | 1,020,674 | 790,320 | 579,382 |
| Impairment of long-lived assets | 2,303,749 | 828,317 | 422,499 |
| Gains on sale of assets and other, net | (388,733) | (138) | (1,369) |
| Texas margin tax expense (benefit) | 4,053 | 458 | (787) |
| | 3,064,780 | 1,624,208 | 1,001,640 |
| Results of operations | $472,343 | $(13,276) | $198,476 |

There is no federal tax provision included in the results above because the Company’s subsidiaries subject to federal tax do not own any of the Company’s oil and natural gas interests. Limited liability companies are subject to Texas margin tax. See Note 14 for additional information about income taxes.

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LINN ENERGY, LLC
SUPPLEMENTAL OIL AND NATURAL GAS DATA (Unaudited) - Continued

Proved Oil, Natural Gas and NGL Reserves
The proved reserves of oil, natural gas and NGL of the Company have been prepared by the independent engineering firm, DeGolyer and MacNaughton. In accordance with SEC regulations, reserves at December 31, 2014, December 31, 2013, and December 31, 2012, were estimated using the average price during the 12-month period, determined as an unweighted average of the first-day-of-the-month price for each month, excluding escalations based upon future conditions. An analysis of the change in estimated quantities of oil, natural gas and NGL reserves, all of which are located within the U.S., is shown below:

| | Year Ended December 31, 2014 | | | |
|---|---|---|---|---|
| | Natural Gas (Bcf) | Oil (MMBbls) | NGL (MMBbls) | Total (Bcfe) |
| Proved developed and undeveloped reserves: | | | | |
| Beginning of year | 3,010 | 365.6 | 200.0 | 6,403 |
| Revisions of previous estimates | 96 | (22.3) | (46.8) | (318) |
| Purchases of minerals in place | 1,763 | 50.0 | 71.9 | 2,495 |
| Sales of minerals in place | (477) | (51.7) | (49.5) | (1,084) |
| Extensions, discoveries and other additions | 72 | 26.8 | 2.9 | 250 |
| Production | (209) | (26.6) | (12.2) | (442) |
| End of year | 4,255 | 341.8 | 166.3 | 7,304 |
| Proved developed reserves: | | | | |
| Beginning of year | 2,027 | 252.4 | 133.2 | 4,340 |
| End of year | 3,549 | 246.0 | 132.2 | 5,818 |
| Proved undeveloped reserves: | | | | |
| Beginning of year | 983 | 113.2 | 66.8 | 2,063 |
| End of year | 706 | 95.8 | 34.1 | 1,486 |

| | Year Ended December 31, 2013 | | | |
|---|---|---|---|---|
| | Natural Gas (Bcf) | Oil (MMBbls) | NGL (MMBbls) | Total (Bcfe) |
| Proved developed and undeveloped reserves: | | | | |
| Beginning of year | 2,571 | 191.5 | 179.4 | 4,796 |
| Revisions of previous estimates | (17) | (21.3) | (2.0) | (157) |
| Purchases of minerals in place | 356 | 191.1 | 17.8 | 1,610 |
| Sales of minerals in place | (24) | (5.2) | (2.9) | (73) |
| Extensions, discoveries and other additions | 286 | 21.7 | 18.5 | 527 |
| Production | (162) | (12.2) | (10.8) | (300) |
| End of year | 3,010 | 365.6 | 200.0 | 6,403 |
| Proved developed reserves: | | | | |
| Beginning of year | 1,661 | 131.4 | 113.0 | 3,127 |
| End of year | 2,027 | 252.4 | 133.2 | 4,340 |
| Proved undeveloped reserves: | | | | |
| Beginning of year | 910 | 60.1 | 66.4 | 1,669 |
| End of year | 983 | 113.2 | 66.8 | 2,063 |

LINN ENERGY, LLC
SUPPLEMENTAL OIL AND NATURAL GAS DATA (Unaudited) - Continued

| | Year Ended December 31, 2012 | | | |
|---|---|---|---|---|
| | Natural Gas (Bcf) | Oil (MMBbls) | NGL (MMBbls) | Total (Bcfe) |
| Proved developed and undeveloped reserves: | | | | |
| Beginning of year | 1,675 | 189.0 | 93.5 | 3,370 |
| Revisions of previous estimates | (559) | (26.5) | (14.1) | (803) |
| Purchases of minerals in place | 1,176 | 23.1 | 75.3 | 1,766 |
| Extensions, discoveries and other additions | 407 | 16.6 | 33.7 | 709 |
| Production | (128) | (10.7) | (9.0) | (246) |
| End of year | 2,571 | 191.5 | 179.4 | 4,796 |
| Proved developed reserves: | | | | |
| Beginning of year | 998 | 124.8 | 47.8 | 2,034 |
| End of year | 1,661 | 131.4 | 113.0 | 3,127 |
| Proved undeveloped reserves: | | | | |
| Beginning of year | 677 | 64.2 | 45.7 | 1,336 |
| End of year | 910 | 60.1 | 66.4 | 1,669 |

The tables above include changes in estimated quantities of oil and NGL reserves shown in Mcf equivalents at a rate of one barrel per six Mcf.

Since the reserves were estimated in accordance with SEC regulations, 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, the Company had positive price revisions for the year ended December 31, 2014, even though there was a steep decline in commodity prices during the fourth quarter of 2014. From September 30, 2014 to December 31, 2014, NYMEX oil and natural gas prices decreased approximately 42% and 30%, respectively, to $53.27 per Bbl for oil and $2.89 per MMBtu for natural gas at December 31, 2014. For information about potential risks that could affect the Company if lower commodity prices were to continue, see Item 1A. "Risk Factors."

Proved reserves increased by approximately 901 Bcfe to approximately 7,304 Bcfe for the year ended December 31, 2014, from 6,403 Bcfe for the year ended December 31, 2013. The year ended December 31, 2014, includes approximately 318 Bcfe of negative revisions of previous estimates, due primarily to 174 Bcfe of negative revisions due to ethane rejection in the Hugoton and Green River basins, 146 Bcfe of negative revisions due to the SEC five-year development limitation on PUDs and 43 Bcfe of negative revisions due to asset performance, partially offset by 45 Bcfe of positive revisions primarily due to higher natural gas prices. During the year ended December 31, 2014, acquisitions and properties acquired in the two exchanges with Exxon Mobil Corporation increased proved reserves by approximately 2,495 Bcfe and the 2014 divestitures and properties relinquished in the two exchanges with Exxon Mobil Corporation decreased proved reserves by approximately 1,084 Bcfe. In addition, extensions and discoveries, primarily from 917 productive wells drilled during the year, contributed approximately 250 Bcfe to the increase in proved reserves.

Proved reserves increased by approximately 1,607 Bcfe to approximately 6,403 Bcfe for the year ended December 31, 2013, from 4,796 Bcfe for the year ended December 31, 2012. The year ended December 31, 2013, includes 157 Bcfe of negative revisions of previous estimates, due primarily to 100 Bcfe of negative revisions due to asset performance, 109 Bcfe of negative revisions due to the SEC five-year development limitation on PUDs, partially offset by 52 Bcfe of positive revisions primarily due to higher natural gas prices. During the year ended December 31, 2013, three acquisitions increased proved reserves by approximately 1,610 Bcfe and the sale of the Panther Operated Cleveland Properties decreased proved reserves by approximately 73 Bcfe. In addition, extensions and discoveries, primarily from 557 productive wells drilled during the year, contributed approximately 527 Bcfe to the increase in proved reserves.

Proved reserves increased by approximately 1,426 Bcfe to approximately 4,796 Bcfe for the year ended December 31, 2012, from 3,370 Bcfe for the year ended December 31, 2011. The year ended December 31, 2012, includes 803 Bcfe of negative revisions of previous estimates, due primarily to 340 Bcfe of negative revisions due to asset performance, 248 Bcfe of negative revisions due to lower natural gas prices and 215 Bcfe of negative revisions due to the SEC five-year development

LINN ENERGY, LLC
SUPPLEMENTAL OIL AND NATURAL GAS DATA (Unaudited) - Continued

limitation on PUDs. During the year ended December 31, 2012, seven acquisitions increased proved reserves by approximately 1,766 Bcfe. In addition, extensions and discoveries, primarily from 436 productive wells drilled during the year, contributed approximately 709 Bcfe to the increase in proved reserves.

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Reserves

Information with respect to the standardized measure of discounted future net cash flows relating to proved reserves is summarized below. Future cash inflows are computed by applying applicable prices relating to the Company's proved reserves to the year-end quantities of those reserves. Future production, development, site restoration and abandonment costs are derived based on current costs assuming continuation of existing economic conditions. There are no future income tax expenses because the Company is not subject to federal income taxes. Limited liability companies are subject to Texas margin tax; however, these amounts are not material. See Note 14 for additional information about income taxes.

| | December 31, 2014 (in thousands) | 2013 | 2012 |
|---|---|---|---|
| Future estimated revenues | $55,195,268 | $51,112,346 | $30,374,380 |
| Future estimated production costs | (24,100,468) | (19,306,728) | (11,460,854) |
| Future estimated development costs | (4,032,588) | (5,110,896) | (3,574,058) |
| Future net cash flows | 27,062,212 | 26,694,722 | 15,339,468 |
| 10% annual discount for estimated timing of cash flows | (14,549,921) | (14,795,393) | (9,266,487) |
| Standardized measure of discounted future net cash flows | $12,512,291 | $11,899,329 | $6,072,981 |
| | | | |
| Representative NYMEX prices: (1) | | | |
| Natural gas (MMBtu) | $4.35 | $3.67 | $2.76 |
| Oil (Bbl) | $95.27 | $96.89 | $94.64 |

(1) In accordance with SEC regulations, reserves at December 31, 2014, December 31, 2013, and December 31, 2012, 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.

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

| | Year Ended December 31, 2014 (in thousands) | 2013 | 2012 |
|---|---|---|---|
| Sales and transfers of oil, natural gas and NGL produced during the period | $(2,330,944) | $(1,433,075) | $(1,075,354) |
| Changes in estimated future development costs | 156,614 | 317,064 | 289,762 |
| Net change in sales and transfer prices and production costs related to future production | (599,121) | 203,370 | (1,463,820) |
| Purchases of minerals in place | 3,021,768 | 5,113,335 | 2,153,651 |
| Sales of minerals in place | (1,681,504) | (139,384) | — |
| Extensions, discoveries and improved recovery | 910,787 | 801,254 | 413,702 |
| Previously estimated development costs incurred during the period | 819,987 | 444,861 | 442,322 |
| Net change due to revisions in quantity estimates | (672,800) | (220,224) | (1,595,302) |
| Accretion of discount | 1,189,933 | 607,298 | 661,486 |
| Changes in production rates and other | (201,758) | 131,849 | (368,326) |
| | $612,962 | $5,826,348 | $(541,879) |

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The data presented should not be viewed as representing the expected cash flow from, or current value of, existing proved reserves since the computations are based on a large number of estimates and assumptions. The required projection of production and related expenditures over time requires further estimates with respect to pipeline availability, rates of demand and governmental control. Actual future prices and costs are likely to be substantially different from the current prices and costs utilized in the computation of reported amounts. Any analysis or evaluation of the reported amounts should give specific recognition to the computational methods utilized and the limitations inherent therein.

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LINN ENERGY, LLC
SUPPLEMENTAL QUARTERLY DATA (Unaudited)
The following discussion and analysis should be read in conjunction with the “Consolidated Financial Statements” and “Notes to Consolidated Financial Statements,” which are included in this Annual Report on Form 10-K in Item 8. “Financial Statements and Supplementary Data.”
Quarterly Financial Data

| | Quarters Ended | | | |
|---|---|---|---|---|
| | March 31 | June 30 | September 30 | December 31 |
| | (in thousands, except per unit amounts) | | | |
| 2014: | | | | |
| Oil, natural gas and natural gas liquid sales | $938,877 | $967,850 | $937,458 | $766,354 |
| Gains (losses) on oil and natural gas derivatives | (241,493) | (408,788) | 451,702 | 1,404,758 |
| Total revenues and other | 733,587 | 596,951 | 1,435,115 | 2,217,650 |
| Total expenses [(1)] | 674,568 | 664,452 | 1,320,157 | 2,533,947 |
| (Gains) losses on sale of assets and other, net | 2,586 | 5,467 | (35,803) | (338,750) |
| Net loss | (85,337) | (207,870) | (4,100) | (154,502) |
| Net loss per unit: | | | | |
| Basic | $(0.27) | $(0.64) | $(0.02) | $(0.47) |
| Diluted | $(0.27) | $(0.64) | $(0.02) | $(0.47) |

| | Quarters Ended | | | |
|---|---|---|---|---|
| | March 31 | June 30 | September 30 | December 31 |
| | (in thousands, except per unit amounts) | | | |
| 2013: | | | | |
| Oil, natural gas and natural gas liquid sales | $462,732 | $488,207 | $537,671 | $584,630 |
| Gains (losses) on oil and natural gas derivatives | (108,370) | 326,733 | (63,931) | 23,425 |
| Total revenues and other | 369,060 | 838,825 | 494,562 | 629,208 |
| Total expenses [(1)] | 478,235 | 385,540 | 420,803 | 1,292,058 |
| (Gains) losses on sale of assets and other, net | 3,172 | (959) | 827 | 10,597 |
| Net income (loss) | (221,885) | 345,157 | (30,060) | (784,549) |
| Net income (loss) per unit: | | | | |
| Basic | $(0.96) | $1.47 | $(0.13) | $(3.15) |
| Diluted | $(0.96) | $1.46 | $(0.13) | $(3.15) |

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

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## Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

None

## Item 9A. Controls and Procedures

### Evaluation of Disclosure Controls and Procedures

The Company maintains disclosure controls and procedures that are designed to ensure that information required to be disclosed in the Company's reports under the Securities Exchange Act of 1934, as amended (the "Exchange Act") is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to management, including the Company's Chief Executive Officer and Chief Financial Officer, and the Company's Audit Committee of the Board of Directors, as appropriate, to allow timely decisions regarding required disclosure. In designing and evaluating the disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and management is required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures.

The Company carried out an evaluation under the supervision and with the participation of its management, including its Chief Executive Officer and Chief Financial Officer, of the effectiveness of its disclosure controls and procedures as of the end of the period covered by this report. Based on this evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company's disclosure controls and procedures were effective as of December 31, 2014.

### Management's Annual Report on Internal Control Over Financial Reporting

See "Management's Report on Internal Control Over Financial Reporting" in Item 8. "Financial Statements and Supplementary Data."

### Changes in the Company's Internal Control Over Financial Reporting

The Company's management is also responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act. The Company's internal controls were designed to provide reasonable assurance as to the reliability of its financial reporting and the preparation and presentation of the consolidated financial statements for external purposes in accordance with accounting principles generally accepted in the U.S.

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

There were no changes in the Company's internal control over financial reporting during the fourth quarter of 2014 that materially affected, or were reasonably likely to materially affect, the Company's internal control over financial reporting.

## Item 9B. Other Information

None

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Part III

Item 10. Directors, Executive Officers and Corporate Governance

A list of the Company's executive officers and biographical information appears below under the caption "Executive Officers of the Company." Information about Company Directors may be found under the caption "Proposal One: Election of Directors" of the Proxy Statement for the Annual Meeting of Unitholders to be held on April 21, 2015 (the "2015 Proxy Statement"). That information is incorporated herein by reference.

The information in the 2015 Proxy Statement set forth under the caption "Section 16(a) Beneficial Ownership Reporting Compliance" is incorporated herein by reference.

The information required by this item regarding audit committee related matters, codes of ethics and committee charters is incorporated herein by reference to the 2015 Proxy Statement under the caption "Corporate Governance."

Executive Officers of the Company

| Name | Age | Position with the Company |
|---|---|---|
| Mark E. Ellis | 58 | Chairman, President and Chief Executive Officer |
| Kolja Rockov | 44 | Executive Vice President and Chief Financial Officer |
| Arden L. Walker, Jr. | 55 | Executive Vice President and Chief Operating Officer |
| David B. Rottino | 48 | Executive Vice President, Business Development and Chief Accounting Officer |
| Thomas E. Emmons | 46 | Senior Vice President – Corporate Services |
| Jamin B. McNeil | 49 | Senior Vice President – Houston Division Operations |
| Candice J. Wells | 40 | Vice President, General Counsel and Corporate Secretary |

Mark E. Ellis is the Chairman, President and Chief Executive Officer and has served in such capacity since December 2011. He previously served as President, Chief Executive Officer and Director from January 2010 to December 2011 and from December 2007 to January 2010, Mr. Ellis served as President and Chief Operating Officer of the Company. Mr. Ellis serves on the boards of the Independent Petroleum Association of America, National Petroleum Council, American Exploration & Production Council, Industry Board of Petroleum Engineering at Texas A&M University, Houston Museum of Natural Science and The Center for the Performing Arts at The Woodlands. In addition, he is a member of the Society of Petroleum Engineers, Chairman of the Board for The Center for Hearing and Speech and holds a position as trustee on the Texas A&M University 12th Man Foundation Board of Trustees.

Kolja Rockov is the Executive Vice President and Chief Financial Officer and has served in such capacity since joining the Company in March 2005. Mr. Rockov has more than 15 years of experience in the oil and natural gas finance industry. From October 2004 until he joined the Company in March 2005, Mr. Rockov served as a Managing Director in the Energy Group at RBC Capital Markets, where he was primarily responsible for investment banking coverage of the U.S. exploration and production sector. Mr. Rockov is the founding chairman of a philanthropic organization benefiting Texas Children's Cancer Center in Houston, which has raised more than $2 million since 2009.

Arden L. Walker, Jr. is the Executive Vice President and Chief Operating Officer and has served in such capacity since January 2011. From January 2010 to January 2011, he served as Senior Vice President and Chief Operating Officer. Mr. Walker joined the Company in February 2007 as Senior Vice President, Operations and Chief Engineer. Mr. Walker is a member of the Society of Petroleum Engineers and Independent Petroleum Association of America. He also serves on the boards of the Sam Houston Area Council of the Boy Scouts of America and Theatre Under The Stars.

David B. Rottino is the Executive Vice President, Business Development and Chief Accounting Officer and has served in such capacity since January 2014. He previously served as Senior Vice President of Finance, Business Development and Chief Accounting Officer from July 2010 to January 2014 and from June 2008 to July 2010, Mr. Rottino served as Senior Vice President and Chief Accounting Officer. Mr. Rottino is a Certified Public Accountant. He also serves on the Board of Camp for All.

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Item 10. Directors, Executive Officers and Corporate Governance - Continued

Thomas E. Emmons is the Senior Vice President – Corporate Services and has served in such capacity since January 2014. He previously served as Vice President – Corporate Services from September 2012 to January 2014 and from August 2008 to September 2012, Mr. Emmons served as Vice President, Human Resources and Environmental, Health and Safety. He also serves on the Board of the Nehemiah Center in Houston.

Jamin B. McNeil is the Senior Vice President – Houston Division Operations and has served in such capacity since January 2014. From June 2007 to January 2014, Mr. McNeil served as Vice President – Houston Division Operations. Mr. McNeil is a member of the Society of Petroleum Engineers.

Candice J. Wells is the Vice President, General Counsel and Corporate Secretary and has served in such capacity since October 2013. From March 2013 to October 2013, Ms. Wells served as Vice President, acting General Counsel and Corporate Secretary. From September 2011 to March 2013, Ms. Wells served as Vice President, Assistant General Counsel and Corporate Secretary and from August 2007 to September 2011, she served as Senior Corporate Counsel and Assistant Corporate Secretary. Ms. Wells serves on the Board of the Youth Development Center.

Item 11. Executive Compensation

Information required by this item is incorporated herein by reference to the 2015 Proxy Statement.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information required by this item is incorporated herein by reference to the 2015 Proxy Statement.

Securities Authorized for Issuance Under Equity Compensation Plans

The following summarizes information regarding the number of units that are available for issuance under all of the Company's equity compensation plans as of December 31, 2014:

| Plan Category | Number of Securities to be Issued Upon Exercise of Outstanding Unit Options, Warrants and Rights | Weighted Average Exercise Price of Outstanding Unit Options, Warrants and Rights | Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a)) |
|---|---|---|---|
| | (a) | (b) | (c) |
| Equity compensation plans approved by security holders | 5,444,417 | $31.95 | 4,679,783 |
| Equity compensation plans not approved by security holders | — | — | — |
| | 5,444,417 | $31.95 | 4,679,783 |

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

Information required by this item is incorporated herein by reference to the 2015 Proxy Statement.

Item 14. Principal Accounting Fees and Services

Information required by this item is incorporated herein by reference to the 2015 Proxy Statement.

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## Part IV

### Item 15. Exhibits and Financial Statement Schedules

(a) - 1. Financial Statements:

All financial statements are omitted for the reason that they are not required or the information is otherwise supplied in Item 8. “Financial Statements and Supplementary Data” in this Annual Report on Form 10-K.

(a) - 2. Financial Statement Schedules:

All schedules are omitted for the reason that they are not required or the information is otherwise supplied in Item 8. “Financial Statements and Supplementary Data” in this Annual Report on Form 10-K.

(a) - 3. Exhibits:

The exhibits required to be filed by this Item 15 are set forth in the “Index to Exhibits” accompanying this report.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

LINN ENERGY, LLC

| | | |
|---|---|---|
| Date: February 19, 2015 | By: | /s/ Mark E. Ellis<br>Mark E. Ellis<br>Chairman, President and Chief Executive Officer |
| Date: February 19, 2015 | By: | /s/ David B. Rottino<br>David B. Rottino<br>Executive Vice President, Business Development and Chief Accounting Officer |

Pursuant to the requirements of the Securities Exchange Act of 1934, this Annual Report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

| Signature | Title | Date |
|---|---|---|
| /s/ Mark E. Ellis<br>Mark E. Ellis | Chairman, President and Chief Executive Officer<br>(Principal Executive Officer) | February 19, 2015 |
| /s/ Kolja Rockov<br>Kolja Rockov | Executive Vice President and Chief Financial Officer<br>(Principal Financial Officer) | February 19, 2015 |
| /s/ David B. Rottino<br>David B. Rottino | Executive Vice President, Business Development and Chief Accounting Officer<br>(Principal Accounting Officer) | February 19, 2015 |
| /s/ Michael C. Linn<br>Michael C. Linn | Founder and Director | February 19, 2015 |
| /s/ David D. Dunlap<br>David D. Dunlap | Independent Director | February 19, 2015 |
| /s/ Stephen J. Hadden<br>Stephen J. Hadden | Independent Director | February 19, 2015 |
| /s/ Joseph P. McCoy<br>Joseph P. McCoy | Independent Director | February 19, 2015 |
| /s/ Jeffrey C. Swoveland<br>Jeffrey C. Swoveland | Independent Director | February 19, 2015 |

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Index to Exhibits

| Exhibit Number | | Description |
|---|---|---|
| 2.1 | — | Exchange Agreement by and among Linn Energy Holdings, LLC, Berry Petroleum Company, LLC, XTO Energy Inc., ExxonMobil Oil Corporation, Mobil E&P U.S. Development Corporation and Exxon Mobil Corporation, dated as of May 20, 2014 (incorporated herein by reference to Exhibit 2.5 to Amendment No. 2 to Registration Statement on Form S-4 (File No. 333-187458) filed on May 28, 2014) |
| 2.2 | — | First Amendment to Exchange Agreement by and among Linn Energy Holdings, LLC, Berry Petroleum Company, LLC, XTO Energy Inc., ExxonMobil Oil Corporation, Mobil E&P U.S. Development Corporation and Exxon Mobil Corporation, dated as of May 22, 2014 (incorporated herein by reference to Exhibit 2.6 to Amendment No. 2 to Registration Statement on Form S-4 (File No. 333-187458) filed on May 28, 2014) |
| 2.3 | — | Purchase and Sale Agreement by and between Devon Energy Production, L.P. and Devon Uinta Basin Corporation, as seller, and Linn Energy Holdings, LLC as buyer, executed as of June 27, 2014 (incorporated herein by reference to Exhibit 2.3 to Quarterly Report on Form 10-Q filed on August 7, 2014) |
| 2.4 | — | Exchange Agreement by and among Linn Energy Holdings, LLC, Berry Petroleum Company, LLC and Exxon Mobil Corporation, dated as of September 18, 2014 (incorporated herein by reference to Exhibit 2.1 to Quarterly Report on Form 10-Q filed on November 4, 2014) |
| 2.5 | — | Purchase and Sale Agreement by and between Linn Energy Holdings, LLC, Linn Operating, Inc., Linn Exploration Mid-Continent, LLC, Mid-Continent II, LLC and Linn Midstream, LLC as Seller, and EnerVest Energy Institutional Fund XIII-A, L.P., EnerVest Energy Institutional Fund XIII-WIB, L.P., EnerVest Energy Institutional Fund XIII-WIC, L.P., and FourPoint Energy, LLC as Buyer, executed on October 2, 2014 (incorporated herein by reference to Exhibit 2.2 to Quarterly Report on Form 10-Q filed on November 4, 2014) |
| 2.6 | — | Contribution Agreement, dated February 20, 2013, by and between LinnCo, LLC and Linn Energy LLC, as amended by Amendment No. 1 to Contribution Agreement, dated as of November 3, 2013 (incorporated herein by reference to Exhibit 2.2 to Amendment No. 7 to Registration Statement on Form S-4 (File No. 333-187484-01) filed on November 6, 2013) |
| 3.1 | — | Certificate of Formation of Linn Energy Holdings, LLC (now Linn Energy, LLC) (incorporated herein by reference to Exhibit 3.1 to Registration Statement on Form S-1 (File No. 333-125501) filed by Linn Energy, LLC on June 3, 2005) |
| 3.2 | — | Certificate of Amendment to Certificate of Formation of Linn Energy Holdings, LLC (now Linn Energy, LLC) (incorporated herein by reference to Exhibit 3.2 to Registration Statement on Form S-1 (File No. 333-125501) filed by Linn Energy, LLC on June 3, 2005) |
| 3.3 | — | Third Amended and Restated Limited Liability Company Agreement of Linn Energy, LLC dated as of September 3, 2010, (incorporated herein by reference to Exhibit 3.1 to Current Report on Form 8-K, filed on September 7, 2010) |
| 3.4 | — | Amendment No. 1, dated April 23, 2013, to Third Amended and Restated LLC Agreement of Linn Energy, LLC, dated September 3, 2010 (incorporated herein by reference to Exhibit 3.1 to Quarterly Report on Form 10-Q filed on April 25, 2013) |
| 4.1 | — | Form of specimen unit certificate for the units of Linn Energy, LLC (incorporated herein by reference to Exhibit 4.1 to Annual Report on Form 10-K for the year ended December 31, 2005, filed on May 31, 2006) |
| 4.2 | — | Indenture, dated as of April 6, 2010, among Linn Energy, LLC, Linn Energy Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as Trustee (incorporated herein by reference to Exhibit 4.1 to Current Report on Form 8-K filed on April 9, 2010) |
| 4.3 | — | |

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| | | Indenture, dated as of September 13, 2010, among Linn Energy, LLC, Linn Energy Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as Trustee (incorporated herein by reference to Exhibit 4.1 to Current Report on Form 8-K filed on September 13, 2010) |
| 4.4 | — | Indenture, dated as of May 13, 2011, among Linn Energy, LLC, Linn Energy Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as Trustee (incorporated herein by reference to Exhibit 4.1 to Current Report on Form 8-K filed on May 16, 2011) |

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Index to Exhibits - Continued

| Exhibit Number | | Description |
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| 4.5 | — | Indenture, dated as of March 2, 2012, among Linn Energy, LLC, Linn Energy Finance Corp., the Subsidiary Guarantors named therein and U. S. Bank National Association, as Trustee (incorporated herein by reference to Exhibit 4.1 to Current Report on Form 8-K filed on March 2, 2012) |
| 4.6 | — | First Supplemental Indenture, dated as of July 2, 2010, to Indenture, dated as of April 6, 2010, between Linn Energy, LLC, Linn Energy Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as Trustee (incorporated herein by reference to Exhibit 4.3 to Quarterly Report on Form 10-Q filed on July 29, 2010) |
| 4.7 | — | First Supplemental Indenture relating to 6.500% senior notes due 2019, dated September 9, 2014, among Linn Energy, LLC, Linn Energy Finance Corp., the Subsidiary Guarantors named therein and U. S. Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.1 to Current Report on Form 8-K filed on September 9, 2014) |
| 4.8 | — | Senior Indenture, dated September 9, 2014, among Linn Energy, LLC, Linn Energy Finance Corp., the Subsidiary Guarantors named therein and U. S. Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.2 to Current Report on Form 8-K filed on September 9, 2014) |
| 4.9 | — | First Supplemental Indenture relating to 6.500% senior notes due 2021, dated September 9, 2014, among Linn Energy, LLC, Linn Energy Finance Corp., the Subsidiary Guarantors named therein and U. S. Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.3 to Current Report on Form 8-K filed on September 9, 2014) |
| 4.10 | — | Indenture, dated June 15, 2006, between Berry Petroleum Company and Wells Fargo Bank, National Association, as trustee, relating to senior debt securities (incorporated by reference to Exhibit 4.1 to Berry Petroleum Company's Current Report on Form 8-K filed on May 29, 2009) |
| 4.11 | — | Second Supplemental Indenture, dated November 1, 2010, between Berry Petroleum Company and Wells Fargo Bank, National Association, as trustee, including the form of 6.75% senior note due 2020 (incorporated by reference to Exhibit 4.2 to Berry Petroleum Company's Current Report on Form 8-K filed on November 1, 2010) |
| 4.12 | — | Third Supplemental Indenture, dated March 9, 2012, between Berry Petroleum Company and Wells Fargo Bank, National Association, as trustee, including the form of 6.375% senior note due 2022 (incorporated by reference to Exhibit 4.2 to Berry Petroleum Company's Current Report on Form 8-K filed on March 9, 2012) |
| 10.1* | — | Linn Energy, LLC Amended and Restated Long-Term Incentive Plan (incorporated herein by reference to Annex D to the Joint Proxy Statement/Prospectus for 2013 Annual Meeting, filed on November 14, 2013) |
| 10.2* | — | Form of Executive Unit Option Agreement pursuant to the Linn Energy, LLC Amended and Restated Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.3 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009) |
| 10.3* | — | Form of Executive Restricted Unit Agreement pursuant to the Linn Energy, LLC Amended and Restated Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.4 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009) |
| 10.4* | — | Form of Phantom Unit Grant Agreement for Independent Directors pursuant to the Linn Energy, LLC Amended and Restated Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.1 to Current Report on Form 8-K filed on August 9, 2006) |
| 10.5* | — | Form of Director Restricted Unit Grant Agreement pursuant to the Linn Energy, LLC Amended and Restated Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.6 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009) |

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| 10.6* | — | Form of Non-Executive Phantom Unit Agreement pursuant to the Linn Energy, LLC Amended and Restated Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.8 to Annual Report on Form 10-K for the year ended December 31, 2012, filed on February 21, 2013) |
| 10.7* | — | Form of Performance Unit Award Agreement pursuant to the Linn Energy, LLC Amended and Restated Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.7 to Annual Report on Form 10-K for the year ended December 31, 2013, filed on February 27, 2014) |

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Index to Exhibits - Continued

| Exhibit Number | | Description |
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| 10.8* | — | Retirement Agreement, dated as of November 29, 2011, by and among Linn Operating, Inc., Linn Energy, LLC and Michael C. Linn (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed on December 1, 2011) |
| 10.9* | — | Third Amended and Restated Employment Agreement, dated effective as of December 17, 2008, between Linn Operating, Inc. and Kolja Rockov (incorporated herein by reference to Exhibit 10.8 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009) |
| 10.10* | — | Amended and Restated Employment Agreement, dated effective as of December 17, 2008, between Linn Operating, Inc. and Mark E. Ellis (incorporated herein by reference to Exhibit 10.9 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009) |
| 10.11* | — | Amendment No. 1, dated effective as of January 1, 2010, to Amended and Restated Employment Agreement, dated effective as of December 17, 2008, between Linn Operating, Inc. and Mark E. Ellis (incorporated herein by reference to Exhibit 10.29 to Annual Report on Form 10-K for the year ended December 31, 2009, filed on February 25, 2010) |
| 10.12* | — | Amended and Restated Employment Agreement, dated effective December 17, 2008, between Linn Operating, Inc. and Arden L. Walker, Jr. (incorporated herein by reference to Exhibit 10.11 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009) |
| 10.13* | — | Amendment No. 1, dated April 26, 2011, to First Amended and Restated Employment Agreement, dated December 17, 2008, between Linn Operating, Inc. and Arden L. Walker, Jr. (incorporated herein by reference to Quarterly Report on Form 10-Q filed on April 28, 2011) |
| 10.14* | — | Second Amended and Restated Employment Agreement, dated December 17, 2008, between Linn Operating, Inc. and David B. Rottino (incorporated herein by reference to Exhibit 10.12 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009) |
| 10.15* | — | Indemnity Agreement, dated as of February 4, 2009, between Linn Energy, LLC and George A. Alcorn (incorporated herein by reference to Exhibit 10.15 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009) |
| 10.16* | — | Indemnity Agreement, dated as of February 4, 2009, between Linn Energy, LLC and Joseph P. McCoy (incorporated herein by reference to Exhibit 10.16 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009) |
| 10.17* | — | Indemnity Agreement, dated as of February 4, 2009, between Linn Energy, LLC and Terrence S. Jacobs (incorporated herein by reference to Exhibit 10.17 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009) |
| 10.18* | — | Indemnity Agreement, dated as of February 4, 2009, between Linn Energy, LLC and Jeffrey C. Swoveland (incorporated herein by reference to Exhibit 10.18 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009) |
| 10.19* | — | Indemnity Agreement, dated as of February 4, 2009, between Linn Energy, LLC and Michael C. Linn (incorporated herein by reference to Exhibit 10.19 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009) |
| 10.20* | — | Indemnity Agreement, dated as of February 4, 2009, between Linn Energy, LLC and Mark E. Ellis (incorporated herein by reference to Exhibit 10.20 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009) |
| 10.21* | — | Indemnity Agreement, dated as of February 4, 2009, between Linn Energy, LLC and Kolja Rockov (incorporated herein by reference to Exhibit 10.21 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009) |

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| 10.22* | — | Indemnity Agreement, dated as of February 4, 2009, between Linn Energy, LLC and David B. Rottino (incorporated herein by reference to Exhibit 10.23 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009) |
| 10.23* | — | Indemnity Agreement, dated as of February 4, 2009, between Linn Energy, LLC and Arden L. Walker, Jr. (incorporated herein by reference to Exhibit 10.24 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009) |
| 10.24* | — | Indemnity Agreement, dated as of July 10, 2012, between Linn Energy, LLC and David D. Dunlap (incorporated herein by reference to Exhibit 10.28 to Annual Report on Form 10-K for the year ended December 31, 2012, filed on February 21, 2013) |

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Index to Exhibits - Continued

| Exhibit Number | | Description |
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| 10.25* | — | Indemnity Agreement, dated as of February 4, 2013, between Linn Energy, LLC and Linda M. Stephens (incorporated herein by reference to Exhibit 10.29 to Annual Report on Form 10-K for the year ended December 31, 2012, filed on February 21, 2013) |
| 10.26* | — | Amended and Restated Indemnity Agreement, dated as of January 16, 2014, between Linn Energy, LLC, LinnCo, LLC and Stephen J. Hadden (incorporated herein by reference to Exhibit 10.26 to Annual Report on Form 10-K for the year ended December 31, 2013, filed on February 27, 2014) |
| 10.27 | — | Sixth Amended and Restated Credit Agreement dated as of April 24, 2013, among Linn Energy, LLC as Borrower, Wells Fargo Bank, National Association as Administrative Agent, and the Lenders and agents party thereto (incorporated herein by reference to Exhibit 10.1 to Quarterly Report on Form 10-Q filed on April 25, 2013) |
| 10.28 | — | First Amendment to Sixth Amended and Restated Credit Agreement, dated October 30, 2013, among Linn Energy, LLC as Borrower, Wells Fargo Bank, National Association as Administrative Agent, and the Lenders and agents party thereto (incorporated herein by reference to Exhibit 10.28 to Annual Report on Form 10-K for the year ended December 31, 2013, filed on February 27, 2014) |
| 10.29 | — | Second Amendment to Sixth Amended and Restated Credit Agreement, dated December 13, 2013, among Linn Energy, LLC as Borrower, Wells Fargo Bank, National Association as Administrative Agent, and the Lenders and agents party thereto (incorporated herein by reference to Exhibit 10.29 to Annual Report on Form 10-K for the year ended December 31, 2013, filed on February 27, 2014) |
| 10.30 | — | Third Amendment to Sixth Amended and Restated Credit Agreement, dated April 30, 2014, among Linn Energy, LLC as Borrower, Wells Fargo Bank, National Association as Administrative Agent, and the Lenders and agents party thereto (incorporated by reference to Exhibit 10.2 to Quarterly Report on Form 10-Q filed on May 1, 2014) |
| 10.31 | — | Fourth Amendment to Sixth Amended and Restated Credit Agreement, dated as of August 6, 2014, among Linn Energy, LLC as Borrower, Wells Fargo Bank, National Association as Administrative Agent, and the Lenders and agents party thereto (incorporated by reference to Exhibit 10.1 to Quarterly Report on Form 10-Q filed on November 4, 2014) |
| 10.32 | — | Fifth Amendment to Sixth Amended and Restated Credit Agreement, dated as of September 10, 2014, among Linn Energy, LLC as Borrower, Wells Fargo Bank, National Association as Administrative Agent, and the Lenders and agents party thereto (incorporated by reference to Exhibit 10.2 to Quarterly Report on Form 10-Q filed on November 4, 2014) |
| 10.33 | — | Second Amended and Restated Credit Agreement, dated November 15, 2010, by and among Berry Petroleum Company, Wells Fargo Bank, N.A., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 99.1 to Berry Petroleum Company’s Current Report on Form 8-K filed on November 17, 2010). |
| 10.34 | — | First Amendment to Second Amended and Restated Credit Agreement, dated April 13, 2011, by and among Berry Petroleum Company, Wells Fargo Bank, N.A., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 4.1 to Berry Petroleum Company’s Current Report on Form 8-K filed on April 13, 2011) |
| 10.35 | — | Second Amendment to Second Amended and Restated Credit Agreement, dated June 17, 2011, by and among Berry Petroleum Company, Wells Fargo Bank, N.A., as administrative agent, and the lenders party thereto. (incorporated by reference to Exhibit 4.1 to Berry Petroleum Company’s Quarterly Report on Form 10-Q filed on November 3, 2011) |
| 10.36 | — | Third Amendment to Second Amended and Restated Credit Agreement, dated October 26, 2011, by and among Berry Petroleum Company, Wells Fargo Bank, N.A. and the other lenders |

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| | | party thereto (incorporated by reference to Exhibit 4.1 to Berry Petroleum Company's Current Report on Form 8-K filed on October 27, 2011) |
| 10.37 | — | Fourth Amendment to Second Amended and Restated Credit Agreement dated April 13, 2012 by and among the Registrant and Wells Fargo Bank, N.A. and other lenders (incorporated by reference to Exhibit 4.1 to Berry Petroleum Company's Current Report on Form 8-K filed on April 17, 2012) |
| 10.38 | — | Fifth Amendment to Second Amended and Restated Credit Agreement, dated May 21, 2012, by and among Berry Petroleum Company, Wells Fargo Bank, N.A., as administrative agent, and the lenders party thereto (incorporated herein by reference to Exhibit 10.1 to Berry Petroleum Company's Quarterly Report on Form 10-Q filed on October 24, 2013) |

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| Exhibit Number | | Description |
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| 10.39 | — | Sixth Amendment to Second Amended and Restated Credit Agreement, dated October 22, 2013, by and among Berry Petroleum Company, Wells Fargo Bank, N.A., as administrative agent, and the lenders party thereto (incorporated herein by reference to Exhibit 10.2 to Berry Petroleum Company's Quarterly Report on Form 10-Q filed on October 24, 2013) |
| 10.40 | — | Seventh Amendment to Second Amended and Restated Credit Agreement of Berry Petroleum Company, LLC, dated December 16, 2013, among Berry Petroleum Company, LLC as Borrower, Wells Fargo Bank, National Association as Administrative Agent, and the Lenders and agents party thereto (incorporated herein by reference to Exhibit 10.37 to Annual Report on Form 10-K for the year ended December 31, 2013, filed on February 27, 2014) |
| 10.41 | — | Eighth Amendment to Second Amended and Restated Credit Agreement of Berry Petroleum Company, LLC, dated February 21, 2014, among Berry Petroleum Company, LLC as Borrower, Wells Fargo Bank, National Association as Administrative Agent, and the Lenders and agents party thereto (incorporated herein by reference to Exhibit 10.38 to Annual Report on Form 10-K for the year ended December 31, 2013, filed on February 27, 2014) |
| 10.42 | — | Ninth Amendment to Second Amended and Restated Credit Agreement of Berry Petroleum Company, LLC, dated April 30, 2014, among Berry Petroleum Company, LLC as Borrower, Wells Fargo Bank, National Association as Administrative Agent, and the Lenders and agents party thereto (incorporated herein by reference to Exhibit 10.4 to Quarterly Report on Form 10-Q filed on May 1, 2014) |
| 10.43 | — | Fifth Amended and Restated Guaranty and Pledge Agreement, dated as of May 2, 2011, made by Linn Energy, LLC and each of the other Obligors in favor of BNP Paribas, as Administrative Agent (incorporated herein by reference to Exhibit 10.1 to Quarterly Report on Form 10-Q filed on July 28, 2011) |
| 10.44 | — | Bridge Loan Agreement, dated August 29, 2014, by and among Linn Energy, LLC, certain subsidiary guarantors party thereto, each of the other lenders party thereto and The Bank of Nova Scotia, as administrative agent (incorporated herein by reference to Exhibit 10.1 to Post-Effective Amendment No. 1 to Registration Statement on Form S-3 (File No. 333-184647) filed by Linn Energy, LLC on September 4, 2014) |
| 10.45 | — | Term Loan Agreement, dated August 29, 2014, by and among Linn Exchange Properties, LLC, each of the other lenders party thereto, and The Bank of Nova Scotia, as administrative agent (incorporated herein by reference to Exhibit 10.2 to Post-Effective Amendment No. 1 to Registration Statement on Form S-3 (File No. 333-184647) filed by Linn Energy, LLC on September 4, 2014) |
| 10.46 | — | Linn Energy, LLC Change of Control Protection Plan, dated as of April 25, 2009, (incorporated herein by reference to Exhibit 10.3 to Quarterly Report on Form 10-Q filed on May 7, 2009) |
| 12.1** | — | Computation of Ratio of Earnings to Fixed Charges |
| 21.1** | — | Significant Subsidiaries of Linn Energy, LLC |
| 23.1** | — | Consent of KPMG LLP |
| 23.2** | — | Consent of DeGolyer and MacNaughton |
| 31.1** | — | Section 302 Certification of Mark E. Ellis, Chairman, President and Chief Executive Officer of Linn Energy, LLC |
| 31.2** | — | Section 302 Certification of Kolja Rockov, Executive Vice President and Chief Financial Officer of Linn Energy, LLC |
| 32.1** | — | Section 906 Certification of Mark E. Ellis, Chairman, President and Chief Executive Officer of Linn Energy, LLC |
| 32.2** | — | Section 906 Certification of Kolja Rockov, Executive Vice President and Chief Financial Officer of Linn Energy, LLC |

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| 99.1** | — | 2014 Report of DeGolyer and MacNaughton |
| 101.INS† | — | XBRL Instance Document |
| 101.SCH† | — | XBRL Taxonomy Extension Schema Document |
| 101.CAL† | — | XBRL Taxonomy Extension Calculation Linkbase Document |
| 101.DEF† | — | XBRL Taxonomy Extension Definition Linkbase Document |

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Index to Exhibits - Continued

| Exhibit Number | | Description |
|---|---|---|
| 101.LAB† | — | XBRL Taxonomy Extension Label Linkbase Document |
| 101.PRE† | — | XBRL Taxonomy Extension Presentation Linkbase Document |

* Management Contract or Compensatory Plan or Arrangement required to be filed as an exhibit hereto pursuant to Item 601 of Regulation S-K.
** Filed herewith.
† Furnished herewith.