LINN ENERGY, LLC
Form 10-K
February 27, 2014

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, 2013

¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission file number: 000-51719

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

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

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

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

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

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

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the 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 $6.6 billion on June 30, 2013, based on $33.18 per unit, the last reported sales price of the units on the NASDAQ Global Select Market on such date.

As of January 31, 2014, there were 331,287,217 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 22, 2014.

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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 (“U.S.”) 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 mainly of a certain type of rock or combination of rock types with thickness that may range from less than two feet to hundreds of feet.
Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.
MBbls. One thousand barrels of oil or other liquid hydrocarbons.
MBbls/d. MBbls per day.
Mcf. One thousand cubic feet.
Mcfe. One thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of oil, condensate or natural gas liquids.
MMBbls. One million barrels of oil or other liquid hydrocarbons.
MMBoe. One million barrels of oil equivalent, determined using a ratio of one Bbl of oil, condensate or natural gas liquids to six Mcf.
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.

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Glossary of Terms - Continued

MMcfe/d. MMcfe per day.
MMMBtu. One billion British thermal units.
Net acres or net wells. The sum of the fractional working interests owned in gross acres or gross wells, as the case may be.
NGL. Natural gas liquids, which are the hydrocarbon liquids contained within natural gas.
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 (“SEC”), 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%.

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Glossary of Terms - Continued

Tcfe. One trillion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of oil, condensate or natural gas liquids.
Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil, natural gas and NGL regardless of whether such acreage contains proved reserves.
Unproved reserves. Reserves that are considered less certain to be recovered than proved reserves. Unproved reserves may be further sub-classified to denote progressively increasing uncertainty of recoverability and include probable reserves and possible reserves.
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 “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 Mid-Continent, the Hugoton Basin, California, the Permian Basin, Michigan, Illinois and east Texas.

Proved reserves at December 31, 2013, were approximately 6,403 Bcfe, of which approximately 34% were oil, 47% were natural gas and 19% were natural gas liquids (“NGL”). Approximately 68% were classified as proved developed, with a total standardized measure of discounted future net cash flows of approximately $11.9 billion. At December 31, 2013, the Company operated 14,594 or 74% of its 19,810 gross productive wells and had an average proved reserve-life index of approximately 16 years, based on the December 31, 2013, reserve reports and fourth quarter 2013 annualized production, including full fourth quarter 2013 Berry Petroleum Company (“Berry”) 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, 2009, the Company has completed 35 acquisitions of working and royalty interests in oil and natural gas properties and related gathering and pipeline assets. Total acquired proved reserves at the date of acquisition were approximately 4.7 Tcfe with acquisition costs of approximately $1.97 per Mcfe. Estimates of proved reserves at the date of acquisition were primarily prepared by the independent engineering firm, DeGolyer and MacNaughton. The Company finances acquisitions with equity or a combination of funds from equity and debt offerings, bank borrowings and net cash provided by operating activities. See Note 2 for additional details about the Company’s acquisitions.

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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 that 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 2014, the Company estimates its total capital expenditures, excluding acquisitions, will be approximately $1.6 billion, including approximately $1.55 billion related to its oil and natural gas capital program and approximately $35 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 and bank borrowings.

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. 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. 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.

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.

As part of the 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.

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.

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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
Acquisitions
On December 16, 2013, the Company completed the previously-announced 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 has a preliminary value of 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.
The consolidated financial statements and financial and operational results of the Company reflect the combined entities since the acquisition date. The Company plans to file the stand-alone financial statements of Berry with the Securities and Exchange Commission ("SEC") at a later date.
Berry's principal reserves and producing properties are located in California (San Joaquin Valley Basin and Los Angeles Basin), Texas (Permian Basin and east Texas), Utah (Uinta Basin) and Colorado (Piceance Basin). The acquisition included approximately 1,408 Bcfe of proved reserves as of the acquisition date. At December 31, 2013, Berry had approximately 3,400 gross productive wells and more than 200,000 net acres.
On October 31, 2013, the Company completed the acquisition of certain oil and natural gas properties located in the Permian Basin for total consideration of approximately $528 million. The acquisition included approximately 175 Bcfe of proved reserves as of the acquisition date.
During 2013, 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 $40 million in total consideration for these properties.
Proved reserves as of the acquisition date for all of the above referenced acquisitions were estimated using the average oil and natural gas prices during the preceding 12-month period, determined as an unweighted average of the first-day-of-the-month prices for each month. Estimates of proved reserves as of the acquisition date for all of the above referenced acquisitions as well as estimates of proved reserves at December 31, 2013, were prepared by the independent engineering firm, DeGolyer and MacNaughton.
The Company regularly engages in discussions with potential sellers regarding acquisition opportunities. Such acquisition efforts may involve its participation in auction processes, as well as situations in which the Company believes it is the only party or one of a very limited number of potential buyers in negotiations with the potential seller. These acquisition efforts can involve assets that, if acquired, would have a material effect on the Company's financial condition and results of operations.
Divestiture
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. Proceeds received for the Company's portion of its interests in the 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, as defined below.
Distributions
On January 2, 2014, the Company's Board of Directors declared a cash distribution of $0.725 per unit with respect to the fourth quarter of 2013, to be paid in three equal monthly installments of $0.2416 per unit. The first monthly distribution with respect to the fourth quarter of 2013, totaling approximately $80 million, was paid on January 16,

2014, to unitholders of

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record as of the close of business on January 13, 2014, and the second monthly distribution, totaling approximately $80 million, was paid on February 13, 2014, to unitholders of record as of the close of business on February 10, 2014.

Operating Regions

The Company's properties, including those acquired in the Berry acquisition, are located in seven operating regions in the U.S.:

- Rockies, which includes properties located in Wyoming (Green River Basin and Powder River Basin), Utah (Uinta Basin), North Dakota (Williston Basin) and Colorado (Piceance Basin);
- Mid-Continent, which includes properties in Oklahoma, Louisiana and the eastern portion of the Texas Panhandle (including the Granite Wash and Cleveland horizontal plays);
- Hugoton Basin, which includes properties located primarily in Kansas and the Shallow Texas Panhandle;
- California, which includes the San Joaquin Valley Basin and the Los Angeles Basin;
- Permian Basin, which includes areas in west Texas and southeast New Mexico;
- Michigan/Illinois, which includes the Antrim Shale formation in the northern part of Michigan and oil properties in southern Illinois; and
- East Texas, which includes properties located in east Texas.

Rockies

The Rockies region consists of properties located in Wyoming (Green River Basin and Powder River Basin), northeastern Utah (Uinta Basin), North Dakota (Bakken and Three Forks formations in the Williston Basin) and northwestern Colorado (Piceance Basin). Properties located in the Uinta and Piceance basins were acquired in the Berry acquisition. Wells in this diverse region produce from both oil and natural gas reservoirs at depths ranging from 1,000 feet to over 13,000 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 13,500 feet. The Company's properties in the Powder River Basin consist of a CO2 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 7,500 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.

Rockies proved reserves represented approximately 28% of total proved reserves at December 31, 2013, of which 46% were classified as proved developed. This region produced 187 MMcfe/d or 23% of the Company's 2013 average daily production. During 2013, the Company invested approximately $306 million to drill in this region. During 2014, the Company anticipates spending approximately 38% of its total oil and natural gas capital budget for development activities in the Rockies region.

Mid-Continent

The Mid-Continent region includes properties located in Oklahoma, Louisiana and the eastern portion of the Texas Panhandle (including the Granite Wash and Cleveland horizontal plays). Wells in this diverse region produce from both oil and natural gas reservoirs at depths ranging from 1,500 feet to over 18,000 feet. The Granite Wash formation and other shallower producing horizons are currently being developed using horizontal drilling and multi-stage stimulations. In the northern Texas Panhandle and extending into western Oklahoma, the Cleveland formation is being developed as a horizontal oil play. Elsewhere in Oklahoma, several producing formations are being targeted using similar horizontal drilling and completion technologies. The majority of wells in this region are mature, low-decline oil and natural gas wells.

Mid-Continent proved reserves represented approximately 20% of total proved reserves at December 31, 2013, of which 77% were classified as proved developed. This region produced 330 MMcfe/d or 40% of the Company's 2013 average daily production. During 2013, the Company invested approximately $439 million to drill in this region. During 2014, the Company anticipates spending approximately 16% of its total oil and natural gas capital budget for development activities in the Mid-Continent region.

To more efficiently transport its natural gas in the Mid-Continent region to market, the Company owns and operates a network of natural gas gathering systems comprised of approximately 325 miles of pipeline and associated compression and metering facilities. In connection with the horizontal development activities in the Granite Wash formation, the Company continues to expand this gathering system which connects to numerous natural gas processing facilities in the region.

Hugoton Basin

The Hugoton Basin is a large oil and natural gas producing area located in the central portion of the Texas Panhandle extending into southwestern Kansas. The Company's Texas properties in the basin primarily produce from the Brown Dolomite formation at depths of approximately 3,200 feet and its Kansas properties primarily produce from the Council Grove and Chase formations at depths ranging from 2,500 feet to 3,000 feet. Hugoton Basin proved reserves represented approximately 18% of total proved reserves at December 31, 2013, of which 82% were classified as proved developed. This region produced 143 MMcfe/d or 17% of the Company's 2013 average daily production. During 2013, the Company invested approximately $35 million to drill in this region. During 2014, the Company anticipates spending approximately 3% of its total oil and natural gas capital budget for development activities in the Hugoton Basin region.

To more efficiently transport its natural gas in the Texas Panhandle to market, the Company owns and operates a network of natural gas gathering systems comprised of approximately 665 miles of pipeline and associated compression and metering facilities that connect to numerous sales outlets in the area. The Company also owns and operates the Jayhawk natural gas processing plant in southwestern Kansas with a capacity of approximately 450 MMcfe/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 plant via a system of approximately 2,100 miles of pipeline and related facilities operated by the Company, of which approximately 250 miles of pipeline are owned by the Company.

California

The California region consists of the Midway-Sunset Field, Diatomite, McKittrick and Poso Creek properties in the San Joaquin Valley Basin and the Brea Olinda Field and Placerita Field in the Los Angeles Basin. 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 properties in the Midway-Sunset Field, Diatomite, McKittrick, Placerita Field and Poso Creek were acquired in the Berry acquisition and produce using thermal enhanced oil recovery methods at depths ranging from 800 feet to 2,000 feet. California proved reserves represented approximately 14% of total proved reserves at December 31, 2013, of which 80% were classified as proved developed. This region produced 19 MMcfe/d or 2% of the Company's 2013 average daily production. During 2013, the Company invested approximately $33 million to drill in this region. During 2014, the Company anticipates spending approximately 16% of its total oil and natural gas capital budget for development activities in the California region.

Permian Basin

The Permian Basin is one of the largest and most prolific oil and natural gas basins in the U.S. 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. The Wolfberry trend is located in the north central portion of the basin where the Company has been actively drilling vertical oil wells since 2010. The Company also produces oil and natural gas from mature, low-decline wells including several waterflood properties located across the basin. Certain of the properties located in Texas were acquired in the Berry acquisition. Permian Basin proved reserves represented approximately 13% of total proved reserves at December 31, 2013, of which 51% were classified as proved developed. Recent industry activity has begun focusing on Wolfcamp horizontal drilling in the vicinity of the Company's properties. The Company had no proved reserves booked for Wolfcamp horizontal wells at December 31, 2013. This region produced 87 MMcfe/d or 11% of the Company's 2013 average daily production. During 2013, the Company invested approximately $218 million to drill in this region. During 2014, the Company anticipates spending approximately 25% of its total oil and natural gas capital budget for development activities in the Permian Basin region, primarily in the Wolfberry trend.

Michigan/Illinois

The Michigan/Illinois region includes properties producing from the Antrim Shale formation in the northern part of Michigan and oil properties in southern 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, 2013, of which 97% were classified as proved developed. This region produced 34 MMcfe/d or 4% of the Company’s 2013 average daily production. During 2014, 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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East Texas

The East Texas region consists of properties located in east Texas and primarily produces natural gas from the Cotton Valley formation and the Haynesville/Bossier Shale at depths ranging from 7,000 to 13,500 feet. Certain of the properties located in the Cotton Valley formation and all of the Haynesville/Bossier Shale properties were acquired in the Berry acquisition. Proved reserves for these mature, low-decline producing properties, all of which are proved developed, represented approximately 3% of total proved reserves at December 31, 2013. This region produced 22 MMcfe/d or 3% of the Company's 2013 average daily production. During 2014, the Company anticipates spending approximately 1% of its total oil and natural gas capital budget for development activities in the East 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,		
	2013	2012	2011
Gross wells:			
Productive	557	436	292
Dry	2	4	2
	559	440	294
Net development wells:			
Productive	304	223	186
Dry	1	2	2
	305	225	188
Net exploratory wells:			
Productive	1	—	—
Dry	—	—	—
	1	—	—

There were no lateral segments added to existing vertical wellbores during the years ended December 31, 2013, December 31, 2012, or December 31, 2011. At December 31, 2013, the Company had 188 gross (90 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, 2013:

	Total [(1)]
Proved undeveloped	3,154
Other locations	10,273
Total drilling locations	13,427
Leasehold interests – net acres (in thousands)	2,028

(1) Does not include optimization projects.

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As shown in the table above, as of December 31, 2013, the Company had 3,154 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 10,273 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, 2013. 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 an 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 2,500 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)]	7,384	6,280	7,210	6,833	14,594	13,113
Nonoperated [(2)]	2,079	531	3,137	424	5,216	955
	9,463	6,811	10,347	7,257	19,810	14,068

(1) The Company had 12 operated wells with multiple completions at December 31, 2013.

(2) The Company had no nonoperated wells with multiple completions at December 31, 2013.

Developed and Undeveloped Acreage

The following sets forth information relating to leasehold acreage as of December 31, 2013:

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
	(in thousands)					
Leasehold acreage	2,791	1,913	167	115	2,958	2,028

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 New York Mercantile Exchange (“NYMEX”) price or 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, 2013, approximately 80% 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. At December 31, 2013, the Company had natural gas delivery commitments under long-term contracts of approximately 16 Bcf for the year ended December 31, 2014, approximately 18 Bcf to be delivered by August 2015 and approximately 43 Bcf to be delivered by December 2015.

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The Company's oil production is primarily sold under market-sensitive contracts, which typically sell at a differential to NYMEX, and as of December 31, 2013, approximately 50% of its oil production was sold under short-term contracts. At December 31, 2013, the Company had oil delivery commitments under a long-term contract of 5,475 MBbls to be delivered each year through August 2019.

As discussed in the "Strategy" section above, the Company enters into derivative contracts primarily in the form of swap contracts 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. Currently, the Company's natural gas production is insufficient to fully utilize its contracted capacity on the Rockies Express, Wyoming Interstate and Ruby pipelines.

The following table sets forth information about material long-term firm transportation contracts for pipeline capacity as of December 31, 2013:

Pipeline	From	To	Quantity	Term	Demand Charge per MMBtu		Remaining Contractual Obligations
			(Avg. MMBtu/d)				(in thousands)
Enbridge Pipeline	Limestone and Harrison Counties, TX	Orange, TX	14,940	7/2012 to 6/2014	$0.10		$226
Questar Pipeline	Chipeta Plant, UT	Various UT locations	6,200	7/2012 to 6/2020	0.17		2,633
Questar Pipeline	Chipeta Plant, UT	Goshen, UT	5,000	9/2003 to 10/2022	0.26		4,148
Questar Pipeline	Brundage Canyon, UT	Chipeta Plant, UT	15,640	9/2013 to 8/2023	0.17		9,713
Rockies Express Pipeline	Meeker, CO	Clarington, OH	25,000	2/2008 to 1/2018	1.13	(1)	42,253
Rockies Express Pipeline	Meeker, CO	Clarington, OH	10,000	6/2009 to 11/2019	1.09	(1)	23,413
Ruby Pipeline	Opal, WY	Malin, OR	37,857	8/2011 to 7/2021	0.95		99,546
Wyoming Interstate Company Pipeline	Meeker, CO	Opal, WY	37,857	8/2011 to 7/2021	0.31		32,138
Total							$214,070

(1) Based on weighted average cost.

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Item 1. Business - Continued

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

	Year Ended December 31,		
	2013	2012	2011
Average daily production:			
Natural gas (MMcf/d)	443	349	175
Oil (MBbls/d)	33.5	29.2	21.5
NGL (MBbls/d)	29.7	24.5	10.8
Total (MMcfe/d)	822	671	369
Weighted average prices: (1)			
Natural gas (Mcf)	$3.62	$2.87	$4.35
Oil (Bbl)	$94.15	$88.59	$91.24
NGL (Bbl)	$30.96	$32.10	$42.88
Average NYMEX prices:			
Natural gas (MMBtu)	$3.65	$2.79	$4.05
Oil (Bbl)	$97.97	$94.20	$95.12
Costs per Mcfe of production:			
Lease operating expenses	$1.24	$1.29	$1.73
Transportation expenses	$0.43	$0.31	$0.21
General and administrative expenses (2)	$0.79	$0.71	$0.99
Depreciation, depletion and amortization	$2.76	$2.47	$2.48
Taxes, other than income taxes	$0.46	$0.54	$0.58

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

(2) General and administrative expenses for the years ended December 31, 2013, December 31, 2012, and December 31, 2011, include approximately $37 million, $28 million and $21 million, respectively, of noncash unit-based compensation expenses.

Steaming Operations

The Company’s California assets acquired in the Berry acquisition 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, 2013.

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.

Conventional Steam Generation

As a result of the Berry acquisition, the Company also owns 57 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

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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 93 MW as of December 31, 2013. 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.

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, 2013, based on reserve reports prepared by independent engineers, DeGolyer and MacNaughton:

Estimated proved developed reserves:		
Natural gas (Bcf)	2,027	
Oil (MMBbls)	252	
NGL (MMBbls)	133	
Total (Bcfe)	4,340	
Estimated proved undeveloped reserves:		
Natural gas (Bcf)	983	
Oil (MMBbls)	113	
NGL (MMBbls)	67	
Total (Bcfe)	2,063	
Estimated total proved reserves (Bcfe)	6,403	
Proved developed reserves as a percentage of total proved reserves	68	%
Standardized measure of discounted future net cash flows (in millions) (1)	$11,899	
Representative NYMEX prices: (2)		
Natural gas (MMBtu)	$3.67	
Oil (Bbl)	$96.89	

(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, 2013, the Company's proved undeveloped reserves ("PUDs") increased to 2,063 Bcfe from 1,669 Bcfe at December 31, 2012, representing an increase of 394 Bcfe. The increase was due to 595 Bcfe added primarily as a result of the Berry and Permian Basin acquisitions and 390 Bcfe added as a result of its drilling activities, partially offset by 324 Bcfe of revisions due primarily to asset performance and the SEC five-year development limitation, 229 Bcfe of PUDs developed during 2013 and 38 Bcfe related to the sale of the Panther Operated Cleveland Properties.

During the year ended December 31, 2013, the Company incurred approximately $445 million in capital expenditures to convert 226 Bcfe of reserves that were classified as PUDs at December 31, 2012, to proved developed reserves. Based on the December 31, 2013 reserve reports, the amounts of capital expenditures estimated to be incurred in 2014, 2015 and 2016 to develop the Company's PUDs are approximately $919 million, $1.0 billion and $875 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 2,063 Bcfe of PUDs at December 31, 2013, has remained undeveloped for five years or more. All PUD properties are included in the Company's current five-year development plan.

Reserve engineering is inherently a subjective process of estimating underground accumulations of oil, natural gas and NGL that cannot be measured exactly. The accuracy of any reserve estimate is a function of the quality of available data and engineering and geological interpretation and judgment. Accordingly, reserve estimates may vary from the quantities of oil, natural gas and NGL that are ultimately recovered. Future prices received for production may vary, perhaps significantly, from the prices assumed for the purposes of estimating the standardized measure of discounted future net cash flows. The standardized measure of discounted future net cash flows should not be construed as the market value of the reserves at the

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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 producing 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, 2013, sales of oil, natural gas and NGL to Enbridge Energy Partners, L.P. accounted for approximately 20% 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.

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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 users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer, which can also lessen seasonal demand fluctuations.

Environmental Matters and Regulation

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

- require the acquisition of various permits before drilling commences;
- require the installation of expensive pollution control equipment;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities;

- limit or prohibit drilling activities on lands 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 financial condition or results of operations. Future regulatory issues that could impact the Company include new rules or legislation regulating greenhouse gas emissions, hydraulic fracturing, endangered species and air emissions.

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’s rules relating to emissions of GHGs from large stationary sources of emissions are currently subject to a number of legal challenges, but the federal courts have thus far declined to issue any injunctions to prevent the EPA from implementing, or requiring state environmental agencies to implement the rules. The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the U.S., including, among other things, certain onshore oil and natural gas production facilities, on an annual basis. Legislation has from time to time been introduced in the U.S. 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 will set maximum limits or caps on total emissions of GHGs from all industrial sectors, including the oil and natural gas extraction sector of which the Company is a part, as its California operations emit GHGs. The cap will decline annually thereafter through 2020. The Company will be 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 2013 was in the range of $1.00 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, the EPA has asserted federal regulatory authority over hydraulic fracturing involving fluids that contain diesel fuel under the Safe Drinking Water Act's Underground Injection Control Program and has released draft permitting guidance for hydraulic fracturing operations that use diesel fuel in fracturing fluids in those states where the EPA is the permitting authority. Moreover, on November 23, 2011, the EPA announced that it was granting, in part, a petition to initiate 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.

A number of federal agencies are analyzing or have been requested to review a variety of environmental issues associated with hydraulic fracturing. The EPA is conducting a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater. On December 12, 2012, the EPA released a progress report outlining work currently underway and is expected to release results of the study in 2014. These on-going or proposed studies, depending on their course and any meaningful results obtained, could spur initiatives 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. 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. Compliance with environmental regulations and permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase the Company's operating costs and cause delays, interruptions or termination of its operations, the extent of which cannot be predicted, all of which could have an adverse effect on the Company's operations and financial condition.

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 habitat 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 that prior to January 1, 2015, owners/operators reduce volatile organic compounds emissions from natural gas not sent to the gathering line during well completion either by flaring or by capturing the natural gas using green completions with a completion combustion device. Beginning January 1, 2015, operators must capture the gas 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, effective in 2012, for emissions from compressors, controllers, dehydrators, storage tanks, gas processing plants and certain other equipment. These rules may require changes to the Company's operations, including the installation of new equipment to control emissions.

The Company cannot predict how future environmental laws and regulations may impact its properties or operations. For the year ended December 31, 2013, 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 2014 or that will otherwise have a material impact on its financial position or results of operations.

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.

Employees

As of December 31, 2013, the Company employed approximately 1,645 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.

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 the pending SEC inquiry and other 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;

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- cost to complete the Berry acquisition, which may be more expensive than anticipated as a result of unexpected factors or events; and
- integration of the business and operations acquired in the Berry acquisition, which may take longer than anticipated, may be more costly than anticipated 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 forward-looking statements or 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 position, 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 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.

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 our Credit Facilities, 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 Berry June 2014 Senior Notes, 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;

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- 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 suspended.

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 or eliminated.

Our net cash provided by operating activities is frequently less than cash distributions to our unitholders. 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, our Board of Directors may determine to reduce or eliminate our distribution to unitholders. Any such reduction 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: Although our expected oil production for 2014 is approximately 100% hedged at approximately $92 per Bbl, expected oil production for 2015 and beyond is significantly less hedged. If we are unable to hedge expected oil production for 2015 and beyond to the same degree and at comparable prices, we will be subject to potential commodity price volatility and lower than expected net cash provided by operating activities. As a result, our Board of Directors may determine to reduce or eliminate future distributions to our unitholders.
- Production from existing assets: Our revenues are dependent on how much oil, natural gas and NGL we produce. If our existing assets under-perform for a prolonged period of time with respect to expected production volumes, our revenues may be lower than expected, and net cash provided by operating activities could be insufficient to pay our current distribution to unitholders.
- NGL commodity prices: We have been and continue to be limited in our ability to effectively hedge our NGL production. As a result, currently, we directly hedge only our oil and natural gas production. If the price levels for NGL decrease in the future, and in particular, if mid-2013 NGL price levels were to recur, our revenues and results of operations would be affected, and net cash provided by operating activities could be insufficient to pay our current distribution to unitholders.
- Access to and cost of capital: Accretive acquisitions are an integral component of our business strategy. When revenues are expected to be lower as a result of under-performance of assets, weakening commodity prices on unhedged volumes 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 pending SEC inquiry, 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.

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 or the distribution may be 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;

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- 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.

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

Our ability to grow and to 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 contracts 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 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.

If we are unable to fully offset declines in production and proved developed producing reserves 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 the estimated amounts (which we refer to as discretionary reductions for a portion of oil and natural gas development costs) that we believe will be necessary during the following year to fully offset declines in production and proved developed producing reserves through drilling and development activities. In determining this portion of oil and natural gas development costs (which includes 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 fully offset declines in production and proved developed producing reserves 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. If we are unable to fully offset declines in production and proved developed producing reserves from this discretionary 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. 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 Berry June 2014 Senior Notes, 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 Senior Notes, 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.

As of January 31, 2014, we had an aggregate of approximately $9.3 billion outstanding under Senior Notes and our Credit Facilities (with additional borrowing capacity of approximately $2.3 billion under the LINN Credit Facility, as defined in Note 6). 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, 2013, there was no remaining borrowing capacity available under the Berry Credit Facility, as defined in Note 6. 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 maintain or increase distributions. 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 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 or suspend distributions to our unitholders.

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 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 could limit our ability to access these markets or significantly increase our cost to borrow. Some lenders may 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.

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.

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.

Our limited ability to hedge our NGL production 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 has not developed in the same way that exists for crude oil and natural gas. The current direct NGL hedging market is constrained in terms of price, volume, duration and number of counterparties, which limits our ability to hedge our NGL production effectively or at all. As a result, our net cash provided by operating activities and results of operations could be adversely impacted by fluctuations in the market prices for NGL products.

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 and ability to pay distributions could be impacted.

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 revenue, profitability and cash flow depend upon 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 past, the prices of oil, natural gas and NGL have been extremely volatile, and we expect this volatility to continue. If commodity prices decline significantly for a prolonged period, our net cash provided by operating activities will decline, and we may have to lower our distribution or may not be able to pay distributions at all.

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 and limit our ability to borrow funds.

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 and on our ability to borrow funds under our Credit Facilities, which in turn may adversely affect our ability to make cash distributions to our unitholders.

Unless we replace our reserves, our reserves and production will decline, which would adversely affect our 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 upon reservoir characteristics and other factors. The overall rate of decline for our production will change if production from our existing wells declines in a different manner than we have estimated and can change when we drill additional wells, make acquisitions and under other circumstances. Thus, our future oil, natural gas and NGL reserves and production and, therefore, our cash flow and income, are highly dependent on our success in efficiently developing our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs, which would adversely affect our net cash provided by operating activities and our ability to make distributions to our unitholders.

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

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

Our development operations require substantial capital expenditures, which will reduce our cash available 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 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 position, 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, 2013, we had 3,154 proved undeveloped drilling locations.

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Item 1A. Risk Factors - Continued

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 base 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. If we drill future wells that we identify as dry holes, our drilling success rate would decline, which could have an adverse effect on our business, financial position or results of operations.
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 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, 2013, sales of oil, natural gas and NGL to Enbridge Energy Partners, L.P. accounted for approximately 20% of our total production volumes. For the year ended December 31, 2012, Enbridge Energy Partners, L.P. and DCP Midstream Partners, LP accounted for approximately 24% and 13%, respectively, of our total production volumes, or 37% in the aggregate. To the extent these 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.
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, 2013, we had identified 13,427 drilling locations, of which 3,154 were proved undeveloped locations and 10,273 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 10,273 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.

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, 2013, nonoperated wells represented approximately 26% of our total owned gross wells, or approximately 7% 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.

We may experience difficulties in integrating the Berry business, which could cause the combined company to fail to realize many of the anticipated potential benefits of the Berry acquisition.

We entered into the merger agreement and contribution agreement because we believe that the transaction is beneficial to LinnCo and its shareholders and us and our unitholders. Achieving the anticipated benefits of the transaction will depend in part upon whether we are able to integrate the business of Berry in an efficient and effective manner. We may not be able to accomplish this integration process smoothly or successfully. The difficulties of integrating Berry's business with our business potentially will include, among other things, the necessity of coordinating geographically separated organizations and addressing possible differences incorporating cultures and management philosophies, and the integration of certain operations, which will require the dedication of significant management resources and which may temporarily distract management's attention from the day-to-day business of the combined company.

An inability to realize the full extent of the anticipated benefits of the transaction, as well as any delays encountered in the transition process, could have an adverse effect upon our revenues, level of expenses and operating results, which may affect the value of our units.

The terms of Berry's indebtedness may restrict Berry's ability to make distributions to us.

Berry's credit facility and the indentures governing its outstanding notes contain, and any future indebtedness may also contain, a number of restrictive covenants that impose operating restrictions on Berry, including restrictions on Berry's ability to make distributions to us. Any such restrictions on Berry's ability to make distributions to us would adversely affect our ability to make distributions to our unitholders.

We have incurred, and expect to continue to incur substantial expenses related to the Berry acquisition.

We have incurred, and expect to continue to incur substantial expenses in connection with integrating the business, operations, networks, systems, technologies, policies and procedures of Berry with our own. There are a large number of systems that must be integrated, including billing, management information, purchasing, accounting and finance, sales, payroll and benefits, fixed assets, lease administration and regulatory compliance. Although we have assumed that a certain level of transaction and integration expenses would be incurred, and have incurred substantial transaction and integration expenses already, there are a number of factors beyond our control that could affect the total amount or the timing of integration expenses. Many of the expenses that will be incurred, by their nature, are difficult to estimate accurately at the present time. Due to these factors, the transaction and integration expenses associated with the Berry acquisition could, particularly in the near term, exceed the savings that we expect to achieve from the elimination of duplicative expenses and the realization of economies of scale and cost savings related to the integration of Berry. During the year ended December 31, 2013, we incurred approximately $48 million in expenses related to the Berry acquisition.

We may be unable to retain key employees.

Our success after the Berry acquisition will depend in part upon our ability to retain key Berry and our employees. Key employees may depart after the Berry acquisition because of issues relating to the uncertainty and difficulty of integration or a desire not to remain following the Berry acquisition. Accordingly, no assurance can be given that we will be able to retain key Berry employees or our employees to the same extent as in the past.

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

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

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

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

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

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. Due to concerns raised relating to potential impacts of hydraulic fracturing on groundwater quality, legislative and regulatory efforts at the federal level and in some states have been initiated to render permitting and compliance requirements more stringent for hydraulic fracturing or prohibit the activity altogether. For example, the EPA has asserted federal regulatory authority over hydraulic fracturing involving fluids that contain diesel fuel under the Safe Drinking Water Act’s Underground Injection Control Program and has released draft permitting guidance for hydraulic fracturing operations that use diesel fuel in fracturing fluids in those states where the EPA is the permitting authority. In addition, both Texas and Louisiana have adopted disclosure regulations requiring varying degrees of disclosure of the constituents in hydraulic fracturing fluids. Such efforts could have an adverse effect on our oil and natural gas production activities. For a more detailed discussion of hydraulic fracturing matters impacting our business, see Item 1. “Business - Environmental Matters and Regulation.”

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 2013, 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.

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 are 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 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 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.

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.

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.

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.

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.

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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 2013, 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. 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.

Recently enacted derivatives legislation could have an adverse impact on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

New comprehensive financial reform legislation was signed into law by the President on July 21, 2010. The legislation calls for the Commodity Futures Trading Commission ("CFTC") to regulate certain markets for over-the-counter ("OTC") derivative products. In its rulemaking under the new legislation, the CFTC has proposed regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalent. Certain bona fide hedging transactions or positions would be exempt from these position limits. The CFTC's original position limits rule was challenged in court by two industry associations and was vacated and remanded by a federal district court. Since that time, the CFTC has reproposed the rule in substantially the same form as the rule that was vacated by the court, but with certain non-substantive changes in response to the court's decision. The CFTC has sought comment on the position limits rule as reproposed, but has yet to issue its final rule. The CFTC also has withdrawn its appeal of the court order vacating the original position limits rule. The financial reform legislation may also require our swap-dealer counterparties to comply with margin requirements and/or capital requirements relating to our uncleared swaps with those counterparties, but the timing of any adoption of any such regulations, and their scope, are uncertain. These and other CFTC rules implementing Dodd-Frank could impose burdens on market participants to such an extent that liquidity in the bilateral OTC derivative market decreases substantially. The legislation and new regulations may also require counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The new legislation and any new regulations, including determinations with respect to the applicability of margin and capital requirements for uncleared trades, could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures and to generate sufficient cash flow to pay distributions at the current levels or at all. Any of these consequences could have a material, adverse effect on us, our financial condition, and our results of operations.

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.

Risks Relating to the SEC Inquiry and Shareholder Litigation

We will incur significant costs associated with the pending SEC inquiry and other legal proceedings, and the ultimate outcome of these matters is uncertain.

We, LinnCo and our and LinnCo's current and former directors and officers are the subjects of a number of purported class action lawsuits and derivative lawsuits, and there is an ongoing private SEC inquiry regarding us and LinnCo. We cannot predict the duration, outcome or impact of these pending matters, but the lawsuits could result in judgments against us and LinnCo and directors and officers named as defendants. Furthermore, we are unable to predict the timing or outcome of the SEC inquiry or estimate the nature or amount of any possible sanction or enforcement action the SEC could seek to impose, which could include fines, penalties, damages, sanctions, administrative remedies and modifications to our disclosure, accounting and business practices, including a prohibition on specific conduct or a potential restatement of our financial statements, any of which could be material. Our legal expenses incurred in defending the lawsuits and responding to the SEC inquiry have been significant and we expect them to continue to be significant in the future. In addition, members of our senior management have been required to divert significant attention and resources to these matters, reducing the time, attention and resources they have available to devote to managing our business. These additional expenses and diversion of attention and resources, along with any reputational issues raised by these lawsuits and inquiry, may materially affect our business and results of operations and consequently our cash flow.

Our ability to grow and increase cash flow is limited by reduced access to capital markets.

Our business model depends on access to capital markets at an acceptable cost to fund acquisitions and our capital expenditures. Due to uncertainty regarding the timing, duration and subject matter of the SEC's inquiry and negative press related to such inquiry, we are limited in our ability to access the capital markets. If this situation persists, we may not be able to access the capital markets on acceptable terms, or at all, to make acquisitions or fund our capital expenditures necessary to sustain or increase current production, which may reduce our ability to generate higher revenues and consequently our ability to increase cash flow and sustain or increase distributions.

The SEC inquiry, shareholder litigation and other factors may make the market price of our units highly volatile.

The market price of our units could fluctuate substantially in the future due to the factors discussed in this "Risk Factors" section, including the risks relating to the SEC inquiry and shareholder litigation, and other factors including rumors or dissemination of false information; changes in coverage or earnings estimates by analysts; our ability to meet analysts' or market expectations; and sales of our units by existing unitholders. For example, after the announcement of the SEC inquiry, the price of our units dropped significantly. Currently a number of purported class action lawsuits have been filed against us as well as derivative demands on behalf of certain purchasers of our units. Litigation of this kind could result in additional substantial litigation costs, a damages award against us, further diversion of management's attention and additional volatility in the market price of our units.

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Negative press from the SEC inquiry and shareholder litigation or otherwise could have a material adverse effect on our business, financial condition and results of operations.

The negative press resulting from the SEC inquiry and shareholder litigation matters has harmed our reputation and could otherwise result in a loss of future business with our counterparties and business partners. It could also adversely affect the public's perception of us and lead to reluctance by new parties to do business with us. If our business partners and customers curtail their relationships with us, we could experience higher costs of doing business due to less favorable terms and/or the need to find alternative partners. There can be no assurance that our business partners and customers will not attempt to end or curtail their relationships with us.

Item 1B. Unresolved Staff Comments

None

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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 parties in this case are currently engaged in settlement negotiations and based on the current status of those negotiations, the Company estimates a range of possible loss of $1 million to $4.5 million, for which an appropriate reserve has been established. For a certain statewide class action royalty payment dispute where a reserve has not yet been established, the Company has denied that it has any liability on the claims and has raised arguments and defenses that, if accepted by the court, will result in no loss to the Company. Based on the 10th Circuit Court of Appeals’ decision to reverse class certification orders in two unrelated certification cases, the court has permitted additional limited discovery prior to the briefing and hearing on class certification. Briefing and the hearing on class certification have not yet been set by the court. As a result, the Company is unable to estimate a possible loss, or range of possible loss, if any. 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.

On March 21, 2013, a purported stockholder class action captioned Nancy P. Assad Trust v. Berry Petroleum Co., et al. was filed in the District Court for the City and County of Denver, Colorado, No. 13-CV-31365. The action names as defendants Berry, the members of its board of directors, Bacchus HoldCo, Inc., a direct wholly owned subsidiary of Berry (“HoldCo”), Bacchus Merger Sub, Inc., a direct wholly owned subsidiary of HoldCo (“Bacchus Merger Sub”), LinnCo, LINN Energy and Linn Acquisition Company, LLC, a direct wholly owned subsidiary of LinnCo (“LinnCo Merger Sub”). On April 5, 2013, an amended complaint was filed, which alleges that the individual defendants breached their fiduciary duties in connection with the transactions by engaging in an unfair sales process that resulted in an unfair price for Berry, by failing to disclose all material information regarding the transactions, and that the entity defendants aided and abetted those breaches of fiduciary duty. The amended complaint seeks a declaration that the transactions are unlawful and unenforceable, an order directing the individual defendants to comply with their fiduciary duties, an injunction against consummation of the transactions, or, in the event they are completed, rescission of the transactions, an award of fees and costs, including attorneys’ and experts’ fees and expenses, and other relief. On May 21, 2013, the Colorado District Court stayed and administratively closed the Nancy P. Assad Trust action in favor of the Hall action described below that is pending in the Delaware Court of Chancery.

On April 12, 2013, a purported stockholder class action captioned David Hall v. Berry Petroleum Co., et al. was filed in the Delaware Court of Chancery, C.A. No. 8476-VCG. The complaint names as defendants Berry, the members of its board of directors, HoldCo, Bacchus Merger Sub, LinnCo, LINN Energy and LinnCo Merger Sub. The complaint alleges that the individual defendants breached their fiduciary duties in connection with the transactions by engaging in an unfair sales process that resulted in an unfair price for Berry, by failing to disclose all material information regarding the transactions, and that the entity defendants aided and abetted those breaches of fiduciary duty. In December 2013, the parties signed a Memorandum of Understanding to settle the case, and is in the process of seeking court approval of the settlement. The Company is unable to estimate a possible loss, or range of possible loss, if any, at this time.

On July 9, 2013, Anthony Booth, individually and on behalf of all other persons similarly situated, filed a class action complaint in the United States District Court, Southern District of Texas, against LINN Energy, Mark E. Ellis, Kolja Rockov, and David B. Rottino (the "Booth Action"). On July 18, 2013, the Catherine A. Fisher Trust, individually and on behalf of all other persons similarly situated, filed a class action complaint in the United States District Court, Southern District of Texas, against the same defendants (the "Fisher Action"). On July 17, 2013, Don Gentry, individually and on behalf of all other

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persons similarly situated, filed a class action complaint in the United States District Court, Southern District of Texas, against LINN Energy, LinnCo, Mark E. Ellis, Kolja Rockov, David B. Rottino, George A. Alcorn, David D. Dunlap, Terrence S. Jacobs, Michael C. Linn, Joseph P. McCoy, Jeffrey C. Swoveland, and the various underwriters for LinnCo's initial public offering (the "Gentry Action") (the Booth Action, Fisher Action, and Gentry Action together, the "Texas Federal Actions"). The Texas Federal Actions each assert claims under Sections 10(b) and 20(a) of the Securities Exchange Act of 1934 (the "Exchange Act") based on allegations that LINN Energy made false or misleading statements relating to its hedging strategy, the cash flow available for distribution to unitholders, and LINN Energy's energy production. The Gentry Action asserts additional claims under Sections 11 and 15 of the Securities Act of 1933 based on alleged misstatements relating to these issues in the prospectus and registration statement for LinnCo's initial public offering. On September 23, 2013, the Southern District of Texas entered an order transferring the Texas Federal Actions to the Southern District of New York so that they could be consolidated with the New York Federal Actions, which are described below.

On July 10, 2013, David Adrian Luciano, individually and on behalf of all other persons similarly situated, filed a class action complaint in the United States District Court, Southern District of New York, against LINN Energy, LinnCo, Mark E. Ellis, Kolja Rockov, David B. Rottino, George A. Alcorn, David D. Dunlap, Terrence S. Jacobs, Michael C. Linn, Joseph P. McCoy, Jeffrey C. Swoveland, and the various underwriters for LinnCo's initial public offering (the "Luciano Action"). The Luciano Action asserts claims under Sections 11 and 15 of the Securities Act of 1933 based on alleged misstatements relating to LINN Energy's hedging strategy, the cash flow available for distribution to unitholders, and LINN Energy's energy production in the prospectus and registration statement for LinnCo's initial public offering. On July 12, 2013, Frank Donio, individually and on behalf of all other persons similarly situated, filed a class action complaint in the United States District Court, Southern District of New York, against LINN Energy, Mark E. Ellis, Kolja Rockov, and David B. Rottino (the "Donio Action"). The Donio Action asserts claims under Sections 10(b) and 20(a) of the Exchange Act based on allegations that LINN Energy made false or misleading statements relating to its hedging strategy, the cash flow available for distribution to unitholders, and LINN Energy's energy production. Several additional class action cases substantially similar to the Luciano Action and the Donio Action were subsequently filed in the Southern District of New York and assigned to the same judge (the Luciano Action, Donio Action, and all similar subsequently filed New York federal class actions together, the "New York Federal Actions"). The Texas Federal Actions and the New York Federal Actions have now been consolidated in the United States District Court for the Southern District of New York (the "Combined Actions"). In November 2013, LINN Energy filed a motion to dismiss the Combined Actions. The motion is currently pending before the Southern District of New York. There has not been any discovery conducted in the Combined Actions. As a result, the Company is unable to estimate a possible loss, or range of possible loss, if any.

On July 10, 2013, Judy Mesirov, derivatively on behalf of nominal defendant LINN Energy, filed a shareholder derivative petition against Mark E. Ellis, Kolja Rockov, David B. Rottino, Arden L. Walker, Jr., Charlene A. Ripley, Michael C. Linn, Joseph P. McCoy, George A. Alcorn, Terrence S. Jacobs, David D. Dunlap, Jeffrey C. Swoveland, and Linda M. Stephens in the District Court of Harris County, Texas (the "Mesirov Action"). On July 12, 2013, John Peters, derivatively on behalf of nominal defendant LINN Energy, filed a shareholder derivative petition against many of the same defendants in the District Court of Harris County, Texas (the "Peters Action"). On August 26, 2013, Joseph Abdalla, derivatively on behalf of nominal defendant LINN Energy, filed a shareholder derivative petition against many of the same defendants in the District Court of Harris County, Texas (the "Abdalla Action") (the Mesirov Action, Peters Action, and Abdalla Actions together, the "Texas State Court Derivative Actions"). On August 19, 2013, the Charlote J. Lombardo Trust of 2004, derivatively on behalf of nominal defendant LINN Energy, filed a shareholder derivative petition against many of the same defendants in the United States District Court for the Southern District of Texas (the "Lombardo Action"). On September 30, 2013, the Thelma Feldman Rev. Trust, derivatively on behalf of nominal defendant LINN Energy, filed a shareholder derivative petition against many of the same defendants (the "Feldman Rev. Trust Action"). On October 21, 2013, the Parker Family Trust of 2012, derivatively on behalf of nominal defendant LINN Energy, filed a shareholder derivative petition against many of the same defendants (the "Parker Family Trust Action") (the Lombardo Action, Feldman Rev. Trust Action, and Parker Family Trust Action together, the "Texas Federal Court Derivative Actions") (the Texas State Court Derivative Action and Texas Federal Court

Derivative Actions together, the “Texas Derivative Actions”). The Texas Derivative Actions assert derivative claims on behalf of LINN Energy against the individual defendants 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 Texas Federal Actions and the New York Federal Actions. The cases are in their preliminary stages and it is possible that additional similar actions could be filed in the District Court of Harris County, Texas, or in other jurisdictions. As a result, the Company is unable to estimate a possible loss, or range of possible loss, if any.

During the years ended December 31, 2013, December 31, 2012, and December 31, 2011, 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

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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.

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, 2014, there were approximately 181 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	
2013:				
October 1 – December 31	$31.80	$26.01	$0.725	(1)
July 1 – September 30	$33.29	$22.79	$0.725	(1)
April 1 – June 30	$39.15	$30.52	$0.725	
January 1 – March 31	$39.33	$35.93	$0.725	
2012:				
October 1 – December 31	$42.52	$35.24	$0.725	
July 1 – September 30	$41.47	$38.46	$0.725	
April 1 – June 30	$40.70	$35.00	$0.725	
January 1 – March 31	$38.84	$35.67	$0.69	

(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.

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, 2008, 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, 2008	December 31, 2009	December 31, 2010	December 31, 2011	December 31, 2012	December 31, 2013
LINN Energy	$100	$212	$311	$338	$338	$324
Alerian MLP Index	$100	$176	$240	$273	$286	$365
S&P 500 Index	$100	$126	$145	$149	$172	$228

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.

Sales of Unregistered Securities

In conjunction with LinnCo, LLC’s (“LinnCo”) contribution of Berry Petroleum Company 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 2013 annual meetings for additional information). Total units issued as consideration to LinnCo includes 40,938 (approximately $1 million) of Berry

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

equity awards that vested and converted to LinnCo common shares on the Berry acquisition date and included in total consideration but such shares were unissued at December 31, 2013, due to six month deferred issuance provisions in the original Berry award agreements.

Issuer Purchases of Equity Securities

In October 2008, the Board of Directors of the Company authorized the repurchase of up to $100 million of the Company’s outstanding units from time to time on the open market or in negotiated purchases. 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 three months ended December 31, 2013. At December 31, 2013, approximately $56 million was 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. The results of the Company's Appalachian Basin and Mid Atlantic Well Service, Inc. operations, which were disposed of in 2008, are classified as discontinued operations for the year ended December 31, 2009. Unless otherwise indicated, results of operations information presented herein relates only to continuing operations. The following data at and for the year ended December 31, 2013, reflects the results of the Berry Petroleum Company ("Berry") acquisition since the acquisition date.

	At or for the Year Ended December 31,				
	2013	2012	2011	2010	2009
	(in thousands, except per unit amounts)				
Statement of operations data:					
Oil, natural gas and natural gas liquids sales	$2,073,240	$1,601,180	$1,162,037	$690,054	$408,219
Gains (losses) on oil and natural gas derivatives	177,857	124,762	449,940	75,211	(141,374)
Depreciation, depletion and amortization	829,311	606,150	334,084	238,532	201,782
Interest expense, net of amounts capitalized	421,137	379,937	259,725	193,510	92,701
Income (loss) from continuing operations	(691,337)	(386,616)	438,439	(114,288)	(295,841)
Loss from discontinued operations, net of taxes [1]	—	—	—	—	(2,351)
Net income (loss)	(691,337)	(386,616)	438,439	(114,288)	(298,192)
Income (loss) per unit – continuing operations:					
Basic	(2.94)	(1.92)	2.52	(0.80)	(2.48)
Diluted	(2.94)	(1.92)	2.51	(0.80)	(2.48)
Income (loss) per unit – discontinued operations:					
Basic	—	—	—	—	(0.02)
Diluted	—	—	—	—	(0.02)
Net income (loss) per unit:					
Basic	(2.94)	(1.92)	2.52	(0.80)	(2.50)
Diluted	(2.94)	(1.92)	2.51	(0.80)	(2.50)
Distributions declared per unit	2.90	2.87	2.70	2.55	2.52
Weighted average units outstanding	237,544	203,775	172,004	142,535	119,307
Cash flow data:					
Net cash provided by (used in):					
Operating activities [2]	$1,166,212	$350,907	$518,706	$270,918	$426,804
Investing activities	(1,253,317)	(3,684,829)	(2,130,360)	(1,581,408)	(282,273)
Financing activities	138,033	3,334,051	1,376,767	1,524,260	(150,968)
Balance sheet data: [3]					
Total assets	$16,504,964	$11,451,238	$7,928,854	$5,933,148	$4,340,256
Long-term debt	8,958,658	6,037,817	3,993,657	2,742,902	1,588,831
Unitholders' capital	5,891,427	4,427,180	3,428,910	2,788,216	2,452,004

(1) Includes gains (losses) on sale of assets, net of taxes.

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Item 6. Selected Financial Data - Continued

(2) Net of payments made for commodity derivative premiums of approximately $583 million, $134 million, $120 million and $94 million for the years ended December 31, 2012, December 31, 2011, December 31, 2010, and December 31, 2009, respectively.

(3) The increase in 2013 is primarily related to the Berry acquisition.

	At or for the Year Ended December 31,				
	2013	2012	2011	2010	2009
Production data:					
Average daily production:					
Natural gas (MMcf/d)	443	349	175	137	125
Oil (MBbls/d)	33.5	29.2	21.5	13.1	9.0
NGL (MBbls/d)	29.7	24.5	10.8	8.3	6.5
Total (MMcfe/d)	822	671	369	265	218
Estimated proved reserves: (1)					
Natural gas (Bcf)	3,010	2,571	1,675	1,233	774
Oil (MMBbls)	366	191	189	156	102
NGL (MMBbls)	200	179	94	71	54
Total (Bcfe)	6,403	4,796	3,370	2,597	1,712

(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. The increase in 2013 is primarily related to the Berry acquisition.

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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.

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, including those acquired in the acquisition of Berry Petroleum Company ("Berry"), are located in seven operating regions in the United States ("U.S."):

- Rockies, which includes properties located in Wyoming (Green River Basin and Powder River Basin), Utah (Uinta Basin), North Dakota (Williston Basin) and Colorado (Piceance Basin);
- Mid-Continent, which includes properties in Oklahoma, Louisiana and the eastern portion of the Texas Panhandle (including the Granite Wash and Cleveland horizontal plays);
- Hugoton Basin, which includes properties located primarily in Kansas and the Shallow Texas Panhandle;
- California, which includes the San Joaquin Valley Basin and the Los Angeles Basin;
- Permian Basin, which includes areas in west Texas and southeast New Mexico;
- Michigan/Illinois, which includes the Antrim Shale formation in the northern part of Michigan and oil properties in southern Illinois; and
- East Texas, which includes properties located in east Texas.

Results for the year ended December 31, 2013, included the following:

- oil, natural gas and NGL sales of approximately $2.1 billion compared to $1.6 billion in 2012;
- average daily production of 822 MMcfe/d compared to 671 MMcfe/d in 2012;
- net loss of approximately $691 million compared to a net loss of $387 million in 2012;
- net cash provided by operating activities of approximately $1.2 billion compared to $351 million in 2012;
- capital expenditures, excluding acquisitions, of approximately $1.3 billion compared to $1.1 billion in 2012; and
- 559 wells drilled (557 successful) compared to 440 wells drilled (436 successful) in 2012.

Acquisitions

On December 16, 2013, the Company completed the previously-announced 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 has a preliminary value of 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.

The consolidated financial statements and financial and operational results of the Company reflect the combined entities since the acquisition date.

Berry's principal reserves and producing properties are located in California (San Joaquin Valley Basin and Los Angeles Basin), Texas (Permian Basin and east Texas), Utah (Uinta Basin) and Colorado (Piceance Basin). The acquisition included approximately 1,408 Bcfe of proved reserves as of the acquisition date. At December 31, 2013, Berry had approximately 3,400 gross productive wells and more than 200,000 net acres.

On October 31, 2013, the Company completed the acquisition of certain oil and natural gas properties located in the Permian Basin for total consideration of approximately $528 million. The acquisition included approximately 175 Bcfe of proved reserves as of the acquisition date.

During 2013, 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 $40 million in total consideration for these properties.

Proved reserves as of the acquisition date for all of the above referenced acquisitions were estimated using the average oil and natural gas prices during the preceding 12-month period, determined as an unweighted average of the first-day-of-the-month prices for each month. Estimates of proved reserves as of the acquisition date for all of the above referenced acquisitions as well as estimates of proved reserves at December 31, 2013, were prepared by the independent engineering firm, DeGolyer and MacNaughton.

Divestiture

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. Proceeds received for the Company's portion of its interests in the 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, as defined below.

Financing and Liquidity

In April 2013, the Company entered into a Sixth Amended and Restated Credit Agreement ("LINN Credit Facility"), which provides for a revolving credit facility up to the lesser of: (i) the then-effective borrowing base and (ii) the maximum commitment amount of $4.0 billion. The borrowing base remained unchanged at $4.5 billion and does not include any assets acquired in the Berry acquisition. The maturity date is April 2018. The amended and restated agreement is substantially similar to the previous LINN Credit Facility with revisions to permit the transactions related to the Berry acquisition and to designate Berry as an unrestricted subsidiary under the agreement.

On October 30, 2013, the Company entered into an amendment to the LINN Credit Facility, under which the Company entered into a $500 million senior secured term loan with certain participants in its lender group under the LINN Credit Facility. The term loan has a maturity date of April 2018, consistent with the maturity of the LINN Credit Facility, and incurs interest based on either the London Interbank Offered Rate ("LIBOR") plus a margin of 2.5% per annum or the alternate base rate ("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. The proceeds of the term loan were used to partially fund the acquisition of certain oil and natural gas properties located in the Permian Basin.

In accordance with the provisions of the indentures related to the May 2017 Senior Notes and July 2018 Senior Notes, as defined in Note 6, in June 2013 and July 2013, the Company redeemed the remaining outstanding principal amounts of approximately $41 million and $14 million, respectively.

On December 16, 2013, LinnCo completed its acquisition and subsequent contribution of Berry to LINN Energy in exchange for newly issued LINN Energy units. Approximately 93,756,674 LinnCo common shares representing limited liability company interests were issued to Berry shareholders to acquire Berry, and an equal number of LINN Energy units were issued to LinnCo for the contribution of Berry to LINN Energy. See above for additional information.

In connection with the Berry acquisition, the Company assumed approximately $2.3 billion of Berry’s debt, consisting of a senior secured revolving credit facility, 10.25% senior notes due 2014, 6.75% senior notes due 2020 and 6.375% senior notes due 2022. For information related to Berry’s debt, see Note 6.

In December 2013, Berry entered into an amendment to its Second Amended and Restated Credit Agreement (“Berry Credit Facility”) primarily to conform certain terms in the Berry Credit Facility to like terms in the LINN Credit Facility. The maturity date of the Berry Credit Facility is May 2016. The Berry Credit Facility has a borrowing base of $1.4 billion, subject to lender commitments. At December 31, 2013, lender commitments under the facility were $1.2 billion and there was no remaining borrowing capacity available. In February 2014, Berry entered into an amendment to the Berry Credit Facility to amend the terms of certain financial covenants and reporting covenants.

Commodity Derivatives

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. As part of 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. Currently, the Company has limited abilities to hedge its NGL production because there is no commercially viable market established for this purpose. Therefore, the Company does not directly hedge its NGL production.

Operating Regions

Following is a discussion of the Company’s seven operating regions.

Rockies

The Rockies region consists of properties located in Wyoming (Green River Basin and Powder River Basin), northeastern Utah (Uinta Basin), North Dakota (Bakken and Three Forks formations in the Williston Basin) and northwestern Colorado (Piceance Basin). Properties located in the Uinta and Piceance basins were acquired in the Berry acquisition. Wells in this diverse region produce from both oil and natural gas reservoirs at depths ranging from 1,000 feet to over 13,000 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 13,500 feet. The Company’s properties in the Powder River Basin consist of a CO2 flood operated by Anadarko Petroleum Corporation (“Anadarko”) in the Salt Creek Field. The Company’s properties in the Uinta Basin produce at depths ranging from 5,000 feet to 7,500 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.

Rockies proved reserves represented approximately 28% of total proved reserves at December 31, 2013, of which 46% were classified as proved developed. This region produced 187 MMcfe/d or 23% of the Company’s 2013 average daily production. During 2013, the Company invested approximately $306 million to drill in this region. During 2014, the Company anticipates spending approximately 38% of its total oil and natural gas capital budget for development activities in the Rockies region.

Mid-Continent

The Mid-Continent region includes properties located in Oklahoma, Louisiana and the eastern portion of the Texas Panhandle (including the Granite Wash and Cleveland horizontal plays). Wells in this diverse region produce from both oil and natural gas reservoirs at depths ranging from 1,500 feet to over 18,000 feet. The Granite Wash formation and other shallower producing horizons are currently being developed using horizontal drilling and multi-stage stimulations. In the northern Texas Panhandle and extending into western Oklahoma, the Cleveland formation is being developed as a horizontal oil play. Elsewhere in Oklahoma, several producing formations are being targeted using similar horizontal drilling and completion technologies. The majority of wells in this region are mature, low-decline oil and natural gas wells.

Mid-Continent proved reserves represented approximately 20% of total proved reserves at December 31, 2013, of which 77% were classified as proved developed. This region produced 330 MMcfe/d or 40% of the Company’s 2013 average daily production. During 2013, the Company invested approximately $439 million to drill in this region.

During 2014, the

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Company anticipates spending approximately 16% of its total oil and natural gas capital budget for development activities in the Mid-Continent region.

To more efficiently transport its natural gas in the Mid-Continent region to market, the Company owns and operates a network of natural gas gathering systems comprised of approximately 325 miles of pipeline and associated compression and metering facilities. In connection with the horizontal development activities in the Granite Wash formation, the Company continues to expand this gathering system which connects to numerous natural gas processing facilities in the region.

Hugoton Basin

The Hugoton Basin is a large oil and natural gas producing area located in the central portion of the Texas Panhandle extending into southwestern Kansas. The Company's Texas properties in the basin primarily produce from the Brown Dolomite formation at depths of approximately 3,200 feet and its Kansas properties primarily produce from the Council Grove and Chase formations at depths ranging from 2,500 feet to 3,000 feet. Hugoton Basin proved reserves represented approximately 18% of total proved reserves at December 31, 2013, of which 82% were classified as proved developed. This region produced 143 MMcfe/d or 17% of the Company's 2013 average daily production. During 2013, the Company invested approximately $35 million to drill in this region. During 2014, the Company anticipates spending approximately 3% of its total oil and natural gas capital budget for development activities in the Hugoton Basin region.

To more efficiently transport its natural gas in the Texas Panhandle to market, the Company owns and operates a network of natural gas gathering systems comprised of approximately 665 miles of pipeline and associated compression and metering facilities that connect to numerous sales outlets in the area. The Company also owns and operates the Jayhawk natural gas processing plant in southwestern Kansas with a capacity of approximately 450 MMcfe/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 plant via a system of approximately 2,100 miles of pipeline and related facilities operated by the Company, of which approximately 250 miles of pipeline are owned by the Company.

California

The California region consists of the Midway-Sunset Field, Diatomite, McKittrick and Poso Creek properties in the San Joaquin Valley Basin and the Brea Olinda Field and Placerita Field in the Los Angeles Basin. 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 properties in the Midway-Sunset Field, Diatomite, McKittrick, Placerita Field and Poso Creek were acquired in the Berry acquisition and produce using thermal enhanced oil recovery methods at depths ranging from 800 feet to 2,000 feet. California proved reserves represented approximately 14% of total proved reserves at December 31, 2013, of which 80% were classified as proved developed. This region produced 19 MMcfe/d or 2% of the Company's 2013 average daily production. During 2013, the Company invested approximately $33 million to drill in this region. During 2014, the Company anticipates spending approximately 16% of its total oil and natural gas capital budget for development activities in the California region.

Permian Basin

The Permian Basin is one of the largest and most prolific oil and natural gas basins in the U.S. 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. The Wolfberry trend is located in the north central portion of the basin where the Company has been actively drilling vertical oil wells since 2010. The Company also produces oil and natural gas from mature, low-decline wells including several waterflood properties located across the basin. Certain of the properties located in Texas were acquired in the Berry acquisition. Permian Basin proved reserves represented approximately 13% of total proved reserves at December 31, 2013, of which 51% were classified as proved developed. Recent industry activity has begun focusing on Wolfcamp horizontal drilling in the vicinity of the Company's properties. The Company had no proved reserves booked for Wolfcamp horizontal wells at December 31, 2013. This region produced 87 MMcfe/d or 11% of the Company's 2013 average daily production. During 2013, the Company invested approximately $218 million to drill in this region. During 2014, the Company anticipates spending approximately 25% of its total oil and natural gas capital budget for development activities in the Permian Basin region, primarily in the Wolfberry trend.

Michigan/Illinois

The Michigan/Illinois region includes properties producing from the Antrim Shale formation in the northern part of Michigan and oil properties in southern 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, 2013, of which 97% were classified as proved developed. This region produced 34 MMcfe/d or 4% of the Company's 2013 average daily production. During 2014, the Company anticipates spending approximately 1% of its total oil and natural gas capital budget for development activities in the Michigan/Illinois region.

East Texas

The East Texas region consists of properties located in east Texas and primarily produces natural gas from the Cotton Valley formation and the Haynesville/Bossier Shale at depths ranging from 7,000 to 13,500 feet. Certain of the properties located in the Cotton Valley formation and all of the Haynesville/Bossier Shale properties were acquired in the Berry acquisition. Proved reserves for these mature, low-decline producing properties, all of which are proved developed, represented approximately 3% of total proved reserves at December 31, 2013. This region produced 22 MMcfe/d or 3% of the Company's 2013 average daily production. During 2014, the Company anticipates spending approximately 1% of its total oil and natural gas capital budget for development activities in the East Texas region.

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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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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 822 MMcfe/d during the year ended December 31, 2013, from 671 MMcfe/d during 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 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 decreased 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, including natural gas put options used to indirectly hedge NGL revenues, 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, including natural gas put options used to indirectly hedge NGL revenues, and 106% of its oil production.

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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" in "Liquidity and Capital Resources" below.

Marketing and Other Revenues

Marketing revenues represent third-party activities associated with company-owned gathering systems and plants. 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 and plants. 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 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 a noncash impairment charge, 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

Taxes, other than income taxes, which consist primarily of severance and ad valorem taxes, increased by approximately $7 million or 5% to approximately $139 million for the year ended December 31, 2013, from approximately $132 million for the year ended December 31, 2012. Severance taxes, which are a function of revenues generated from production, increased by approximately $8 million compared to the year ended December 31, 2012, 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 by approximately $1 million compared to the year ended December 31, 2012, largely due to property acquisitions in 2012. The increases in severance and ad valorem taxes were partially offset by a decrease in sales and use taxes of approximately $2 million compared to the year ended December 31, 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. In addition, 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" in "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 for the year ended December 31, 2013, compared to approximately $8 million for the year ended December 31, 2012.

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.

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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, 2012, Compared to Year Ended December 31, 2011

	Year Ended December 31,		
	2012	2011	Variance
	(in thousands)		
Revenues and other:			
Natural gas sales	$367,550	$278,714	$88,836
Oil sales	946,304	714,385	231,919
NGL sales	287,326	168,938	118,388
Total oil, natural gas and NGL sales	1,601,180	1,162,037	439,143
Gains on oil and natural gas derivatives [1]	124,762	449,940	(325,178)
Marketing and other revenues	48,298	10,477	37,821
	1,774,240	1,622,454	151,786
Expenses:			
Lease operating expenses	317,699	232,619	85,080
Transportation expenses	77,322	28,358	48,964
Marketing expenses	31,821	3,681	28,140
General and administrative expenses [2]	173,206	133,272	39,934
Exploration costs	1,915	2,390	(475)
Depreciation, depletion and amortization	606,150	334,084	272,066
Impairment of long-lived assets	422,499	—	422,499
Taxes, other than income taxes	131,679	78,522	53,157
Losses on sale of assets and other, net	1,539	3,494	(1,955)
	1,763,830	816,420	947,410
Other income and (expenses)	(394,236)	(362,129)	(32,107)
Income (loss) before income taxes	(383,826)	443,905	(827,731)
Income tax expense	2,790	5,466	(2,676)
Net income (loss)	$(386,616)	$438,439	$(825,055)

(1) During the year ended December 31, 2011, the Company canceled (before the contract settlement date) derivative contracts on estimated future oil and natural gas production resulting in gains of approximately $27 million. The proceeds from the cancellation of the derivative contracts were reallocated within the Company's derivatives portfolio.

(2) General and administrative expenses for the years ended December 31, 2012, and December 31, 2011, include approximately $28 million and $21 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,			
	2012	2011	Variance	
Average daily production:				
Natural gas (MMcf/d)	349	175	99	%
Oil (MBbls/d)	29.2	21.5	36	%
NGL (MBbls/d)	24.5	10.8	127	%
Total (MMcfe/d)	671	369	82	%
Weighted average prices: (1)				
Natural gas (Mcf)	$2.87	$4.35	(34	)%
Oil (Bbl)	$88.59	$91.24	(3	)%
NGL (Bbl)	$32.10	$42.88	(25	)%
Average NYMEX prices:				
Natural gas (MMBtu)	$2.79	$4.05	(31	)%
Oil (Bbl)	$94.20	$95.12	(1	)%
Costs per Mcfe of production:				
Lease operating expenses	$1.29	$1.73	(25	)%
Transportation expenses	$0.31	$0.21	48	%
General and administrative expenses (2)	$0.71	$0.99	(28	)%
Depreciation, depletion and amortization	$2.47	$2.48	—	
Taxes, other than income taxes	$0.54	$0.58	(7	)%

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

(2) General and administrative expenses for the years ended December 31, 2012, and December 31, 2011, include approximately $28 million and $21 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 $439 million or 38% to approximately $1.6 billion for the year ended December 31, 2012, from approximately $1.2 billion for the year ended December 31, 2011, due to higher production volumes partially offset by lower commodity prices. Lower natural gas, NGL and oil prices resulted in a decrease in revenues of approximately $189 million, $96 million and $28 million, respectively.

Average daily production volumes increased to 671 MMcfe/d during the year ended December 31, 2012, from 369 MMcfe/d during the year ended December 31, 2011. Higher natural gas, oil and NGL production volumes resulted in an increase in revenues of approximately $277 million, $260 million and $215 million, respectively.

The following sets forth average daily production by region:

	Year Ended December 31,			
	2012	2011	Variance	
Average daily production (MMcfe/d):				
Mid-Continent	313	195	118	61 %
Hugoton Basin	120	39	81	208 %
Rockies	91	12	79	658 %
Permian Basin	83	73	10	14 %
Michigan/Illinois	35	36	(1)	(2)%
East Texas	16	—	16	—
California	13	14	(1)	(6)%
	671	369	302	82 %

The increase in average daily production volumes in the Mid-Continent region primarily reflects the Company's 2011 and 2012 capital drilling programs in the Granite Wash formation, as well as the impact of the acquisition in the Cleveland horizontal play on June 1, 2011 and the acquisition from Plains in December 2011. 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 Rockies region reflects the impact of acquisitions in 2011 and 2012 and the joint-venture agreement entered into with Anadarko in April 2012. The increase in average daily production volumes in the Permian Basin region reflects the impact of acquisitions in 2011 and subsequent development capital spending. The Michigan/Illinois and California regions consist of low-decline asset bases and continue to produce at consistent levels. Average daily production volumes in the East Texas region reflect the impact of the acquisition on May 1, 2012.

Gains on Oil and Natural Gas Derivatives

Gains on oil and natural gas derivatives decreased by approximately $325 million to gains of approximately $125 million for the year ended December 31, 2012, from gains of approximately $450 million for the year ended December 31, 2011. Gains on oil and natural gas derivatives decreased primarily due to the changes in fair value of the derivative contracts, partially offset by increased cash settlements during the year. The results for 2012 also include gains of approximately $22 million related to the recovery of a bankruptcy claim (see Note 11). The results for 2011 also include gains of approximately $27 million related to canceled contracts of which the proceeds were reallocated within the Company's derivatives portfolio. 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, 2012, the Company had commodity derivative contracts for approximately 110% of its natural gas production, including natural gas put options used to indirectly hedge NGL revenues, and 106% of its oil production. During the year ended December 31, 2011, the Company had commodity derivative contracts for approximately 101% of its natural gas production, including natural gas put options used to indirectly hedge NGL revenues, and 101% 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" in "Liquidity and Capital Resources" below.

Marketing and Other Revenues

Marketing revenues represent third-party activities associated with company-owned gathering systems and plants. Marketing and other revenues increased by approximately $38 million or 361% to approximately $48 million for the year ended December 31, 2012, from approximately $10 million for the year ended December 31, 2011, primarily due to 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 $85 million or 37% to approximately $318 million for the year ended December 31, 2012, from approximately $233 million for the year ended December 31, 2011. Lease operating expenses increased primarily due to costs associated with properties acquired during 2011 and 2012 (see Note 2). Lease operating expenses per Mcfe decreased to $1.29 per Mcfe for the year ended December 31, 2012, from $1.73 per Mcfe for the year ended December 31, 2011, primarily due to lower rates on newly acquired properties and cost saving initiatives.

Transportation Expenses

Transportation expenses increased by approximately $49 million or 173% to approximately $77 million for the year ended December 31, 2012, from approximately $28 million for the year ended December 31, 2011, primarily due to acquisitions in late 2011 and early 2012.

Marketing Expenses

Marketing expenses represent third-party activities associated with company-owned gathering systems and plants. Marketing expenses increased by approximately $28 million or 765% to approximately $32 million for the year ended December 31, 2012, from approximately $4 million for the year ended December 31, 2011, primarily due to 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 $40 million or 30% to approximately $173 million for the year ended December 31, 2012, from approximately $133 million for the year ended December 31, 2011. The increase was primarily due to an increase in salaries and benefits related expenses of approximately $20 million, driven primarily by increased employee headcount, and an increase in acquisition related expenses of approximately $16 million. Although general and administrative expenses increased, the unit rate decreased to $0.71 per Mcfe for the year ended December 31, 2012, from $0.99 per Mcfe for the year ended December 31, 2011, as a result of efficiencies gained from being a larger, more scalable organization.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization increased by approximately $272 million or 81% to approximately $606 million for the year ended December 31, 2012, from approximately $334 million for the year ended December 31, 2011. Higher total production volumes were the primary reason for the increased expense. Depreciation, depletion and amortization per Mcfe decreased to $2.47 per Mcfe for the year ended December 31, 2012, from $2.48 per Mcfe for the year ended December 31, 2011.

Impairment of Long-Lived Assets

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. The

Company recorded no impairment charge for the year ended December 31, 2011. See Note 1 and "Critical Accounting Policies and Estimates" below for additional information.

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

Taxes, Other Than Income Taxes

Taxes, other than income taxes, which consist primarily of severance and ad valorem taxes, increased by approximately $53 million or 68% to approximately $132 million for the year ended December 31, 2012, from approximately $79 million for the year ended December 31, 2011. Severance taxes, which are a function of revenues generated from production, increased by approximately $21 million compared to the year ended December 31, 2011, primarily due to higher production volumes partially offset by lower commodity prices. Ad valorem taxes, which are primarily based on the value of reserves and production equipment and vary by location, increased by approximately $32 million compared to the year ended December 31, 2011, largely due to property acquisitions in 2011 and 2012 and higher rates on the Company's base properties.

Other Income and (Expenses)

	Year Ended December 31,		
	2012	2011	Variance
	(in thousands)		
Interest expense, net of amounts capitalized	$(379,937)	$(259,725)	$(120,212)
Loss on extinguishment of debt	—	(94,612)	94,612
Other, net	(14,299)	(7,792)	(6,507)
	$(394,236)	$(362,129)	$(32,107)

Other income and (expenses) increased by approximately $32 million during the year ended December 31, 2012, compared to the year ended December 31, 2011. Interest expense increased primarily due to higher outstanding debt during the period and higher amortization of financing fees associated with the May 2019 Senior Notes, November 2019 Senior Notes and amendments made to the LINN Credit Facility during 2012. For the year ended December 31, 2011, the Company also recorded a loss on extinguishment of debt of approximately $95 million as a result of the redemptions of and cash tender offers for a portion of the Original Senior Notes. See "Debt" in "Liquidity and Capital Resources" below for additional details.

Income Tax Expense

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 and were also subject to state income taxes in the state of Michigan during 2011. 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 approximately $3 million for the year ended December 31, 2012, compared to approximately $5 million for the year ended December 31, 2011. Income tax expense decreased primarily due to lower income in 2012 from the Company's taxable subsidiaries.

Net Income (Loss)

Net income decreased by approximately $825 million or 188% to a net loss of approximately $387 million for the year ended December 31, 2012, from net income of approximately $438 million for the year ended December 31, 2011. The decrease was primarily due to lower gains on oil and natural gas derivatives and higher impairment charges and other expenses, including interest, partially offset by higher production revenues. 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, 2013, the Company's total capital expenditures, excluding acquisitions, were approximately $1.3 billion. For 2014, the Company estimates its total capital expenditures, excluding acquisitions, will be approximately $1.6 billion, including approximately $1.55 billion related to its oil and natural gas capital program and approximately $35 million related to its plant and pipeline capital. This estimate 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 these capital expenditures primarily with net cash provided by operating activities and bank borrowings. However, at December 31, 2013, there was no remaining borrowing capacity available under the Berry 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 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."

Statements of Cash Flows

The following is a comparative cash flow summary:

	Year Ended December 31,		
	2013	2012	2011
	(in thousands)		
Net cash:			
Provided by operating activities [1]	$1,166,212	$350,907	$518,706
Used in investing activities	(1,253,317)	(3,684,829)	(2,130,360)
Provided by financing activities	138,033	3,334,051	1,376,767
Net increase (decrease) in cash and cash equivalents	$50,928	$129	$(234,887)

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

Operating Activities

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 approximately $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.

Cash provided by operating activities was approximately $351 million for the year ended December 31, 2012, compared to approximately $519 million for the year ended December 31, 2011. The decrease was primarily due to approximately $583 million in premiums paid for derivatives during the year ended December 31, 2012, compared to $134 million in premiums paid during the year ended December 31, 2011. Premiums paid for commodity derivatives increased primarily due to increased acquisition activity during the year ended December 31, 2012, as compared to the year ended December 31, 2011. Higher premiums and expenses were partially offset by higher revenues primarily due to increased production volumes.

During the years ended December 31, 2012 and 2011, 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.

Investing Activities

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

	Year Ended December 31,		
	2013	2012	2011
	(in thousands)		
Cash flow from investing activities:			
Acquisition of oil and natural gas properties and joint-venture funding, net of cash acquired	$(279,213)	$(2,640,475)	$(1,500,193)
Capital expenditures	(1,170,377)	(1,045,079)	(629,864)
Proceeds from sale of properties and equipment and other	196,273	725	(303)
	$(1,253,317)	$(3,684,829)	$(2,130,360)

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 decrease was primarily due to one significant cash acquisition of properties in the Permian Basin region consummated during the year ended December 31, 2013, compared to a total of four cash acquisitions of properties in the Rockies, Hugoton Basin and East Texas regions during the year ended December 31, 2012. 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 increased primarily due to development activities of properties acquired in 2012 in the Hugoton Basin and Rockies regions, as well as capital additions for pipelines and supporting facilities in the Granite Wash formation. Proceeds from sale of properties and equipment and other for the year ended December 31, 2013, include approximately $218 million in net proceeds received for the sale of the Panther Operated Cleveland Properties in May 2013 (see Note 2).

Cash used in investing activities for the year ended December 31, 2011, primarily relates to acquisitions of properties in the Mid-Continent, Rockies and Permian Basin regions. See Note 2 for additional details of acquisitions. The year ended December 31, 2011, also includes a deposit of approximately $9 million returned to the Company by the other party to a purchase and sale agreement ("PSA") terminated by the Company in 2010.

Financing Activities

Cash provided by financing activities for the year ended December 31, 2013, was approximately $138 million compared to approximately $3.3 billion for the year ended December 31, 2012. The decrease in financing cash flow needs was primarily attributable to reduced cash acquisition activity during the year ended December 31, 2013. Cash provided by financing activities was approximately $1.4 billion for the year ended December 31, 2011.

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

	Year Ended December 31,		
	2013	2012	2011
	(in thousands)		
Proceeds from borrowings:			
LINN Credit Facility	$1,730,000	$3,640,000	$1,790,000
Term loan	500,000	—	—
Senior notes	—	1,799,802	744,240
	$2,230,000	$5,439,802	$2,534,240
Repayments of debt:			
LINN Credit Facility	$(1,350,000)	$(3,400,000)	$(850,000)
Senior notes	(54,898)	—	(451,029)
	$(1,404,898)	$(3,400,000)	$(1,301,029)

Debt

In April 2013, the Company entered into a Sixth Amended and Restated Credit Agreement ("LINN Credit Facility"), which provides for a revolving credit facility up to the lesser of: (i) the then-effective borrowing base and (ii) the maximum commitment amount of $4.0 billion. The borrowing base remained unchanged at $4.5 billion and does not include any assets acquired in the Berry acquisition (see Note 2). The maturity date is April 2018. The amended and restated agreement is substantially similar to the previous LINN Credit Facility with revisions to permit the transactions related to the Berry acquisition and to designate Berry as an unrestricted subsidiary under the agreement. At January 31, 2014, the borrowing capacity under the LINN Credit Facility was approximately $2.3 billion, which includes a $5 million reduction in availability for outstanding letters of credit.

As of December 31, 2013, 2012 and 2011, the Company was in compliance with all financial and other covenants of its Credit Facilities. 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. For information related to the Credit Facilities, see Note 6.

The Company depends, in part, on its Credit Facilities for future capital needs; however, at December 31, 2013, there was no remaining borrowing capacity 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 occurs and is 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."

On October 30, 2013, the Company entered into an amendment to the LINN Credit Facility, under which the Company entered into a $500 million senior secured term loan with certain participants in its lender group under the LINN Credit Facility. The term loan has a maturity date of April 2018, consistent with the maturity of the LINN Credit Facility, and incurs interest based on either 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. The proceeds of the term loan were used to partially fund the acquisition of certain oil and natural gas properties located in the Permian Basin.

In accordance with the provisions of the indentures related to the May 2017 Senior Notes and July 2018 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 Berry acquisition, the Company assumed approximately $2.3 billion of Berry's debt, consisting of a senior secured revolving credit facility, 10.25% senior notes due 2014, 6.75% senior notes due 2020 and 6.375% senior notes due 2022. For information related to Berry's debt, see Note 6.

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Berry's $205 million in aggregate principal amount of 10.25% senior notes due June 2014 (the "Berry June 2014 Senior Notes") matures on June 1, 2014. Therefore, the $205 million is classified as a current obligation on the Company's consolidated balance sheet at December 31, 2013. While the Company has not yet determined how it will repay or refinance the Berry June 2014 Senior Notes, the Company may do so through various alternatives which it may pursue separately or in combination, including (i) issuing new debt or equity securities and (ii) borrowing under the LINN Credit Facility.

In December 2013, Berry entered into an amendment to its Second Amended and Restated Credit Agreement ("Berry Credit Facility") primarily to conform certain terms in the Berry Credit Facility to like terms in the LINN Credit Facility. The maturity date of the Berry Credit Facility is May 2016. The Berry Credit Facility has a borrowing base of $1.4 billion, subject to lender commitments. At December 31, 2013, lender commitments under the facility were $1.2 billion and there was no remaining borrowing capacity available. In February 2014, Berry entered into an amendment to the Berry Credit Facility to amend the terms of certain financial covenants and reporting covenants.

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 previously-announced 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. 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 outstanding indebtedness 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 indebtedness outstanding under the LINN Credit Facility.

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Equity Distribution Agreement

The Company has an equity distribution agreement pursuant to which it may from time to time issue and sell units representing limited liability company interests having an aggregate offering price of up to $500 million. 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.

In January 2012, the Company, under its equity distribution agreement, issued and sold 1,539,651 units representing limited liability company interests at an average unit price of $38.02 for proceeds of approximately $57 million (net of approximately $1 million in commissions). In connection with the issue 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 indebtedness outstanding under the LINN Credit Facility. At December 31, 2013, units equaling approximately $411 million in aggregate offering price remained available to be issued and sold under the agreement.

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, 2013:

Date Paid	Distributions Per Unit	Total Distributions (in millions)
December 2013	$0.2416	$57
November 2013	$0.2416	$57
October 2013	$0.2416	$57
September 2013	$0.2416	$57
August 2013	$0.2416	$57
July 2013	$0.2416	$57
May 2013	$0.725	$170
February 2013	$0.725	$171

In April 2013, the Company's Board of Directors approved a change in its 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 distributions were paid in July 2013.

On January 2, 2014, the Company's Board of Directors declared a cash distribution of $0.725 per unit with respect to the fourth quarter of 2013, to be paid in three equal monthly installments of $0.2416 per unit. The first monthly distribution with respect to the fourth quarter of 2013, totaling approximately $80 million, was paid on January 16, 2014, to unitholders of record as of the close of business on January 13, 2014, and the second monthly distribution, totaling approximately $80 million, was paid on February 13, 2014, to unitholders of record as of the close of business on February 10, 2014.

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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Commitments and Contractual Obligations

The following summarizes, as of December 31, 2013, certain long-term contractual obligations that are reflected in the consolidated balance sheets and/or disclosed in the accompanying notes thereto:

	Payments Due				
Contractual Obligations	Total	2014	2015 – 2016	2017 – 2018	2019 and Beyond
	(in thousands)				
Long-term debt obligations:					
Credit facilities	$2,733,175	$—	$1,173,175	$1,560,000	$—
Term loan	500,000	—	—	500,000	—
Senior notes	5,955,257	205,257	—	—	5,750,000
Interest [(1)]	2,943,502	494,520	949,729	872,878	626,375
Operating lease obligations:					
Office, property and equipment leases	50,036	14,222	19,015	11,013	5,786
Other:					
Commodity derivatives	32,825	28,176	4,649	—	—
Asset retirement obligations	289,321	12,616	11,759	12,246	252,700
Firm natural gas transportation contracts [(2)]	214,070	33,672	66,863	57,388	56,147
Purchase obligations and other [(3)]	15,560	10,967	4,593	—	—
	$12,733,746	$799,430	$2,229,783	$3,013,525	$6,691,008

(1) Represents interest on the Berry Credit Facility computed at 2.67% through maturity in May 2016 and interest on the LINN Credit Facility and term loan computed at 1.92% and 2.67%, respectively, through maturities in April 2018. Interest on the Berry June 2014 Senior Notes, May 2019 Senior Notes, November 2019 Senior Notes, April 2020 Senior Notes, Berry November 2020 Senior Notes, February 2021 Senior Notes and Berry September 2022 Senior Notes, as defined in Note 6, computed at fixed rates of 10.25%, 6.50%, 6.25%, 8.625%, 6.75%, 7.75% 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 one 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.

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Capital Structure

The Company's capitalization is presented below:

	December 31, 2013	2012
	(in thousands)	
Cash and cash equivalents	$52,171	$1,243
Berry Credit Facility	$1,173,175	$—
LINN Credit Facility	1,560,000	1,180,000
Term loan	500,000	—
Berry senior notes due June 2014, net	211,558	—
Senior notes due May 2017, net	—	39,399
Senior notes due July 2018, net	—	13,941
Senior notes due May 2019, net	745,796	745,172
Senior notes due November 2019, net	1,799,841	1,799,818
Senior notes due April 2020, net	1,276,768	1,274,169
Berry senior notes due November 2020, net	309,702	—
Senior notes due February 2021, net	986,650	985,318
Berry senior notes due September 2022, net	606,726	—
	9,170,216	6,037,817
Total unitholders' capital	5,891,427	4,427,180
	$15,061,643	$10,464,997

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 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 each of the years ended December 31, 2012, and December 31, 2011, following acquisitions and development activities during such years, the Company's Board of Directors reviewed the excess 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 in each of those years. In 2013, the Company's Board of Directors considered shortfalls in 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 its current 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 fully offset declines in production and proved developed producing reserves 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" 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 or

eliminated."
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 its Credit Facilities 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 operating cash flows 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,		
	2013	2012	2011
	(in thousands)		
Net cash provided by operating activities	$1,166,212	$350,907	$518,706
Distributions to unitholders	(682,241)	(596,935)	(466,488)
Excess (shortfall) of net cash provided by operating activities after distributions to unitholders	483,971	(246,028)	52,218
Discretionary adjustments considered by the Board of Directors:			
Premiums paid for derivatives (1)	—	583,434	134,352
Cash settlements on canceled derivatives (2)	—	—	(26,752)
Cash recoveries of bankruptcy claim (3)	(11,222)	(21,503)	—
Cash received (paid) for acquisitions or divestitures – revenues less operating expenses (4)	7,144	80,502	57,966
Discretionary reductions for a portion of oil and natural gas development costs (5)	(476,507)	(362,430)	(167,281)
Provision for legal matters (6)	1,000	414	1,086
Changes in operating assets and liabilities and other, net (7)	(9,030)	47,951	72,147
Excess (shortfall) of net cash provided by operating activities after distributions to unitholders and discretionary adjustments considered by the Board of Directors (8)	$(4,644)	$82,340	$123,736

(1) 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.

(2) Represent derivatives canceled prior to the contract settlement date. In 2011, commodity derivatives were canceled and the proceeds were reallocated within the Company's derivatives portfolio.

(3) 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.

(4) Represents adjustments to the purchase price of acquisitions, 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. 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.

(5) 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 fully offset declines in production and proved developed producing reserves 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."

See below for total development of oil and natural gas properties as presented in the statements of cash flows:

	Year Ended December 31,		
	2013	2012	2011
	(in thousands)		
Total development of oil and natural gas properties	$1,078,025	$984,530	$574,635

See below for disclosure 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,		
	2013	2012	2011
Discretionary reductions for a portion of oil and natural gas development costs (in thousands) [(a)]	$476,507	$362,430	$167,281
Portion of non-producing reserves estimated to be converted to producing status through discretionary reductions (Bcfe) [(b)]	313	265	120

(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.

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

(7) Represents primarily working capital adjustments. These adjustments may or may not impact cash provided by 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.

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

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

	Year Ended December 31, 2013	2012	2011
	(in thousands)		
Net cash provided by operating activities	$1,166,212	$350,907	$518,706
Distributions to unitholders	(682,241)	(596,935)	(466,488)
Excess (shortfall) of net cash provided by operating activities after distributions to unitholders	483,971	(246,028)	52,218
Plus (less):			
Net cash provided by financing activities (excluding distributions to unitholders)	820,274	3,930,986	1,843,255
Acquisition of oil and natural gas properties and joint-venture funding, net of cash acquired	(279,213)	(2,640,475)	(1,500,193)
Development of oil and natural gas properties	(1,078,025)	(984,530)	(574,635)
Purchases of other property and equipment	(92,352)	(60,549)	(55,229)
Proceeds from sale of properties and equipment and other	196,273	725	(303)
Net increase (decrease) in cash and cash equivalents	$50,928	$129	$(234,887)

Critical Accounting Policies and Estimates

The discussion and analysis of the Company's financial condition and results of operations is based upon 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 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.

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, 2013, 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 producing 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 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 $2 million for each of the years ended December 31, 2013, December 31, 2012, and December 31, 2011.

Impairment of Proved Properties

Based on the analysis described above, for 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. For the year ended December 31, 2012, the Company recorded a noncash impairment charge, 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. The Company recorded no impairment charge for the year ended December 31, 2011. 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 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. The fair values of unproved 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 unproved 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 market-based weighted average cost of capital rate is subjected to additional project-specific risking factors. 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 $5 million for the year ended December 31, 2013, and approximately $2 million for the years ended December 31, 2012, and December 31, 2011, 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. 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. At December 31, 2013, and December 31, 2012, the Company had natural gas production imbalance receivables of approximately $27 million and $28 million, respectively, which are included in "accounts receivable – trade, net" on the consolidated balance sheets and natural gas production imbalance payables of approximately $16 million and $18 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 sales and natural gas marketing expenses.

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 when the obligation is incurred, and are amortized over proved developed reserves using the unit-of-production method. Accretion expense is included in "depreciation, depletion and amortization" on the consolidated statements of operations. The fair values of additions to the asset retirement obligations are estimated using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation include estimates of: (i) plug and abandon costs per well based on existing regulatory requirements; (ii) remaining life per well; (iii) future inflation factors; and (iv) a credit-adjusted risk-free interest rate. Revisions in estimated liabilities can result from revisions of estimated inflation rates, escalating retirement costs and changes in the estimated timing of settling asset retirement obligations (see Note 10).

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 cash flow from operations due to fluctuations in commodity prices. These transactions are primarily in the form of swap contracts and put options. 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, 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, 2013, the Company had no outstanding derivative contracts in the form of interest rate swaps.

As part of 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. 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.

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.

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. Deferred taxes are recorded for any differences between the assigned values and the tax basis of assets and liabilities. Estimated deferred taxes are based on available information concerning the tax basis of assets acquired and liabilities assumed and loss carryforwards at the acquisition date, although such estimates may change in the future as additional information becomes known.

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.

Legal, Environmental and Other Contingencies

A provision for legal, environmental and other contingencies is charged to expense when the loss is probable and the cost can be reasonably estimated. Determining when expenses should be recorded for these contingencies and the appropriate amounts of the accrual is subject to an estimation process that requires subjective judgment of management. In many cases, management’s judgment is based on the advice and opinions of legal counsel and other advisers, the interpretation of laws and

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regulations which can be interpreted differently by regulators and/or courts of law, the experience of the Company and other companies dealing with similar matters, and management's decision on how it intends to respond to a particular matter; for example, a decision to contest it vigorously or a decision to seek a negotiated settlement. The Company's management closely monitors known and potential legal, environmental and other contingencies and periodically determines when it should record losses for these items based on information available to the Company.

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. See Note 1 and Note 5 for additional details about the Company's accounting for unit-based compensation.

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.

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. 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. 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.

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.

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

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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.

As part of the acquisition of Berry Petroleum Company (“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.

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 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.

At December 31, 2012, the fair value of fixed price swaps and put option contracts was a net asset of approximately $899 million. A 10% increase in the index oil and natural gas prices above December 31, 2012, prices would result in a net liability of approximately $29 million, which represents a decrease in the fair value of approximately $928 million; conversely, a 10% decrease in the index oil and natural gas prices below December 31, 2012, prices would result in a net asset of approximately $1.8 billion, which represents an increase in the fair value of approximately $946 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, 2013, 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 flow and ability to pay distributions could be impacted.

Interest Rate Risk

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 London Interbank Offered Rate (“LIBOR”) would result in an estimated $32 million increase in annual interest expense.

At December 31, 2012, the Company had long-term debt outstanding under the LINN Credit Facility of approximately $1.2 billion, which incurred interest at floating rates (see Note 6). A 1% increase in the LIBOR would result in an estimated $12 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.

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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.

At December 31, 2012, the average public bond yield spread utilized to estimate the impact of the Company's credit risk on derivative liabilities was approximately 2.47%. A 1% increase in the average public bond yield spread would result in an estimated $131,000 increase in net income for the year ended December 31, 2012. At December 31, 2012, the credit default swap spreads utilized to estimate the impact of counterparties' credit risk on derivative assets ranged between 0% and 3.22%. A 1% increase in each of the counterparties' credit default swap spreads would result in an estimated $9 million decrease in net income for the year ended December 31, 2012.

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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, 2013, 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. Based on the assessment, management determined that we maintained effective internal control over financial reporting as of December 31, 2013, based on those criteria. The Company acquired Berry Petroleum Company ("Berry") in December 2013. Berry is a wholly owned subsidiary of the Company, and Berry's internal control over financial reporting associated with total assets of approximately $5.1 billion and total revenues of approximately $47 million included in the consolidated financial statements of the Company as of and for the year ended December 31, 2013, is excluded from our assessment of the effectiveness of internal control over financial reporting as of December 31, 2013.

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, 2013, 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, 2013 and 2012, 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, 2013. 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 audits 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, 2013 and 2012, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2013, 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, 2013, based on criteria established in Internal Control–Integrated Framework (1992) by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 27, 2014, expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

Houston, Texas
February 27, 2014

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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, 2013, based on criteria established in Internal Control–Integrated Framework (1992) 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, 2013, based on criteria established in Internal Control–Integrated Framework (1992) by the Committee of Sponsoring Organizations of the Treadway Commission.

Linn Energy, LLC acquired Berry Petroleum Company (Berry) during 2013 and management excluded from its assessment of the effectiveness of Linn Energy, LLC's internal control over financial reporting as of December 31, 2013, Berry's internal control over financial reporting associated with total assets of approximately $5.1 billion and total revenues of approximately $47 million included in the consolidated financial statements of Linn Energy, LLC and subsidiaries as of and for the year ended December 31, 2013. Our audit of internal control over financial reporting of Linn Energy, LLC also excluded an evaluation of the internal control over financial reporting of Berry.

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, 2013 and 2012, 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, 2013, and our report dated February 27, 2014, expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Houston, Texas
February 27, 2014

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LINN ENERGY, LLC
CONSOLIDATED BALANCE SHEETS

	December 31, 2013	2012
	(in thousands, except unit amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$52,171	$1,243
Accounts receivable – trade, net	488,202	371,333
Derivative instruments	176,130	350,695
Other current assets	99,437	88,157
Total current assets	815,940	811,428
Noncurrent assets:		
Oil and natural gas properties (successful efforts method)	17,888,559	11,611,330
Less accumulated depletion and amortization	(3,546,284)	(2,025,656)
	14,342,275	9,585,674
Other property and equipment	647,882	469,188
Less accumulated depreciation	(110,939)	(73,721)
	536,943	395,467
Derivative instruments	682,002	530,216
Other noncurrent assets	127,804	128,453