LINN ENERGY, LLC
Form 10-K
February 21, 2013

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, 2012

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

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

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

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

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

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes ¨ No x

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes x No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Yes x No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.
Large accelerated filer x Accelerated filer ¨ Non-accelerated filer ¨ Smaller reporting company ¨

Indicate by check-mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).
Yes ¨ No x

The aggregate market value of voting and non-voting common equity held by non-affiliates of the registrant was approximately $7.5 billion on June 30, 2012, based on $38.10 per unit, the last reported sales price of the units on the NASDAQ Global Select Market on such date.

As of January 31, 2013, there were 235,129,742 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 23, 2013.

TABLE OF CONTENTS

Table of Contents

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.

Dry hole or well. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production would exceed production expenses and taxes.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Formation. A stratum of rock that is recognizable from adjacent strata consisting 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.

MMcfe/d. MMcfe per day.

MMMBtu. One billion British thermal units.

Table of Contents

GLOSSARY OF TERMS - Continued

Net acres or net wells. The sum of the fractional working interests owned in gross acres or gross wells, as the case may be.

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

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

Proved developed reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well. Additional reserves expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included in “proved developed reserves” only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved reserves. Reserves that by analysis of geoscience and engineering data can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

Proved undeveloped drilling location. A site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.

Proved undeveloped reserves or PUDs. Reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Estimates for proved undeveloped reserves are not attributed to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

Recompletion. The completion for production of an existing wellbore in another formation from that which the well has been previously completed.

Reservoir. A porous and permeable underground formation containing a natural accumulation of economically productive natural gas and/or oil that is confined by impermeable rock or water barriers and is individual and separate from other reserves.

Royalty interest. An interest that entitles the owner of such interest to a share of the mineral production from a property or to a share of the proceeds there from. It does not contain the rights and obligations of operating the property and normally does not bear any of the costs of exploration, development and operation of the property.

Spacing. The number of wells which conservation laws allow to be drilled on a given area of land.

Standardized measure of discounted future net cash flows. The present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with the regulations of the Securities and Exchange Commission (“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%.

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.

Table of Contents
GLOSSARY OF TERMS - Continued

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

Table of Contents

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.

A 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 Mid-Continent, the Hugoton Basin, the Green River Basin, the Permian Basin, Michigan, Illinois, the Williston/Powder River Basin, California and east Texas.

Proved reserves at December 31, 2012, were 4,796 Bcfe, of which approximately 24% were oil, 54% were natural gas and 22% were natural gas liquids (“NGL”). Approximately 65% were classified as proved developed, with a total standardized measure of discounted future net cash flows of $6.1 billion. At December 31, 2012, the Company operated 11,048 or 70% of its 15,804 gross productive wells and had an average proved reserve-life index of approximately 16 years, based on the December 31, 2012, reserve report and fourth quarter 2012 annualized 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, 2007, excluding three acquisitions of Appalachian Basin properties sold in July 2008, the Company has completed 40 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 4.5 Tcfe with acquisition costs of approximately $2.01 per Mcfe. The Company finances acquisitions with a combination of funds from equity and debt offerings, bank borrowings and cash flow from operations. See Note 2 for additional details about the Company’s acquisitions.

Table of Contents

Item 1. Business - Continued

Efficiently Operate and Develop Acquired Properties

The Company has centralized 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 cash flow. Many of the 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 2013, the Company estimates its total capital expenditures, excluding acquisitions, will be approximately $1.2 billion, including $1.1 billion related to its oil and natural gas capital program and $67 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 cash flow from operations 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 pay distributions, service debt and manage its business. 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.

The Company enters into commodity hedging transactions primarily in the form of swap contracts and put options that are designed to provide a fixed price (swap contracts) or fixed price floor with the opportunity for upside (put options) that the Company will receive as compared to floating market prices. For additional details about the Company’s commodity derivative contracts, see Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and Item 7A. “Quantitative and Qualitative Disclosures About Market Risk.” See also Note 7 and Note 8.

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

Recent Developments

LinnCo Initial Public Offering

On October 17, 2012, LinnCo, LLC (“LinnCo”), an affiliate of LINN Energy, completed its initial public offering (the “LinnCo IPO”) of 34,787,500 common shares representing limited liability company interests (“Common Shares”) for net proceeds of approximately $1.2 billion. 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 its Credit Facility.

LinnCo is a Delaware limited liability company formed on April 30, 2012, under the Delaware Limited Liability Company Act and its Common Shares are listed on the NASDAQ Global Select Market under the symbol “LNCO.” LinnCo’s sole purpose is to own units in LINN Energy and it expects to have no significant assets or operations other than those related to its interest in LINN Energy. At December 31, 2012, LINN Energy owned 100% of LinnCo’s sole voting share and all of LinnCo’s Common Shares were held by the public. At December 31, 2012, LinnCo owned approximately 15% of LINN Energy’s outstanding units.

Acquisitions

On July 31, 2012, the Company completed the acquisition of certain oil and natural gas properties in the Jonah Field located in the Green River Basin of southwest Wyoming from BP America Production Company (“BP”) for total consideration of approximately $990 million. The acquisition included approximately 806 Bcfe of proved reserves as of the acquisition date.

2

Table of Contents

Item 1. Business - Continued

On May 1, 2012, the Company completed the acquisition of certain oil and natural gas properties located in east Texas for total consideration of approximately $168 million. The acquisition included approximately 110 Bcfe of proved reserves as of the acquisition date.

On April 3, 2012, the Company entered into a joint-venture agreement ("JV Agreement") with an affiliate of Anadarko Petroleum Corporation ("Anadarko") whereby the Company participates as a partner in the CO2 enhanced oil recovery development of the Salt Creek Field, located in the Powder River Basin of Wyoming. Anadarko assigned the Company 23% of its interest in the field in exchange for future funding of $400 million of Anadarko's development costs. As of December 31, 2012, the Company has paid approximately $201 million towards the future funding commitment. The acquisition included approximately 16 MMBoe (96 Bcfe) of proved reserves as of the JV Agreement date.

On March 30, 2012, the Company completed the acquisition of certain oil and natural gas properties and the Jayhawk natural gas processing plant located in the Hugoton Basin in Kansas from BP for total consideration of approximately $1.16 billion. The acquisition included approximately 689 Bcfe of proved reserves as of the acquisition date.

During 2012, the Company completed other smaller acquisitions of oil and natural gas properties located in its various operating regions. The Company, in the aggregate, paid approximately $122 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.

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 its financial condition and results of operations.

Distributions

On January 24, 2013, the Company's Board of Directors declared a cash distribution of $0.725 per unit, or $2.90 per unit on an annualized basis, with respect to the fourth quarter of 2012. The distribution, totaling approximately $170 million, was paid on February 14, 2013, to unitholders of record as of the close of business on February 7, 2013.

Operating Regions

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

- 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;
- Green River Basin, which includes properties located in southwest Wyoming;
- 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;
- Williston/Powder River Basin, which includes the Bakken formation in North Dakota and the Powder River Basin in Wyoming;
- California, which includes the Brea Olinda Field of the Los Angeles Basin; and
- East Texas, which includes properties located in east Texas.

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

3

Table of Contents

Item 1. Business - Continued

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 34% of total proved reserves at December 31, 2012, of which 59% were classified as proved developed. This region produced 313 MMcfe/d or 48% of the Company's 2012 average daily production. During 2012, the Company invested approximately $578 million to drill in this region. During 2013, the Company anticipates spending approximately 49% of its total oil and natural gas capital budget for development activities in the Mid-Continent region, primarily in the Granite Wash formation.

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 300 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. The Company's Kansas properties in the basin, acquired in March 2012, 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 21% of total proved reserves at December 31, 2012, of which 85% were classified as proved developed. This region produced 120 MMcfe/d or 18% of the Company's 2012 average daily production. During 2012, the Company invested approximately $11 million to drill in this region. During 2013, 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.

Green River Basin

The Green River Basin region consists of properties acquired in July 2012. These properties are located in southwest Wyoming and primarily produce natural gas at depths ranging from 8,000 feet to 12,000 feet. Green River Basin proved reserves represented approximately 21% of total proved reserves at December 31, 2012, of which 43% were classified as proved developed. This region produced 62 MMcfe/d or 9% of the Company's 2012 average daily production. During 2012, the Company invested approximately $22 million to drill in this region. During 2013, the Company anticipates spending approximately 12% of its total oil and natural gas capital budget for development activities in the Green River Basin 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 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. Permian Basin proved reserves represented approximately 8% of total proved reserves at December 31, 2012, of which 56% were classified as proved developed. This region produced 83 MMcfe/d or 12% of the Company's 2012 average daily production. During 2012, the Company invested approximately $240 million to drill in this region. During 2013, the Company anticipates spending approximately 20% of its total oil and natural gas capital budget for development activities in the Permian Basin region, primarily in the Wolfberry trend.

Table of Contents

Item 1. Business - Continued

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 6% of total proved reserves at December 31, 2012, of which 94% were classified as proved developed. This region produced 35 MMcfe/d or 5% of the Company's 2012 average daily production. During 2013, the Company anticipates spending approximately 1% of its total oil and natural gas capital budget for development activities in the Michigan/Illinois region.

Williston/Powder River Basin

The Williston/Powder River Basin region includes the Bakken formation in North Dakota and the Powder River Basin in Wyoming. The Company's nonoperated properties in the Williston Basin, one of the premier oil basins in the U.S., produce at depths ranging from 9,000 feet to 12,000 feet. The Company's properties in the Powder River Basin, acquired in April 2012, consist of a CO_2 flood operated by Anadarko in the Salt Creek Field. Williston/Powder River Basin proved reserves represented approximately 4% of total proved reserves at December 31, 2012, of which 66% were classified as proved developed. This region produced 29 MMcfe/d or 4% of the Company's 2012 average daily production. During 2012, the Company invested approximately $124 million to drill in this region. During 2013, the Company anticipates spending approximately 12% of its total oil and natural gas capital budget for development activities in the Williston/Powder River Basin region.

California

The California region consists of the Brea Olinda Field of 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. California proved reserves represented approximately 4% of total proved reserves at December 31, 2012, of which 96% were classified as proved developed. This region produced 13 MMcfe/d or 2% of the Company's 2012 average daily production. During 2012, the Company invested approximately $1 million to drill in this region. During 2013, the Company anticipates spending approximately 2% of its total oil and natural gas capital budget for development activities in the California region.

East Texas

The East Texas region consists of properties acquired in May 2012. These properties are located in east Texas and primarily produce natural gas from the Cotton Valley formation at depths of approximately 11,000 feet. Proved reserves for these mature, low-decline producing properties, all of which are proved developed, represented approximately 2% of total proved reserves at December 31, 2012. This region produced 16 MMcfe/d or 2% of the Company's 2012 average daily production. During 2013, the Company anticipates spending approximately 1% of its total oil and natural gas capital budget for development activities in the East Texas region.

Table of Contents

Item 1. Business - Continued

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,		
	2012	2011	2010
Gross wells:			
Productive	436	292	138
Dry	4	2	1
	440	294	139
Net development wells:			
Productive	223	186	116
Dry	2	2	1
	225	188	117
Net exploratory wells:			
Productive	—	—	—
Dry	—	—	—
	—	—	—

The totals above do not include 8 lateral segments added to existing vertical wellbores in the Hugoton Basin region during the year ended December 31, 2010. There were no lateral segments added to existing vertical wellbores during the years ended December 31, 2012, or December 31, 2011. At December 31, 2012, the Company had 139 gross (53 net) wells in progress (two 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, 2012:

	Total [(1)]
Proved undeveloped	2,504
Other locations	8,477
Total drilling locations	10,981
Leasehold interests – net acres (in thousands)	1,770

(1) Does not include optimization projects.

As shown in the table above, as of December 31, 2012, the Company had 2,504 proved undeveloped drilling locations (specific drilling locations as to which the independent engineering firm, DeGolyer and MacNaughton, assigned proved undeveloped reserves as of such date) and the Company had identified 8,477 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.

Table of Contents

Item 1. Business - Continued

Productive Wells

The following sets forth information relating to the productive wells in which the Company owned a working interest as of December 31, 2012. Productive wells consist of producing wells and wells capable of production, including wells awaiting pipeline or other connections to commence deliveries. “Gross” wells refers to the total number of producing wells in which the Company has an interest, and “net” wells refers to the sum of its fractional working interests owned in gross wells. The number of wells below does not include approximately 2,590 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)]	6,929	5,925	4,119	3,825	11,048	9,750
Nonoperated [(2)]	2,273	564	2,483	381	4,756	945
	9,202	6,489	6,602	4,206	15,804	10,695

[(1)] The Company had 12 operated wells with multiple completions at December 31, 2012.

[(2)] The Company had no nonoperated wells with multiple completions at December 31, 2012.

Developed and Undeveloped Acreage

The following sets forth information relating to leasehold acreage as of December 31, 2012:

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
	(in thousands)					
Leasehold acreage	2,536	1,719	118	51	2,654	1,770

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, 2012, approximately 85% of the Company’s natural gas and NGL production was sold under short-term contracts at market-sensitive or spot prices. At December 31, 2012, the Company had natural gas throughput delivery commitments under long-term contracts of approximately 24 Bcf to be delivered by August 2015.

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, 2012, approximately 90% of its oil production was sold under short-term contracts. At December 31, 2012, the Company had no delivery commitments for oil production.

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 cash flow from operations. 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 due to fluctuations in commodity prices.

Table of Contents

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,		
	2012	2011	2010
Average daily production:			
Natural gas (MMcf/d)	349	175	137
Oil (MBbls/d)	29.2	21.5	13.1
NGL (MBbls/d)	24.5	10.8	8.3
Total (MMcfe/d)	671	369	265
Weighted average prices (hedged): (1)			
Natural gas (Mcf)	$5.48	$8.20	$8.52
Oil (Bbl)	$93.10	$89.21	$94.71
NGL (Bbl)	$32.10	$42.88	$39.14
Weighted average prices (unhedged): (2)			
Natural gas (Mcf)	$2.87	$4.35	$4.24
Oil (Bbl)	$88.59	$91.24	$75.16
NGL (Bbl)	$32.10	$42.88	$39.14
Average NYMEX prices:			
Natural gas (MMBtu)	$2.79	$4.05	$4.40
Oil (Bbl)	$94.20	$95.12	$79.53
Costs per Mcfe of production:			
Lease operating expenses	$1.29	$1.73	$1.64
Transportation expenses	$0.31	$0.21	$0.20
General and administrative expenses (3)	$0.71	$0.99	$1.02
Depreciation, depletion and amortization	$2.47	$2.48	$2.46
Taxes, other than income taxes	$0.54	$0.58	$0.47

(1) Includes the effect of realized gains on derivatives of approximately $381 million (excluding $22 million realized gains on recovery of bankruptcy claim), $230 million (excluding $27 million realized gains on canceled contracts of which the proceeds were reallocated within the Company’s derivatives portfolio), and $308 million for the years ended December 31, 2012, December 31, 2011, and December 31, 2010, respectively.

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

(3) General and administrative expenses for the years ended December 31, 2012, December 31, 2011, and December 31, 2010, include approximately $28 million, $21 million and $13 million, respectively, of noncash unit-based compensation expenses. Excluding these amounts, general and administrative expenses for the years ended December 31, 2012, December 31, 2011, and December 31, 2010, were $0.59 per Mcfe, $0.83 per Mcfe and $0.88 per Mcfe, respectively. This measure is not in accordance with U.S. Generally Accepted Accounting Principles (“GAAP”) and thus is a non-GAAP measure, used by management to analyze the Company’s performance.

Table of Contents

Item 1. Business - Continued

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, 2012, based on reserve reports prepared by independent engineers, DeGolyer and MacNaughton:

Estimated proved developed reserves:		
Natural gas (Bcf)	1,661	
Oil (MMBbls)	131	
NGL (MMBbls)	113	
Total (Bcfe)	3,127	
Estimated proved undeveloped reserves:		
Natural gas (Bcf)	910	
Oil (MMBbls)	60	
NGL (MMBbls)	66	
Total (Bcfe)	1,669	
Estimated total proved reserves (Bcfe)	4,796	
Proved developed reserves as a percentage of total proved reserves	65	%
Standardized measure of discounted future net cash flows (in millions) (1)	$6,073	
Representative NYMEX prices: (2)		
Natural gas (MMBtu)	$2.76	
Oil (Bbl)	$94.64	

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

(2) In accordance with Securities and Exchange Commission ("SEC") regulations, reserves were estimated using the average price during the 12-month period, determined as an unweighted average of the first-day-of-the-month price for each month, unless prices are defined by contractual arrangements, 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, 2012, the Company's proved undeveloped reserves ("PUDs") increased to 1,669 Bcfe from 1,336 Bcfe at December 31, 2011, representing an increase of 333 Bcfe. The increase was primarily due to 415 Bcfe added as a result of the Company's acquisitions in the Mid-Continent, Hugoton Basin, Williston/Powder River Basin, East Texas and Green River Basin regions and 588 Bcfe added as a result of its drilling activities, partially offset by 443 Bcfe of revisions and 227 Bcfe of PUDs developed during 2012.

During the year ended December 31, 2012, the Company incurred approximately $442 million in capital expenditures to convert 208 Bcfe of reserves classified as PUDs at December 31, 2011. Based on the December 31, 2012 reserve report, the amounts of capital expenditures estimated to be incurred in 2013, 2014 and 2015 to develop the Company's PUDs are approximately $679 million, $688 million and $622 million, respectively. The amount and timing of these expenditures will depend on a number of factors, including actual drilling results, service costs and product prices. None of the 1,669 Bcfe of PUDs at December 31, 2012, has remained undeveloped for five years or more. All PUD properties are included in the Company's current five-year development plan.

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

standardized measure of discounted future net cash flows should not be construed as the market value of the reserves at the dates shown. The 10% discount factor required to be used under the provisions of applicable accounting standards may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with the Company or the oil and natural gas industry. The standardized measure of discounted future net cash flows is materially affected by assumptions about 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 for 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 Reservoir Engineering Advisor, who has Master of Petroleum Engineering and Master of Business Administration degrees and more than 25 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, 2012, sales of oil, natural gas and NGL to Enbridge Energy Partners, L.P. and DCP Midstream Partners, LP accounted for approximately 24% and 13%, respectively, of the Company's total production volumes, or 37% in the aggregate. 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

10

personnel, which has delayed development drilling and has caused significant price increases. The Company is unable to predict when, or if, such shortages may occur or how they would affect its drilling program.

Operating Hazards and Insurance

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

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

Title to Properties

Prior to the commencement of drilling operations, the Company conducts a title examination and performs curative work with respect to significant defects. To the extent title opinions or other investigations reflect title defects on those properties, the Company is typically responsible for curing any title defects at its expense prior to commencing drilling operations. Prior to completing an acquisition of producing leases, the Company performs title reviews on the most significant leases and, depending on the materiality of properties, the Company may obtain a title opinion or review previously obtained title opinions. As a result, the Company has obtained title opinions on a significant portion of its properties and believes that it has satisfactory title to its producing properties in accordance with standards generally accepted in the industry. Oil and natural gas properties are subject to customary royalty and other interests, liens for current taxes and other burdens which do not materially interfere with the use of or affect the carrying value of the properties.

Seasonal Nature of Business

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

The demand for natural gas typically decreases during the summer months and increases during the winter months. Seasonal anomalies sometimes lessen this fluctuation. In addition, certain natural gas 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;

11

- 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
- with respect to operations affecting federal lands or leases, require preparation of a Resource Management Plan, an Environmental Assessment, and/or an Environmental Impact Statement.

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, 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 response to findings that emissions of carbon dioxide and certain other gases may be contributing to warming of the Earth’s atmosphere, the Environmental Protection Agency (“EPA”) has adopted regulations under existing provisions of the federal Clean Air Act that would require a reduction in emissions of greenhouse gases (“GHG”) from motor vehicles and also may trigger construction and operating permit review for GHG emissions from certain stationary sources.

The EPA has asserted that the final motor vehicle GHG emission standards triggered construction and operating permit requirements for stationary sources. Thus, on June 3, 2010, the EPA issued a final rule to address permitting of

GHG emissions from stationary sources under the Clean Air Act's Prevention of Significant Deterioration ("PSD") and Title V programs. This final rule "tailors" the PSD and Title V programs to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. In addition, on November 8, 2010, the EPA published a final rule expanding its existing GHG emissions reporting rule published in October 2009 to include onshore and offshore oil and natural gas production and onshore oil and natural gas processing, transmission, storage and distribution activities. Facilities containing petroleum and natural gas systems that emit 25,000 metric tons or more of CO_2 equivalent per year are now required to report annual GHG emissions to the EPA, with the first report for emissions occurring in 2011 due on September 28, 2012. In addition, both houses of Congress have considered legislation to reduce emissions of GHGs, and almost one-half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Any laws or regulations that may be adopted to restrict or reduce emissions of U.S. greenhouse gases could require the Company to incur increased operating costs such as costs to purchase and operate emissions control systems, to acquire emissions allowances, or comply with new regulatory or reporting requirements, and could have an adverse effect on demand for oil and natural gas.

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 11, 2012, 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.

We use a significant amount of water in our hydraulic fracturing operations. Our inability to locate sufficient amounts of water, or dispose of or recycle water used in our drilling and production operations, could adversely impact our operations. Moreover, new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the development or production of natural gas. 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 our operating costs and cause delays, interruptions or termination of our operations, the extent of which cannot be predicted, all of which could have an adverse affect on our operations and financial condition.

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 have adopted, and other states 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 us to perform fracturing to stimulate production from tight formations. In addition, any such added regulation could lead to operational delays, increased operating costs and additional regulatory burdens, and reduced production of oil and natural gas, which could adversely affect the Company’s revenues and results of operations.

Table of Contents

Item 1. Business - Continued

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 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 our 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, 2012, 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 2013 or that will otherwise have a material impact on its financial position or results of operations.

Employees

As of December 31, 2012, the Company employed approximately 1,136 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.

Table of Contents

Item 1. Business - Continued

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;
- ability to maintain or grow distributions;
- drilling locations;
- oil, natural gas and NGL reserves;
- realized oil, natural gas and NGL prices;
- production volumes;
- lease operating expenses, general and administrative expenses and development costs;
- future operating results; and
- plans, objectives, expectations and intentions.

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 cash flow from operations to pay the quarterly 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 cash flow from operations each quarter to pay the quarterly 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 Facility to pay distributions;
- the costs of acquisitions, if any;
- fluctuations in our working capital needs;
- timing and collectibility of receivables;
- restrictions on distributions contained in our Credit Facility and the Indentures governing our November 2019 Senior Notes, May 2019 Senior Notes, 2010 Issued Senior Notes, and our Original Senior Notes, as defined in Note 6;
- prevailing economic conditions;
- access to credit or capital markets; and
- the amount of cash reserves established by our Board of Directors for the proper conduct of our business.

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

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

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

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

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 available cash flow per unit. 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 available cash flow per unit, these acquisitions may nevertheless result in a decrease in available cash flow per unit.

We have significant indebtedness under our November 2019 Senior Notes, May 2019 Senior Notes, 2010 Issued Senior Notes, and Original Senior Notes (collectively, “Senior Notes”) and, from time to time, our Credit Facility. For a discussion of our Senior Notes, see Note 6. Our Credit Facility 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, 2013, we had an aggregate of approximately $6.1 billion outstanding under Senior Notes and our Credit Facility (with additional borrowing capacity of approximately $1.8 billion under our Credit Facility). As a result of our indebtedness, we will use a portion of our cash flow to pay interest and principal when due, which will reduce the cash available to finance our operations and other business activities and could limit our flexibility in planning for or reacting to changes in our business and the industry in which we operate.
The Credit Facility restricts 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 Facility 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 Facility for future capital needs. We have drawn on our Credit Facility to fund or partially fund quarterly cash distribution payments, since we use operating cash flow primarily for drilling and development of oil and natural gas properties and acquisitions and borrow as cash is needed. Absent such borrowing, we would have at times experienced a shortfall in cash available to pay our declared quarterly cash distribution amount. If there is a default by us under our Credit Facility 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 Facility or the incurrence of additional debt. To the extent that we are unable to incur additional debt under our Credit Facility or otherwise because we are not in compliance with the financial covenants in the Credit Facility, 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 Facility on terms that are as favorable as those in our existing Credit Facility, or at all, our ability to fund our operations and our ability to pay distributions could be affected.
The borrowing base under our Credit Facility is determined semi-annually at the discretion of the lenders and is 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 Facility. 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 do not currently have substantial unpledged properties, and we may not have the financial resources in the future to make any mandatory principal prepayments required under the Credit Facility. 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.
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 Facility 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 cash flow 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 cash flow and results of operations.

A liquid, readily available and commercially viable market for hedging NGLs 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, tenor and number of counterparties, which limits our ability to hedge our NGL production effectively or at all. As a result, our cash flow 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 cash flow 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, cash flow from operations 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 cash flow. 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 cash flow from operations 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 Facility, 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 cash flow 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 cash flow from operations 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.

Table of Contents
Item 1A. Risk Factors - Continued

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 cash flow from operations and to the extent necessary, with equity and debt offerings or bank borrowings. Our cash flow from operations 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; and
- our ability to acquire, locate and produce new reserves.

If our revenues or the borrowing base under our Credit Facility 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 Facility restricts our ability to obtain new financing. If additional capital is needed, we may not be able to obtain debt or equity financing on terms favorable to us, or at all. If cash flow from operations or cash available under our Credit Facility 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 maintain 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, 2012, we had 2,504 proved undeveloped drilling locations. To the extent that we do not drill these locations within five years of initial booking, they may not continue to qualify for classification as proved reserves, and we may be required to reclassify such reserves as unproved reserves. The reclassification of such reserves could also have a negative effect on the borrowing base under our Credit Facility.

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

Table of Contents

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, 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. For the year ended December 31, 2011, Enbridge Energy Partners, L.P. and DCP Midstream Partners, LP accounted for approximately 21% and 19%, respectively, of our total production volumes, or 40% 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 cash from operations, 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, 2012, we had identified 10,981 drilling locations, of which 2,504 were proved undeveloped locations and 8,477 were other locations. These identified drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of factors, including the availability of capital, seasonal conditions, regulatory approvals, oil, natural gas and NGL prices, costs and drilling results. In addition, DeGolyer and MacNaughton has not estimated proved reserves for the 8,477 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:

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- the high cost, shortages or delivery delays of equipment and services;
- unexpected operational events;
- adverse weather conditions;
- facility or equipment malfunctions;

Table of Contents
Item 1A. Risk Factors - Continued

- 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 cash flow to pay quarterly 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 impact 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. Nonoperated wells represented approximately 30% of our total owned gross wells, or approximately 9% of our owned net wells, as of December 31, 2012. We have limited ability to influence or control the operation or future development of these nonoperated properties, including timing of drilling and other scheduled operations activities, compliance with environmental, safety and other regulations, or the amount of capital expenditures that we are required to fund with respect to them. The failure of an operator of our wells to adequately perform operations, an operator’s breach of the applicable agreements or an operator’s failure to act in ways that are in our best interest could reduce our production and revenues. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence or control the operation and future development of these properties could materially adversely affect the realization of our targeted returns on capital in drilling or acquisition activities and lead to unexpected future costs.

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

The operations of our wells, gathering systems, turbines, pipelines and other facilities are subject to stringent and complex federal, state and local environmental laws and regulations. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of orders enjoining future operations. There is an inherent risk that we may incur environmental costs and liabilities due to the nature of our business and the substances we handle. Certain environmental statutes, including the RCRA, CERCLA and analogous state laws and regulations, impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances have been disposed of or 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.”

Table of Contents

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.”

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

23

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 quarterly 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.

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 2012, 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 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 percentage depletion 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 (the "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

Table of Contents

bona fide hedging transactions or positions would be exempt from these position limits. The position limits rule was challenged in court by two industry associations and was vacated and remanded by a federal district court. The CFTC appealed the district court's ruling and that appeal is pending. 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 quarterly 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.

Item 1B. Unresolved Staff Comments

None

Item 2. Properties

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

The Company's obligations under its Credit Facility 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 Facility.

Offices

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

Table of Contents

Item 3. Legal Proceedings

For a discussion of general legal proceedings, see Note 11 of Notes to Consolidated Financial Statements.

Executive Officers of the Company

Name	Age	Position with the Company
Mark E. Ellis	57	Chairman, President and Chief Executive Officer
Kolja Rockov	42	Executive Vice President and Chief Financial Officer
Arden L. Walker, Jr.	53	Executive Vice President and Chief Operating Officer
Charlene A. Ripley	49	Senior Vice President and General Counsel
David B. Rottino	47	Senior Vice President of Finance, Business Development and Chief Accounting Officer

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

Kolja Rockov is the Executive Vice President and Chief Financial Officer and has served in such capacity since joining the Company in March 2005. Mr. Rockov is the founding chairman of a philanthropic organization benefitting Texas Children's Cancer Center in Houston, which has raised more than $1 million since 2009.

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

Charlene A. Ripley is the Senior Vice President and General Counsel and has served in such capacity since April 2007. She also serves on several nonprofit boards, including the Impact Youth Development Center, Girls Inc., the American Heart Association of Houston and Mercury – The Orchestra Redefined.

David B. Rottino is the Senior Vice President of Finance, Business Development and Chief Accounting Officer and has served in such capacity since July 2010. From June 2008 to July 2010, Mr. Rottino served as the Senior Vice President and Chief Accounting Officer. Prior to joining LINN Energy, Mr. Rottino served as Vice President and E&P Controller for El Paso Corporation from June 2006 to May 2008. Mr. Rottino is a Certified Public Accountant. In addition, he currently serves on the Board of Camp for All.

Item 4. Mine Safety Disclosures

Not applicable

Table of Contents

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, 2013, there were approximately 202 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.

	Unit Price Range		Cash
			Distributions
Quarter	High	Low	Declared Per Unit
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
2011:			
October 1 – December 31	$39.05	$32.80	$0.69
July 1 – September 30	$40.90	$31.91	$0.69
April 1 – June 30	$40.38	$36.65	$0.66
January 1 – March 31	$39.94	$37.34	$0.66

Distributions

The Company's limited liability company agreement requires it to make quarterly distributions to unitholders of all "available cash." Available cash means, for each fiscal quarter, all cash on hand at the end of the quarter less the amount of cash reserves established by the Board of Directors to:

- provide for the proper conduct of business (including reserves for future capital expenditures, future debt service requirements, and for anticipated credit needs); and
- comply with applicable laws, debt instruments or other agreements;

plus all cash on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made after the end of the quarter for which the determination is being made.

Working capital borrowings are borrowings that will be made under the Company's Credit Facility and in all cases are used solely for working capital purposes or to pay distributions to unitholders. See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources" for a discussion on the payment of future distributions.

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, 2007, 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.

Table of Contents

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

	December 31, 2007	December 31, 2008	December 31, 2009	December 31, 2010	December 31, 2011	December 31, 2012
LINN Energy	$100	$68	$145	$212	$230	$230
Alerian MLP Index	$100	$63	$111	$152	$173	$180
S&P 500 Index	$100	$63	$80	$92	$94	$109

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

None

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, 2012. At December 31, 2012, approximately $56 million was available for unit repurchase under the program.

Table of Contents

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 years ended December 31, 2008, and December 31, 2009. Unless otherwise indicated, results of operations information presented herein relates only to continuing operations.

	At or for the Year Ended December 31,				
	2012	2011	2010	2009	2008
	(in thousands, except per unit amounts)				
Statement of operations data:					
Oil, natural gas and natural gas liquids sales	$1,601,180	$1,162,037	$690,054	$408,219	$755,644
Gains (losses) on oil and natural gas derivatives	124,762	449,940	75,211	(141,374)	662,782
Depreciation, depletion and amortization	606,150	334,084	238,532	201,782	194,093
Interest expense, net of amounts capitalized	379,937	259,725	193,510	92,701	94,517
Income (loss) from continuing operations	(386,616)	438,439	(114,288)	(295,841)	825,657
Income (loss) from discontinued operations, net of taxes (1)	—	—	—	(2,351)	173,959
Net income (loss)	(386,616)	438,439	(114,288)	(298,192)	999,616
Income (loss) per unit – continuing operations:					
Basic	(1.92)	2.52	(0.80)	(2.48)	7.18
Diluted	(1.92)	2.51	(0.80)	(2.48)	7.18
Income (loss) per unit – discontinued operations:					
Basic	—	—	—	(0.02)	1.52
Diluted	—	—	—	(0.02)	1.52
Net income (loss) per unit:					
Basic	(1.92)	2.52	(0.80)	(2.50)	8.70
Diluted	(1.92)	2.51	(0.80)	(2.50)	8.70
Distributions declared per unit	2.865	2.70	2.55	2.52	2.52
Weighted average units outstanding	203,775	172,004	142,535	119,307	114,140
Cash flow data:					
Net cash provided by (used in):					
Operating activities (2)	$350,907	$518,706	$270,918	$426,804	$179,515
Investing activities	(3,684,829)	(2,130,360)	(1,581,408)	(282,273)	(35,550)
Financing activities	3,334,051	1,376,767	1,524,260	(150,968)	(116,738)
Balance sheet data:					
Total assets	$11,451,238	$7,928,854	$5,933,148	$4,340,256	$4,722,020
Long-term debt	6,037,817	3,993,657	2,742,902	1,588,831	1,653,568

Unitholders’ capital	4,427,180	3,428,910	2,788,216	2,452,004	2,760,686

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

Table of Contents

Item 6. Selected Financial Data - Continued

(2) Includes premiums paid for derivatives of approximately $583 million, $134 million, $120 million, $94 million and $130 million for the years ended December 31, 2012, December 31, 2011, December 31, 2010, December 31, 2009, and December 31, 2008, respectively.

	At or for the Year Ended December 31,				
	2012	2011	2010	2009	2008
Production data:					
Average daily production – continuing operations:					
Natural gas (MMcf/d)	349	175	137	125	124
Oil (MBbls/d)	29.2	21.5	13.1	9.0	8.6
NGL (MBbls/d)	24.5	10.8	8.3	6.5	6.2
Total (MMcfe/d)	671	369	265	218	212
Average daily production – discontinued operations:					
Total (MMcfe/d)	—	—	—	—	12
Estimated proved reserves: (1)					
Natural gas (Bcf)	2,571	1,675	1,233	774	851
Oil (MMBbls)	191	189	156	102	84
NGL (MMBbls)	179	94	71	54	51
Total (Bcfe)	4,796	3,370	2,597	1,712	1,660

(1) In accordance with Securities and Exchange Commission (“SEC”) regulations, reserves at December 31, 2012, December 31, 2011, December 31, 2010, and December 31, 2009, 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, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. In accordance with SEC regulations, reserves at December 31, 2008, were estimated using year-end prices. The price used to estimate reserves is held constant over the life of the reserves.

Table of Contents

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.

A reference to a "Note" herein refers to the accompanying Notes to Consolidated Financial Statements contained in Item 8. "Financial Statements and Supplementary Data."

Executive Overview

LINN Energy's mission is to acquire, develop and maximize cash flow from a growing portfolio of long-life oil and natural gas assets. LINN Energy is an independent oil and natural gas company that began operations in March 2003 and completed its initial public offering in January 2006. The Company's properties are located in eight operating regions in the United States ("U.S."):

- 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;
- Green River Basin, which includes properties located in southwest Wyoming;
- 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;
- Williston/Powder River Basin, which includes the Bakken formation in North Dakota and the Powder River Basin in Wyoming;
- California, which includes the Brea Olinda Field of the Los Angeles Basin; and
- East Texas, which includes properties located in east Texas.

Results for the year ended December 31, 2012, included the following:

- oil, natural gas and NGL sales of approximately $1.6 billion compared to $1.2 billion in 2011;
- average daily production of 671 MMcfe/d compared to 369 MMcfe/d in 2011;
- realized gains on commodity derivatives of approximately $403 million compared to $257 million in 2011;
- adjusted EBITDA of approximately $1.4 billion compared to approximately $1.0 billion in 2011;
- adjusted net income of approximately $293 million compared to $313 million in 2011;
- capital expenditures, excluding acquisitions, of approximately $1.1 billion compared to $697 million in 2011; and
- 440 wells drilled (436 successful) compared to 294 wells drilled (292 successful) in 2011.

Adjusted EBITDA and adjusted net income are non-GAAP financial measures used by management to analyze Company performance. Adjusted EBITDA is a measure used by Company management to evaluate cash flow and the Company's ability to sustain or increase distributions. The most significant reconciling items between net income (loss) and adjusted EBITDA are interest expense and noncash items, including the change in fair value of derivatives, and depreciation, depletion and amortization. Adjusted net income is used by Company management to evaluate its operational performance from oil and natural gas properties, prior to unrealized (gains) losses on derivatives, realized (gains) losses on canceled derivatives, realized gains on recovery of bankruptcy claim, impairment of long-lived assets, loss on extinguishment of debt and (gains) losses on sale of assets, net. See "Non-GAAP Financial Measures" on page 56 for a reconciliation of each non-GAAP financial measure to its most directly comparable financial measure calculated and presented in accordance with GAAP.

Acquisitions

On July 31, 2012, the Company completed the acquisition of certain oil and natural gas properties in the Jonah Field located in the Green River Basin of southwest Wyoming from BP America Production Company ("BP") for total consideration of approximately $990 million. The acquisition included approximately 806 Bcfe of proved reserves as of the acquisition date.

On May 1, 2012, the Company completed the acquisition of certain oil and natural gas properties located in east Texas for total consideration of approximately $168 million. The acquisition included approximately 110 Bcfe of proved reserves as of the acquisition date.

On April 3, 2012, the Company entered into a joint-venture agreement ("JV Agreement") with an affiliate of Anadarko Petroleum Corporation ("Anadarko") whereby the Company participates as a partner in the CO2 enhanced oil recovery development of the Salt Creek Field, located in the Powder River Basin of Wyoming. Anadarko assigned the Company 23% of its interest in the field in exchange for future funding of $400 million of Anadarko's development costs. As of December 31, 2012, the Company has paid approximately $201 million towards the future funding commitment. The acquisition included approximately 16 MMBoe (96 Bcfe) of proved reserves as of the JV Agreement date.

On March 30, 2012, the Company completed the acquisition of certain oil and natural gas properties and the Jayhawk natural gas processing plant located in the Hugoton Basin in Kansas from BP for total consideration of approximately $1.16 billion. The acquisition included approximately 689 Bcfe of proved reserves as of the acquisition date.

During 2012, the Company completed other smaller acquisitions of oil and natural gas properties located in its various operating regions. The Company, in the aggregate, paid approximately $122 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.

Acquisition - Subsequent Event

On February 21, 2013, LinnCo, LLC ("LinnCo"), an affiliate of LINN Energy, and Berry Petroleum Company ("Berry") announced they had signed a definitive merger agreement under which LinnCo would acquire all of the outstanding common shares of Berry. The transaction has a preliminary value of approximately $4.3 billion, including the assumption of debt, and is expected to close by June 30, 2013, subject to approvals by Berry and LinnCo shareholders, Linn Energy's unitholders and regulatory agencies.

Under the terms of the agreement, Berry's shareholders will receive 1.25 of LinnCo common shares for each Berry common share they own. This transaction, which is expected to be a tax-free exchange to Berry's shareholders, represents value of $46.2375 per common share, based on the closing price of LinnCo common shares on February 20, 2013.

Financing and Liquidity

The Company's Fifth Amended and Restated Credit Agreement ("Credit Facility") provides for a revolving credit facility up to the lesser of: (i) the then-effective borrowing base and (ii) maximum commitment amount. The Credit Facility has a borrowing base of $4.5 billion with a maximum commitment amount of $3.0 billion. The maturity date is April 2017. At January 31, 2013, the borrowing capacity under the Credit Facility was approximately $1.8 billion, which includes a $5 million reduction in availability for outstanding letters of credit.

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 $2 million in commissions and professional services expenses). The Company used the net proceeds for general corporate purposes, including the repayment of a portion of the indebtedness outstanding under its Credit Facility. At December 31, 2012, units equaling approximately $411 million in aggregate offering price remained available to be issued and sold under the agreement.

In January 2012, the Company also completed a public offering of units for net proceeds of approximately $674 million. The Company used the net proceeds from the sale of these units to repay a portion of the outstanding indebtedness under its Credit Facility.

In March 2012, the Company issued $1.8 billion in aggregate principal amount of 6.25% senior notes due November 2019 (see Note 6) and used the net proceeds of approximately $1.77 billion to fund the Hugoton acquisition (see Note 2). The remaining proceeds were used to repay indebtedness under the Company's Credit Facility and for general corporate purposes.

On May 8, 2012, the Company filed a registration statement on Form S-4 to register exchange notes that are identical in all material respects to those of the outstanding May 2019 Senior Notes, except that the transfer restrictions, registration rights and additional interest provisions relating to the outstanding notes do not apply to the exchange notes. On September 24, 2012, the registration statement was declared effective and the Company commenced an offer to exchange any and all of its $750 million outstanding principal amount of May 2019 Senior Notes for an equal amount of new May 2019 Senior Notes. The offer expired on October 23, 2012.

On October 17, 2012, LinnCo completed its initial public offering (the "LinnCo IPO") of 34,787,500 common shares representing limited liability company interests for net proceeds of approximately $1.2 billion. 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 its Credit Facility.

Commodity Derivatives

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

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 34% of total proved reserves at December 31, 2012, of which 59% were classified as proved developed. This region produced 313 MMcfe/d or 48% of the Company's 2012 average daily production. During 2012, the Company invested approximately $578 million to drill in this region. During 2013, the Company anticipates spending approximately 49% of its total oil and natural gas capital budget for development activities in the Mid-Continent region, primarily in the Granite Wash formation.

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 300 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. The Company's Kansas properties in the basin, acquired in March 2012, 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 21% of total proved reserves at December 31, 2012, of which 85% were classified as proved developed. This region produced 120 MMcfe/d or 18% of the Company's 2012 average daily production. During 2012, the Company invested approximately $11 million to drill in this region. During 2013, 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.

Green River Basin

The Green River Basin region consists of properties acquired in July 2012. These properties are located in southwest Wyoming and primarily produce natural gas at depths ranging from 8,000 feet to 12,000 feet. Green River Basin proved reserves represented approximately 21% of total proved reserves at December 31, 2012, of which 43% were classified as proved developed. This region produced 62 MMcfe/d or 9% of the Company's 2012 average daily production. During 2012, the Company invested approximately $22 million to drill in this region. During 2013, the Company anticipates spending approximately 12% of its total oil and natural gas capital budget for development activities in the Green River Basin 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 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. Permian Basin proved reserves represented approximately 8% of total proved reserves at December 31, 2012, of which 56% were classified as proved developed. This region produced 83 MMcfe/d or 12% of the Company's 2012 average daily production. During 2012, the Company invested approximately $240 million to drill in this region. During 2013, the Company anticipates spending approximately 20% 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 6% of total proved reserves at December 31, 2012, of which 94% were classified as proved developed. This region produced 35 MMcfe/d or 5% of the Company's 2012 average daily production. During 2013, the Company anticipates spending approximately 1% of its total oil and natural gas capital budget for development activities in the Michigan/Illinois region.

Williston/Powder River Basin

The Williston/Powder River Basin region includes the Bakken formation in North Dakota and the Powder River Basin in Wyoming. The Company's nonoperated properties in the Williston Basin, one of the premier oil basins in the U.S., produce at depths ranging from 9,000 feet to 12,000 feet. The Company's properties in the Powder River Basin, acquired in April 2012, consist of a CO_2 flood operated by Anadarko in the Salt Creek Field. Williston/Powder River

Basin proved reserves

36

Table of Contents

represented approximately 4% of total proved reserves at December 31, 2012, of which 66% were classified as proved developed. This region produced 29 MMcfe/d or 4% of the Company's 2012 average daily production. During 2012, the Company invested approximately $124 million to drill in this region. During 2013, the Company anticipates spending approximately 12% of its total oil and natural gas capital budget for development activities in the Williston/Powder River Basin region.

California

The California region consists of the Brea Olinda Field of 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. California proved reserves represented approximately 4% of total proved reserves at December 31, 2012, of which 96% were classified as proved developed. This region produced 13 MMcfe/d or 2% of the Company's 2012 average daily production. During 2012, the Company invested approximately $1 million to drill in this region. During 2013, the Company anticipates spending approximately 2% of its total oil and natural gas capital budget for development activities in the California region.

East Texas

The East Texas region consists of properties acquired in May 2012. These properties are located in east Texas and primarily produce natural gas from the Cotton Valley formation at depths of approximately 11,000 feet. Proved reserves for these mature, low-decline producing properties, all of which are proved developed, represented approximately 2% of total proved reserves at December 31, 2012. This region produced 16 MMcfe/d or 2% of the Company's 2012 average daily production. During 2013, the Company anticipates spending approximately 1% of its total oil and natural gas capital budget for development activities in the East Texas region.

Table of Contents

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)
Adjusted EBITDA (3)	$1,402,694	$997,621	$405,073
Adjusted net income (3)	$293,423	$313,331	$(19,908)

(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 realized 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.

(3) This is a non-GAAP measure used by management to analyze the Company's performance. See "Non-GAAP Financial Measures" on page 56 for a reconciliation of the non-GAAP financial measure to its most directly comparable financial measure calculated and presented in accordance with GAAP.

Table of Contents
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 (hedged): (1)				
Natural gas (Mcf)	$5.48	$8.20	(33	)%
Oil (Bbl)	$93.10	$89.21	4	%
NGL (Bbl)	$32.10	$42.88	(25	)%
Weighted average prices (unhedged): (2)				
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 (3)	$0.71	$0.99	(28	)%
Depreciation, depletion and amortization	$2.47	$2.48	—	
Taxes, other than income taxes	$0.54	$0.58	(7	)%

(1) Includes the effect of realized gains on derivatives of approximately $381 million (excluding $22 million realized gains on recovery of bankruptcy claim) and $230 million (excluding $27 million realized gains on canceled contracts of which the proceeds were reallocated within the Company’s derivatives portfolio) for the years ended December 31, 2012, and December 31, 2011, respectively.

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

(3) 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. Excluding these amounts, general and administrative expenses for the years ended December 31, 2012, and December 31, 2011, were $0.59 per Mcfe and $0.83 per Mcfe, respectively. This is a non-GAAP measure used by management to analyze the Company’s performance.

Table of Contents

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 %
Permian Basin	83	73	10	14 %
Green River Basin	62	—	62	—
Michigan/Illinois	35	36	(1)	(2)%
Williston/Powder River Basin	29	12	17	129 %
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 in June 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 in March 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. Average daily production volumes in the Green River Basin region reflect the impact of the acquisitions in 2012. The Michigan/Illinois and California regions consist of low-decline asset bases and continue to produce at consistent levels. The increase in average daily production volumes in the Williston/Powder River Basin region reflects the impact of acquisitions in 2011 and the joint-venture agreement entered into with Anadarko in April 2012. Average daily production volumes in the East Texas region reflect the impact of the acquisition in May 2012 (see Note 2).

Table of Contents

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

Gains (Losses) on Oil and Natural Gas Derivatives

The following presents the Company's reported gains and losses on derivative instruments:

	Year Ended December 31,		
	2012	2011	Variance
	(in thousands)		
Realized gains:			
Commodity derivatives	$381,141	$230,237	$150,904
Canceled derivatives	—	26,752	(26,752)
Recoveries of bankruptcy claim (see Note 11)	21,503	—	21,503
	402,644	256,989	145,655
Unrealized gains (losses):			
Commodity derivatives	(277,882)	192,951	(470,833)
Total gains	$124,762	$449,940	$(325,178)

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," Note 7 and Note 8 for additional information about the Company's commodity derivatives. During the year ended December 31, 2012, the Company had commodity derivative contracts for approximately 110% of its natural gas production and 106% of its oil production, which resulted in realized gains of approximately $381 million. The results for 2012 also include realized gains of approximately $22 million related to the recovery of a bankruptcy claim (see Note 11). During the year ended December 31, 2011, the Company had commodity derivative contracts for approximately 101% of its natural gas production and 101% of its oil production, which resulted in realized gains of approximately $257 million (including realized gains on canceled contracts of approximately $27 million).

Unrealized gains and losses from commodity derivatives represent adjustments in market valuations of derivatives from period to period and include the premiums associated with put option contracts over time. For the years ended December 31, 2012, and December 31, 2011, the Company recorded net unrealized losses of approximately $278 million and net unrealized gains of approximately $193 million, respectively, on 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 related to 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.

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 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 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, primarily 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)		
Loss on extinguishment of debt	$—	$(94,612)	$94,612
Interest expense, net of amounts capitalized	(379,937)	(259,725)	(120,212)
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 and the November 2019 Senior Notes, as defined in Note 6, and amendments made to the Company’s 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, as defined in Note 6. 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 unitholders. Limited liability companies are subject to Texas margin tax. Limited liability companies 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 same period in 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.

Adjusted EBITDA

Adjusted EBITDA (a non-GAAP financial measure) increased by approximately $405 million or 41% to approximately $1.4 billion for the year ended December 31, 2012, from approximately $998 million for the year ended December 31, 2011. The increase was primarily due to higher revenues, partially offset by higher expenses. See discussions above for explanations of variances. See “Non-GAAP Financial Measures” on page 56 for a reconciliation of adjusted EBITDA to its most directly comparable financial measure calculated and presented in accordance with GAAP.

Adjusted Net Income

Adjusted net income (a non-GAAP financial measure) decreased by approximately $20 million or 6% to approximately $293 million for the year ended December 31, 2012, from approximately $313 million for the year ended December 31, 2011. The decrease was primarily due to higher expenses, including interest, partially offset by higher revenues. See discussions above for explanations of variances.

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

Results of Operations
Year Ended December 31, 2011, Compared to Year Ended December 31, 2010

	Year Ended December 31,		
	2011	2010	Variance
	(in thousands)		
Revenues and other:			
Natural gas sales	$278,714	$211,596	$67,118
Oil sales	714,385	359,996	354,389
NGL sales	168,938	118,462	50,476
Total oil, natural gas and NGL sales	1,162,037	690,054	471,983
Gains on oil and natural gas derivatives [1]	449,940	75,211	374,729
Marketing and other revenues	10,477	7,015	3,462
	1,622,454	772,280	850,174
Expenses:			
Lease operating expenses	232,619	158,382	74,237
Transportation expenses	28,358	19,594	8,764
Marketing expenses	3,681	2,716	965
General and administrative expenses [2]	133,272	99,078	34,194
Exploration costs	2,390	5,168	(2,778)
Depreciation, depletion and amortization	334,084	238,532	95,552
Impairment of long-lived assets	—	38,600	(38,600)
Taxes, other than income taxes	78,522	45,182	33,340
Losses on sale of assets and other, net	3,494	6,490	(2,996)
	816,420	613,742	202,678
Other income and (expenses)	(362,129)	(268,585)	(93,544)
Income (loss) before income taxes	443,905	(110,047)	553,952
Income tax expense	5,466	4,241	1,225
Net income (loss)	$438,439	$(114,288)	$552,727
Adjusted EBITDA [3]	$997,621	$732,131	$265,490
Adjusted net income [3]	$313,331	$219,489	$93,842

(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 realized 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, 2011, and December 31, 2010, include approximately $21 million and $13 million, respectively, of noncash unit-based compensation expenses.

(3) This is a non-GAAP measure used by management to analyze the Company's performance. See "Non-GAAP Financial Measures" on page 56 for a reconciliation of the non-GAAP financial measure to its most directly comparable financial measure calculated and presented in accordance with GAAP.

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

	Year Ended December 31, 2011	2010	Variance	
Average daily production:				
Natural gas (MMcf/d)	175	137	28	%
Oil (MBbls/d)	21.5	13.1	64	%
NGL (MBbls/d)	10.8	8.3	30	%
Total (MMcfe/d)	369	265	39	%
Weighted average prices (hedged): (1)				
Natural gas (Mcf)	$8.20	$8.52	(4	)%
Oil (Bbl)	$89.21	$94.71	(6	)%
NGL (Bbl)	$42.88	$39.14	10	%
Weighted average prices (unhedged): (2)				
Natural gas (Mcf)	$4.35	$4.24	3	%
Oil (Bbl)	$91.24	$75.16	21	%
NGL (Bbl)	$42.88	$39.14	10	%
Average NYMEX prices:				
Natural gas (MMBtu)	$4.05	$4.40	(8	)%
Oil (Bbl)	$95.12	$79.53	20	%
Costs per Mcfe of production:				
Lease operating expenses	$1.73	$1.64	5	%
Transportation expenses	$0.21	$0.20	5	%
General and administrative expenses (3)	$0.99	$1.02	(3	)%
Depreciation, depletion and amortization	$2.48	$2.46	1	%
Taxes, other than income taxes	$0.58	$0.47	23	%

(1) Includes the effect of realized gains on derivatives of approximately $230 million (excluding $27 million realized gains on canceled contracts of which the proceeds were reallocated within the Company's derivatives portfolio) and $308 million for the years ended December 31, 2011, and December 31, 2010, respectively.

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

(3) General and administrative expenses for the years ended December 31, 2011, and December 31, 2010, include approximately $21 million and $13 million, respectively, of noncash unit-based compensation expenses. Excluding these amounts, general and administrative expenses for the years ended December 31, 2011, and December 31, 2010, were $0.83 per Mcfe and $0.88 per Mcfe, respectively. This is a non-GAAP measure used by management to analyze the Company's performance.

Table of Contents

Revenues and Other

Oil, Natural Gas and NGL Sales

Oil, natural gas and NGL sales increased by approximately $472 million or 68% to approximately $1.2 billion for the year ended December 31, 2011, from approximately $690 million for the year ended December 31, 2010, due to higher commodity prices and higher production volumes. Higher oil, NGL and natural gas prices resulted in an increase in revenues of approximately $126 million, $15 million and $7 million, respectively.

Average daily production volumes increased to 369 MMcfe/d during the year ended December 31, 2011, from 265 MMcfe/d during the year ended December 31, 2010. Higher oil, natural gas and NGL production volumes resulted in an increase in revenues of approximately $228 million, $60 million and $36 million, respectively.

The following sets forth average daily production by region:

	Year Ended December 31,			
	2011	2010	Variance	
Average daily production (MMcfe/d):				
Mid-Continent	195	157	38	24 %
Hugoton Basin	39	41	(2)	(6)%
Permian Basin	73	31	42	134 %
Michigan/Illinois	36	22	14	61 %
Williston/Powder River Basin	12	—	12	—
California	14	14	—	—
	369	265	104	39 %

The increase in average daily production volumes in the Mid-Continent region primarily reflects the Company's 2010 and 2011 capital drilling programs in the Granite Wash formation, as well as the impact of the acquisition in the Cleveland horizontal play in June 2011. The decrease in average daily production volumes in the Hugoton Basin region reflects downtime related to weather and third-party plant maintenance, and the effects of natural declines, partially offset by the results of the Company's drilling and optimization programs. The increase in average daily production volumes in the Permian Basin region reflects the impact of acquisitions in 2010 and 2011 and subsequent development capital spending. The increase in average daily production volumes in the Michigan/Illinois region reflects the full year impact of acquisitions in the second and fourth quarters of 2010. Average daily production volumes in the Williston/Powder River Basin region reflect the impact of the Company's acquisitions in this region in 2011. The California region consists of a low-decline asset base and continues to produce at a consistent level.

Table of Contents

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

Gains (Losses) on Oil and Natural Gas Derivatives

The following presents the Company's reported gains and losses on derivative instruments:

	Year Ended December 31,		
	2011	2010	Variance
	(in thousands)		
Realized gains:			
Commodity derivatives	$230,237	$307,587	$(77,350)
Canceled derivatives	26,752	—	26,752
	256,989	307,587	(50,598)
Unrealized gains (losses):			
Commodity derivatives	192,951	(232,376)	425,327
Total gains	$449,940	$75,211	$374,729

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," Note 7 and Note 8 for additional information about the Company's commodity derivatives. During the year ended December 31, 2011, the Company had commodity derivative contracts for approximately 101% of its natural gas production and 101% of its oil production, which resulted in realized gains of approximately $257 million (including realized gains on canceled contracts of approximately $27 million). During the year ended December 31, 2010, the Company had commodity derivative contracts for approximately 114% of its natural gas production and 97% of its oil production, which resulted in realized gains of approximately $308 million.

Unrealized gains and losses from commodity derivatives represent adjustments in market valuations of derivatives from period to period and include the premiums associated with put option contracts over time. For the years ended December 31, 2011, and December 31, 2010, the Company recorded net unrealized gains of approximately $193 million and net unrealized losses of approximately $232 million, respectively, on commodity derivatives. For information about the Company's credit risk related to derivative contracts, see "Counterparty Credit Risk" in "Liquidity and Capital Resources" below.

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 $75 million or 47% to approximately $233 million for the year ended December 31, 2011, from approximately $158 million for the year ended December 31, 2010. Lease operating expenses per Mcfe also increased to $1.73 per Mcfe for the year ended December 31, 2011, from $1.64 per Mcfe for the year ended December 31, 2010. Lease operating expenses increased primarily due to costs associated with properties acquired during 2010 and 2011 (see Note 2). Temporary oil handling costs in the Granite Wash formation and higher post-acquisition maintenance costs in the Permian Basin also contributed to the increase.

Transportation Expenses

Transportation expenses increased by approximately $9 million or 45% to approximately $28 million for the year ended December 31, 2011, from approximately $19 million for the year ended December 31, 2010, primarily due to higher production volumes.

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 $34 million or 35% to approximately $133 million for the year ended December 31, 2011, from approximately $99 million for the year ended December 31, 2010. The increase was primarily due to an increase in salaries and benefits related expenses of approximately $26 million, driven primarily by increased employee headcount, an increase in professional services expense of approximately $3 million and an increase in acquisition integration expenses of approximately $3 million. General and administrative expenses per Mcfe decreased to $0.99 per Mcfe for the year ended December 31, 2011, from $1.02 per Mcfe for the year ended December 31, 2010, due to higher production volumes.

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

Exploration Costs

Exploration costs decreased by approximately $3 million or 54% to approximately $2 million for the year ended December 31, 2011, from approximately $5 million for the year ended December 31, 2010. The decrease was primarily due to lower leasehold impairment expenses on unproved properties.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization increased by approximately $95 million or 40% to approximately $334 million for the year ended December 31, 2011, from approximately $239 million for the year ended December 31, 2010. Higher total production volumes were the primary reason for the increased expense. Depreciation, depletion and amortization per Mcfe also increased to $2.48 per Mcfe for the year ended December 31, 2011, from $2.46 per Mcfe for the year ended December 31, 2010.

Impairment of Long-Lived Assets

The Company recorded no impairment charge for the year ended December 31, 2011. During the year ended December 31, 2010, the Company recorded a noncash impairment charge of approximately $39 million primarily associated with the impairment of proved oil and natural gas properties related to an unfavorable marketing contract. See Note 1 and "Critical Accounting Policies and Estimates" below for additional information.

Taxes, Other Than Income Taxes

Taxes, other than income taxes, which consist primarily of severance and ad valorem taxes, increased by approximately $34 million or 74% to approximately $79 million for the year ended December 31, 2011, from approximately $45 million for the year ended December 31, 2010. Severance taxes, which are a function of revenues generated from production, increased approximately $31 million compared to the year ended December 31, 2010, primarily due to higher commodity prices and higher production volumes. Ad valorem taxes, which are based on the value of reserves and production equipment and vary by location, increased by approximately $3 million compared to the year ended December 31, 2010, primarily due to property acquisitions in 2011.

Other Income and (Expenses)

	Year Ended December 31, 2011	2010	Variance
	(in thousands)		
Loss on extinguishment of debt	$(94,612)	$—	$(94,612)
Interest expense, net of amounts capitalized	(259,725)	(193,510)	(66,215)
Realized losses on interest rate swaps	—	(8,021)	8,021
Realized losses on canceled interest rate swaps	—	(123,865)	123,865
Unrealized gains on interest rate swaps	—	63,978	(63,978)
Other, net	(7,792)	(7,167)	(625)
	$(362,129)	$(268,585)	$(93,544)

Other income and (expenses) increased by approximately $94 million during the year ended December 31, 2011, compared to the year ended December 31, 2010. Interest expense increased primarily due to higher outstanding debt during the period and higher amortization of financing fees associated with the 2019 Senior Notes and the 2010 Issued Senior Notes, as defined in Note 6. In addition, in May 2011, the Company entered into a Fifth Amended and Restated Credit Facility, which also resulted in higher amortization of financing fees. 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, as defined in Note 6. See "Debt" in "Liquidity and Capital Resources" below for additional details. The year ended December 31, 2010, included approximately $68 million in net losses on interest rate swaps.

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

unitholders. Limited liability companies are subject to Texas margin tax. Limited liability companies were also subject to state income taxes in the state of Michigan during 2011 and 2010. 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 $5 million for the year ended December 31, 2011, compared to approximately $4 million for the same period in 2010. Income tax expense increased primarily due to higher income in 2011 from the Company's taxable subsidiaries.

Net Income (Loss)

Net income increased by approximately $552 million or 484% to approximately $438 million for the year ended December 31, 2011, from a net loss of approximately $114 million for the year ended December 31, 2010. The increase was primarily due higher revenues, partially offset by higher expenses, including interest. See discussions above for explanations of variances.

Adjusted EBITDA

Adjusted EBITDA (a non-GAAP financial measure) increased by approximately $266 million or 36% to approximately $998 million for the year ended December 31, 2011, from approximately $732 million for the year ended December 31, 2010. The increase was primarily due to higher production revenues, partially offset by higher expenses and lower realized gains on oil and natural gas derivatives. See "Non-GAAP Financial Measures" on page 56 for a reconciliation of adjusted EBITDA to its most directly comparable financial measure calculated and presented in accordance with GAAP.

Adjusted Net Income

Adjusted net income (a non-GAAP financial measure) increased by approximately $94 million or 43% to approximately $313 million for the year ended December 31, 2011, from approximately $219 million for the year ended December 31, 2010. The increase was primarily due to higher production revenues, partially offset by higher expenses, including interest and lower realized gains on oil and natural gas derivatives. The year ended December 31, 2010, also included realized losses on interest rate swaps and there was no comparable amount reported for the year ended December 31, 2011. See discussions above for explanations of variances.

Reserve Replacement Metrics

The Company calculates two primary reserve metrics: (i) reserve replacement cost and (ii) reserve replacement ratio, to measure its ability to establish a long-term trend of adding reserves at a reasonable cost. The reserve replacement cost calculation provides an assessment of the cost of adding reserves that is ultimately included in depreciation, depletion and amortization expense. The reserve replacement ratio is an indicator of the Company's ability to replenish annual production volumes and grow reserves. The metrics are calculated as follow:

Reserve replacement cost per Mcfe	=	Oil and natural gas capital costs expended [1] Sum of reserve additions [2]
Reserve replacement ratio	=	Sum of reserve additions [2] Annual production

(1) Oil and natural gas capital costs expended include the costs of property acquisition, exploration and development activities conducted to add reserves and exclude asset retirement costs. The Company expects to incur development costs in the future for proved undeveloped reserves; such future costs are excluded from costs expended and are not considered in the reserve replacement metrics presented herein.

(2) Reserve additions include proved reserves (developed and undeveloped) and reflect reserve revisions for prices and performance, extensions, discoveries and other additions and acquisitions, and do not include unproved reserve quantities.

The reserve replacement metrics are presented separately, both: (i) including and excluding the impact of price revisions on reserves, to demonstrate the effectiveness of the Company's drilling program exclusive of economic factors (such as price) outside of its control and (ii) including and excluding acquisitions, to demonstrate the Company's ability to add reserves through its drilling program and through acquisitions. Reserve replacement cost and reserve replacement ratio are non-

GAAP financial measures. The methods used by the Company to calculate these measures may differ from methods used by other companies to compute similar measures. As a result, the Company's measures may not be comparable to similar measures provided by other companies. The Company believes that providing such measures is useful in evaluating the cost to add proved reserves; however, these measures should not be considered in isolation or as a substitute for GAAP measures. The reserve replacement cost per Mcfe and reserve replacement ratio are statistical indicators that have limitations, including their predictive and comparative value. The reserve replacement ratio is limited because it may vary widely based on the extent and timing of new discoveries, project sanctioning and property acquisitions. In addition, since the reserve replacement ratio does not consider the development cost or timing of future production of new reserves, it should not be used as a measure of value creation.
The following presents reserve replacement cost and reserve replacement ratio including and excluding the effect of price revisions on reserves:

	Including Price Revisions Year Ended December 31,						Excluding Price Revisions Year Ended December 31,					
	2012		2011		2010		2012		2011		2010	
Costs per Mcfe:												
Reserve replacement cost, including acquisitions	$2.26		$2.37		$1.63		$1.97		$2.46		$1.94	
Reserve replacement cost, excluding acquisitions (finding and development cost)	NM (1)		$1.94		$0.79		$6.92		$2.15		$1.57	
Percentage of production:												
Reserve replacement ratio, including acquisitions	680	%	674	%	1,014	%	781	%	651	%	854	%
Reserve replacement ratio, excluding acquisitions	NM (1)		244	%	321	%	63	%	221	%	161	%

(1) Not meaningful due to the impact of a significant decrease in year-end natural gas prices at December 31, 2012, compared to December 31, 2011.

The Company considers the premiums it pays for derivatives as part of the investment in its business and includes the cost of acquisition-related derivatives in the transaction economics. For the years ended December 31, 2012, December 31, 2011, and December 31, 2010, the Company paid premiums of approximately $583 million, $134 million and $120 million, respectively, for derivatives designed to reduce its exposure to fluctuations in commodity prices. The amounts paid were for derivative instruments that hedged production for multiple years. Of these amounts, approximately $320 million, $52 million and $21 million was paid for derivatives specifically related to the acquisitions consummated by the Company during the respective years.
If the premiums paid for derivatives were included in the reserve replacement cost calculations for the year ended December 31, 2012, the reserve replacement cost per Mcfe including price revisions and acquisitions would have been approximately $2.61. The reserve replacement cost including price revisions and excluding acquisitions is not meaningful for the year ended December 31, 2012, due to the impact of a significant decrease in year-end natural gas prices at December 31, 2012, compared to December 31, 2011. For the year ended December 31, 2012, the reserve replacement cost per Mcfe excluding price revisions and including acquisitions would have been approximately $2.27 and approximately $8.63 excluding price revisions and acquisitions. If the premiums paid for derivatives were included in the reserve replacement cost calculations for the years ended December 31, 2011, and December 31, 2010, the reserve replacement cost per Mcfe including price revisions and acquisitions would have been approximately $2.52 and $1.75, respectively, and approximately $2.19 and $1.11, respectively, including price revisions and excluding acquisitions. For the same periods, the reserve replacement cost per Mcfe excluding price revisions and including acquisitions would have been approximately $2.62 and $2.08, respectively, and approximately $2.43 and $2.21, respectively, excluding price revisions and acquisitions.

Amounts used for the calculations in the tables above are derived directly from the data presented in "Supplemental Oil and Natural Gas Data (Unaudited)" in Item 8. "Financial Statements and Supplementary Data." The following provides a reconciliation of oil and natural gas capital costs used in these calculations to its most directly comparable financial measure calculated and presented in accordance with GAAP:

	Year Ended December 31,		
	2012	2011	2010
	(in thousands)		
Costs incurred in oil and natural gas property acquisition, exploration and development	$3,779,713	$2,158,639	$1,602,086
Less:			
Asset retirement costs	(4,675)	(2,427)	(748)
Property acquisition costs	(2,712,543)	(1,516,737)	(1,356,430)
Oil and natural gas capital costs expended, excluding acquisitions	$1,062,495	$639,475	$244,908

Liquidity and Capital Resources

The Company utilizes funds from equity and debt offerings, bank borrowings and cash flow from operations 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, 2012, the Company's total capital expenditures, excluding acquisitions, were approximately $1.1 billion. For 2013, the Company estimates its total capital expenditures, excluding acquisitions, will be approximately $1.2 billion, including $1.1 billion related to its oil and natural gas capital program and $67 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 cash flow from operations and bank borrowings.

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 Facility, if available, or obtain additional debt or equity financing. The Company's Credit Facility and Indentures governing its November 2019 Senior Notes, May 2019 Senior Notes, 2010 Issued Senior Notes, and Original 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.

Statements of Cash Flows

The following is a comparative cash flow summary:

	Year Ended December 31,		
	2012	2011	2010
	(in thousands)		
Net cash:			
Provided by operating activities [1]	$350,907	$518,706	$270,918
Used in investing activities	(3,684,829)	(2,130,360)	(1,581,408)
Provided by financing activities	3,334,051	1,376,767	1,524,260
Net increase (decrease) in cash and cash equivalents	$129	$(234,887)	$213,770

(1) The years ended December 31, 2012, December 31, 2011, and December 31, 2010, include premiums paid for derivatives of approximately $583 million, $134 million and $120 million, respectively.

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

Operating Activities

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

Cash provided by operating activities was approximately $519 million for the year ended December 31, 2011, compared to approximately $271 million for the year ended December 31, 2010. The increase was primarily due to higher production volumes and commodity prices partially offset by higher expenses.

Premiums paid during 2012, 2011 and 2010 were for commodity derivative contracts that hedge future production. These derivative contracts provide the Company long-term cash flow predictability to manage its business, service debt and pay distributions and the premiums are primarily funded through the Company's Credit Facility. The amount of derivative contracts the Company enters into in the future will be directly related to expected future production. 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,		
	2012	2011	2010
	(in thousands)		
Cash flow from investing activities:			
Acquisition of oil and natural gas properties, net of cash acquired	$(2,640,475)	$(1,500,193)	$(1,351,033)
Capital expenditures	(1,045,079)	(629,864)	(223,013)
Proceeds from sale of properties and equipment and other	725	(303)	(7,362)
	$(3,684,829)	$(2,130,360)	$(1,581,408)

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. Cash used in investing activities for the year ended December 31, 2012, primarily relates to acquisitions of properties in the Hugoton Basin, Williston/Powder River Basin, East Texas and Green River Basin regions. See Note 2 for additional details of acquisitions. Development expenditures are higher primarily due to increased drilling activities in the Granite Wash formation.

Cash used in investing activities for the year ended December 31, 2011, primarily relates to acquisitions of properties in the Williston/Powder River Basin, Permian Basin and Mid-Continent 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.

Cash used in investing activities for the year ended December 31, 2010, primarily relates to acquisitions and the development of properties in the Permian Basin, Mid-Continent and Michigan/Illinois regions (see Note 2). The year ended December 31, 2010, also includes a deposit made by the Company of approximately $9 million and held by the other party to a PSA terminated by the Company (see Note 2).

Financing Activities

Cash provided by financing activities for the year ended December 31, 2012, was approximately $3.3 billion compared to approximately $1.4 billion for the year ended December 31, 2011. The increase in financing cash flow needs was primarily attributable to increased acquisitions and development activity during the year ended December 31, 2012. In comparison, cash provided by financing activities was approximately $1.5 billion for the year ended December 31, 2010.

Table of Contents

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

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

	Year Ended December 31,		
	2012	2011	2010
	(in thousands)		
Proceeds from borrowings:			
Credit facility	$3,640,000	$1,790,000	$1,050,000
Senior notes	1,799,802	744,240	2,250,816
	$5,439,802	$2,534,240	$3,300,816
Repayments of debt:			
Credit facility	$(3,400,000)	$(850,000)	$(2,150,000)
Senior notes	—	(451,029)	—
	$(3,400,000)	$(1,301,029)	$(2,150,000)

Debt

The Company's Fifth Amended and Restated Credit Agreement ("Credit Facility") provides for a revolving credit facility up to the lesser of: (i) the then-effective borrowing base and (ii) the maximum commitment amount. The Credit Facility has a borrowing base of $4.5 billion with a maximum commitment amount of $3.0 billion. The maturity date is April 2017. At January 31, 2013, the borrowing capacity under the Credit Facility was approximately $1.8 billion, which includes a $5 million reduction in availability for outstanding letters of credit.

On March 2, 2012, the Company issued $1.8 billion in aggregate principal amount of 6.25% senior notes due November 2019 (see Note 6) and used the net proceeds of approximately $1.77 billion to fund the Hugoton acquisition (see Note 2). The remaining proceeds were used to repay indebtedness under the Company's Credit Facility and for general corporate purposes.

On May 8, 2012, the Company filed a registration statement on Form S-4 to register exchange notes that are identical in all material respects to those of the outstanding May 2019 Senior Notes, except that the transfer restrictions, registration rights and additional interest provisions relating to the outstanding notes do not apply to the exchange notes. On September 24, 2012, the registration statement was declared effective and the Company commenced an offer to exchange any and all of its $750 million outstanding principal amount of May 2019 Senior Notes for an equal amount of new May 2019 Senior Notes. The offer expired on October 23, 2012.

The Company depends, in part, on its Credit Facility for future capital needs. In addition, the Company has drawn on the Credit Facility to fund or partially fund quarterly cash distribution payments, since it uses operating cash flow primarily for investing activities and borrows as cash is needed. Absent such borrowings, the Company would have at times experienced a shortfall in cash available to pay the declared quarterly cash distribution amount. If an event of default occurs and is continuing under the Credit Facility, 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."

Counterparty Credit Risk

The Company accounts for its commodity derivatives and, when applicable, its interest rate derivatives at fair value. The Company's counterparties are current participants or affiliates of participants in its Credit Facility or were participants or affiliates of participants in its Credit Facility at the time it originally entered into the derivatives. The Credit Facility is secured by the Company's oil, natural gas and NGL reserves; therefore, the Company is not required to post any collateral. The Company does not receive collateral from its counterparties. The 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 and, when applicable, its interest rate derivatives are subject to counterparty netting under agreements governing such derivatives and therefore the risk of loss due to counterparty nonperformance is somewhat mitigated.

53

LinnCo Initial Public Offering

On October 17, 2012, LinnCo, an affiliate of LINN Energy, completed 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 its 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 its Credit Facility.

In March 2011, the Company sold 16,726,067 units representing limited liability company interests at $38.80 per unit ($37.248 per unit, net of underwriting discount) for net proceeds of approximately $623 million (after underwriting discount and offering expenses of approximately $26 million). The Company used a portion of the net proceeds from the sale of these units to fund the March 2011 redemptions of a portion of the outstanding 2017 Senior Notes and 2018 Senior Notes and to fund the cash tender offers and related expenses for a portion of the remaining 2017 Senior Notes and 2018 Senior Notes (see Note 6). The Company used the remaining net proceeds from the sale of units to finance a portion of the March 31, 2011, acquisition in the Williston/Powder Basin region.

Equity Distribution Agreement

In August 2011, the Company entered into 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 its Credit Facility. At December 31, 2012, units equaling approximately $411 million in aggregate offering price remained available to be issued and sold under the agreement.

In September 2011, the Company issued and sold 16,060 units representing limited liability company interests at an average unit price of $38.25 for proceeds of approximately $602,000 (net of approximately $12,000 in commissions).

In December 2011, the Company issued and sold 772,104 units representing limited liability company interests at an average unit price of $38.03 for proceeds of approximately $29 million (net of approximately $587,000 in commissions). In connection with the issue and sale of these units, the Company also incurred professional service expenses of approximately $139,000. The Company used the net proceeds for general corporate purposes, including the repayment of a portion of the indebtedness outstanding under its Credit Facility.

Unit Repurchase Plan

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. In August 2011, the Company repurchased 400,000 units at an average unit price of $32.98 for a total cost of approximately $13 million. In addition, in October 2011, the Company repurchased 129,734 units at an average unit price of $32.08 for a total cost of approximately $4 million. At December 31, 2012, approximately $56 million was available for unit repurchase under the program.

Distributions

Under the Company's limited liability company agreement, unitholders are entitled to receive a quarterly distribution of available cash to the extent there is sufficient cash from operations after establishment of cash reserves and payment of fees and expenses. The following provides a summary of distributions paid by the Company during the year ended December 31, 2012:

Date Paid	Period Covered by Distribution	Distributions Per Unit	Total Distributions (in millions)
November 2012	July 1 – September 30, 2012	$0.725	$170
August 2012	April 1 – June 30, 2012	$0.725	$145
May 2012	January 1 – March 31, 2012	$0.725	$144
February 2012	October 1 – December 31, 2011	$0.69	$138

On April 24, 2012, the Company's Board of Directors approved an increase in the quarterly cash distribution from $0.69 per unit to $0.725 per unit, representing an increase of 5%. On January 24, 2013, the Company's Board of Directors declared a cash distribution of $0.725 per unit, or $2.90 per unit on an annualized basis, with respect to the fourth quarter of 2012. The distribution, totaling approximately $170 million, was paid on February 14, 2013, to unitholders of record as of the close of business on February 7, 2013.

Contingencies

The Company has been named as a defendant in a number of lawsuits, including claims from royalty owners related to disputed royalty payments and royalty valuations. The Company has established reserves that management currently believes are adequate to provide for potential liabilities based upon its evaluation of these matters. 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. Discovery related to class certification has concluded. Briefing and the hearing on class certification have been deferred by court order pending the Tenth Circuit Court of Appeals' resolution of interlocutory appeals of two unrelated class certification orders. 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.

During the years ended December 31, 2012, December 31, 2011, and December 31, 2010, the Company made no significant payments to settle any legal, environmental or tax proceedings. The Company regularly analyzes current information and accrues for probable liabilities on the disposition of certain matters as necessary. Liabilities for loss contingencies arising from claims, assessments, litigation or other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated.

Table of Contents

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

Commitments and Contractual Obligations

The following summarizes, as of December 31, 2012, certain long-term contractual obligations that are reflected in the consolidated balance sheets and/or disclosed in the accompanying notes thereto:

Contractual Obligations	Payments Due Total	2013	2014 – 2015	2016 – 2017	2018 and Beyond
	(in thousands)				
Long-term debt obligations:					
Credit facility	$1,180,000	$—	$—	$1,180,000	$—
Senior notes	4,904,898	—	—	40,737	4,864,161
Interest [(1)]	2,666,850	380,306	760,612	740,784	785,148
Operating lease obligations:					
Office, property and equipment leases	37,375	6,459	13,378	8,777	8,761
Other noncurrent liabilities:					
Asset retirement obligations	151,974	5,221	6,483	5,724	134,546
Other:					
Commodity derivatives	5,027	26	1,639	3,362	—
	$8,946,124	$392,012	$782,112	$1,979,384	$5,792,616

(1) Represents interest on the Credit Facility computed at the weighted average LIBOR of 1.97% through maturity in April 2017 and interest on the Original Senior Notes, May 2019 Senior Notes, November 2019 Senior Notes, and the 2010 Issued Senior Notes, as defined in Note 6, computed at fixed rates of 11.75%, 9.875%, 6.50%, 6.25%, 8.625% and 7.75% through maturities in May 2017, July 2018, May 2019, November 2019, April 2020 and February 2021, respectively.

Capital Structure

The Company's capitalization is presented below:

	December 31, 2012	2011
	(in thousands)	
Cash and cash equivalents	$1,243	$1,114
Credit facility	$1,180,000	$940,000
Senior notes due 2017, net	39,399	39,183
Senior notes due 2018, net	13,941	13,913
Senior notes due May 2019, net	745,172	744,593
Senior notes due November 2019, net	1,799,818	—
Senior notes due 2020, net	1,274,169	1,271,856
Senior notes due 2021, net	985,318	984,112
	6,037,817	3,993,657
Total unitholders' capital	4,427,180	3,428,910
	$10,464,997	$7,422,567

Table of Contents

Non-GAAP Financial Measures

The non-GAAP financial measures of adjusted EBITDA and adjusted net income, as defined by the Company, may not be comparable to similarly titled measures used by other companies. Therefore, these non-GAAP measures should be considered in conjunction with income and other performance measures prepared in accordance with GAAP, such as operating income or cash flow from operating activities. Adjusted EBITDA and adjusted net income should not be considered in isolation or as a substitute for GAAP measures, such as net income, operating income or any other GAAP measure of liquidity or financial performance.

Adjusted EBITDA (Non-GAAP Measure)

Adjusted EBITDA is a measure used by Company management to indicate (prior to the establishment of any reserves by its Board of Directors) the cash distributions the Company expects to make to its unitholders. Adjusted EBITDA is also a quantitative measure used throughout the investment community with respect to publicly-traded partnerships and limited liability companies.

The Company defines adjusted EBITDA as net income (loss) plus the following adjustments:

- Net operating cash flow from acquisitions and divestitures, effective date through closing date;
- Interest expense;
- Depreciation, depletion and amortization;
- Impairment of long-lived assets;
- Write-off of deferred financing fees;
- (Gains) losses on sale of assets and other, net;
- Provision for legal matters;
- Loss on extinguishment of debt;
- Unrealized (gains) losses on commodity derivatives;
- Unrealized (gains) losses on interest rate derivatives;
- Realized (gains) losses on interest rate derivatives;
- Realized (gains) losses on canceled derivatives;
- Realized gains on recovery of bankruptcy claim;
- Unit-based compensation expenses;
- Exploration costs; and
- Income tax expense (benefit).

Table of Contents

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

The following presents a reconciliation of net income (loss) to adjusted EBITDA:

	Year Ended December 31,		
	2012	2011	2010
	(in thousands)		
Net income (loss)	$(386,616)	$438,439	$(114,288)
Plus:			
Net operating cash flow from acquisitions and divestitures, effective date through closing date [(1)]	80,502	57,966	42,846
Interest expense	379,937	259,725	193,510
Depreciation, depletion and amortization	606,150	334,084	238,532
Impairment of long-lived assets	422,499	—	38,600
Write-off of deferred financing fees	7,889	1,189	2,076
Losses on sale of assets and other, net [(2)]	1,302	124	3,008
Provision for legal matters [(3)]	414	1,086	4,362
Loss on extinguishment of debt	—	94,612	—
Unrealized (gains) losses on commodity derivatives [(4)]	277,882	(192,951)	232,376
Unrealized gains on interest rate derivatives [(4)]	—	—	(63,978)
Realized losses on interest rate derivatives [(5)]	—	—	8,021
Realized (gains) losses on canceled derivatives [(6)]	—	(26,752)	123,865
Realized gains on recovery of bankruptcy claim [(7)]	(21,503)	—	—
Unit-based compensation expenses	29,533	22,243	13,792
Exploration costs	1,915	2,390	5,168
Income tax expense	2,790	5,466	4,241
Adjusted EBITDA	$1,402,694	$997,621	$732,131

(1) Represents cash, based on contractual arrangements, the Company received or paid from the effective date to the closing date of the transaction. The effective date is the first date the buyer is entitled to receive the economic benefit from properties included in the transaction.

(2) Represent gains or losses on the sale of assets, gains or losses on inventory valuation and amortization of basis difference for equity method investments.

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

(4) Represent adjustments in market valuations of derivatives from period to period and include the premiums associated with put option contracts over time.

(5) Represent interest-related derivatives settled based on contract terms and are excluded because adjusted EBITDA excludes the impact of interest expense and these derivatives are designed to mitigate interest rate risk.

(6) 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. In 2010, interest rate swaps were canceled in connection with the issuances of certain fixed-rate senior notes.

(7) 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.

Adjusted Net Income (Non-GAAP Measure)

Adjusted net income is a performance measure used by Company management to evaluate its operational performance from oil and natural gas properties, prior to unrealized (gains) losses on derivatives, realized (gains) losses on canceled derivatives, realized gains on recovery of bankruptcy claim, impairment of long-lived assets, loss on extinguishment of debt and (gains) losses on sale of assets, net.

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

The following presents a reconciliation of net income (loss) to adjusted net income:

	Year Ended December 31,		
	2012	2011	2010
	(in thousands, except per unit amounts)		
Net income (loss)	$(386,616)	$438,439	$(114,288)
Plus:			
Unrealized (gains) losses on commodity derivatives	277,882	(192,951)	232,376
Unrealized gains on interest rate derivatives	—	—	(63,978)
Realized (gains) losses on canceled derivatives	—	(26,752)	123,865
Realized gains on recovery of bankruptcy claim	(21,503)	—	—
Impairment of long-lived assets	422,499	—	38,600
Loss on extinguishment of debt	—	94,612	—
(Gains) losses on sale of assets, net	1,161	(17)	2,914
Adjusted net income	$293,423	$313,331	$219,489
Net income (loss) per unit – basic	$(1.92)	$2.52	$(0.80)
Plus, per unit:			
Unrealized (gains) losses on commodity derivatives	1.39	(1.11)	1.63
Unrealized gains on interest rate derivatives	—	—	(0.45)
Realized (gains) losses on canceled derivatives	—	(0.15)	0.87
Realized gains on recovery of bankruptcy claim	(0.11)	—	—
Impairment of long-lived assets	2.07	—	0.27
Loss on extinguishment of debt	—	0.54	—
(Gains) losses on sale of assets, net	0.01	—	0.02
Adjusted net income per unit – basic	$1.44	$1.80	$1.54

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.

Recently Issued Accounting Standards

In December 2011, the Financial Accounting Standards Board ("FASB") issued an Accounting Standards Update ("ASU") that requires an entity to disclose information about offsetting and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. The ASU requires disclosure of both gross information and net information about both instruments and transactions eligible for offset in the statement of financial position and instruments and transactions subject to an agreement similar to a master netting arrangement. The ASU will be

applied retrospectively and is effective for periods beginning on or after January 1, 2013. The Company is currently evaluating the impact, if any, of the adoption of this ASU on its consolidated financial statements and related disclosures.

In May 2011, the FASB issued an ASU that further addresses fair value measurement accounting and related disclosure requirements. The ASU clarifies the FASB’s intent regarding the application of existing fair value measurement and disclosure requirements, changes the fair value measurement requirements for certain financial instruments, and sets forth additional disclosure requirements for other fair value measurements. The ASU is to be applied prospectively and is effective for periods beginning after December 15, 2011. The Company adopted the ASU effective January 1, 2012. The adoption of the requirements of the ASU, which expanded disclosures, had no effect on the Company's results of operations or financial position.

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, 2012, 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 Securities and Exchange Commission (“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 the years ended December 31, 2012, and December 31, 2011, and approximately $1 million for the year ended December 31, 2010.

Impairment of Proved Properties

Based on the analysis described above, the Company recorded noncash impairment charges, before and after tax, of approximately $422 million associated with proved oil and natural gas properties related to lower commodity prices for the year ended December 31, 2012, and a noncash impairment charge, before and after tax, of approximately $39 million primarily associated with proved oil and natural gas properties related to an unfavorable marketing contract for the year ended December 31, 2010. 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 $2 million for the years ended December 31, 2012, and December 31, 2011, and approximately $5 million for the year ended December 31, 2010, 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, 2012, and December 31, 2011, the Company had natural gas production imbalance receivables of approximately $28 million and $19 million, respectively, which are included in "accounts receivable – trade, net" on the consolidated balance sheets and natural gas production imbalance payables of approximately $18 million and $9 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. Currently, the Company has no outstanding derivative contracts in the form of interest rate swaps.

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 securities 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

62

Table of Contents

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 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 payments granted to employees and nonemployee directors. See Note 1 and Note 5 for additional details about the Company’s accounting for unit-based compensation.

Table of Contents

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. A 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

The Company enters into derivative contracts with respect to a portion of its projected production through various transactions that 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 (see Note 7). At December 31, 2012, the fair value of fixed price swaps and put contracts that settle during the next 12 months was a net asset of approximately $344 million. A 10% increase in the index oil and natural gas prices above the December 31, 2012, prices for the next 12 months would result in a net asset of approximately $163 million, which represents a decrease in the fair value of approximately $181 million; conversely, a 10% decrease in the index oil and natural gas prices would result in a net asset of approximately $533 million, which represents an increase in the fair value of approximately $189 million.

Interest Rate Risk

At December 31, 2012, the Company had long-term debt outstanding under its Credit Facility of $1.2 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 $12 million increase in annual interest expense.

Counterparty Credit Risk

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

At December 31, 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.

Table of Contents

Item 8. Financial Statements and Supplementary Data

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Table of Contents

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, 2012, 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, issued 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, 2012, based on those criteria. KPMG LLP, the independent registered public accounting firm that audited the consolidated financial statements of the Company included in this Annual Report on Form 10-K, has issued an attestation report on the effectiveness of the Company’s internal control over financial reporting as of December 31, 2012, which is included herein.

/s/ Linn Energy, LLC

Table of Contents

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, 2012 and 2011, 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, 2012. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Linn Energy, LLC and subsidiaries as of December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2012, 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, 2012, based on criteria established in Internal Control–Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 21, 2013, expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

Houston, Texas
February 21, 2013

Table of Contents

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, 2012, based on criteria established in Internal Control–Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Linn Energy, LLC's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, Linn Energy, LLC maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on criteria established in Internal Control–Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Linn Energy, LLC and subsidiaries as of December 31, 2012 and 2011, 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, 2012, and our report dated February 21, 2013, expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Houston, Texas
February 21, 2013

Table of Contents

LINN ENERGY, LLC
CONSOLIDATED BALANCE SHEETS

	December 31, 2012	2011
	(in thousands, except unit amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$1,243	$1,114
Accounts receivable – trade, net	371,333	213,282
Derivative instruments	350,695	255,063
Other current assets	88,157	80,734
Total current assets	811,428	550,193
Noncurrent assets:		
Oil and natural gas properties (successful efforts method)	11,611,330	7,835,650
Less accumulated depletion and amortization	(2,025,656)	(1,033,617)
	9,585,674	6,802,033
Other property and equipment	469,188	197,235
Less accumulated depreciation	(73,721)	(48,024)
	395,467	149,211
Derivative instruments	530,216	321,840
Other noncurrent assets	128,453	105,577
	658,669	427,417
Total noncurrent assets	10,639,810	7,378,661
Total assets	$11,451,238	$7,928,854
LIABILITIES AND UNITHOLDERS' CAPITAL		
Current liabilities:		
Accounts payable and accrued expenses	$707,861	$332,167
Derivative instruments	26	14,060
Other accrued liabilities	115,245	75,898
Total current liabilities	823,132	422,125
Noncurrent liabilities:		
Credit facility	1,180,000	940,000
Senior notes, net	4,857,817	3,053,657
Derivative instruments	4,114	3,503
Other noncurrent liabilities	158,995	80,659
Total noncurrent liabilities	6,200,926	4,077,819
Commitments and contingencies (Note 11)		
Unitholders' capital:		
234,513,243 units and 177,364,558 units issued and outstanding at December 31, 2012, and December 31, 2011, respectively	4,136,240	2,751,354
Accumulated income	290,940	677,556

	4,427,180	3,428,910
Total liabilities and unitholders' capital	$11,451,238	$7,928,854

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

Table of Contents

LINN ENERGY, LLC
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2012	2011	2010
	(in thousands, except per unit amounts)		
Revenues and other:			
Oil, natural gas and natural gas liquids sales	$1,601,180	$1,162,037	$690,054
Gains on oil and natural gas derivatives	124,762	449,940	75,211
Marketing revenues	37,393	5,868	3,966
Other revenues	10,905	4,609	3,049
	1,774,240	1,622,454	772,280
Expenses:			
Lease operating expenses	317,699	232,619	158,382
Transportation expenses	77,322	28,358	19,594
Marketing expenses	31,821	3,681	2,716
General and administrative expenses	173,206	133,272	99,078
Exploration costs	1,915	2,390	5,168
Depreciation, depletion and amortization	606,150	334,084	238,532
Impairment of long-lived assets	422,499	—	38,600
Taxes, other than income taxes	131,679	78,522	45,182
Losses on sale of assets and other, net	1,539	3,494	6,490
	1,763,830	816,420	613,742
Other income and (expenses):			
Loss on extinguishment of debt	—	(94,612)	—
Interest expense, net of amounts capitalized	(379,937)	(259,725)	(193,510)
Losses on interest rate swaps	—	—	(67,908)
Other, net	(14,299)	(7,792)	(7,167)
	(394,236)	(362,129)	(268,585)
Income (loss) before income taxes	(383,826)	443,905	(110,047)
Income tax expense	2,790	5,466	4,241
Net income (loss)	$(386,616)	$438,439	$(114,288)
Net income (loss) per unit:			
Basic	$(1.92)	$2.52	$(0.80)
Diluted	$(1.92)	$2.51	$(0.80)
Weighted average units outstanding:			
Basic	203,775	172,004	142,535
Diluted	203,775	172,729	142,535
Distributions declared per unit	$2.865	$2.70	$2.55

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

Table of Contents

LINN ENERGY, LLC
CONSOLIDATED STATEMENTS OF UNITHOLDERS' CAPITAL

	Units	Unitholders' Capital	Accumulated Income (Deficit)	Treasury Units (at Cost)	Total Unitholders' Capital
	(in thousands)				
December 31, 2009	129,941	$2,098,599	$353,405	$—	$2,452,004
Sale of units, net of underwriting discounts and expenses of $34,556	28,750	809,774	—	—	809,774
Issuance of units	815	4,418	—	—	4,418
Cancellation of units	(496)	(11,832)	—	11,832	—
Purchase of units		—	—	(11,832)	(11,832)
Distributions to unitholders		(365,711)	—	—	(365,711)
Unit-based compensation expenses		13,792	—	—	13,792
Reclassification of distributions paid on forfeited restricted units		59	—	—	59
Net loss		—	(114,288)	—	(114,288)
December 31, 2010	159,010	2,549,099	239,117	—	2,788,216
Sale of units, net of underwriting discounts and expenses of $27,427	17,514	651,522	—	—	651,522
Issuance of units	1,371	7,446	—	—	7,446
Cancellation of units	(530)	(17,352)	—	17,352	—
Purchase of units		—	—	(17,352)	(17,352)
Distributions to unitholders		(466,488)	—	—	(466,488)
Unit-based compensation expenses		22,243	—	—	22,243
Reclassification of distributions paid on forfeited restricted units		79	—	—	79
Excess tax benefit from unit-based compensation		4,805	—	—	4,805
Net income		—	438,439	—	438,439
December 31, 2011	177,365	2,751,354	677,556	—	3,428,910
Sale of units, net of underwriting discounts and expenses of $32,044	55,877	1,942,045	—	—	1,942,045
Issuance of units	1,271	7,061	—	—	7,061
Distributions to unitholders		(596,935)	—	—	(596,935)
Unit-based compensation expenses		29,533	—	—	29,533
Reclassification of distributions paid on forfeited restricted units		92	—	—	92
Excess tax benefit from unit-based compensation		3,090	—	—	3,090
Net loss		—	(386,616)	—	(386,616)
December 31, 2012	234,513	$4,136,240	$290,940	$—	$4,427,180

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

LINN ENERGY, LLC
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2012	2011	2010
	(in thousands)		
Cash flow from operating activities:			
Net income (loss)	$(386,616)	$438,439	$(114,288)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	606,150	334,084	238,532
Impairment of long-lived assets	422,499	—	38,600
Unit-based compensation expenses	29,533	22,243	13,792
Loss on extinguishment of debt	—	94,612	—
Amortization and write-off of deferred financing fees	25,598	21,526	22,113
Losses on sale of assets and other, net	92	2,021	6,619
Deferred income tax	(360)	310	3,088
Mark-to-market on derivatives:			
Total gains	(124,762)	(449,940)	(7,303)
Cash settlements	390,765	237,134	302,875
Cash settlements on canceled derivatives	—	26,752	(123,865)
Premiums paid for derivatives	(583,434)	(134,352)	(120,376)
Changes in assets and liabilities:			
Increase in accounts receivable – trade, net	(77,573)	(191,338)	(66,283)
(Increase) decrease in other assets	(5,451)	(2,951)	2,926
Increase in accounts payable and accrued expenses	26,372	129,499	25,457
Increase (decrease) in other liabilities	28,094	(9,333)	49,031
Net cash provided by operating activities	350,907	518,706	270,918
Cash flow from investing activities:			
Acquisition of oil and natural gas properties, net of cash acquired	(2,640,475)	(1,500,193)	(1,351,033)
Development of oil and natural gas properties	(984,530)	(574,635)	(204,832)
Purchases of other property and equipment	(60,549)	(55,229)	(18,181)
Proceeds from sale of properties and equipment and other	725	(303)	(7,362)
Net cash used in investing activities	(3,684,829)	(2,130,360)	(1,581,408)
Cash flow from financing activities:			
Proceeds from sale of units	1,973,989	678,949	844,330
Proceeds from borrowings	5,439,802	2,534,240	3,300,816
Repayments of debt	(3,400,000)	(1,301,029)	(2,150,000)
Distributions to unitholders	(596,935)	(466,488)	(365,711)
Financing fees, offering expenses and other, net	(85,895)	(56,358)	(93,343)
Excess tax benefit from unit-based compensation	3,090	4,805	—
Purchase of units	—	(17,352)	(11,832)
Net cash provided by financing activities	3,334,051	1,376,767	1,524,260
Net increase (decrease) in cash and cash equivalents	129	(234,887)	213,770
Cash and cash equivalents:			
Beginning	1,114	236,001	22,231
Ending	$1,243	$1,114	$236,001

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

LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 – Basis of Presentation and Significant Accounting Policies
Nature of Business
Linn Energy, LLC ("LINN Energy" or the "Company") is an independent oil and natural gas company that began operations in March 2003 and was formed as a Delaware limited liability company in April 2005. The Company completed its initial public offering ("IPO") in January 2006 and its units representing limited liability company interests ("units") are listed on the NASDAQ Global Select Market under the symbol "LINE." LINN Energy's mission is to acquire, develop and maximize cash flow from a growing portfolio of long-life oil and natural gas assets.
The Company's properties are located in the United States ("U.S."), in the Mid-Continent, the Hugoton Basin, the Green River Basin, the Permian Basin, Michigan, Illinois, the Williston/Powder River Basin, California and east Texas. Effective January 1, 2012, the Company realigned its existing regions. The realignment had no effect on the Company's operations. The Company added the East Texas region in May 2012 and the Green River Basin region in July 2012, and currently has eight operating regions in the U.S.: 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; Green River Basin, which includes properties located in southwest Wyoming; 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; Williston/Powder River Basin, which includes the Bakken formation in North Dakota and the Powder River Basin in Wyoming; California, which includes the Brea Olinda Field of the Los Angeles Basin; and East Texas, which includes properties located in east Texas.
The operations of the Company are governed by the provisions of a limited liability company agreement executed by and among its members. The agreement includes specific provisions with respect to the maintenance of the capital accounts of each of the Company's unitholders. Pursuant to applicable provisions of the Delaware Limited Liability Company Act (the "Delaware Act") and the Third Amended and Restated Limited Liability Company Agreement of Linn Energy, LLC (the "LLC Agreement"), unitholders have no liability for the debts, obligations and liabilities of the Company, except as expressly required in the LLC Agreement or the Delaware Act. The Company will remain in existence unless and until dissolved in accordance with the terms of the LLC Agreement.
Principles of Consolidation and Reporting
The Company presents its financial statements in accordance with U.S. generally accepted accounting principles ("GAAP"). The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries. All significant intercompany transactions and balances have been eliminated upon consolidation. Investments in noncontrolled entities over which the Company exercises significant influence are accounted for under the equity method. The Company's other investment is carried at cost.
The consolidated financial statements for previous periods include certain reclassifications that were made to conform to current presentation. Such reclassifications have no impact on previously reported net income (loss), unitholders' capital or cash flows.
Use of Estimates
The preparation of the accompanying consolidated financial statements in conformity with GAAP requires management of the Company to make estimates and assumptions about future events. These estimates and the underlying assumptions affect the amount of assets and liabilities reported, disclosures about contingent assets and liabilities, and reported amounts of revenues and expenses. The estimates that are particularly significant to the financial statements include estimates of the Company's reserves of oil, natural gas and natural gas liquids ("NGL"), future cash flows from oil and natural gas properties, depreciation, depletion and amortization, asset retirement obligations, certain revenues and operating expenses, fair values of commodity and interest rate derivatives, if any, and fair values of assets acquired and liabilities assumed. As fair value is a market-based measurement, it is determined based on the assumptions that market participants would use. These estimates and assumptions are based

on management’s best estimates and judgment. Management evaluates its estimates and assumptions on an ongoing basis using historical experience and other factors, including the current economic environment, which management believes to be reasonable under the circumstances. Such estimates and assumptions are adjusted when facts and circumstances dictate. As future events and their effects cannot be determined with precision, actual results could differ from these estimates. Any changes in estimates resulting from continuous changes in the economic environment will be reflected in the financial statements in future periods.

Recently Issued Accounting Standards

In December 2011, the Financial Accounting Standards Board ("FASB") issued an Accounting Standards Update ("ASU") that requires an entity to disclose information about offsetting and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. The ASU requires disclosure of both gross information and net information about both instruments and transactions eligible for offset in the statement of financial position and instruments and transactions subject to an agreement similar to a master netting arrangement. The ASU will be applied retrospectively and is effective for periods beginning on or after January 1, 2013. The Company is currently evaluating the impact, if any, of the adoption of this ASU on its consolidated financial statements and related disclosures.

In May 2011, the FASB issued an ASU that further addresses fair value measurement accounting and related disclosure requirements. The ASU clarifies the FASB's intent regarding the application of existing fair value measurement and disclosure requirements, changes the fair value measurement requirements for certain financial instruments, and sets forth additional disclosure requirements for other fair value measurements. The ASU is to be applied prospectively and is effective for periods beginning after December 15, 2011. The Company adopted the ASU effective January 1, 2012. The adoption of the requirements of the ASU, which expanded disclosures, had no effect on the Company's results of operations or financial position.

Cash Equivalents

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

Accounts Receivable – Trade, Net

Trade accounts receivable are recorded at the invoiced amount and do not bear interest. The Company maintains an allowance for doubtful accounts for estimated losses inherent in its accounts receivable portfolio. In establishing the required allowance, management considers historical losses, current receivables aging, and existing industry and national economic data. The Company reviews its allowance for doubtful accounts monthly. Past due balances over 90 days and over a specified amount are reviewed individually for collectibility. Account balances are charged off against the allowance after all means of collection have been exhausted and the potential recovery is remote. The balance in the Company's allowance for doubtful accounts related to trade accounts receivable was approximately $450,000 at December 31, 2012, and $1 million at December 31, 2011.

Inventories

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

Oil and Natural Gas Properties

Proved Properties

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

The Company evaluates the impairment of its proved oil and natural gas properties on a field-by-field basis whenever events or changes in circumstances indicate that the carrying value may not be recoverable. The carrying values of proved properties are reduced to fair value when the expected undiscounted future cash flows 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 the years ended December 31, 2012, and December 31, 2011, and approximately $1 million for the year ended December 31, 2010.

Impairment of Proved Properties

Based on the analysis described above, the Company recorded noncash impairment charges, before and after tax, of approximately $422 million associated with proved oil and natural gas properties related to lower commodity prices for the year ended December 31, 2012, and a noncash impairment charge, before and after tax, of approximately $39 million primarily associated with proved oil and natural gas properties related to an unfavorable marketing contract for the year ended December 31, 2010. 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 $2 million for the years ended December 31, 2012, and December 31, 2011, and approximately $5 million for the year ended December 31, 2010, which are included in “exploration costs” on the consolidated statements of operations.

Other Property and Equipment

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

Revenue Recognition

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

The Company has elected the entitlements method to account for natural gas production imbalances. Imbalances occur when the Company sells more or less than its entitled ownership percentage of total natural gas production. In accordance with the entitlements method, any amount received in excess of the Company's share is treated as a liability. If the Company receives less than its entitled share, the underproduction is recorded as a receivable. At December 31, 2012, and December 31, 2011, the Company had natural gas production imbalance receivables of approximately $28 million and $19 million, respectively, which are included in "accounts receivable – trade, net" on the consolidated balance sheets and natural gas production imbalance payables of approximately $18 million and $9 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 marketing expenses.

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

Restricted Cash

Restricted cash of approximately $5 million and $4 million is included in "other noncurrent assets" on the consolidated balance sheets at December 31, 2012, and December 31, 2011, respectively, and represents cash the Company has deposited into a separate account and designated for asset retirement obligations in accordance with contractual agreements.

Derivative Instruments

The Company uses derivative financial instruments to reduce exposure to fluctuations in the prices of oil and natural gas. By removing a significant portion of the price volatility associated with future production, the Company expects to mitigate, but not eliminate, the potential effects of variability in cash flow from operations due to fluctuations in commodity prices. These transactions are primarily in the form of swap contracts and put options. 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, 2012, the Company had no outstanding interest rate swap agreements.

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 securities trade in active markets. See Note 7 and Note 8 for additional details about the Company's derivative financial instruments.

Unit-Based Compensation

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

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

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

Deferred Financing Fees

The Company incurred legal and bank fees related to the issuance of debt (see Note 6). At December 31, 2012, and December 31, 2011, net deferred financing fees of approximately $114 million and $94 million, respectively, are included in "other noncurrent assets" on the consolidated balance sheets. These debt issuance costs are amortized over the life of the debt agreement. Upon early retirement or amendment to the debt agreement, certain fees are written off to expense. For the years ended December 31, 2012, December 31, 2011, and December 31, 2010, amortization expense of approximately $13 million, $16 million and $17 million, respectively, is included in "interest expense, net of amounts capitalized" and approximately $8 million, $1 million and $2 million, respectively, was written off to "other, net" on the consolidated statements of operations.

Fair Value of Financial Instruments

The carrying values of the Company's receivables, payables and Credit Facility (as defined in Note 6) are estimated to be substantially the same as their fair values at December 31, 2012, and December 31, 2011. See Note 6 for fair value disclosures related to the Company's other outstanding debt. As noted above, the Company carries its derivative financial instruments at fair value. See Note 8 for details about the fair value of the Company's derivative financial instruments.

Income Taxes

The Company is a limited liability company treated as a partnership for federal and state income tax purposes, with the exception of the state of Texas, in which income tax liabilities and/or benefits of the Company are passed through to unitholders. As such, with the exception of the state of Texas, the Company is not a taxable entity, it does not directly pay federal and state income tax and recognition has not been given to federal and state income taxes for the operations of the Company except as described below.

Limited liability companies are subject to Texas margin tax. Limited liability companies were also subject to state income taxes in the state of Michigan during 2011 and 2010. In addition, certain of the Company's subsidiaries are Subchapter C-corporations subject to federal and state income taxes, which are accounted for using the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis and operating loss and tax credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. See Note 14 for detail of amounts recorded in the consolidated financial statements.

Note 2 – Acquisitions

Acquisitions – 2012

On July 31, 2012, the Company completed the acquisition of certain oil and natural gas properties in the Jonah Field located in the Green River Basin of southwest Wyoming from BP America Production Company ("BP"). The Company paid approximately $990 million in total consideration for these properties. The transaction was financed with borrowings under the Company's Credit Facility, as defined in Note 6.

On May 1, 2012, the Company completed the acquisition of certain oil and natural gas properties located in east Texas. The Company paid approximately $168 million in total consideration for these properties. The transaction was financed with borrowings under the Company's Credit Facility.

On April 3, 2012, the Company entered into a joint-venture agreement ("JV Agreement") with an affiliate of Anadarko Petroleum Corporation ("Anadarko") whereby the Company participates as a partner in the CO2 enhanced oil recovery development of the Salt Creek Field, located in the Powder River Basin of Wyoming. Anadarko assigned the Company 23% of its interest in the field in exchange for future funding of $400 million of Anadarko's development costs. The Company assigned approximately $392 million to the net assets acquired as of the JV Agreement date, which reflects an imputed discount of approximately $8 million on the future funding of this transaction. As of December 31, 2012, the Company has paid approximately $201 million towards the future funding commitment.

On March 30, 2012, the Company completed the acquisition of certain oil and natural gas properties and the Jayhawk natural gas processing plant located in the Hugoton Basin in Kansas from BP. The Company paid approximately $1.16 billion in total consideration for these properties. The transaction was financed primarily with proceeds from the March 2012 debt offering (see Note 6).

During 2012, the Company completed other smaller acquisitions of oil and natural gas properties located in its various operating regions. The Company, in the aggregate, paid approximately $122 million in total consideration for these properties.

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

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

Assets:	
Current	$12,215
Noncurrent	210,390
Oil and natural gas properties	2,701,385
Total assets acquired	$2,923,990
Liabilities:	
Current	$223,114
Asset retirement obligations	63,663
Noncurrent	196,601
Total liabilities assumed	$483,378
Net assets acquired	$2,440,612

Current assets include receivables and inventory and noncurrent assets include other property and equipment. Current liabilities include payables, ad valorem taxes payable and environmental liabilities. Current liabilities and noncurrent liabilities, as of the JV Agreement date, consist of payables of approximately $195 million and $197 million, respectively, related to the future funding commitment associated with the Anadarko transaction discussed above. As of December 31, 2012, the Company has paid approximately $201 million towards this commitment.

The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and therefore represent Level 3 inputs. The fair values of oil and natural gas properties and asset retirement

78

obligations were measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation of oil and natural gas properties include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; (iv) estimated future cash flows; and (v) a market-based weighted average cost of capital rate. These inputs require significant judgments and estimates by the Company's management at the time of the valuation and are the most sensitive and subject to change.

The revenues and expenses related to certain properties acquired from BP, Plains Exploration & Production Company ("Plains"), Panther Energy Company, LLC and Red Willow Mid-Continent, LLC (collectively referred to as "Panther"), SandRidge Exploration and Production, LLC ("SandRidge") and an affiliate of Concho Resources Inc. ("Concho") are included in the consolidated results of operations of the Company as of July 31, 2012 (BP Green River Basin acquisition), March 30, 2012 (BP Hugoton Basin acquisition), December 15, 2011 (Plains acquisition), June 1, 2011 (Panther acquisition), April 1, 2011 (SandRidge acquisition), and March 31, 2011 (Concho acquisition). The following unaudited pro forma financial information presents a summary of the Company's consolidated results of operations for the years ended December 31, 2012, and December 31, 2011, assuming the acquisitions from BP had been completed as of January 1, 2011, and the acquisitions from Plains, Panther, SandRidge and Concho had been completed as of January 1, 2010, including adjustments to reflect the values assigned to the net assets acquired. The pro forma financial information is not necessarily indicative of the results of operations if the acquisitions had been effective as of these dates.

	Year Ended December 31,	
	2012	2011
	(in thousands, except per unit amounts)	
Total revenues and other	$1,937,620	$2,422,381
Total operating expenses	$1,900,231	$1,293,283
Net income (loss)	$(391,868)	$639,664
Net income (loss) per unit:		
Basic	$(1.95)	$3.65
Diluted	$(1.95)	$3.64

Acquisitions – 2011 and 2010

The following is a summary of certain significant acquisitions completed by the Company during the years ended December 31, 2011, and December 31, 2010:

- On December 15, 2011, the Company completed the acquisition of certain oil and natural gas properties located primarily in the Granite Wash of Texas and Oklahoma from Plains Exploration & Production Company for approximately $542 million.
- On November 1, 2011, and November 18, 2011, the Company completed two acquisitions of certain oil and natural gas properties located in the Permian Basin for approximately $110 million.
- On June 1, 2011, the Company completed the acquisition of certain oil and natural gas properties in the Cleveland play, located in the Texas Panhandle, from Panther Energy Company, LLC and Red Willow Mid-Continent, LLC for approximately $224 million.
- On May 2, 2011, and May 11, 2011, the Company completed two acquisitions of certain oil and natural gas properties located in the Williston Basin for approximately $153 million.
- On April 1, 2011, and April 5, 2011, the Company completed two acquisitions of certain oil and natural gas properties located in the Permian Basin, including properties from SandRidge Exploration and Production, LLC for approximately $239 million.

- On March 31, 2011, the Company completed the acquisition of certain oil and natural gas properties located in the Williston Basin from an affiliate of Concho Resources Inc. for approximately $192 million.

- On November 16, 2010, the Company completed the acquisition of certain oil and natural gas properties located in the Wolfberry trend of the Permian Basin from Element Petroleum, LP for approximately $118 million.
- On October 14, 2010, the Company completed two acquisitions of certain oil and natural gas properties located in the Wolfberry trend of the Permian Basin from Crownrock, LP and Patriot Resources Partners LLC for approximately $260 million.
- On August 16, 2010, the Company completed the acquisition of certain oil and natural gas properties located in the Permian Basin from Crownrock, LP and Element Petroleum, LP for approximately $95 million.
- On May 27, 2010, the Company completed the acquisition of interests in Henry Savings LP and Henry Savings Management LLC that primarily hold oil and natural gas properties located in the Permian Basin for approximately $323 million.
- On April 30, 2010, the Company completed the acquisition of interests in two wholly owned subsidiaries of HighMount Exploration & Production LLC that hold oil and natural gas properties in the Antrim Shale located in northern Michigan for approximately $327 million.
- On January 29, 2010, the Company completed the acquisition of certain oil and natural gas properties located in the Anadarko Basin in Oklahoma and Kansas and the Permian Basin in Texas and New Mexico from certain affiliates of Merit Energy Company for approximately $151 million.

Note 3 – Unitholders' Capital

LinnCo Initial Public Offering

On October 17, 2012, LinnCo, LLC ("LinnCo"), an affiliate of LINN Energy, 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 its 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 outstanding indebtedness under its Credit Facility.

In March 2011, the Company sold 16,726,067 units representing limited liability company interests at $38.80 per unit ($37.248 per unit, net of underwriting discount) for net proceeds of approximately $623 million (after underwriting discount and offering expenses of approximately $26 million). The Company used a portion of the net proceeds from the sale of these units to fund the March 2011 redemptions of a portion of the outstanding 2017 Senior Notes and 2018 Senior Notes and to fund the cash tender offers and related expenses for a portion of the remaining 2017 Senior Notes and 2018 Senior Notes (see Note 6). The Company used the remaining net proceeds from the sale of units to finance a portion of the March 31, 2011, acquisition in the Williston/Powder Basin region.

In December 2010, the Company sold 11,500,000 units representing limited liability company interests at $35.92 per unit ($34.48 per unit, net of underwriting discount) for net proceeds of approximately $396 million (after underwriting discount and offering expenses of approximately $17 million). The Company used the net proceeds from the sale of these units to repay all outstanding indebtedness under its Credit Facility and for other general corporate purposes, including the partial notes redemption (see Note 6).

In March 2010, the Company sold 17,250,000 units representing limited liability company interests at $25.00 per unit ($24.00 per unit, net of underwriting discount) for net proceeds of approximately $414 million (after underwriting discount and offering expenses of approximately $17 million). The Company used a portion of the net proceeds from the sale of these units to finance the HighMount acquisition.

Table of Contents

Equity Distribution Agreement

In August 2011, the Company entered into 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. In connection with entering into the agreement, the Company incurred expenses of approximately $423,000. 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 its Credit Facility. At December 31, 2012, units equaling approximately $411 million in aggregate offering price remained available to be issued and sold under the agreement.

In September 2011, the Company, under its equity distribution agreement, issued and sold 16,060 units representing limited liability company interests at an average unit price of $38.25 for proceeds of approximately $602,000 (net of approximately $12,000 in commissions). In December 2011, the Company issued and sold 772,104 units representing limited liability company interests at an average unit price of $38.03 for proceeds of approximately $29 million (net of approximately $587,000 in commissions). In connection with the issue and sale of these units, the Company also incurred professional service expenses of approximately $139,000. The Company used the net proceeds for general corporate purposes, including the repayment of a portion of the indebtedness outstanding under its Credit Facility.

Unit Repurchase Plan

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. During the year ended December 31, 2011, 529,734 units were repurchased at an average unit price of $32.76 for a total cost of approximately $17 million. During the year ended December 31, 2010, 486,700 units were repurchased at an average unit price of $23.79 for a total cost of approximately $12 million. All units were subsequently canceled.

No units were repurchased by the Company during the year ended December 31, 2012. At December 31, 2012, approximately $56 million was available for unit repurchase under the program. The timing and amounts of any such repurchases are at the discretion of management, subject to market conditions and other factors, and in accordance with applicable securities laws and other legal requirements. The repurchase plan does not obligate the Company to acquire any specific number of units and may be discontinued at any time. Units are repurchased at fair market value on the date of repurchase.

Other Issuance and Cancellation of Units

During the year ended December 31, 2010, the Company purchased 9,055 units for approximately $300,000 in conjunction with units received by the Company for the payment of minimum withholding taxes due on units issued under its equity compensation plan (see Note 5). All units were subsequently canceled. The Company purchased no units for this purpose during the years ended December 31, 2012, and December 31, 2011.

Distributions

Under the LLC Agreement, Company unitholders are entitled to receive a quarterly distribution of available cash to the extent there is sufficient cash from operations after establishment of cash reserves and payment of fees and expenses. Distributions paid by the Company are presented on the consolidated statements of unitholders' capital. On January 24, 2013, the Company's Board of Directors declared a cash distribution of $0.725 per unit with respect to the fourth quarter of 2012. The distribution, totaling approximately $170 million, was paid on February 14, 2013, to unitholders of record as of the close of business on February 7, 2013.

Note 4 – Business and Credit Concentrations

Cash

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

Revenue and Trade Receivables

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

For the year ended December 31, 2012, the Company's two largest customers represented approximately 12% and 11%, respectively, of the Company's sales. For the year ended December 31, 2011, the Company's three largest customers represented approximately 13%, 10% and 10%, respectively, of the Company's sales. For the year ended December 31, 2010, the Company's three largest customers represented approximately 17%, 14% and 13%, respectively, of the Company's sales.

At December 31, 2012, trade accounts receivable from two customers represented approximately 21% and 11%, respectively, of the Company's receivables. At December 31, 2011, trade accounts receivable from three customers represented approximately 12%, 10% and 10%, respectively, of the Company's receivables.

Note 5 – Unit-Based Compensation and Other Benefit Plans

Incentive Plan Summary

The Linn Energy, LLC Amended and Restated Long-Term Incentive Plan, as amended (the "Plan"), originally became effective in December 2005. The Plan, which is administered by the Compensation Committee of the Board of Directors ("Compensation Committee"), permits granting unit grants, unit options, restricted units, phantom units and unit appreciation rights to employees, consultants and nonemployee directors under the terms of the Plan. The unit options and restricted units vest ratably over three years. The contractual life of unit options is 10 years.

The Plan limits the number of units that may be delivered pursuant to awards to 12.2 million units. The Board of Directors and the Compensation Committee have the right to alter or amend the Plan or any part of the Plan from time to time, including increasing the number of units that may be granted, subject to unitholder approval as required by the exchange upon which the units are listed at that time. However, no change in any outstanding grant may be made that would materially reduce the benefits to the participant without the consent of the participant.

Upon exercise or vesting of an award of units, or an award settled in units, the Company will issue new units, acquire units on the open market or directly from any person, or use any combination of the foregoing, at the Compensation Committee's discretion. If the Company issues new units upon exercise or vesting of an award, the total number of units outstanding will increase. To date, the Company has issued awards of unit grants, unit options, restricted units and phantom units. The Plan provides for all of the following types of awards:

Unit Grants – A unit grant is a unit that vests immediately upon issuance.

Unit Options – A unit option is a right to purchase a unit at a specified price at terms determined by the Compensation Committee. Unit options will have an exercise price that will not be less than the fair market value of the units on the date of grant, and in general, will become exercisable over a vesting period but may accelerate upon a change in control of the Company. If a grantee's employment or service relationship terminates for any reason other than death, the grantee's unvested unit options will be automatically forfeited unless the option agreement or the Compensation Committee provides otherwise.

Restricted Units – A restricted unit is a unit that vests over a period of time and that during such time is subject to forfeiture, and may contain such terms as the Compensation Committee shall determine. The Company intends the restricted units under the Plan to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of its units. Therefore, Plan participants will not pay any consideration for the restricted units they receive. If a grantee's employment or service relationship terminates for any reason other than death, the grantee's unvested restricted units will be automatically forfeited unless the Compensation Committee or the terms of the award agreement provide otherwise.

Phantom Units/Unit Appreciation Rights – These awards may be settled in units, cash or a combination thereof. Such grants contain terms as determined by the Compensation Committee, including the period or terms over which phantom units vest. If a grantee's employment or service relationship terminates for any reason other than death or retirement, the grantee's phantom units or unit appreciation rights will be automatically forfeited unless, and to the extent, the Compensation Committee or the terms of the award agreement provide otherwise. Upon death or retirement, as defined in the Plan, a participant's phantom units vest in full unless the terms of the award agreement provide otherwise. While phantom units require no payment from the grantee, unit appreciation rights will have an exercise price that will not be less than the fair market value of the units on the date of grant. At December 31, 2012, the Company had 36,784 phantom units issued and outstanding. To date, the Company has not issued unit appreciation rights.

Securities Authorized for Issuance Under the Plan

As of December 31, 2012, approximately 4.6 million units were issuable under the Plan pursuant to outstanding award or other agreements, and 769,316 additional units were reserved for future issuance under the Plan.

Accounting for Unit-Based Compensation

The Company recognizes as expense, beginning at the grant date, the fair value of unit options and other equity-based compensation issued to employees and nonemployee directors. The value of the portion of the award that is ultimately expected to vest is recognized as expense over the requisite service period using the straight-line method in the Company's consolidated statements of operations. A summary of unit-based compensation expenses included on the consolidated statements of operations is presented below:

	Year Ended December 31,		
	2012	2011	2010
	(in thousands)		
General and administrative expenses	$27,641	$21,131	$13,450
Lease operating expenses	1,892	1,112	342
Total unit-based compensation expenses	$29,533	$22,243	$13,792
Income tax benefit	$10,912	$8,219	$5,096

Restricted/Unrestricted Units

The fair value of unrestricted unit grants and restricted units issued is determined based on the fair market value of the Company units on the date of grant. A summary of the status of the nonvested units as of December 31, 2012, is presented below:

	Number of Nonvested Units	Weighted Average Grant-Date Fair Value
Nonvested units at December 31, 2011	1,859,662	$31.54
Granted	1,046,590	$37.42
Vested	(875,877)	$27.20
Forfeited	(77,244)	$34.34
Nonvested units at December 31, 2012	1,953,131	$36.16

The weighted average grant-date fair value of unrestricted unit grants and restricted units granted was $38.54 and $25.89 during the years ended December 31, 2011, and December 31, 2010, respectively. The total fair value of units that vested was approximately $24 million, $13 million and $14 million for the years ended December 31, 2012, December 31, 2011, and December 31, 2010, respectively. As of December 31, 2012, there was approximately $35 million of unrecognized compensation cost related to nonvested restricted units. The cost is expected to be recognized over a weighted average period of approximately 1.6 years .

In January 2013, the Company granted 612,240 restricted units and 105,530 phantom units as part of its annual review of its nonexecutive employees' compensation.

Changes in Unit Options and Unit Options Outstanding

The following provides information related to unit option activity for the year ended December 31, 2012:

	Number of Units Underlying Options	Weighted Average Exercise Price Per Unit	Weighted Average Remaining Contractual Life in Years	Aggregate Intrinsic Value in Millions
Outstanding at December 31, 2011	1,409,993	$22.14	5.83	$22
Granted	3,400,000	$40.01		
Exercised	(167,188)	$21.65		
Outstanding at December 31, 2012	4,642,805	$35.25	6.28	$16
Exercisable at December 31, 2012	1,242,805	$22.21	4.93	$16

During the year ended December 31, 2012, the weighted average grant-date fair value of unit options granted was $5.31. No unit options were granted during the years ended December 31, 2011, or December 31, 2010. The total intrinsic value of unit options exercised was approximately $3 million, $5 million and $2 million, during the years ended December 31, 2012, December 31, 2011, and December 31, 2010, respectively. The Company received approximately $4 million from the exercise of unit options during the year ended December 31, 2012. No unit options expired during the years ended December 31, 2012, December 31, 2011, or December 31, 2010. As of December 31, 2012, total unrecognized compensation cost related to nonvested unit options was approximately $15 million. The cost is expected to be recognized over a weighted average period of approximately 3.1 years.

The fair value of unit-based compensation for unit options was estimated on the date of grant using a Black-Scholes pricing model based on certain assumptions. That value may not be indicative of the fair value observed in a willing buyer/willing seller market transaction. The Company's determination of the fair value of unit-based payment awards is affected by the Company's unit price as well as assumptions regarding a number of complex and subjective variables. The Company's employee unit options have various restrictions including vesting provisions and restrictions on transfers and hedging, among others, and often are expected to be exercised prior to their contractual maturity. Expected volatilities used in the estimation of fair value of the 2012 unit option grants have been determined using available volatility data for the Company. Expected volatilities used in the estimation of fair value of unit options granted in previous years were determined using available volatility data for the Company as well as an average of volatility computations of other identified peer companies in the oil and natural gas industry. Expected distributions are estimated based on the Company's distribution rate at the date of grant. Forfeitures are estimated using historical Company data and are revised, if necessary, in subsequent periods if actual forfeitures differ from estimates. The risk-free rate for periods within the expected term of the unit option is based on the U.S. Treasury yield curve in effect at the time of grant. Historical data of the Company is used to estimate expected term. All employees granted awards have been determined to have similar behaviors for purposes of determining the expected term used to estimate fair value. The fair values of the 2012 unit option grants were based upon the following assumptions:

	2012	
Expected volatility	34.10	%
Expected distributions	7.25	%
Risk-free rate	0.67	%
Expected term	5 years	

Nonemployee Grants

In 2007, the Company granted an aggregate 150,000 unit warrants to certain individuals in connection with an acquisition transition services agreement. The unit warrants, 15,000 of which remain outstanding, have an exercise price of $25.50 per unit warrant, are fully exercisable at December 31, 2012, and expire 10 years from the date of issuance. During the year ended December 31, 2012, 135,000 unit warrants were exercised, and the Company received approximately $3 million from these exercises.

Defined Contribution Plan

The Company sponsors a 401(k) defined contribution plan for eligible employees. Company contributions to the 401(k) plan consist of a discretionary matching contribution equal to 100% of the first 6% of eligible compensation contributed by the employee on a before-tax basis. The Company contributed approximately $5 million, $4 million and $3 million during the years ended December 31, 2012, December 31, 2011, and December 31, 2010, respectively, to the 401(k) plan's trustee account. The 401(k) plan funds are held in a trustee account on behalf of the plan participants.

Note 6 – Debt

The following summarizes debt outstanding:

	December 31, 2012		December 31, 2011	
	Carrying Value	Fair Value [1]	Carrying Value	Fair Value [1]
	(in millions, except percentages)			
Credit facility [2]	$1,180	$1,180	$940	$940
11.75% senior notes due 2017	41	44	41	46
9.875% senior notes due 2018	14	15	14	16
6.50% senior notes due May 2019	750	755	750	742
6.25% senior notes due November 2019	1,800	1,802	—	—
8.625% senior notes due 2020	1,300	1,414	1,300	1,406
7.75% senior notes due 2021	1,000	1,061	1,000	1,036
Less current maturities	—	—	—	—
	6,085	$6,271	4,045	$4,186
Unamortized discount	(47)		(51)	
Total debt, net of discount	$6,038		$3,994	

(1) The carrying value of the Credit Facility is estimated to be substantially the same as its fair value. Fair values of the senior notes were estimated based on prices quoted from third-party financial institutions.

(2) Variable interest rates of 1.97% and 2.57% at December 31, 2012, and December 31, 2011, respectively.

Credit Facility

The Company's Fifth Amended and Restated Credit Agreement ("Credit Facility") provides for a revolving credit facility up to the lesser of: (i) the then-effective borrowing base and (ii) the maximum commitment amount. The Credit Facility has a borrowing base of $4.5 billion with a maximum commitment amount of $3.0 billion. The maturity date is April 2017. At December 31, 2012, the borrowing capacity under the Credit Facility was approximately $1.8 billion, which includes a $5 million reduction in availability for outstanding letters of credit.

During 2012, in connection with amendments to its Credit Facility, the Company incurred financing fees and expenses of approximately $12 million, which will be amortized over the life of the Credit Facility. Such amortized expenses are recorded in "interest expense, net of amounts capitalized" on the consolidated statements of operations.

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

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

Senior Notes Due November 2019

On March 2, 2012, the Company issued $1.8 billion in aggregate principal amount of 6.25% senior notes due November 2019 ("November 2019 Senior Notes") at a price of 99.989%. The November 2019 Senior Notes were sold to a group of initial purchasers and then resold to qualified institutional buyers, each in transactions exempt from the registration requirements of the Securities Act of 1933, as amended (the "Securities Act"). The Company received net proceeds of approximately $1.77 billion (after deducting the initial purchasers' discount of $198,000 and offering expenses of approximately $29 million). The Company used the net proceeds to fund the BP acquisition (see Note 2). The remaining proceeds were used to repay indebtedness under the Company's Credit Facility and for general corporate purposes. The financing fees and expenses of approximately $29 million incurred in connection with the November 2019 Senior Notes will be amortized over the life of the notes. Such amortized financing fees and expenses are recorded in "interest expense, net of amounts capitalized" on the consolidated statements of operations.

The November 2019 Senior Notes were issued under an indenture dated March 2, 2012 ("November 2019 Indenture"), mature November 1, 2019, and bear interest at 6.25%. Interest is payable semi-annually on May 1 and November 1, beginning November 1, 2012. The November 2019 Senior Notes are general unsecured senior obligations of the Company and are effectively junior in right of payment to any secured indebtedness of the Company to the extent of the collateral securing such indebtedness. Each of the Company's material subsidiaries has guaranteed the November 2019 Senior Notes on a senior unsecured basis. The November 2019 Indenture provides that the Company may redeem: (i) on or prior to November 1, 2015, up to 35% of the aggregate principal amount of the November 2019 Senior Notes at a redemption price of 106.25% of the principal amount redeemed, plus accrued and unpaid interest, with the net cash proceeds of one or more equity offerings; (ii) prior to November 1, 2015, all or part of the November 2019 Senior Notes at a redemption price equal to the principal amount redeemed, plus a make-whole premium (as defined in the November 2019 Indenture) and accrued and unpaid interest; and (iii) on or after November 1, 2015, all or part of the November 2019 Senior Notes at a redemption price equal to 103.125%, and decreasing percentages thereafter, of the principal amount redeemed, plus accrued and unpaid interest. The November 2019 Indenture also provides that, if a change of control (as defined in the November 2019 Indenture) occurs, the holders have a right to require the Company to repurchase all or part of the November 2019 Senior Notes at a redemption price equal to 101%, plus accrued and unpaid interest.

The November 2019 Indenture contains covenants substantially similar to those under the Company's May 2019 Senior Notes, 2010 Issued Senior Notes and Original Senior Notes, as defined below, that, among other things, limit the Company's ability to: (i) pay distributions on, purchase or redeem the Company's units or redeem its subordinated debt; (ii) make investments; (iii) incur or guarantee additional indebtedness or issue certain types of equity securities; (iv) create certain liens; (v) sell assets; (vi) consolidate, merge or transfer all or substantially all of the Company's assets; (vii) enter into agreements that restrict distributions or other payments from the Company's restricted subsidiaries to the Company; (viii) engage in transactions with affiliates; and (ix) create unrestricted subsidiaries. The Company is in compliance with all financial and other covenants of the November 2019 Senior Notes.

In connection with the issuance and sale of the November 2019 Senior Notes, the Company entered into a Registration Rights Agreement ("November 2019 Registration Rights Agreement") with the initial purchasers. Under the November

2019 Registration Rights Agreement, the Company agreed to use its reasonable efforts to file with the Securities and Exchange Commission (“SEC”) and cause to become effective a registration statement relating to an offer to issue new notes having terms substantially identical to the November 2019 Senior Notes in exchange for outstanding November 2019 Senior Notes within 400 days after the notes were issued. In certain circumstances, the Company may be required to file a shelf registration statement to cover resales of the November 2019 Senior Notes. If the Company fails to satisfy these obligations, the Company may be required to pay additional interest to holders of the November 2019 Senior Notes under certain circumstances.

Senior Notes Due May 2019

On May 13, 2011, the Company issued $750 million in aggregate principal amount of 6.5% senior notes due 2019 (the "May 2019 Senior Notes"). The indentures related to the May 2019 Senior Notes contain redemption provisions and covenants that are substantially similar to those of the November 2019 Senior Notes. On May 8, 2012, the Company filed a registration statement on Form S-4 to register exchange notes that are also substantially similar to the November 2019 Senior Notes. On September 24, 2012, the registration statement was declared effective and the Company commenced an offer to exchange any and all of its $750 million outstanding principal amount of May 2019 Senior Notes for an equal amount of new May 2019 Senior Notes.

The terms of the new May 2019 Senior Notes are identical in all material respects to those of the outstanding May 2019 Senior Notes, except that the transfer restrictions, registration rights and additional interest provisions relating to the outstanding May 2019 Senior Notes do not apply to the new May 2019 Senior Notes. The exchange offer expired on October 23, 2012. Pursuant to the terms of the registration rights agreement entered into in connection with the May 2019 Senior Notes, the Company agreed to use its reasonable efforts to cause the registration statement relating to the new May 2019 Senior Notes to become effective within 400 days after the notes were issued. The effective date of the registration statement was past the deadline in the registration rights agreement, and therefore, the Company was required to pay additional interest of approximately $850,000 to holders of the May 2019 Senior Notes in November 2012.

Senior Notes Due 2020 and Senior Notes Due 2021

The Company has $1.3 billion in aggregate principal amount of 8.625% senior notes due 2020 (the "2020 Senior Notes") and $1.0 billion in aggregate principal amount of 7.75% senior notes due 2021 (the "2021 Senior Notes," and together with the 2020 Senior Notes, the "2010 Issued Senior Notes"). The indentures related to the 2010 Issued Senior Notes contain redemption provisions and covenants that are substantially similar to those of the November 2019 Senior Notes. However, in 2011, the Company caused the trustee to remove the restrictive legends from each of the 2010 Issued Senior Notes making them freely tradable (other than with respect to persons that are affiliates of the Company), thereby terminating the Company's obligations under each of the registration rights agreements entered into in connection with the issuance of the 2010 Issued Senior Notes.

Senior Notes Due 2017 and Senior Notes Due 2018

The Company also has $41 million (originally $250 million) in aggregate principal amount of 11.75% senior notes due 2017 (the "2017 Senior Notes") and $14 million (originally $256 million) in aggregate principal amount of 9.875% senior notes due 2018 (the "2018 Senior Notes" and together with the 2017 Senior Notes, the "Original Senior Notes"). The indentures related to the Original Senior Notes initially contained redemption provisions and covenants that were substantially similar to those of the November 2019 Senior Notes; however, in conjunction with the tender offers in 2011, the indentures were amended and most of the covenants and certain default provisions were eliminated. The amendments became effective upon the execution of the supplemental indentures to the indentures governing the Original Senior Notes.

In March 2011 and June 2011, in accordance with the indentures related to the Original Senior Notes, the Company redeemed and also repurchased through cash tender offers, a portion of the Original Senior Notes. In connection with the redemptions and cash tender offers of a portion of the Original Senior Notes, the Company recorded a loss on extinguishment of debt of approximately $95 million for the year ended December 31, 2011.

Note 7 – Derivatives

Commodity Derivatives

The Company utilizes derivative instruments to minimize the variability in cash flow due to commodity price movements. The Company has historically entered into derivative instruments such as swap contracts, put options and collars to economically hedge its forecasted oil, natural gas and NGL sales. The Company did not designate any of these contracts as cash flow hedges; therefore, the changes in fair value of these instruments are recorded in current earnings. See Note 8 for fair value disclosures about oil and natural gas commodity derivatives.

88

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

The following table summarizes derivative positions for the periods indicated as of December 31, 2012:

	2013	2014	2015	2016	2017	2018
Natural gas positions:						
Fixed price swaps:						
Hedged volume (MMMBtu)	87,290	97,401	118,041	121,841	120,122	36,500
Average price ($/MMBtu)	$5.22	$5.25	$5.19	$4.20	$4.26	$5.00
Puts: (1)						
Hedged volume (MMMBtu)	86,198	79,628	71,854	76,269	66,886	—
Average price ($/MMBtu)	$5.37	$5.00	$5.00	$5.00	$4.88	$—
Total:						
Hedged volume (MMMBtu)	173,488	177,029	189,895	198,110	187,008	36,500
Average price ($/MMBtu)	$5.29	$5.14	$5.12	$4.51	$4.48	$5.00
Oil positions:						
Fixed price swaps: (2)						
Hedged volume (MBbls)	11,871	11,903	11,599	11,464	4,755	—
Average price ($/Bbl)	$94.97	$92.92	$96.23	$90.56	$89.02	$—
Puts:						
Hedged volume (MBbls)	3,105	3,960	3,426	3,271	384	—
Average price ($/Bbl)	$97.86	$91.30	$90.00	$90.00	$90.00	$—
Total:						
Hedged volume (MBbls)	14,976	15,863	15,025	14,735	5,139	—
Average price ($/Bbl)	$95.57	$92.52	$94.81	$90.44	$89.10	$—
Natural gas basis differential positions: (3)						
Panhandle basis swaps:						
Hedged volume (MMMBtu)	77,800	79,388	87,162	19,764	—	—
Hedged differential ($/MMBtu)	$(0.56)	$(0.33)	$(0.33)	$(0.31)	$—	$—
NWPL - Rockies basis swaps:						
Hedged volume (MMMBtu)	34,785	36,026	38,362	39,199	—	—
Hedge differential ($/MMBtu)	$(0.20)	$(0.20)	$(0.20)	$(0.20)	$—	$—
MichCon basis swaps:						
Hedged volume (MMMBtu)	9,600	9,490	9,344	—	—	—
Hedged differential ($/MMBtu)	$0.10	$0.08	$0.06	$—	$—	$—
Houston Ship Channel basis swaps:						
Hedged volume (MMMBtu)	5,731	5,256	4,891	4,575	—	—
Hedged differential ($/MMBtu)	$(0.10)	$(0.10)	$(0.10)	$(0.10)	$—	$—
Permian basis swaps:						
Hedged volume (MMMBtu)	4,636	4,891	5,074	—	—	—
Hedged differential ($/MMBtu)	$(0.20)	$(0.21)	$(0.21)	$—	$—	$—
Oil timing differential positions:						
Trade month roll swaps: (4)						
Hedged volume (MBbls)	6,944	7,254	7,251	7,446	6,486	—
Hedged differential ($/Bbl)	$0.22	$0.22	$0.24	$0.25	$0.25	$—

(1) Includes certain outstanding natural gas puts of approximately 10,570 MMMBtu for each of the years ending December 31, 2013, December 31, 2014, and December 31, 2015, and 10,599 MMMBtu for the year ending December 31, 2016, used to hedge revenues associated with NGL production.

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

(3) Settle on the respective pricing index to hedge basis differential associated with natural gas production.

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

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

Settled derivatives on natural gas production for the year ended December 31, 2012, included volumes of 140,884 MMMBtu at an average contract price of $5.41 per MMBtu. Settled derivatives on oil production for the year ended December 31, 2012, included volumes of 11,289 MBbls at an average contract price of $97.61 per Bbl. Settled derivatives on natural gas production for the year ended December 31, 2011, included volumes of 64,457 MMMBtu at an average contract price of $8.24 per MMBtu. Settled derivatives on oil production for the year ended December 31, 2011, included volumes of 7,917 MBbls at an average contract price of $85.70 per Bbl. The natural gas derivatives are settled based on the closing price of NYMEX natural gas on the last trading day for the delivery month, which occurs on the third business day preceding the delivery month, or the relevant index prices of natural gas published in Inside FERC’s Gas Market Report on the first business day of the delivery month. The oil derivatives are settled based on the average closing price of NYMEX light crude oil for each day of the delivery month.

Interest Rate Swaps

The Company may from time to time enter into interest rate swap agreements based on LIBOR to minimize the effect of fluctuations in interest rates. If LIBOR is lower than the fixed rate in the contract, the Company is required to pay the counterparty the difference, and conversely, the counterparty is required to pay the Company if LIBOR is higher than the fixed rate in the contract. The Company does not designate interest rate swap agreements as cash flow hedges; therefore, the changes in fair value of these instruments are recorded in current earnings.

In 2010, the Company restructured its interest rate swap portfolio in conjunction with the repayments of all of the outstanding indebtedness under its Credit Facility with net proceeds from the issuances of the 2020 and 2021 Senior Notes (see Note 6). In connection with the repayments of borrowings under its Credit Facility with net proceeds from the issuances of the 2020 and 2021 Senior Notes, the Company canceled (before the contract settlement date) all of its interest rate swap agreements resulting in realized losses of approximately $124 million. At December 31, 2012, and December 31, 2011, the Company had no outstanding interest rate swap agreements.

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

Balance Sheet Presentation

The Company's commodity derivatives and, when applicable, its interest rate swap derivatives are presented on a net basis in "derivative instruments" on the consolidated balance sheets. The following summarizes the fair value of derivatives outstanding on a gross basis:

	December 31,	
	2012	2011
	(in thousands)	
Assets:		
Commodity derivatives	$1,282,390	$880,175
Liabilities:		
Commodity derivatives	$405,619	$320,835

By using derivative instruments to economically hedge exposures to changes in commodity prices and interest rates, when applicable, the Company exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes the Company, which creates credit risk. The Company's counterparties are current participants or affiliates of participants in its Credit Facility or were participants or affiliates of participants in its Credit Facility at the time it originally entered into the derivatives. The Credit Facility is secured by the Company's oil and natural gas reserves; therefore, the Company is not required to post any collateral. The Company does not receive collateral from its counterparties. The maximum amount of loss due to credit risk that the Company would incur if its counterparties failed completely to perform according to the terms of the contracts, based on the gross fair value of financial instruments, was approximately $1.3 billion at December 31, 2012. 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 and, when applicable, its interest rate derivatives are subject to counterparty netting under agreements governing such derivatives and therefore the risk of loss is somewhat mitigated.

Gains (Losses) on Derivatives

Total gains and losses on derivatives, including realized and unrealized gains and losses, were approximately $125 million, $450 million and $7 million for the years ended December 31, 2012, December 31, 2011, and December 31, 2010, respectively, and are reported on the consolidated statements of operations in "gains on oil and natural gas derivatives" and "losses on interest rate swaps."

Note 8 – Fair Value Measurements on a Recurring Basis

The Company accounts for its commodity derivatives and, when applicable, its interest rate derivatives at fair value (see Note 7) on a recurring basis. 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 securities trade in active markets. Assumed credit risk adjustments, based on published credit ratings, public bond yield spreads and credit default swap spreads, are applied to the Company's commodity derivatives and, when applicable, its interest rate derivatives.

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

Fair Value Hierarchy

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

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

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

When the inputs used to measure fair value fall within different levels of the hierarchy in a liquid environment, the level within which the fair value measurement is categorized is based on the lowest level input that is significant to the fair value measurement in its entirety. The Company conducts a review of fair value hierarchy classifications on a quarterly basis. Changes in the observability of valuation inputs may result in a reclassification for certain financial assets or liabilities.

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

	Fair Value Measurements on a Recurring Basis		
	December 31, 2012		
	Level 2	Netting [1]	Total
	(in thousands)		
Assets:			
Commodity derivatives	$1,282,390	$(401,479)	$880,911
Liabilities:			
Commodity derivatives	$405,619	$(401,479)	$4,140

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

Note 9 – Other Property and Equipment

Other property and equipment consists of the following:

	December 31, 2012	2011
	(in thousands)	
Natural gas plant and pipeline	$371,292	$129,863
Buildings and leasehold improvements	19,999	16,158
Vehicles	19,731	13,653
Drilling and other equipment	6,265	3,645
Furniture and office equipment	47,623	29,972
Land	4,278	3,944
	469,188	197,235
Less accumulated depreciation	(73,721)	(48,024)
	$395,467	$149,211

Note 10 – Asset Retirement Obligations

Asset retirement obligations associated with retiring tangible long-lived assets are recognized as a liability in the period in which a legal obligation is incurred and becomes determinable and are included in “other noncurrent liabilities” on the consolidated balance sheets. Accretion expense is included in “depreciation, depletion and amortization” on the consolidated statements of operations. The fair value of additions to the asset retirement obligations is estimated using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation include estimates of: (i) plug and abandon costs per well based on existing regulatory requirements; (ii) remaining life per well; (iii) future inflation factors (2.0% for each of the years in the three-year period ended December 31, 2012); and (iv) a credit-adjusted risk-free interest rate (average of 6.8%, 7.5% and 8.6% for the years ended December 31, 2012, December 31, 2011, and December 31, 2010, respectively). These inputs require significant judgments and estimates by the Company’s management at the time of the valuation and are the most sensitive and subject to change.

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

	December 31, 2012	2011
	(in thousands)	
Asset retirement obligations at beginning of year	$71,142	$42,945
Liabilities added from acquisitions	63,663	19,853
Liabilities added from drilling	1,799	1,277
Current year accretion expense	8,550	4,140
Settlements	(3,640)	(2,218)
Revision of estimates	10,460	5,145
Asset retirement obligations at end of year	$151,974	$71,142

Note 11 – Commitments and Contingencies

The Company has been named as a defendant in a number of lawsuits, including claims from royalty owners related to disputed royalty payments and royalty valuations. The Company has established reserves that management currently believes are adequate to provide for potential liabilities based upon its evaluation of these matters. 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. Discovery related to class certification has concluded. Briefing and the hearing on class certification have been

deferred by court order pending the Tenth Circuit Court of Appeals' resolution of interlocutory appeals of two unrelated class certification orders. 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.

In 2008, Lehman Brothers Holdings Inc. and Lehman Brothers Commodity Services Inc. (together "Lehman"), filed voluntary petitions for reorganization under Chapter 11 of the U.S. Bankruptcy Code with the U.S. Bankruptcy Court for the Southern District of New York. In March 2011, the Company and Lehman entered into Termination Agreements under which the Company was granted general unsecured claims against Lehman in the amount of $51 million (the "Company Claim"). In December 2011, a Chapter 11 Plan ("Lehman Plan") was approved by the Bankruptcy Court. Based on the recovery estimates described in the approved disclosure statement relating to the Lehman Plan, the Company expects to ultimately receive a substantial portion of the Company Claim. During 2012, the Company received approximately $28 million of the Company Claim under the Lehman Plan resulting in realized gains of approximately $22 million, which is included in "gains on oil and natural gas derivatives" on the consolidated statement of operations. Additional distributions may occur in the future.

Note 12 – Earnings Per Unit

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

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

	Net Income (Loss) (Numerator) (in thousands)	Units (Denominator)	Per Unit Amount
Year ended December 31, 2012:			
Net loss:			
Allocated to units	$(386,616)		
Allocated to unvested restricted units	(4,575)		
	$(391,191)		
Net loss per unit:			
Basic net loss per unit		203,775	$(1.92)
Dilutive effect of unit equivalents		—	—
Diluted net loss per unit		203,775	$(1.92)
Year ended December 31, 2011:			
Net income:			
Allocated to units	$438,439		
Allocated to unvested restricted units	(4,739)		
	$433,700		
Net income per unit:			
Basic net income per unit		172,004	$2.52
Dilutive effect of unit equivalents		725	(0.01)
Diluted net income per unit		172,729	$2.51
Year ended December 31, 2010:			
Net loss:			
Allocated to units	$(114,288)		
Allocated to unvested restricted units	—		
	$(114,288)		
Net loss per unit:			
Basic net loss per unit		142,535	$(0.80)
Dilutive effect of unit equivalents		—	—
Diluted net loss per unit		142,535	$(0.80)

Basic units outstanding excludes the effect of weighted average anti-dilutive unit equivalents related to approximately 2 million unit options and warrants for each of the years ended December 31, 2012, and December 31, 2010. All equivalent units were anti-dilutive for the years ended December 31, 2012, and December 31, 2010, respectively. There were no anti-dilutive unit equivalents for the year ended December 31, 2011.

Note 13 – Operating Leases

The Company leases office space and other property and equipment under lease agreements expiring on various dates through 2019. The Company recognized expense under operating leases of approximately $7 million, $5 million and $5 million, for the years ended December 31, 2012, December 31, 2011, and December 31, 2010, respectively.

As of December 31, 2012, future minimum lease payments were as follows (in thousands):

2013	$6,459
2014	6,718
2015	6,660
2016	4,396
2017	4,381
Thereafter	8,761
	$37,375

Note 14 – Income Taxes

The Company is a limited liability company treated as a partnership for federal and state income tax purposes, with the exception of the state of Texas, in which income tax liabilities and/or benefits of the Company are passed through to its unitholders. Limited liability companies are subject to Texas margin tax. Limited liability companies were also subject to state income taxes in the state of Michigan during 2011 and 2010. In addition, certain of the Company’s subsidiaries are Subchapter C-corporations subject to federal and state income taxes. As such, with the exception of the state of Texas and certain subsidiaries, the Company is not a taxable entity, it does not directly pay federal and state income taxes and recognition has not been given to federal and state income taxes for the operations of the Company, except as set forth in the tables below. Amounts recognized for income taxes are reported in “income tax expense” on the consolidated statements of operations.

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

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

	Year Ended December 31,		
	2012	2011	2010
	(in thousands)		
Current taxes:			
Federal	$2,711	$4,551	$65
State	439	605	1,088
Deferred taxes:			
Federal	323	(1,148)	2,862
State	(683)	1,458	226
	$2,790	$5,466	$4,241

As of December 31, 2012, the Company’s taxable entities had approximately $10 million of net operating loss carryforwards for federal income tax purposes which will begin expiring in 2031.

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

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

	Year Ended December 31,		
	2012	2011	2010
Federal statutory rate	35.0 %	35.0 %	35.0 %
State, net of federal tax benefit	0.1	0.5	(1.2)
Loss excluded from nontaxable entities	(35.6)	(34.4)	(37.5)
Other items	(0.2)	0.1	(0.1)
Effective rate	(0.7)%	1.2 %	(3.8)%

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

	December 31,	
	2012	2011
	(in thousands)	
Deferred tax assets:		
Net operating loss carryforwards	$—	$159
Unit-based compensation	10,579	9,146
Other	4,924	3,606
Total deferred tax assets	15,503	12,911
Deferred tax liabilities:		
Property and equipment principally due to differences in depreciation	(11,049)	(8,226)
Other	(1,055)	(1,646)
Total deferred tax liabilities	(12,104)	(9,872)
Net deferred tax assets	$3,399	$3,039

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

	December 31,	
	2012	2011
	(in thousands)	
Deferred tax assets	$10,318	$8,279
Deferred tax liabilities	(612)	(589)
Other current assets	$9,706	$7,690
Deferred tax assets	$5,186	$4,632
Deferred tax liabilities	(11,493)	(9,283)
Other noncurrent liabilities	$(6,307)	$(4,651)

In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment. At December 31, 2012, based upon the level of historical taxable income and projections for future taxable income over the periods in which the deferred tax assets are deductible, management believes it is more likely than not that the Company will realize the benefits of these deductible differences. The amount of deferred tax assets considered realizable could be reduced in the future if estimates of future taxable income during the carryforward period are reduced.

97

In accordance with the applicable accounting standard, the Company recognizes only the impact of income tax positions that, based on their merits, are more likely than not to be sustained upon audit by a taxing authority. To evaluate its current tax positions in order to identify any material uncertain tax positions, the Company developed a policy of identifying and evaluating uncertain tax positions that considers support for each tax position, industry standards, tax return disclosures and schedules, and the significance of each position. It is the Company's policy to recognize interest and penalties, if any, related to unrecognized tax benefits in income tax expense. The Company had no material uncertain tax positions at December 31, 2012, and December 31, 2011.

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

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

	December 31,	
	2012	2011
	(in thousands)	
Accrued compensation	$35,431	$19,581
Accrued interest	72,668	55,170
Other	7,146	1,147
	$115,245	$75,898

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

	Year Ended December 31,		
	2012	2011	2010
	(in thousands)		
Cash payments for interest, net of amounts capitalized	$343,331	$247,217	$128,807
Cash payments for income taxes	$366	$487	$1,797
Noncash investing activities:			
In connection with the acquisition of oil and natural gas properties, liabilities were assumed as follow:			
Fair value of assets acquired	$2,923,990	$1,523,466	$1,375,010
Cash paid, net of cash acquired	(2,640,475)	(1,500,193)	(1,351,033)
Receivable from seller	2,132	3,557	9,976
Payables to sellers	443	(4,847)	—
Liabilities assumed	$286,090	$21,983	$33,953

For purposes of the consolidated statements of cash flows, the Company considers all highly liquid short-term investments with original maturities of three months or less to be cash equivalents. Restricted cash of approximately $5 million and $4 million is included in "other noncurrent assets" on the consolidated balance sheets at December 31, 2012, and December 31, 2011, respectively, and represents cash deposited by the Company into a separate account and designated for asset retirement obligations in accordance with contractual agreements.

The Company manages its working capital and cash requirements to borrow only as needed from its Credit Facility. At December 31, 2012, and December 31, 2011, approximately $35 million and $54 million, respectively, were included in "accounts payable and accrued expenses" on the consolidated balance sheets which represent reclassified net outstanding checks. The Company presents these net outstanding checks as cash flows from financing activities on the consolidated statements of cash flows.

Note 16 - Related Party Transactions

LinnCo

LinnCo, an affiliate of LINN Energy, was formed on April 30, 2012, for the sole purpose of owning units in LINN Energy. LinnCo expects to have no significant assets or operations other than those related to its interest in LINN Energy. Upon the formation of LinnCo, LINN Energy paid $1,000 for 100% of LinnCo's sole voting share. In October 2012, LinnCo completed its IPO and used the net proceeds of approximately $1.2 billion from the offering to acquire 34,787,500 of LINN Energy's units which represent approximately 15% of LINN Energy's outstanding units at December 31, 2012. All of LinnCo's common shares are held by the public. See Note 3 for additional details about the LinnCo IPO.

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

For the period from April 30, 2012 (LinnCo's inception) to December 31, 2012, LinnCo incurred total general and administrative expenses of approximately $1 million, all of which were paid by LINN Energy on LinnCo's behalf. These expenses included approximately $772,000 related to services provided by LINN Energy necessary for the conduct of LinnCo's business, such as accounting, legal, tax, information technology and other expenses. LINN Energy also paid, on LinnCo's behalf, approximately $3 million of offering costs in connection with the LinnCo IPO. All expenses and costs paid by LINN Energy on LinnCo's behalf are recorded as investment at cost and included in "other noncurrent assets" on the consolidated balance sheet.

In November 2012, the Company paid approximately $25 million in distributions to LinnCo attributable to LinnCo's interest in LINN Energy. On January 24, 2013, the Company's Board of Directors declared a cash distribution of $0.725 per unit with respect to the fourth quarter of 2012. The distribution attributable to LinnCo's interest in LINN Energy, totaling approximately $25 million, was paid to LinnCo on February 14, 2013.

Other

One of the Company's directors, appointed to the Board in May 2012, is the President and Chief Executive Officer of Superior Energy Services, Inc. ("Superior"), which provides oilfield services to the Company. For the year ended December 31, 2012, the Company paid approximately $21 million to Superior and its subsidiaries for services rendered to the Company. These payments were consummated on terms equivalent to those that prevail in arm's-length transactions.

Note 17 - Subsidiary Guarantors

The November 2019 Senior Notes, the May 2019 Senior Notes, the 2010 Issued Notes and the Original Senior Notes are guaranteed by all of the Company's material subsidiaries. The Company is a holding company and has no independent assets or operations of its own, the guarantees under each series of notes are full and unconditional and joint and several, and any subsidiaries of the Company other than the subsidiary guarantors are minor. There are no restrictions on the Company's ability to obtain cash dividends or other distributions of funds from the guarantor subsidiaries.

Note 18 - Subsequent Event

On February 21, 2013, LinnCo and Berry Petroleum Company ("Berry") announced they had signed a definitive merger agreement under which LinnCo would acquire all of the outstanding common shares of Berry. The transaction has a preliminary value of approximately $4.3 billion, including the assumption of debt, and is expected to close by June 30, 2013, subject to approvals by Berry and LinnCo shareholders, Linn Energy's unitholders and regulatory agencies. Under the terms of the agreement, Berry's shareholders will receive 1.25 of LinnCo common shares for each Berry common share they own. This transaction, which is expected to be a tax-free exchange to Berry's shareholders, represents value of $46.2375 per common share, based on the closing price of LinnCo common shares on February 20, 2013.

Table of Contents

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

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

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

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

	Year Ended December 31,		
	2012	2011	2010
	(in thousands)		
Property acquisition costs: [1]			
Proved	$2,531,419	$1,328,328	$1,290,826
Unproved	181,124	188,409	65,604
Exploration costs	452	80	74
Development costs	1,062,043	639,395	244,834
Asset retirement costs	4,675	2,427	748
Total costs incurred	$3,779,713	$2,158,639	$1,602,086

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

Oil and Natural Gas Capitalized Costs

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

	December 31,	
	2012	2011
	(in thousands)	
Proved properties:		
Leasehold acquisition	$8,603,888	$6,040,239
Development	2,553,127	1,484,486
Unproved properties	454,315	310,925
	11,611,330	7,835,650
Less accumulated depletion and amortization	(2,025,656)	(1,033,617)
	$9,585,674	$6,802,033

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

Results of Oil and Natural Gas Producing Activities

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

	Year Ended December 31,		
	2012	2011	2010
	(in thousands)		
Revenues and other:			
Oil, natural gas and natural gas liquid sales	$1,601,180	$1,162,037	$690,054
Gains on oil and natural gas derivatives	124,762	449,940	75,211
	1,725,942	1,611,977	765,265
Production costs:			
Lease operating expenses	317,699	232,619	158,382
Transportation expenses	77,322	28,358	19,594
Severance and ad valorem taxes	130,805	78,458	45,114
	525,826	339,435	223,090
Other costs:			
Exploration costs	1,915	2,390	5,168
Depletion and amortization	579,382	320,096	226,552
Impairment of long-lived assets	422,499	—	38,600
Gains on sale of assets and other, net	(1,369)	(1,001)	—
Texas margin tax (benefit) expense	(787)	1,599	657
	1,001,640	323,084	270,977
Results of operations	$198,476	$949,458	$271,198

There is no federal tax provision included in the results above because the Company’s subsidiaries subject to federal tax do not own any of the Company’s oil and natural gas interests. Limited liability companies are subject to Texas margin tax. Limited liability companies were also subject to state income taxes in the state of Michigan during 2011 and 2010; however, no taxes were assessed in this state for producing activities during these years. See Note 14 for additional information about income taxes.

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

Proved Oil, Natural Gas and NGL Reserves

The proved reserves of oil, natural gas and NGL of the Company have been prepared by the independent engineering firm, DeGolyer and MacNaughton. In accordance with SEC regulations, reserves at December 31, 2012, December 31, 2011, and December 31, 2010, 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, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. An analysis of the change in estimated quantities of oil, natural gas and NGL reserves, all of which are located within the U.S., is shown below:

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

	Year Ended December 31, 2011			
	Natural Gas (Bcf)	Oil (MMBbls)	NGL (MMBbls)	Total (Bcfe)
Proved developed and undeveloped reserves:				
Beginning of year	1,233	156.4	70.9	2,597
Revisions of previous estimates	(71)	(9.2)	0.9	(121)
Purchase of minerals in place	337	39.3	1.0	579
Extensions, discoveries and other additions	240	10.3	24.6	450
Production	(64)	(7.8)	(3.9)	(135)
End of year	1,675	189.0	93.5	3,370
Proved developed reserves:				
Beginning of year	805	103.0	39.9	1,662
End of year	998	124.8	47.8	2,034
Proved undeveloped reserves:				
Beginning of year	428	53.4	31.0	935
End of year	677	64.2	45.7	1,336

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

	Year Ended December 31, 2010			
	Natural Gas (Bcf)	Oil (MMBbls)	NGL (MMBbls)	Total (Bcfe)
Proved developed and undeveloped reserves:				
Beginning of year	774	102.1	54.2	1,712
Revisions of previous estimates	22	3.9	5.2	77
Purchase of minerals in place	369	49.1	1.2	671
Extensions, discoveries and other additions	118	6.1	13.3	234
Production	(50)	(4.8)	(3.0)	(97)
End of year	1,233	156.4	70.9	2,597
Proved developed reserves:				
Beginning of year	549	77.9	33.9	1,220
End of year	805	103.0	39.9	1,662
Proved undeveloped reserves:				
Beginning of year	225	24.2	20.3	492
End of year	428	53.4	31.0	935

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

Proved reserves increased by approximately 1,426 Bcfe to approximately 4,796 Bcfe for the year ended December 31, 2012, from 3,370 Bcfe for the year ended December 31, 2011. The year ended December 31, 2012, includes 803 Bcfe of negative revisions of previous estimates, due primarily to 340 Bcfe of negative revisions due to asset performance, 248 Bcfe of negative revisions primarily due to lower natural gas prices and 215 Bcfe of negative revisions due to the SEC five-year development limitation on PUDs. Seven acquisitions during the year ended December 31, 2012, increased proved reserves by approximately 1,766 Bcfe. In addition, extensions and discoveries, primarily from 436 productive wells drilled during the year, contributed approximately 709 Bcfe to the increase in proved reserves.

Proved reserves increased by approximately 773 Bcfe to approximately 3,370 Bcfe for the year ended December 31, 2011, from 2,597 Bcfe for the year ended December 31, 2010. The year ended December 31, 2011, includes 121 Bcfe of negative revisions of previous estimates, due primarily to 153 Bcfe of negative revisions due to asset performance. These negative revisions were partially offset by 32 Bcfe of positive revisions primarily due to higher oil prices. Twelve acquisitions during the year ended December 31, 2011, increased proved reserves by approximately 579 Bcfe. In addition, extensions and discoveries, primarily from 292 productive wells drilled during the year, contributed approximately 450 Bcfe to the increase in proved reserves.

Proved reserves increased by approximately 885 Bcfe to approximately 2,597 Bcfe for the year ended December 31, 2010, from 1,712 Bcfe for the year ended December 31, 2009. The year ended December 31, 2010, includes 77 Bcfe of positive revisions of previous estimates, due primarily to higher oil and natural gas prices, which contributed approximately 155 Bcfe. These positive revisions were partially offset by 78 Bcfe of negative revisions primarily due to asset performance. Eleven acquisitions during the year ended December 31, 2010, increased proved reserves by approximately 671 Bcfe. In addition, extensions and discoveries, primarily from 138 productive wells drilled during the year, contributed approximately 234 Bcfe to the increase in proved reserves.

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

Information with respect to the standardized measure of discounted future net cash flows relating to proved reserves is summarized below. Future cash inflows are computed by applying applicable prices relating to the Company's proved reserves to the year-end quantities of those reserves. Future production, development, site restoration and abandonment costs are derived based on current costs assuming continuation of existing economic conditions. There are no future income tax expenses because the Company is not subject to federal income taxes. Limited liability companies are subject to Texas margin tax. Limited liabilities companies were also subject to state income taxes in the state of Michigan during 2011 and 2010; however, these amounts are not material. See Note 14 for additional information about income taxes.

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

	December 31, 2012	2011	2010
	(in thousands)		
Future estimated revenues	$30,374,380	$29,319,369	$20,160,275
Future estimated production costs	(11,460,854)	(9,464,319)	(6,825,147)
Future estimated development costs	(3,574,058)	(2,848,497)	(1,733,929)
Future net cash flows	15,339,468	17,006,553	11,601,199
10% annual discount for estimated timing of cash flows	(9,266,487)	(10,391,693)	(7,377,667)
Standardized measure of discounted future net cash flows	$6,072,981	$6,614,860	$4,223,532
Representative NYMEX prices: [1]			
Natural gas (MMBtu)	$2.76	$4.12	$4.38
Oil (Bbl)	$94.64	$95.84	$79.29

(1) In accordance with SEC regulations, reserves at December 31, 2012, December 31, 2011, and December 31, 2010, 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, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. The price used to estimate reserves is held constant over the life of the reserves.

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

	Year Ended December 31, 2012	2011	2010
	(in thousands)		
Sales and transfers of oil, natural gas and NGL produced during the period	$(1,075,354)	$(822,602)	$(466,964)
Changes in estimated future development costs	289,762	27,236	(56,001)
Net change in sales and transfer prices and production costs related to future production	(1,463,820)	784,308	886,438
Purchase of minerals in place	2,153,651	1,452,169	1,277,134
Extensions, discoveries, and improved recovery	413,702	552,704	329,642
Previously estimated development costs incurred during the period	442,322	306,827	42,947
Net change due to revisions in quantity estimates	(1,595,302)	(292,343)	164,999
Accretion of discount	661,486	422,353	172,328
Changes in production rates and other	(368,326)	(39,324)	149,727
	$(541,879)	$2,391,328	$2,500,250

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

Table of Contents

LINN ENERGY, LLC
SUPPLEMENTAL QUARTERLY DATA (Unaudited)

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

Quarterly Financial Data

	Quarters Ended			
	March 31	June 30	September 30	December 31
	(in thousands, except per unit amounts)			
2012:				
Oil, natural gas and natural gas liquid sales	$348,895	$347,227	$444,082	$460,976
Gains (losses) on oil and natural gas derivatives	2,031	439,647	(411,405)	94,489
Total revenues and other	354,090	800,597	48,328	571,225
Total expenses (1)	269,108	460,617	376,353	656,111
(Gain) losses on sale of assets and other, net	1,478	36	(14)	141
Net income (loss)	(6,202)	237,086	(430,005)	(187,495)
Net income (loss) per unit:				
Basic	$(0.04)	$1.19	$(2.18)	$(0.83)
Diluted	$(0.04)	$1.19	$(2.18)	$(0.83)

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

	Quarters Ended			
	March 31	June 30	September 30	December 31
	(in thousands, except per unit amounts)			
2011:				
Oil, natural gas and natural gas liquid sales	$240,707	$302,390	$292,482	$326,458
Gains (losses) on oil and natural gas derivatives	(369,476)	205,515	824,240	(210,339)
Total revenues and other	(126,473)	510,571	1,119,483	118,873
Total expenses (1)	165,625	195,672	211,254	240,353
Losses on sale of assets and other, net	614	977	279	1,646
Net income (loss)	(446,682)	237,109	837,627	(189,615)
Net income (loss) per unit:				
Basic	$(2.75)	$1.34	$4.74	$(1.09)
Diluted	$(2.75)	$1.33	$4.72	$(1.09)

(1) Includes the following expenses: lease operating, transportation, marketing, general and administrative, exploration, bad debt, depreciation, depletion and amortization and taxes, other than income taxes.

Table of Contents

Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure
None
Item 9A. Controls and Procedures
Evaluation of Disclosure Controls and Procedures
The Company maintains disclosure controls and procedures that are designed to ensure that information required to be disclosed in the Company’s reports under the Securities Exchange Act of 1934, as amended (the “Exchange Act”) is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms, and that such information is accumulated and communicated to management, including the Company’s Chief Executive Officer and Chief Financial Officer, and the Company’s Audit Committee of the Board of Directors, as appropriate, to allow timely decisions regarding required disclosure. In designing and evaluating the disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and management is required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures.
The Company carried out an evaluation under the supervision and with the participation of its management, including its Chief Executive Officer and Chief Financial Officer, of the effectiveness of its disclosure controls and procedures as of the end of the period covered by this report. Based on this evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company’s disclosure controls and procedures were effective as of December 31, 2012.
Management’s Annual Report on Internal Control Over Financial Reporting
See “Management’s Report on Internal Control Over Financial Reporting” in Item 8. “Financial Statements and Supplementary Data.”
Changes in the Company’s Internal Control Over Financial Reporting
The Company’s management is also responsible for establishing and maintaining adequate internal controls over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act. The Company’s internal controls were designed to provide reasonable assurance as to the reliability of its financial reporting and the preparation and presentation of the consolidated financial statements for external purposes in accordance with accounting principles generally accepted in the U.S.
Because of its inherent limitations, internal control over financial reporting may not detect or prevent misstatements. Projections of any evaluation of the effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.
There were no changes in the Company’s internal controls over financial reporting during the fourth quarter of 2012 that materially affected, or were reasonably likely to materially affect, the Company’s internal control over financial reporting.
Item 9B. Other Information
On October 17, 2012, LinnCo, LLC (“LinnCo”), an affiliate of LINN Energy, completed its initial public offering of 34,787,500 common shares representing limited liability company interests. LinnCo has elected to be taxed as a corporation, and accordingly, its shareholders will receive a Form 1099 in respect of any dividends paid by LinnCo. The net proceeds 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. LinnCo will have no significant assets or operations other than those related to its ownership of LINN Energy units. The Company used the proceeds it received from the sale of its units to LinnCo to pay the expenses of the offering and repay a portion of the outstanding indebtedness under its Credit Facility. LinnCo’s common shares are listed on the NASDAQ Global Select Market under the symbol “LNCO.”

Table of Contents

The Company is a limited liability company and its units representing limited liability company interests ("units") are listed on the NASDAQ Global Select Market. The SEC's taxonomy for interactive data reporting does not contain tags that include the term "units" for all existing equity accounts; therefore, in certain instances, the Company has used tags that refer to "shares" or "stock" rather than "units" in its interactive data exhibit. These tags were selected to enhance comparability between the Company and its peers and it should not be inferred from the usage of these tags that an investment in the Company is in any form other than "units" as described above. The Company's interactive data files are included as Exhibit 101 to this Annual Report on Form 10-K.

Table of Contents

Part III

Item 10. Directors, Executive Officers and Corporate Governance

A list of the Company's executive officers and biographical information appears in Part I in this Annual Report on Form 10-K under the caption "Executive Officers of the Company." Information about Company Directors may be found under the caption "Election of Directors" of the Proxy Statement for the Annual Meeting of Unitholders to be held on April 23, 2013 (the "2013 Proxy Statement"). That information is incorporated herein by reference.

The information in the 2013 Proxy Statement set forth under the caption "Section 16(a) Beneficial Ownership Reporting Compliance" is incorporated herein by reference.

The information required by this item regarding audit committee related matters, codes of ethics and committee charters is incorporated by reference from the 2013 Proxy Statement under the caption "Corporate Governance."

Item 11. Executive Compensation

Information required by this item is incorporated herein by reference to the 2013 Proxy Statement.

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

Information required by this item is incorporated herein by reference to the 2013 Proxy Statement.

Securities Authorized for Issuance Under Equity Compensation Plans

The following summarizes information regarding the number of units that are available for issuance under all of the Company's equity compensation plans as of December 31, 2012:

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Unit Options, Warrants and Rights	Weighted Average Exercise Price of Outstanding Unit Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders	4,642,805	$35.25	769,316
Equity compensation plans not approved by security holders	—	—	—
	4,642,805	$35.25	769,316

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

Information required by this item is incorporated herein by reference to the 2013 Proxy Statement.

Item 14. Principal Accounting Fees and Services

Information required by this item is incorporated herein by reference to the 2013 Proxy Statement.

Table of Contents

Part IV

Item 15. Exhibits and Financial Statement Schedules

(a) - 2. Financial Statement Schedules:

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

(a) - 3. Exhibits Filed:

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

Table of Contents

SIGNATURES

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

LINN ENERGY, LLC

Date: February 21, 2013	By:	/s/ Mark E. Ellis Mark E. Ellis Chairman, President and Chief Executive Officer
Date: February 21, 2013	By:	/s/ David B. Rottino David B. Rottino Senior Vice President of Finance, Business Development and Chief Accounting Officer

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

Signature	Title	Date
/s/ Mark E. Ellis Mark E. Ellis	Chairman, President and Chief Executive Officer (Principal Executive Officer)	February 21, 2013
/s/ Kolja Rockov Kolja Rockov	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 21, 2013
/s/ David B. Rottino David B. Rottino	Senior Vice President of Finance, Business Development and Chief Accounting Officer (Principal Accounting Officer)	February 21, 2013
/s/ Michael C. Linn Michael C. Linn	Founder and Director	February 21, 2013
/s/ George A. Alcorn George A. Alcorn	Independent Director	February 21, 2013
/s/ David D. Dunlap David D. Dunlap	Independent Director	February 21, 2013
/s/ Terrence S. Jacobs Terrence S. Jacobs	Independent Director	February 21, 2013
/s/ Joseph P. McCoy Joseph P. McCoy	Independent Director	February 21, 2013
/s/ Linda M. Stephens Linda M. Stephens	Independent Director	February 21, 2013

/s/ Jeffrey C. Swoveland Jeffrey C. Swoveland	Independent Director	February 21, 2013

Table of Contents

INDEX TO EXHIBITS

Exhibit Number		Description
3.1	—	Certificate of Formation of Linn Energy Holdings, LLC (now Linn Energy, LLC) (incorporated herein by reference to Exhibit 3.1 to Registration Statement on Form S-1 (File No. 333-125501) filed by Linn Energy, LLC on June 3, 2005)
3.2	—	Certificate of Amendment to Certificate of Formation of Linn Energy Holdings, LLC (now Linn Energy, LLC) (incorporated herein by reference to Exhibit 3.2 to Registration Statement on Form S-1 (File No. 333-125501) filed by Linn Energy, LLC on June 3, 2005)
3.3	—	Third Amended and Restated Limited Liability Company Agreement of Linn Energy, LLC dated as of September 3, 2010, (incorporated herein by reference to Exhibit 3.1 to Current Report on Form 8-K, filed on September 7, 2010)
4.1	—	Form of specimen unit certificate for the units of Linn Energy, LLC (incorporated herein by reference to Exhibit 4.1 to Annual Report on Form 10-K for the year ended December 31, 2005, filed on May 31, 2006)
4.2	—	Indenture, dated as of June 27, 2008, among Linn Energy, LLC, Linn Energy Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as Trustee (incorporated herein by reference to Exhibit 4.1 to Current Report on Form 8-K filed on June 30, 2008)
4.3	—	Indenture, dated as of May 18, 2009, among Linn Energy, LLC, Linn Energy Finance Corp., the Subsidiary Guarantors named therein and U. S. Bank National Association, as Trustee (incorporated herein by reference to Exhibit 4.1 to Current Report on Form 8-K filed on May 18, 2009)
4.4	—	Indenture, dated as of April 6, 2010, among Linn Energy, LLC, Linn Energy Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as Trustee (incorporated herein by reference to Exhibit 4.1 to Current Report on Form 8-K filed on April 9, 2010)
4.5	—	Indenture, dated as of September 13, 2010, among Linn Energy, LLC, Linn Energy Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as Trustee (incorporated herein by reference to Exhibit 4.1 to Current Report on Form 8-K filed on September 13, 2010)
4.6	—	Indenture, dated as of May 13, 2011, among Linn Energy, LLC, Linn Energy Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as Trustee (incorporated herein by reference to Exhibit 4.1 to Current Report on Form 8-K filed on May 16, 2011)
4.7	—	Indenture, dated as of March 2, 2012, among Linn Energy, LLC, Linn Energy Finance Corp., the Subsidiary Guarantors named therein and U. S. Bank National Association, as Trustee (incorporated herein by reference to Exhibit 4.1 to Current Report on Form 8-K filed on March 2, 2012)
4.8	—	First Supplemental Indenture, dated as of July 2, 2010, to Indenture, dated as of June 27, 2008, between Linn Energy, LLC, Linn Energy Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as Trustee (incorporated herein by reference to Exhibit 4.1 to Quarterly Report on Form 10-Q filed on July 29, 2010)
4.9	—	First Supplemental Indenture, dated as of July 2, 2010, to Indenture, dated as of May 18, 2009, between Linn Energy, LLC, Linn Energy Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as Trustee (incorporated herein by reference to Exhibit 4.2 to Quarterly Report on Form 10-Q filed on July 29, 2010)
4.10	—	First Supplemental Indenture, dated as of July 2, 2010, to Indenture, dated as of April 6, 2010, between Linn Energy, LLC, Linn Energy Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as Trustee (incorporated herein by

		reference to Exhibit 4.3 to Quarterly Report on Form 10-Q filed on July 29, 2010)
4.11	—	Second Supplemental Indenture, dated as of March 16, 2011, to Indenture, dated as of May 18, 2009, by and among Linn Energy LLC, Linn Energy Finance Corp., the Guarantors party thereto and U.S. Bank National Association (incorporated herein by reference to Exhibit 4.1 to Current Report on Form 8-K filed on March 22, 2011)
4.12	—	Second Supplemental Indenture, dated as of March 16, 2011, to the Indenture dated as of June 27, 2008, by and among Linn Energy LLC, Linn Energy Finance Corp., the Guarantors party thereto and U.S. Bank National Association (incorporated herein by reference to Exhibit 4.1 to Current Report on Form 8-K filed on March 22, 2011)

Table of Contents

Exhibit Number		Description
4.13	—	Registration Rights Agreement, dated as of March 2, 2012, among Linn Energy, LLC, Linn Energy Finance Corp., the Subsidiary Guarantors named therein and the representatives of the Initial Purchasers named therein (incorporated herein by reference to Exhibit 4.2 to Current Report on Form 8-K filed on March 2, 2012)
10.1*	—	Linn Energy, LLC Amended and Restated Long-Term Incentive Plan (incorporated herein by reference to Annex A to the Proxy Statement for 2008 Annual Meeting, filed on April 21, 2008)
10.2*	—	Amendment No. 1 to Linn Energy, LLC Amended and Restated Long-Term Incentive Plan, dated February 4, 2009, (incorporated herein by reference to Exhibit 10.2 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.3*	—	Amendment No. 2 to Linn Energy, LLC Amended and Restated Long-Term Incentive Plan, dated July 19, 2010, (incorporated herein by reference to Exhibit 10.3 to Quarterly Report on Form 10-Q filed on July 29, 2010)
10.4*	—	Form of Executive Unit Option Agreement pursuant to the Linn Energy, LLC Amended and Restated Long-Term Incentive Plan, as amended (incorporated herein by reference to Exhibit 10.3 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.5*	—	Form of Executive Restricted Unit Agreement pursuant to the Linn Energy, LLC Amended and Restated Long-Term Incentive Plan, as amended (incorporated herein by reference to Exhibit 10.4 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.6*	—	Form of Phantom Unit Grant Agreement for Independent Directors pursuant to the Linn Energy, LLC Amended and Restated Long-Term Incentive Plan, as amended (incorporated herein by reference to Exhibit 10.1 to Current Report on Form 8-K filed on August 9, 2006)
10.7*	—	Form of Director Restricted Unit Grant Agreement pursuant to the Linn Energy, LLC Amended and Restated Long-Term Incentive Plan, as amended (incorporated herein by reference to Exhibit 10.6 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.8* **	—	Form of Non-Executive Phantom Unit Agreement pursuant to the Linn Energy, LLC Amended and Restated Long-Term Incentive Plan, as amended
10.9* **	—	Form of Executive Phantom Unit Agreement pursuant to the Linn Energy, LLC Amended and Restated Long-Term Incentive Plan, as amended
10.10*	—	Retirement Agreement, dated as of November 29, 2011, by and among Linn Operating, Inc., Linn Energy, LLC and Michael C. Linn (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed on December 1, 2011)
10.11*	—	Third Amended and Restated Employment Agreement, dated effective as of December 17, 2008, between Linn Operating, Inc. and Kolja Rockov (incorporated herein by reference to Exhibit 10.8 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.12*	—	Amended and Restated Employment Agreement, dated effective as of December 17, 2008, between Linn Operating, Inc. and Mark E. Ellis (incorporated herein by reference to Exhibit 10.9 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.13*	—	Amendment No. 1, dated effective as of January 1, 2010, to Amended and Restated Employment Agreement, dated effective as of December 17, 2008, between Linn Operating, Inc. and Mark E. Ellis (incorporated herein by reference to Exhibit 10.29 to Annual Report on Form 10-K for the year ended December 31, 2009, filed on February 25, 2010)
10.14*	—	

		Amended and Restated Employment Agreement, dated effective December 17, 2008, between Linn Operating, Inc. and Charlene A. Ripley (incorporated herein by reference to Exhibit 10.10 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.15*	—	Amended and Restated Employment Agreement, dated effective December 17, 2008, between Linn Operating, Inc. and Arden L. Walker, Jr. (incorporated herein by reference to Exhibit 10.11 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.16*	—	Amendment No. 1, dated April 26, 2011, to First Amended and Restated Employment Agreement, dated December 17, 2008, between Linn Operating, Inc. and Arden L. Walker, Jr. (incorporated herein by reference to Quarterly Report on Form 10-Q for the quarter ended March 31, 2011, filed on April 28, 2011)

Table of Contents

Exhibit Number		Description
10.17*	—	Second Amended and Restated Employment Agreement, dated December 17, 2008, between Linn Operating, Inc. and David B. Rottino (incorporated herein by reference to Exhibit 10.12 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.18*	—	Indemnity Agreement, dated as of February 4, 2009, between Linn Energy, LLC and George A. Alcorn (incorporated herein by reference to Exhibit 10.15 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.19*	—	Indemnity Agreement, dated as of February 4, 2009, between Linn Energy, LLC and Joseph P. McCoy (incorporated herein by reference to Exhibit 10.16 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.20*	—	Indemnity Agreement, dated as of February 4, 2009, between Linn Energy, LLC and Terrence S. Jacobs (incorporated herein by reference to Exhibit 10.17 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.21*	—	Indemnity Agreement, dated as of February 4, 2009, between Linn Energy, LLC and Jeffrey C. Swoveland (incorporated herein by reference to Exhibit 10.18 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.22*	—	Indemnity Agreement, dated as of February 4, 2009, between Linn Energy, LLC and Michael C. Linn (incorporated herein by reference to Exhibit 10.19 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.23*	—	Indemnity Agreement, dated as of February 4, 2009, between Linn Energy, LLC and Mark E. Ellis (incorporated herein by reference to Exhibit 10.20 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.24*	—	Indemnity Agreement, dated as of February 4, 2009, between Linn Energy, LLC and Kolja Rockov (incorporated herein by reference to Exhibit 10.21 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.25*	—	Indemnity Agreement, dated as of February 4, 2009, between Linn Energy, LLC and Charlene A. Ripley (incorporated herein by reference to Exhibit 10.22 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.26*	—	Indemnity Agreement, dated as of February 4, 2009, between Linn Energy, LLC and David B. Rottino (incorporated herein by reference to Exhibit 10.23 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.27*	—	Indemnity Agreement, dated as of February 4, 2009, between Linn Energy, LLC and Arden L. Walker, Jr. (incorporated herein by reference to Exhibit 10.24 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.28**	—	Indemnity Agreement, dated as of July 10, 2012, between Linn Energy, LLC and David D. Dunlap
10.29**	—	Indemnity Agreement, dated as of February 4, 2013, between Linn Energy, LLC and Linda M. Stephens
10.30	—	Fifth Amended and Restated Credit Agreement dated as of May 2, 2011, among Linn Energy, LLC as Borrower, BNP Paribas, as Administrative Agent, and the Lenders and agents Party thereto (incorporated herein by reference to Exhibit 10.1 to Quarterly Report on Form 10-Q filed on July 28, 2011)
10.31	—	First Amendment to Fifth Amended and Restated Credit Agreement, dated February 29, 2012, among Linn Energy, LLC, BNP Paribas, as administrative agent, and the other agents and lenders party thereto (incorporated herein by reference to Exhibit 1.2 to Current Report on Form 8-K filed on March 2, 2012)
10.32	—	Second Amendment to Fifth Amended and Restated Credit Agreement, dated May 10, 2012, among Linn Energy, LLC, Wells Fargo Bank, National Association, as administrative agent,

		and the other agents and lenders party thereto (incorporated herein by reference to Exhibit 10.1 to Current Report on Form 8-K filed on May 15, 2012)
10.33	—	Third Amendment to Fifth Amended and Restated Credit Agreement, dated July 25, 2012, among Linn Energy, LLC, Wells Fargo Bank, National Association, as administrative agent, and the other agents and lenders party thereto (incorporated herein by reference to Exhibit 10.2 to Quarterly Report on Form 10-Q filed on July 26, 2012)
10.34	—	Fourth Amendment to the Fifth Amended and Restated Credit Agreement among Linn Energy, LLC, as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lenders and agents party thereto (incorporated herein by reference to Exhibit 10.31 to Amendment No. 5 to Registration Statement on Form S-1/A filed on October 10, 2012)

Table of Contents

Exhibit Number		Description
10.35**	—	Fifth Amendment, dated February 20, 2013, to the Fifth Amended and Restated Credit Agreement among Linn Energy, LLC, as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lenders and agents party thereto
10.36	—	Fifth Amended and Restated Guaranty and Pledge Agreement, dated as of May 2, 2011, made by Linn Energy, LLC and each of the other Obligors in favor of BNP Paribas, as Administrative Agent (incorporated herein by reference to Exhibit 10.1 to Quarterly Report on Form 10-Q filed on July 28, 2011)
10.37	—	Linn Energy, LLC Change of Control Protection Plan, dated as of April 25, 2009, (incorporated herein by reference to Exhibit 10.3 to Quarterly Report on Form 10-Q filed on May 7, 2009)
10.38	—	Salt Creek EOR Participation Agreement, dated April 3, 2012, by and between Howell Petroleum Corporation and Linn Energy Holdings, LLC (incorporated herein by reference to Exhibit 10.2 to Quarterly Report on Form 10-Q filed on April 26, 2012)
12.1**	—	Computation of Ratio of Earnings to Fixed Charges
21.1**	—	Significant Subsidiaries of Linn Energy, LLC
23.1**	—	Consent of KPMG LLP
23.2**	—	Consent of DeGolyer and MacNaughton
31.1**	—	Section 302 Certification of Mark E. Ellis, Chairman, President and Chief Executive Officer of Linn Energy, LLC
31.2**	—	Section 302 Certification of Kolja Rockov, Executive Vice President and Chief Financial Officer of Linn Energy, LLC
32.1**	—	Section 906 Certification of Mark E. Ellis, Chairman, President and Chief Executive Officer of Linn Energy, LLC
32.2**	—	Section 906 Certification of Kolja Rockov, Executive Vice President and Chief Financial Officer of Linn Energy, LLC
99.1**	—	2012 Report of DeGolyer and MacNaughton
101.INS†	—	XBRL Instance Document
101.SCH†	—	XBRL Taxonomy Extension Schema Document
101.CAL†	—	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF†	—	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB†	—	XBRL Taxonomy Extension Label Linkbase Document
101.PRE†	—	XBRL Taxonomy Extension Presentation Linkbase Document

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