LINN ENERGY, LLC
Form 10-Q
August 08, 2013

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-Q

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

For the Quarterly Period Ended June 30, 2013

OR

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

for the transition period from _______________ to _______________

Commission File Number: 000-51719

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

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

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

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 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 registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No x

As of July 31, 2013, there were 235,190,863 units outstanding.

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GLOSSARY OF TERMS

As commonly used in the oil and natural gas industry and as used in this Quarterly Report on Form 10-Q, the following terms have the following meanings:

Bbl. One stock tank barrel or 42 United States gallons liquid volume.

Bcf. One billion cubic feet.

Bcfe. One billion cubic feet equivalent, determined using a ratio of six Mcf of natural gas to one Bbl of oil, condensate or natural gas liquids.

Btu. One British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 degrees to 59.5 degrees Fahrenheit.

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.

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PART I – FINANCIAL INFORMATION
Item 1. Financial Statements
LINN ENERGY, LLC
CONDENSED CONSOLIDATED BALANCE SHEETS

	June 30, 2013 (Unaudited)	December 31, 2012
	(in thousands, except unit amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$1,152	$1,243
Accounts receivable – trade, net	343,002	371,333
Derivative instruments	289,499	350,695
Other current assets	57,727	88,157
Total current assets	691,380	811,428
Noncurrent assets:		
Oil and natural gas properties (successful efforts method)	11,866,089	11,611,330
Less accumulated depletion and amortization	(2,358,158)	(2,025,656)
	9,507,931	9,585,674
Other property and equipment	534,280	469,188
Less accumulated depreciation	(91,357)	(73,721)
	442,923	395,467
Derivative instruments	663,765	530,216
Other noncurrent assets	124,995	128,453
	788,760	658,669
Total noncurrent assets	10,739,614	10,639,810
Total assets	$11,430,994	$11,451,238
LIABILITIES AND UNITHOLDERS' CAPITAL		
Current liabilities:		
Accounts payable and accrued expenses	$673,926	$707,861
Derivative instruments	2,632	26
Other accrued liabilities	100,699	115,245
Total current liabilities	777,257	823,132
Noncurrent liabilities:		
Credit facility	1,435,000	1,180,000
Senior notes, net	4,820,673	4,857,817
Derivative instruments	—	4,114
Other noncurrent liabilities	166,532	158,995
Total noncurrent liabilities	6,422,205	6,200,926
Commitments and contingencies (Note 10)		
Unitholders' capital:		

235,209,281 units and 234,513,243 units issued and outstanding at June 30, 2013, and December 31, 2012, respectively	3,817,320	4,136,240
Accumulated income	414,212	290,940
	4,231,532	4,427,180
Total liabilities and unitholders’ capital	$11,430,994	$11,451,238

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

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LINN ENERGY, LLC
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(in thousands, except per unit amounts)			
Revenues and other:				
Oil, natural gas and natural gas liquids sales	$488,207	$347,227	$950,939	$696,122
Gains on oil and natural gas derivatives	326,733	439,647	218,363	441,678
Marketing revenues	17,222	10,841	27,074	12,131
Other revenues	6,663	2,882	11,509	4,756
	838,825	800,597	1,207,885	1,154,687
Expenses:				
Lease operating expenses	83,584	70,129	172,305	141,765
Transportation expenses	29,298	21,815	56,481	32,377
Marketing expenses	9,360	6,458	16,734	7,150
General and administrative expenses	46,305	41,185	104,871	84,506
Exploration costs	818	407	3,044	817
Depreciation, depletion and amortization	198,629	143,506	396,070	260,782
Impairment of long-lived assets	(14,851)	146,499	42,202	146,499
Taxes, other than income taxes	32,397	30,656	72,068	55,851
(Gains) losses on sale of assets and other, net	(959)	(2)	2,213	1,492
	384,581	460,653	865,988	731,239
Other income and (expenses):				
Interest expense, net of amounts capitalized	(103,847)	(94,390)	(204,206)	(171,909)
Loss on extinguishment of debt	(4,187)	—	(4,187)	—
Other, net	(2,182)	(7,956)	(3,825)	(11,225)
	(110,216)	(102,346)	(212,218)	(183,134)
Income before income taxes	344,028	237,598	129,679	240,314
Income tax expense (benefit)	(1,129)	512	6,407	9,430
Net income	$345,157	$237,086	$123,272	$230,884
Net income per unit:				
Basic	$1.47	$1.19	$0.52	$1.17
Diluted	$1.46	$1.19	$0.52	$1.16
Weighted average units outstanding:				
Basic	233,448	197,507	233,313	195,382
Diluted	233,910	198,160	233,800	196,039
Distributions declared per unit	$0.725	$0.725	$1.45	$1.415

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

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LINN ENERGY, LLC
CONDENSED CONSOLIDATED STATEMENT OF UNITHOLDERS' CAPITAL
(Unaudited)

	Units	Unitholders' Capital	Accumulated Income	Total Unitholders' Capital
	(in thousands)			
December 31, 2012	234,513	$4,136,240	$290,940	$4,427,180
Issuance of units	696	2,031	—	2,031
Distributions to unitholders		(341,117)	—	(341,117)
Unit-based compensation expenses		19,575	—	19,575
Excess tax benefit from unit-based compensation		591	—	591
Net income		—	123,272	123,272
June 30, 2013	235,209	$3,817,320	$414,212	$4,231,532

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

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LINN ENERGY, LLC
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six Months Ended June 30, 2013	2012
	(in thousands)	
Cash flow from operating activities:		
Net income	$123,272	$230,884
Adjustments to reconcile net income to net cash provided by (used in) operating activities:		
Depreciation, depletion and amortization	396,070	260,782
Impairment of long-lived assets	42,202	146,499
Unit-based compensation expenses	19,575	14,834
Loss on extinguishment of debt	4,187	—
Amortization and write-off of deferred financing fees	10,905	15,001
Losses on sale of assets and other, net	16,814	903
Deferred income tax	5,725	5,991
Derivatives activities:		
Total gains	(218,363)	(441,678)
Cash settlements	144,502	174,316
Premiums paid for derivatives	—	(583,434)
Changes in assets and liabilities:		
(Increase) decrease in accounts receivable – trade, net	36,174	(14,372)
(Increase) decrease in other assets	2,260	(1,840)
Increase (decrease) in accounts payable and accrued expenses	(5,319)	39,346
Increase (decrease) in other liabilities	(16,648)	30,339
Net cash provided by (used in) operating activities	561,356	(122,429)
Cash flow from investing activities:		
Acquisition of oil and natural gas properties and joint-venture funding	(64,381)	(1,762,933)
Development of oil and natural gas properties	(495,899)	(481,140)
Purchases of other property and equipment	(55,147)	(22,433)
Proceeds from sale of properties and equipment and other	210,899	575
Net cash used in investing activities	(404,528)	(2,265,931)
Cash flow from financing activities:		
Proceeds from sale of units	—	761,362
Proceeds from borrowings	775,000	3,954,802
Repayments of debt	(560,737)	(1,945,000)
Distributions to unitholders	(341,117)	(282,166)
Financing fees, offering expenses and other, net	(30,656)	(103,121)
Excess tax benefit from unit-based compensation	591	3,252
Net cash provided by (used in) financing activities	(156,919)	2,389,129
Net increase (decrease) in cash and cash equivalents	(91)	769
Cash and cash equivalents:		
Beginning	1,243	1,114
Ending	$1,152	$1,883

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

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LINN ENERGY, LLC
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

Note 1 – Basis of Presentation

Nature of Business

Linn Energy, LLC (“LINN Energy” or the “Company”) is an independent oil and natural gas company. 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, the Williston/Powder River Basin, Michigan, Illinois, California and east Texas.

Principles of Consolidation and Reporting

The condensed consolidated financial statements at June 30, 2013, and for the three months and six months ended June 30, 2013, and June 30, 2012, are unaudited, but in the opinion of management include all adjustments (consisting of normal recurring adjustments) necessary for a fair presentation of the results for the interim periods. Certain information and note disclosures normally included in annual financial statements prepared in accordance with U.S. generally accepted accounting principles (“GAAP”) have been condensed or omitted under Securities and Exchange Commission (“SEC”) rules and regulations; as such, this report should be read in conjunction with the financial statements and notes in the Company’s Annual Report on Form 10 K for the year ended December 31, 2012. The results reported in these unaudited condensed consolidated financial statements should not necessarily be taken as indicative of results that may be expected for the entire year.

The condensed 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 accounted for at cost.

The condensed 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 condensed consolidated financial statements in conformity with GAAP requires Company management to make estimates and assumptions about future events. These estimates and the underlying assumptions affect the amount of assets and liabilities reported, disclosures about contingent assets and liabilities, and reported amounts of revenues and expenses. The estimates that are particularly significant to the financial statements include estimates of the Company’s reserves of oil, natural gas and natural gas liquids (“NGL”), future cash flows from oil and natural gas properties, depreciation, depletion and amortization, asset retirement obligations, certain revenues and operating expenses, fair values of commodity derivatives and fair values of assets acquired and liabilities assumed. As fair value is a market-based measurement, it is determined based on the assumptions that market participants would use. These estimates and assumptions are based on management’s best estimates and judgment. Management evaluates its estimates and assumptions on an ongoing basis using historical experience and other factors, including the current economic environment, which management believes to be reasonable under the circumstances. Such estimates and assumptions are adjusted when facts and circumstances dictate. As future events and their effects cannot be determined with precision, actual results could differ from these estimates. Any changes in estimates resulting from continuing changes in the economic environment will be reflected in the financial statements in future periods.

Recently Issued Accounting Standards

In December 2011, the Financial Accounting Standards Board 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 is to be applied retrospectively and is effective for periods beginning on or after January 1, 2013. The

Company adopted the ASU effective January 1, 2013. The adoption of the requirements of the ASU, which expanded disclosures, had no effect on the Company's financial position.

Note 2 – Acquisitions, Joint-Venture Funding and Divestiture

For the six months ended June 30, 2013, the Company paid approximately $69 million, including interest, towards the future funding commitment related to the joint-venture agreement it entered into with an affiliate of Anadarko Petroleum Corporation ("Anadarko") in April 2012. From inception of the agreement through June 30, 2013, the Company has funded approximately $270 million towards the total commitment of $400 million.

Acquisition – Pending

On February 20, 2013, LinnCo, LLC ("LinnCo"), an affiliate of LINN Energy, and Berry Petroleum Company ("Berry") entered into a definitive merger agreement under which LinnCo would acquire all of the outstanding common shares of Berry. Under the terms of the agreement, Berry's shareholders will receive 1.25 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, the last trading day before the public announcement.

In connection with the proposed transaction described above, LinnCo will contribute Berry to LINN Energy in exchange for newly issued LINN Energy units, after which Berry will be an indirect wholly owned subsidiary of LINN Energy. At February 21, 2013, the date of the public announcement, the transaction had a preliminary value of approximately $4.4 billion, including the assumption of approximately $1.7 billion of Berry's debt. The transaction is subject to approvals by Berry and LinnCo shareholders, LINN Energy unitholders and regulatory agencies. Due to the pending SEC inquiry (see Note 16), the timing of closing this proposed transaction is uncertain.

Acquisitions – 2012

On May 1, 2012, the Company completed the acquisition of certain oil and natural gas properties located in east Texas. The results of operations of these properties have been included in the condensed consolidated financial statements since the acquisition date. The Company paid approximately $168 million in total consideration for these properties. The transaction was financed primarily with borrowings under the Company's Credit Facility, as defined in Note 6.

On April 3, 2012, the Company entered into a joint-venture agreement ("Agreement") with Anadarko whereby the Company will participate as a partner in the CO_2 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 results of operations of these properties have been included in the condensed consolidated financial statements since the 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 America Production Company ("BP"). The results of operations of these properties have been included in the condensed consolidated financial statements since the acquisition date. 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).

Divestiture – 2013

On May 31, 2013, the Company, through one of its wholly owned subsidiaries, together with the Company's partners, Panther Energy, LLC and Red Willow Mid-Continent, LLC, completed the sale of its interests in certain oil and natural gas properties located in the Mid-Continent region ("Panther Properties") to Midstates Petroleum Company, Inc. At March 31, 2013, the carrying value of the Panther Properties was reduced to fair value less costs to sell resulting in an impairment charge of approximately $57 million and the properties were classified as "assets held for sale." On May 31, 2013, upon the completion of the sale, the Company recorded an adjustment of approximately $15 million to reduce the initial impairment charge recorded in March 2013 resulting in a total impairment charge of approximately $42 million for the six months ended June 30, 2013. Proceeds received for the Company's portion of its interests in the properties were approximately $219 million, net of costs to sell of approximately $2 million. The Company used the net proceeds from the sale to repay borrowings under its Credit Facility, as defined in Note 6.

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Note 3 – Unitholders' Capital

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.

Equity Distribution Agreement

The Company has an equity distribution agreement pursuant to which it may from time to time issue and sell units representing limited liability company interests having an aggregate offering price of up to $500 million. Sales of units, if any, will be made through a sales agent by means of ordinary brokers' transactions, in block transactions, or as otherwise agreed with the agent. The Company expects to use the net proceeds from any sale of the units for general corporate purposes, which may include, among other things, capital expenditures, acquisitions and the repayment of debt.

In January 2012, the Company, under its equity distribution agreement, issued and sold 1,539,651 units representing limited liability company interests at an average unit price of $38.02 for proceeds of approximately $57 million (net of approximately $2 million in commissions and professional service 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 June 30, 2013, units equaling approximately $411 million in aggregate offering price remained available to be issued and sold under the agreement.

Distributions

Under the Company's limited liability company agreement, the Company's unitholders are entitled to receive a distribution of available cash, which includes cash on hand plus borrowings less any reserves established by the Board of Directors to provide for the proper conduct of the Company's business (including reserves for future capital expenditures, including drilling, acquisitions and anticipated future credit needs) or to fund distributions over the next four quarters. Distributions paid by the Company are presented on the condensed consolidated statement of unitholders' capital and the condensed consolidated statements of cash flows. In April 2013, the Company's Board of Directors approved a change in its distribution policy that provides a distribution with respect to any quarter may be made, at the discretion of the Board of Directors, (i) within 45 days following the end of each quarter or (ii) in three equal installments within 15, 45 and 75 days following the end of each quarter. On July 1, 2013, the Company's Board of Directors declared a cash distribution of $0.725 per unit with respect to the second quarter of 2013, to be paid in three equal monthly installments of $0.2416 per unit. The first monthly distribution, totaling approximately $57 million, was paid on July 15, 2013, to unitholders of record as of the close of business on July 10, 2013.

Note 4 – Oil and Natural Gas Properties

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:

	June 30, 2013	December 31, 2012
	(in thousands)	
Proved properties:		
Leasehold acquisition	$8,466,258	$8,603,888
Development	3,015,279	2,553,127
Unproved properties	384,552	454,315
	11,866,089	11,611,330
Less accumulated depletion and amortization	(2,358,158)	(2,025,656)
	$9,507,931	$9,585,674

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Note 5 – Unit-Based Compensation

During the six months ended June 30, 2013, the Company granted 652,840 restricted units and 105,530 phantom units to employees, primarily as part of its annual review of its nonexecutive employees' compensation, with an aggregate fair value of approximately $29 million. The restricted units and phantom units vest over three years. A summary of unit-based compensation expenses included on the condensed consolidated statements of operations is presented below:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(in thousands)			
General and administrative expenses	$7,136	$6,289	$17,001	$13,911
Lease operating expenses	1,177	374	2,574	923
Total unit-based compensation expenses	$8,313	$6,663	$19,575	$14,834
Income tax benefit	$3,072	$2,462	$7,233	$5,481

Note 6 – Debt

The following summarizes debt outstanding:

	June 30, 2013		December 31, 2012	
	Carrying Value	Fair Value (1)	Carrying Value	Fair Value (1)
	(in millions, except percentages)			
Credit facility (2)	$1,435	$1,435	$1,180	$1,180
11.75% senior notes due 2017	—	—	41	44
9.875% senior notes due 2018	14	15	14	15
6.50% senior notes due May 2019	750	730	750	755
6.25% senior notes due November 2019	1,800	1,708	1,800	1,802
8.625% senior notes due 2020	1,300	1,362	1,300	1,414
7.75% senior notes due 2021	1,000	999	1,000	1,061
Less current maturities	—	—	—	—
	6,299	$6,249	6,085	$6,271
Unamortized discount	(43)		(47)	
Total debt, net of discount	$6,256		$6,038	

(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 1.95% and 1.97% at June 30, 2013, and December 31, 2012, respectively.

Credit Facility

In April 2013, the Company entered into a Sixth Amended and Restated Credit Agreement ("Credit Facility"), which provides for a revolving credit facility up to the lesser of: (i) the then-effective borrowing base and (ii) the maximum commitment amount of $4.0 billion. The borrowing base remained unchanged at $4.5 billion and does not include any assets to be acquired in the pending transaction with Berry (see Note 2). The maturity date is April 2018. The amended and restated agreement is substantially similar to the previous Credit Facility with revisions to permit the transactions related to the acquisition of Berry and to designate Berry as an unrestricted subsidiary under the agreement. At June 30, 2013, the borrowing capacity under the Credit Facility was approximately $2.6 billion, which includes a $5 million reduction in availability for outstanding letters of credit.

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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 once annually upon requested interim redetermination 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 condensed 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 2018 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 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. On March 22, 2013, the Company filed a registration statement on Form S-4 to register exchange notes that are substantially similar to the November 2019 Senior Notes. As of August 8, 2013, the registration statement has not been declared effective and due to the pending SEC inquiry (see Note 16), the timing for the registration statement to be declared effective is uncertain. Accordingly, beginning on April 8, 2013, interest accruing on the November 2019 Senior Notes increased by 0.25%, and will increase by an additional 0.25% on the 90th, 180th and 270th day after such date until such registration statement is declared effective and the Company completes an offer to exchange the November 2019 Senior Notes for registered notes. Such additional interest is expected to be approximately $4 million through October 2013 and will continue to increase until the registration statement is declared effective.

Senior Notes Due May 2019

The Company has $750 million in aggregate principal amount of 6.50% 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. In an exchange offer that expired in October 2012, the Company exchanged 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.

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, the restrictive legends from each of the 2010 Issued Senior Notes have been removed making them freely tradable (other than with respect to persons that are affiliates of the Company), thereby terminating the Company's obligations under each of the registration rights agreements entered into in connection with the issuance of the 2010 Issued Senior Notes.

Senior Notes Due 2018

At June 30, 2013, the Company also had $14 million (originally $256 million) in aggregate principal amount of 9.875% senior notes due 2018 (the "2018 Senior Notes"). The indenture related to the 2018 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 offer in 2011, the indenture was amended and most of the covenants and certain default provisions were eliminated. The amendment became effective upon the execution of the supplemental indenture to the indenture governing the 2018 Senior Notes. In accordance with the provisions of the indenture related to the 2018 Senior Notes, in July 2013, the Company redeemed the remaining outstanding principal amount of $14 million.

Redemption of Senior Notes Due 2017

In accordance with the provisions of the indenture related to the Company's 11.75% senior notes due 2017 (the "2017 Senior Notes"), in June 2013, the Company redeemed the remaining outstanding principal amount of $41 million. In connection with the redemption, the Company recorded a loss on extinguishment of debt of approximately $4 million.

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.

The following table summarizes derivative positions for the periods indicated as of June 30, 2013:

	July 1 - December 31, 2013	2014	2015	2016	2017	2018
Natural gas positions:						
Fixed price swaps:						
Hedged volume (MMMBtu)	44,004	97,401	118,041	121,841	120,122	36,500
Average price ($/MMBtu)	$5.22	$5.25	$5.19	$4.20	$4.26	$5.00
Put options: (1)						
Hedged volume (MMMBtu)	43,453	79,628	71,854	76,269	66,886	—
Average price ($/MMBtu)	$5.37	$5.00	$5.00	$5.00	$4.88	$—
Total:						
Hedged volume (MMMBtu)	87,457	177,029	189,895	198,110	187,008	36,500
Average price ($/MMBtu)	$5.29	$5.14	$5.12	$4.51	$4.48	$5.00
Oil positions:						
Fixed price swaps: (2)						
Hedged volume (MBbls)	5,985	11,903	11,599	11,464	4,755	—
Average price ($/Bbl)	$94.97	$92.92	$96.23	$90.56	$89.02	$—
Put options:						
Hedged volume (MBbls)	1,565	3,960	3,426	3,271	384	—
Average price ($/Bbl)	$97.86	$91.30	$90.00	$90.00	$90.00	$—
Total:						
Hedged volume (MBbls)	7,550	15,863	15,025	14,735	5,139	—
Average price ($/Bbl)	$95.57	$92.52	$94.81	$90.44	$89.10	$—
Natural gas basis differential positions: (3)						
Panhandle basis swaps:						
Hedged volume (MMMBtu)	39,089	79,388	87,162	59,954	59,138	16,425
Hedged differential ($/MMBtu)	$(0.56)	$(0.33)	$(0.33)	$(0.32)	$(0.33)	$(0.33)
NWPL Rockies basis swaps:						
Hedged volume (MMMBtu)	17,778	39,718	43,292	46,294	38,880	10,804
Hedged differential ($/MMBtu)	$(0.20)	$(0.20)	$(0.20)	$(0.20)	$(0.19)	$(0.19)
MichCon basis swaps:						
Hedged volume (MMMBtu)	4,839	9,490	9,344	7,768	7,437	2,044
Hedged differential ($/MMBtu)	$0.10	$0.08	$0.06	$0.05	$0.05	$0.05
Houston Ship Channel basis swaps:						
Hedged volume (MMMBtu)	2,889	5,256	4,891	4,575	3,604	986
Hedged differential ($/MMBtu)	$(0.10)	$(0.10)	$(0.10)	$(0.10)	$(0.08)	$(0.08)
Permian basis swaps:						
Hedged volume (MMMBtu)	2,337	4,891	5,074	4,219	4,819	1,314
	$(0.20)	$(0.21)	$(0.21)	$(0.20)	$(0.20)	$(0.20)

Hedged differential ($/MMBtu)						
Oil basis differential positions: [3]						
Midland - Cushing basis swaps:						
Hedged volume (MBbls)	1,012	—	—	—	—	—
Hedged differential ($/Bbl)	$(0.95)	$—	$—	$—	$—	$—
Oil timing differential positions:						
Trade month roll swaps: [4]						
Hedged volume (MBbls)	3,501	7,254	7,251	7,446	6,486	—
Hedged differential ($/Bbl)	$0.22	$0.22	$0.24	$0.25	$0.25	$—

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(1) Includes certain outstanding natural gas put options of approximately 5,329 MMMBtu for the period July 1, 2013, through December 31, 2013, 10,570 MMMBtu for each of the years ending December 31, 2014, and December 31, 2015, and 10,599 MMMBtu for the year ending December 31, 2016, used to indirectly 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 and oil 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 six months ended June 30, 2013, the Company entered into commodity derivative contracts consisting of oil basis swaps for April 2013 through December 2013 and natural gas basis swaps for October 2013 through 2018.

Settled derivatives on natural gas production for the three months and six months ended June 30, 2013, included volumes of 43,253 MMMBtu and 86,031 MMMBtu, respectively, at an average contract price of $5.29 per MMBtu. Settled derivatives on oil production for the three months and six months ended June 30, 2013, included volumes of 3,734 MBbls and 7,426 MBbls, respectively, at an average contract price of $95.57 per Bbl. Settled derivatives on natural gas production for the three months and six months ended June 30, 2012, included volumes of 34,438 MMBtu and 58,080 MMMBtu, respectively, at average contract prices of $5.45 per MMBtu and $5.61 per MMBtu. Settled derivatives on oil production for the three months and six months ended June 30, 2012, included volumes of 2,731 MBbls and 5,308 MBbls, respectively, at average contract prices of $98.08 per Bbl and $98.01 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.

Balance Sheet Presentation

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

	June 30, 2013	December 31, 2012
	(in thousands)	
Assets:		
Commodity derivatives	$1,181,540	$1,282,390
Liabilities:		
Commodity derivatives	$230,908	$405,619

By using derivative instruments to economically hedge exposures to changes in commodity prices, the Company exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes the Company, which creates credit risk. The Company’s counterparties are current participants or affiliates of participants in its Credit 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 $1.2 billion at June 30, 2013. The Company minimizes the credit risk in derivative instruments by: (i) limiting its exposure to any single counterparty; (ii) entering into derivative instruments only with counterparties that meet the Company’s minimum credit quality standard, or have a guarantee from an affiliate that meets the Company’s minimum credit quality standard; and (iii) monitoring the creditworthiness of the Company’s counterparties on an ongoing basis. In accordance with the Company's standard practice, its commodity derivatives are subject to counterparty netting under agreements governing such derivatives and therefore the risk of loss is somewhat mitigated.

Gains (Losses) on Derivatives

Gains and losses on derivatives were net gains of approximately $327 million and $218 million for the three months and six months ended June 30, 2013, respectively. Gains and losses on derivatives were net gains of approximately $440 million and $442 million for the three months and six months ended June 30, 2012, respectively. Gains and losses are reported on the condensed consolidated statements of operations in "gains on oil and natural gas derivatives."

Note 8 – Fair Value Measurements on a Recurring Basis

The Company accounts for its commodity derivatives at fair value (see Note 7) on a recurring basis. The Company determines the fair value of its oil and natural gas derivatives utilizing pricing models that use a variety of techniques, including market quotes and pricing analysis. Inputs to the pricing models include publicly available prices and forward price curves generated from a compilation of data gathered from third parties. Company management validates the data provided by third parties by understanding the pricing models used, obtaining market values from other pricing sources, analyzing pricing data in certain situations and confirming that those 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.

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

	June 30, 2013		
	Level 2	Netting [1]	Total
	(in thousands)		
Assets:			
Commodity derivatives	$1,181,540	$(228,276)	$953,264
Liabilities:			
Commodity derivatives	$230,908	$(228,276)	$2,632

	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 – 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 accrued liabilities" and "other noncurrent liabilities" on the condensed consolidated balance sheets. Accretion expense is included in "depreciation, depletion and amortization" on the condensed 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 the six months ended June 30, 2013); and (iv) a credit-adjusted risk-free interest rate (average of 6.5% for the six months ended June 30, 2013). 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 asset retirement obligations (in thousands):

Asset retirement obligations at December 31, 2012	$151,974
Liabilities added from drilling	1,575
Liabilities associated with assets sold	(1,092)
Current year accretion expense	5,575
Settlements	(2,687)
Revision of estimates	2,500
Asset retirement obligations at June 30, 2013	$157,845

Note 10 – 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.

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

On April 12, 2013, a purported stockholder class action captioned David Hall v. Berry Petroleum Co., et al. was filed in the Delaware Court of Chancery, C.A. No. 8476-VCG. The complaint names as defendants Berry, the members of its board of directors, HoldCo, Bacchus Merger Sub, LinnCo, LINN Energy and LinnCo Merger Sub. The complaint alleges that the individual defendants breached their fiduciary duties in connection with the transactions by engaging in an unfair sales process that resulted in an unfair price for Berry, by failing to disclose all material information regarding the transactions, and that the entity defendants aided and abetted those breaches of fiduciary duty. The complaint seeks a declaration that the transactions are unlawful and unenforceable, an order directing the individual defendants to comply with their fiduciary duties, an injunction against consummation of the transactions, or, in the event they are completed, rescission of the transactions, an award of fees and costs, including attorneys' and experts' fees and expenses, and other relief. After expedited discovery, the plaintiffs in this case made a settlement proposal and the parties are currently engaged in settlement discussions. The Company is unable to estimate a possible loss, or range of possible loss, if any, at this time.

On July 9, 2013, Anthony Booth, individually and on behalf of all other persons similarly situated, filed a class action complaint in the United States District Court, Southern District of Texas, against LINN Energy, Mark E. Ellis, Kolja Rockov, and David B. Rottino (the “Booth Action”). On July 18, 2013, the Catherine A. Fisher Trust, individually and on behalf of all other persons similarly situated, filed a class action complaint in the United States District Court, Southern District of Texas, against the same defendants (the “Fisher Action”). On July 17, 2013, Don Gentry, individually and on behalf of all other persons similarly situated, filed a class action complaint in the United States District Court, Southern District of Texas, against LINN Energy, LinnCo, Mark E. Ellis, Kolja Rockov, David B. Rottino, George A. Alcorn, David D. Dunlap, Terrence S. Jacobs, Michael C. Linn, Joseph P. McCoy, Jeffrey C. Swoveland, and the various underwriters for LinnCo’s initial public offering (the “Gentry Action”) (the Booth Action, Fisher Action, and Gentry Action together, the “Texas Federal Actions”). The Texas Federal Actions each assert claims under Sections 10(b) and 20(a) of the Securities Exchange Act of 1934 (the “Exchange Act”) based on allegations that the Company made false or misleading statements relating to its hedging strategy, the cash flow available for distribution to unitholders, and the Company’s energy production. The Gentry Action asserts additional claims under Sections 11 and 15 of the Securities Act of 1933 based on alleged misstatements relating to these issues in the prospectus and registration statement for LinnCo’s initial public offering. The cases are in their preliminary stages and it is possible that additional similar actions could be filed. As a result, the Company is unable to estimate a possible loss, or range of possible loss, if any.

On July 10, 2013, David Adrian Luciano, individually and on behalf of all other persons similarly situated, filed a class action complaint in the United States District Court, Southern District of New York, against LINN Energy, LinnCo, Mark E. Ellis, Kolja Rockov, David B. Rottino, George A. Alcorn, David D. Dunlap, Terrence S. Jacobs, Michael C. Linn, Joseph P. McCoy, Jeffrey C. Swoveland, and the various underwriters for LinnCo’s initial public offering (the “Luciano Action”). On July 12, 2013, Frank Donio, individually and on behalf of all other persons similarly situated, filed a class action complaint in the United States District Court, Southern District of New York, against the same defendants (the “Donio Action”). On July 19, 2013, John Cottrell, individually and on behalf of all other persons similarly situated, filed a class action complaint in the United States District Court, Southern District of New York, against LINN Energy, Mark E. Ellis, Kolja Rockov, and David B. Rottino (the “Cottrell Action”). On July 23, 2013, Kevin Feldman, individually and on behalf of all other persons similarly situated, filed a class action complaint in the United States District Court, Southern District of New York, against the same defendants as in the Luciano Action (the “Feldman Action”) (the Luciano Action, Donio Action, Cottrell Action, and Feldman Action together, the “New York Federal Actions”). The Donio Action and the Cottrell Action assert claims under Sections 10(b) and 20(a) of the Exchange Act based on allegations that the Company made false or misleading statements relating to its hedging strategy, the cash flow available for distribution to unitholders, and the Company’s energy production. The Luciano Action and the Feldman Action assert claims under Sections 11 and 15 of the Securities Act of 1933 based on alleged misstatements relating to these issues in the prospectus and registration statement for LinnCo’s initial public offering. The cases are in their preliminary stages and it is possible that additional similar actions could be filed. As a result, the Company is unable to estimate a possible loss, or range of possible loss, if any.

On July 10, 2013, Judy Mesirov, derivatively on behalf of nominal defendant LINN Energy, filed a shareholder derivative petition against Mark E. Ellis, Kolja Rockov, David B. Rottino, Arden L. Walker, Jr., Charlene A. Ripley, Michael C. Linn, Joseph P. McCoy, George A. Alcorn, Terrence S. Jacobs, David D. Dunlap, Jeffrey C. Swoveland, and Linda M. Stephens in the District Court of Harris County, Texas (the “Mesirov Action”). On July 12, 2013, John Peters, derivatively on behalf of nominal defendant LINN Energy, filed a shareholder derivative petition against many of the same defendants in the District Court of Harris County, Texas (the “Peters Action”) (the Mesirov Action and Peters Action together, the “Texas Derivative Actions”). The Texas Derivative Actions assert derivative claims on behalf of LINN Energy against the individual defendants for alleged breaches of fiduciary duty, waste of corporate assets, mismanagement, abuse of control, and unjust enrichment based on factual allegations similar to those in the Texas Federal Actions and the New York Federal Actions. The cases are in their preliminary stages and it is possible that additional similar actions could be filed in the District Court of Harris County, Texas, or in other jurisdictions. As a result, the Company is unable to estimate a possible loss, or range of possible loss, if any.

In 2008, Lehman Brothers Holdings Inc. and Lehman Brothers Commodity Services Inc. (together “Lehman”), filed voluntary petitions for reorganization under Chapter 11 of the U.S. Bankruptcy Code with the U.S. Bankruptcy Court for the Southern District of New York. In March 2011, the Company and Lehman entered into Termination

Agreements under which the Company was granted general unsecured claims against Lehman in the amount of $51 million (the "Company Claim"). In December 2011, a Chapter 11 Plan ("Lehman Plan") was approved by the Bankruptcy Court. Based on the recovery estimates described in the approved disclosure statement relating to the Lehman Plan, the Company expects to ultimately receive a substantial portion of the Company Claim. In April 2012, an initial distribution under the Lehman Plan of approximately $25 million was received by the Company resulting in a gain of approximately $18 million, and in April 2013, the Company received approximately $5 million of the Company Claim, both of which are included in “gains on oil and natural gas derivatives” on the condensed consolidated statements of operations. In the aggregate, the Company has received approximately $33 million, including approximately $3 million received in October 2012, of the Company Claim and additional distributions are expected to occur in the future.

Note 11 – 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.

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

	Net Income (Numerator) (in thousands)	Units (Denominator)	Per Unit Amount
Three months ended June 30, 2013:			
Net income:			
Allocated to units	$345,157		
Allocated to participating securities	(2,629)		
	$342,528		
Net income per unit:			
Basic net income per unit		233,448	$1.47
Dilutive effect of unit equivalents		462	(0.01)
Diluted net income per unit		233,910	$1.46
Three months ended June 30, 2012:			
Net income:			
Allocated to units	$237,086		
Allocated to participating securities	(2,232)		
	$234,854		
Net income per unit:			
Basic net income per unit		197,507	$1.19
Dilutive effect of unit equivalents		653	—
Diluted net income per unit		198,160	$1.19
Six months ended June 30, 2013:			
Net income:			
Allocated to units	$123,272		
Allocated to participating securities	(2,599)		
	$120,673		
Net income per unit:			
Basic net income per unit		233,313	$0.52
Dilutive effect of unit equivalents		487	—
Diluted net income per unit		233,800	$0.52
Six months ended June 30, 2012:			
Net income:			
Allocated to units	$230,884		
Allocated to participating securities	(2,735)		
	$228,149		
Net income per unit:			
Basic net income per unit		195,382	$1.17
Dilutive effect of unit equivalents		657	(0.01)
Diluted net income per unit		196,039	$1.16

Basic units outstanding excludes the effect of weighted average anti-dilutive unit equivalents related to approximately 3 million unit options and warrants for the three months and six months ended June 30, 2013. There were no anti-dilutive unit equivalents for the three months or six months ended June 30, 2012.

Note 12 – Income Taxes

The Company is a limited liability company treated as a partnership for federal and state income tax purposes, with the exception of the state of Texas, in which income tax liabilities and/or benefits of the Company are passed through to its unitholders. Limited liability companies are subject to Texas margin tax. In addition, certain of the Company's subsidiaries are Subchapter C-corporations subject to federal and state income taxes. As such, with the exception of the state of Texas and certain subsidiaries, the Company is not a taxable entity, it does not directly pay federal and state income taxes and recognition has not been given to federal and state income taxes for the operations of the Company. Amounts recognized for income taxes are reported in "income tax expense (benefit)" on the condensed consolidated statements of operations.

Note 13 – Supplemental Disclosures to the Condensed Consolidated Balance Sheets and Condensed Consolidated Statements of Cash Flows

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

	June 30, 2013	December 31, 2012
	(in thousands)	
Accrued compensation	$20,513	$35,431
Accrued interest	73,453	72,668
Other	6,733	7,146
	$100,699	$115,245

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

	Six Months Ended June 30,	
	2013	2012
	(in thousands)	
Cash payments for interest, net of amounts capitalized	$192,517	$128,617
Cash payments for income taxes	$14	$306
Noncash investing activities:		
In connection with the acquisition of oil and natural gas properties and joint-venture funding, assets were acquired and liabilities were assumed as follows:		
Fair value of assets acquired	$7,655	$1,841,027
Cash (paid) received	3,231	(1,455,433)
Receivables from sellers	1,792	772
Payables to sellers	(6,854)	(422)
Liabilities assumed	$5,824	$385,944

Included in "acquisition of oil and natural gas properties and joint-venture funding" on the condensed consolidated statements of cash flows for the six months ended June 30, 2013, and June 30, 2012, respectively, are approximately $68 million paid by the Company towards the future funding commitment related to the joint-venture agreement entered into with Anadarko and a deposit of approximately $308 million paid by the Company for the acquisition in the Green River Basin region that was pending at June 30, 2012.

For purposes of the condensed 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 is included in "other noncurrent assets" on the condensed consolidated balance sheets at June 30, 2013, and December 31, 2012, 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 June 30, 2013, and December 31, 2012, net outstanding checks of approximately $14 million and $35 million, respectively, were reclassified and included in "accounts payable and accrued expenses" on the condensed consolidated balance sheet. The Company presents net outstanding checks as cash flows from financing activities on the condensed consolidated statements of cash flows.

Note 14 – 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. 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 June 30, 2013. All of LinnCo's common shares are held by the public. As of June 30, 2013, LinnCo had no significant assets or operations other than those related to its interest in LINN Energy. In connection with the pending acquisition of Berry (see Note 2), LinnCo intends to amend its limited liability company agreement to permit the acquisition and subsequent contribution of assets to LINN Energy.

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

For the three months and six months ended June 30, 2013, LinnCo incurred total general and administrative expenses and certain offering costs of approximately $3 million and $15 million, respectively, of which approximately $8 million had been paid by LINN Energy on LinnCo's behalf as of June 30, 2013. The expenses for the three months and six months ended June 30, 2013, include approximately $2 million and $13 million, respectively, of transaction costs related to professional services rendered by third parties in connection with the pending acquisition of Berry (see Note 2). The expenses for the three months and six months ended June 30, 2013, also include approximately $344,000 and $806,000, respectively, related to services provided by LINN Energy necessary for the conduct of LinnCo's business, such as accounting, legal, tax, information technology and other expenses. The offering costs of approximately $361,000 were incurred in connection with LinnCo's registration statement on Form S-4 also related to the pending acquisition of Berry. All expenses and costs paid by LINN Energy on LinnCo's behalf are accounted for as investment at cost.

During the six months ended June 30, 2013, the Company paid approximately $50 million in distributions to LinnCo attributable to LinnCo's interest in LINN Energy.

Other

One of the Company's directors is the President and Chief Executive Officer of Superior Energy Services, Inc. ("Superior"), which provides oilfield services to the Company. For the three months and six months ended June 30, 2013, the Company paid approximately $7 million and $13 million, respectively, to Superior and its subsidiaries for services rendered to the Company. The transactions associated with these payments were consummated on terms equivalent to those that prevail in arm’s-length transactions.

Note 15 – Subsidiary Guarantors

The November 2019 Senior Notes, the May 2019 Senior Notes, the 2010 Issued Notes and the 2018 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 16 – SEC Inquiry

On July 1, 2013, the Company and its affiliate, LinnCo, (the "Companies") announced that they have been notified by the staff of the SEC that its Fort Worth Regional Office has commenced a private, nonpublic inquiry regarding the Companies. The SEC has requested the production of documents and communications that are potentially relevant to, among other things, the Companies' use of non-GAAP financial measures and hedging strategy. The SEC has stated that the fact of the inquiry should not be construed as an indication that the SEC or its staff has a negative view of any entity, individual or security. The Companies are cooperating fully with the SEC in this matter. Due to the pending SEC inquiry, the timing of closing of the proposed merger with Berry is uncertain.

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

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 set forth in "Cautionary Statement" below and in Item 1A. "Risk Factors" in this Quarterly Report on Form 10-Q and in the Annual Report on Form 10-K for the year ended December 31, 2012, and elsewhere in the Annual Report. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur.

The following discussion and analysis should be read in conjunction with the financial statements and related notes included in this Quarterly Report on Form 10-Q and in the Company's Annual Report on Form 10-K for the year ended December 31, 2012. A reference to a "Note" herein refers to the accompanying Notes to Condensed Consolidated Financial Statements contained in Item 1. "Financial Statements."

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;
- Williston/Powder River Basin, which includes the Bakken formation in North Dakota and the Powder River Basin in Wyoming;
- Michigan/Illinois, which includes the Antrim Shale formation in the northern part of Michigan and oil properties in southern Illinois;
- 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 three months ended June 30, 2013, included the following:

- oil, natural gas and NGL sales of approximately $488 million compared to $347 million for the second quarter of 2012;
- average daily production of 780 MMcfe/d compared to 630 MMcfe/d for the second quarter of 2012;
- net income of approximately $345 million compared to $237 million for the second quarter of 2012;
- adjusted EBITDA of approximately $362 million compared to $319 million for the second quarter of 2012;
- capital expenditures, excluding acquisitions, of approximately $334 million compared to $298 million for the second quarter of 2012; and
- 145 wells drilled (all successful) compared to 100 wells drilled (99 successful) for the second quarter of 2012.

Results for the six months ended June 30, 2013, included the following:

- oil, natural gas and NGL sales of approximately $951 million compared to $696 million for the six months ended June 30, 2012;
- average daily production of 788 MMcfe/d compared to 550 MMcfe/d for the six months ended June 30, 2012;
- net income of approximately $123 million compared to $231 million for the six months ended June 30, 2012;
- net cash provided by operating activities of approximately $561 million compared to net cash used in operating activities of $122 million for the six months ended June 30, 2012;
- adjusted EBITDA of approximately $718 million compared to $621 million for the six months ended June 30, 2012;

- capital expenditures, excluding acquisitions, of approximately $606 million compared to $557 million for the six months ended June 30, 2012; and
- 258 wells drilled (all successful) compared to 181 wells drilled (178 successful) for the six months ended June 30, 2012.

Adjusted EBITDA is a non-GAAP financial measure used by Company management and by external users of the Company's financial statements such as investors, lenders under the Company's Credit Facility, research analysts, rating agencies and others. 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. See "Non-GAAP Financial Measures" on page 40 for a reconciliation of adjusted EBITDA to its most directly comparable financial measure calculated and presented in accordance with GAAP.

Acquisition – Pending

On February 20, 2013, LinnCo, LLC ("LinnCo"), an affiliate of LINN Energy, and Berry Petroleum Company ("Berry") entered into a definitive merger agreement under which LinnCo would acquire all of the outstanding common shares of Berry. Under the terms of the agreement, Berry's shareholders will receive 1.25 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, the last trading day before the public announcement.

In connection with the proposed transaction described above, LinnCo will contribute Berry to LINN Energy in exchange for newly issued LINN Energy units, after which Berry will be an indirect wholly owned subsidiary of LINN Energy. At February 21, 2013, the date of the public announcement, the transaction had a preliminary value of approximately $4.4 billion, including the assumption of approximately $1.7 billion of Berry's debt. The transaction is subject to approvals by Berry and LinnCo shareholders, LINN Energy unitholders and regulatory agencies. Due to the pending SEC inquiry (see Note 16), the timing of closing this proposed transaction is uncertain.

Divestiture – 2013

On May 31, 2013, the Company, through one of its wholly owned subsidiaries, together with the Company's partners, Panther Energy, LLC and Red Willow Mid-Continent, LLC, completed the sale of its interests in certain oil and natural gas properties located in the Mid-Continent region ("Panther Properties") to Midstates Petroleum Company, Inc. Proceeds received for the Company's portion of its interests in the properties were approximately $219 million, net of costs to sell of approximately $2 million. The Company used the net proceeds from the sale to repay borrowings under its Credit Facility, as defined in Note 6.

Financing and Liquidity

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

In accordance with the provisions of the indenture related to the 2017 Senior Notes, in June 2013, the Company redeemed the remaining outstanding principal amount of $41 million. In accordance with the provisions of the indenture related to the 2018 Senior Notes, in July 2013, the Company redeemed the remaining outstanding principal amount of $14 million.

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Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations - Continued

Results of Operations
Three Months Ended June 30, 2013, Compared to Three Months Ended June 30, 2012

	Three Months Ended June 30,		
	2013	2012	Variance
	(in thousands)		
Revenues and other:			
Natural gas sales	$160,766	$59,258	$101,508
Oil sales	261,912	224,344	37,568
NGL sales	65,529	63,625	1,904
Total oil, natural gas and NGL sales	488,207	347,227	140,980
Gains on oil and natural gas derivatives	326,733	439,647	(112,914)
Marketing and other revenues	23,885	13,723	10,162
	838,825	800,597	38,228
Expenses:			
Lease operating expenses	83,584	70,129	13,455
Transportation expenses	29,298	21,815	7,483
Marketing expenses	9,360	6,458	2,902
General and administrative expenses (1)	46,305	41,185	5,120
Exploration costs	818	407	411
Depreciation, depletion and amortization	198,629	143,506	55,123
Impairment of long-lived assets	(14,851)	146,499	(161,350)
Taxes, other than income taxes	32,397	30,656	1,741
Gains on sale of assets and other, net	(959)	(2)	(957)
	384,581	460,653	(76,072)
Other income and (expenses)	(110,216)	(102,346)	(7,870)
Income before income taxes	344,028	237,598	106,430
Income tax expense (benefit)	(1,129)	512	(1,641)
Net income	$345,157	$237,086	$108,071

(1) General and administrative expenses for the three months ended June 30, 2013, and June 30, 2012, include approximately $7 million and $6 million, respectively, of noncash unit-based compensation expenses.

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations - Continued

	Three Months Ended June 30,			
	2013	2012	Variance	
Average daily production:				
Natural gas (MMcf/d)	429	317	35	%
Oil (MBbls/d)	31.5	28.2	12	%
NGL (MBbls/d)	27.0	24.0	13	%
Total (MMcfe/d)	780	630	24	%
Weighted average prices (hedged): (1)				
Natural gas (Mcf)	$5.24	$5.65	(7	)%
Oil (Bbl)	$93.49	$92.92	1	%
NGL (Bbl)	$26.69	$29.08	(8	)%
Weighted average prices (unhedged): (2)				
Natural gas (Mcf)	$4.12	$2.06	100	%
Oil (Bbl)	$91.27	$87.36	4	%
NGL (Bbl)	$26.69	$29.08	(8	)%
Average NYMEX prices:				
Natural gas (MMBtu)	$4.09	$2.22	84	%
Oil (Bbl)	$94.22	$93.49	1	%
Costs per Mcfe of production:				
Lease operating expenses	$1.18	$1.22	(3	)%
Transportation expenses	$0.41	$0.38	8	%
General and administrative expenses (3)	$0.65	$0.72	(10	)%
Depreciation, depletion and amortization	$2.80	$2.50	12	%
Taxes, other than income taxes	$0.46	$0.53	(13	)%

(1) Includes the effect of settlements on derivatives of approximately $50 million (excluding an approximate $5 million gain on recovery of bankruptcy claim) and $118 million (excluding an approximate $18 million gain on recovery of bankruptcy claim) for the three months ended June 30, 2013, and June 30, 2012, respectively.

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

(3) General and administrative expenses for the three months ended June 30, 2013, and June 30, 2012, include approximately $7 million and $6 million, respectively, of noncash unit-based compensation expenses. Excluding these amounts, general and administrative expenses for the three months ended June 30, 2013, and June 30, 2012, were $0.55 per Mcfe and $0.61 per Mcfe, respectively. This is a non-GAAP measure used by management to analyze the Company's performance.

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations - Continued

Revenues and Other

Oil, Natural Gas and NGL Sales

Oil, natural gas and NGL sales increased approximately $141 million or 41% to approximately $488 million for the three months ended June 30, 2013, from approximately $347 million for the three months ended June 30, 2012, due to higher production volumes and higher natural gas and oil prices partially offset by lower NGL prices. Higher natural gas and oil prices resulted in an increase in revenues of approximately $81 million and $11 million, respectively. Lower NGL prices resulted in a decrease in revenues of approximately $6 million.

Average daily production volumes increased to 780 MMcfe/d during the three months ended June 30, 2013, from 630 MMcfe/d during the three months ended June 30, 2012. Higher oil, natural gas and NGL production volumes resulted in an increase in revenues of approximately $26 million, $21 million and $8 million, respectively.

The following sets forth average daily production by region:

	Three Months Ended June 30,					
	2013	2012	Variance			
Average daily production (MMcfe/d):						
Mid-Continent	315	306	9		3	%
Hugoton Basin	140	151	(11	)	(8	)%
Green River Basin	138	—	138		—	
Permian Basin	84	80	4		5	%
Williston/Powder River Basin	35	29	6		22	%
Michigan/Illinois	33	35	(2	)	(5	)%
East Texas	22	16	6		39	%
California	13	13	—		—	
	780	630	150		24	%

The increase in average daily production volumes in the Mid-Continent region primarily reflects the Company's 2012 and 2013 capital drilling programs in the Granite Wash formation, partially offset by a decrease of approximately 7 MMcfe/d of production volumes related to one month's production of the Panther Properties sold on May 31, 2013. The decrease in average daily production volumes in the Hugoton Basin region reflects downtime related to weather and plant maintenance, and the effects of natural declines, partially offset by the results of the Company's development capital spending. Average daily production volumes in the Green River Basin region reflect the impact of the acquisition from BP America Production Company ("BP") in July 2012, partially offset by a reduction caused by ethane rejection in the region. The increase in average daily production volumes in the Permian Basin region primarily reflects development capital spending, partially offset by downtime from third parties' infrastructure. The increase in average daily production volumes in the Williston/Powder River Basin region reflects development capital spending in the Williston Basin. 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 East Texas region reflects the impact of the acquisition in May 2012.

Gains on Oil and Natural Gas Derivatives

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

	Three Months Ended June 30,				
	2013		2012	Variance	
	(in thousands)				
Cash settlements on commodity derivatives [(1)]	$53,635		$97,522	$(43,887	)
Cash settlements on bankruptcy claim [(2)]	5,073		18,277	(13,204	)
Total cash settlements	58,708		115,799	(57,091	)
Oil derivative contracts related to current production period [(3)]	(3,458	)	20,218	(23,676	)

Changes in fair value on unsettled commodity derivatives [4]	271,483	303,630	(32,147)
Gains on oil and natural gas derivatives	$326,733	$439,647	$(112,914)

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(1) Exclude the cost of any premiums paid for put option contracts.
(2) Represent the recoveries of a bankruptcy claim against Lehman Brothers.
(3) Represent the timing difference related to contracts that have settled (contract terms have expired) but cash has not been received at the end of the reporting period.
(4) Represent changes in fair value of the derivatives contracts from period to period and include the reduction of put option premium value over time. The Company pays cash for put options at the time of execution and no additional amounts are payable in the future under the contracts. The premiums paid for put options that settled during the three months ended June 30, 2013, and June 30, 2012, were approximately $43 million and $36 million, respectively.

Gains on oil and natural gas derivatives decreased by approximately $113 million to gains of approximately $327 million for the three months ended June 30, 2013, from gains of approximately $440 million for the three months ended June 30, 2012. Gains on oil and natural gas derivatives decreased primarily due to reduced cash settlements during the period and changes in fair value on unsettled derivatives contracts. The results for 2013 and 2012 also include gains of approximately $5 million and $18 million, respectively, related to the recoveries of a bankruptcy claim (see Note 10). The fair value on unsettled derivatives contracts changes as future commodity price expectations change compared to the contract prices on the derivatives. If the expected future commodity prices increase compared to the contract prices on the derivatives, losses are recognized; and if the expected future commodity prices decrease compared to the contract prices on the derivatives, gains are recognized.

During the three months ended June 30, 2013, the Company had commodity derivative contracts for approximately 111% of its natural gas production, including natural gas put options used to indirectly hedge NGL revenues, and 130% of its oil production. During the three months ended June 30, 2012, the Company had commodity derivative contracts for approximately 120% of its natural gas production, including natural gas put options used to indirectly hedge NGL revenues, and 106% of its oil production.

The Company determines the fair value of its oil and natural gas derivatives utilizing pricing models that use a variety of techniques, including market quotes and pricing analysis. See Item 3. "Quantitative and Qualitative Disclosures About Market Risk" and Note 7 and Note 8 for additional information about the Company's commodity derivatives. For information about the Company's credit risk related to derivative contracts, see "Counterparty Credit Risk" in "Liquidity and Capital Resources" below.

Marketing and Other Revenues

Marketing revenues represent third-party activities associated with company-owned gathering systems and plants. Marketing and other revenues increased by approximately $10 million or 74% to approximately $24 million for the three months ended June 30, 2013, from approximately $14 million for the three months ended June 30, 2012, primarily due to higher revenues generated from the Jayhawk natural gas processing plant.

Expenses

Lease Operating Expenses

Lease operating expenses include expenses such as labor, field office, vehicle, supervision, maintenance, tools and supplies and workover expenses. Lease operating expenses increased by approximately $14 million or 19% to approximately $84 million for the three months ended June 30, 2013, from approximately $70 million for the three months ended June 30, 2012. Lease operating expenses increased primarily due to higher costs associated with horizontal wells drilled in the Mid-Continent region during the second half of 2012 and also properties acquired during 2012. Lease operating expenses per Mcfe decreased to $1.18 per Mcfe for the three months ended June 30, 2013, from $1.22 per Mcfe for the three months ended June 30, 2012, primarily due to lower rates on newly acquired properties and cost saving initiatives.

Transportation Expenses

Transportation expenses increased by approximately $7 million or 34% to approximately $29 million for the three months ended June 30, 2013, from approximately $22 million for the three months ended June 30, 2012, primarily due to the BP acquisitions in 2012.

Marketing Expenses

Marketing expenses represent third-party activities associated with company-owned gathering systems and plants. Marketing expenses increased by approximately $3 million or 45% to approximately $9 million for the three months ended June 30, 2013, from approximately $6 million for the three months ended June 30, 2012, primarily due to higher expenses associated with the Jayhawk natural gas processing plant.

General and Administrative Expenses

General and administrative expenses are costs not directly associated with field operations and reflect the costs of employees including executive officers, related benefits, office leases and professional fees. General and administrative expenses increased by approximately $5 million or 12% to approximately $46 million for the three months ended June 30, 2013, from approximately $41 million for the three months ended June 30, 2012. The increase was primarily due to an increase in salaries and benefits related expenses of approximately $5 million, driven primarily by increased employee headcount, and an increase in professional services expenses of approximately $2 million, partially offset by a decrease in acquisition related expenses of approximately $3 million. Although general and administrative expenses increased, the unit rate decreased to $0.65 per Mcfe for the three months ended June 30, 2013, from $0.72 per Mcfe for the three months ended June 30, 2012, as a result of efficiencies gained from being a larger, more scalable organization.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization increased by approximately $55 million or 38% to approximately $199 million for the three months ended June 30, 2013, from approximately $144 million for the three months ended June 30, 2012. Higher depletion rates and higher total production volumes were the primary reasons for the increased expense. Depreciation, depletion and amortization per Mcfe also increased to $2.80 per Mcfe for the three months ended June 30, 2013, from $2.50 per Mcfe for the three months ended June 30, 2012, primarily due to negative reserve revisions from the prior year, partially offset by lower rates on properties acquired in 2012.

Impairment of Long-Lived Assets

During the three months ended June 30, 2013, the Company recorded an adjustment of approximately $15 million to reduce the initial impairment charge recorded in March 2013 to reflect the fair value less costs to sell the Panther Properties sold in May 2013 (see Note 2). At March 31, 2013, the carrying value of the Panther Properties was reduced to fair value less costs to sell resulting in an impairment charge of approximately $57 million and the properties were classified as "assets held for sale." During the three months ended June 30, 2012, the Company recorded a noncash impairment charge, before and after tax, of approximately $146 million associated with proved oil and natural gas properties related to a decline in commodity prices.

Taxes, Other Than Income Taxes

Taxes, other than income taxes, which consist primarily of severance and ad valorem taxes, increased by approximately $1 million or 6% to approximately $32 million for the three months ended June 30, 2013, from approximately $31 million for the three months ended June 30, 2012. Severance taxes, which are a function of revenues generated from production, increased by approximately $4 million compared to the three months ended June 30, 2012, primarily due to higher production volumes and higher natural gas and oil prices partially offset by lower NGL prices. Ad valorem taxes, which are based on the value of reserves and production equipment and vary by location, decreased by approximately $2 million compared to the three months ended June 30, 2012, primarily due to an adjustment related to the properties acquired in the Green River Basin region partially offset by taxes associated with property acquisitions in 2012 and higher rates on the Company's base properties.

Other Income and (Expenses)

	Three Months Ended June 30, 2013	2012	Variance
	(in thousands)		
Interest expense, net of amounts capitalized	$(103,847)	$(94,390)	$(9,457)
Loss on extinguishment of debt	(4,187)	—	(4,187)
Other, net	(2,182)	(7,956)	5,774
	$(110,216)	$(102,346)	$(7,870)

Other income and (expenses) increased by approximately $8 million for the three months ended June 30, 2013, compared to the three months ended June 30, 2012. Interest expense increased primarily due to higher outstanding debt during the period and higher amortization of financing fees and expenses associated with amendments made to the Company's Credit Facility during 2012 and 2013. In addition, for the three months ended June 30, 2013, the Company recorded a loss on extinguishment of debt of approximately $4 million as a result of the redemption of the remaining outstanding 2017 Senior Notes. See "Debt" in "Liquidity and Capital Resources" below for additional details. Other expenses decreased primarily due to no write-offs of deferred financing fees related to the amendment of the Credit Facility for the three months ended June 30, 2013, compared to approximately $6 million for the three months ended June 30, 2012.

Income Tax Expense (Benefit)

The Company is a limited liability company treated as a partnership for federal and state income tax purposes, with the exception of the state of Texas, in which income tax liabilities and/or benefits of the Company are passed through to its unitholders. Limited liability companies are subject to Texas margin tax. In addition, certain of the Company's subsidiaries are Subchapter C-corporations subject to federal and state income taxes. The Company recognized an income tax benefit of approximately $1 million for the three months ended June 30, 2013, compared to an income tax expense of approximately $1 million for the three months ended June 30, 2012. Income tax expense decreased primarily due to lower income from the Company's taxable subsidiaries during the three months ended June 30, 2013, compared to the same period in 2012.

Net Income

Net income increased by approximately $108 million to approximately $345 million for the three months ended June 30, 2013, from approximately $237 million for the three months ended June 30, 2012. The increase was primarily due to higher production revenues and lower expenses, including interest, partially offset by lower gains on oil and natural gas derivatives. See discussions above for explanations of variances.

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Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations - Continued

Results of Operations

Six Months Ended June 30, 2013, Compared to Six Months Ended June 30, 2012

	Six Months Ended June 30,		
	2013	2012	Variance
	(in thousands)		
Revenues and other:			
Natural gas sales	$295,510	$125,043	$170,467
Oil sales	503,710	455,509	48,201
NGL sales	151,719	115,570	36,149
Total oil, natural gas and NGL sales	950,939	696,122	254,817
Gains on oil and natural gas derivatives	218,363	441,678	(223,315)
Marketing and other revenues	38,583	16,887	21,696
	1,207,885	1,154,687	53,198
Expenses:			
Lease operating expenses	172,305	141,765	30,540
Transportation expenses	56,481	32,377	24,104
Marketing expenses	16,734	7,150	9,584
General and administrative expenses (1)	104,871	84,506	20,365
Exploration costs	3,044	817	2,227
Depreciation, depletion and amortization	396,070	260,782	135,288
Impairment of long-lived assets	42,202	146,499	(104,297)
Taxes, other than income taxes	72,068	55,851	16,217
Losses on sale of assets and other, net	2,213	1,492	721
	865,988	731,239	134,749
Other income and (expenses)	(212,218)	(183,134)	(29,084)
Income before income taxes	129,679	240,314	(110,635)
Income tax expense	6,407	9,430	(3,023)
Net income	$123,272	$230,884	$(107,612)

(1) General and administrative expenses for the six months ended June 30, 2013, and June 30, 2012, include approximately $17 million and $14 million, respectively, of noncash unit-based compensation expenses.

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations - Continued

	Six Months Ended June 30, 2013	2012	Variance
Average daily production:			
Natural gas (MMcf/d)	436	273	60%
Oil (MBbls/d)	30.8	27.2	13%
NGL (MBbls/d)	27.8	19.1	46%
Total (MMcfe/d)	788	550	43%
Weighted average prices (hedged): (1)			
Natural gas (Mcf)	$5.23	$5.93	(12)%
Oil (Bbl)	$92.59	$92.86	—
NGL (Bbl)	$30.12	$33.21	(9)%
Weighted average prices (unhedged): (2)			
Natural gas (Mcf)	$3.75	$2.52	49%
Oil (Bbl)	$90.23	$92.12	(2)%
NGL (Bbl)	$30.12	$33.21	(9)%
Average NYMEX prices:			
Natural gas (MMBtu)	$3.71	$2.48	50%
Oil (Bbl)	$94.30	$98.21	(4)%
Costs per Mcfe of production:			
Lease operating expenses	$1.21	$1.42	(15)%
Transportation expenses	$0.40	$0.32	25%
General and administrative expenses (3)	$0.74	$0.84	(12)%
Depreciation, depletion and amortization	$2.78	$2.60	7%
Taxes, other than income taxes	$0.51	$0.56	(9)%

(1) Includes the effect of settlements on derivatives of approximately $130 million (excluding an approximate $5 million gain on recovery of bankruptcy claim) and $173 million (excluding an approximate $18 million gain on recovery of bankruptcy claim) for the six months ended June 30, 2013, and June 30, 2012, respectively.

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

(3) General and administrative expenses for the six months ended June 30, 2013, and June 30, 2012, include approximately $17 million and $14 million, respectively, of noncash unit-based compensation expenses. Excluding these amounts, general and administrative expenses for the six months ended June 30, 2013, and June 30, 2012, were $0.62 per Mcfe and $0.70 per Mcfe, respectively. This is a non-GAAP measure used by management to analyze the Company's performance.

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Revenues and Other

Oil, Natural Gas and NGL Sales

Oil, natural gas and NGL sales increased approximately $255 million or 37% to approximately $951 million for the six months ended June 30, 2013, from approximately $696 million for the six months ended June 30, 2012, due to higher production volumes and higher natural gas prices partially offset by lower NGL and oil prices. Higher natural gas prices resulted in an increase in revenues of approximately $97 million. Lower NGL and oil prices resulted in a decrease in revenues of approximately $16 million and $11 million, respectively.

Average daily production volumes increased to 788 MMcfe/d during the six months ended June 30, 2013, from 550 MMcfe/d during the six months ended June 30, 2012. Higher natural gas, oil and NGL production volumes resulted in an increase in revenues of approximately $74 million, $59 million and $52 million, respectively.

The following sets forth average daily production by region:

	Six Months Ended June 30, 2013	2012	Variance	
Average daily production (MMcfe/d):				
Mid-Continent	321	290	31	11 %
Hugoton Basin	141	95	46	48 %
Green River Basin	140	—	140	—
Permian Basin	82	84	(2)	(3)%
Williston/Powder River Basin	37	25	12	48 %
Michigan/Illinois	34	35	(1)	(5)%
East Texas	21	8	13	171 %
California	12	13	(1)	(5)%
	788	550	238	43 %

The increase in average daily production volumes in the Mid-Continent region primarily reflects the Company's 2012 and 2013 capital drilling programs in the Granite Wash formation. The increase in average daily production volumes in the Hugoton Basin region primarily reflects the impact of the acquisition from BP on March 30, 2012. Average daily production volumes in the Green River Basin region reflect the impact of the acquisition from BP in July 2012, partially offset by a reduction caused by ethane rejection in the region. The decrease in average daily production volumes in the Permian Basin region primarily reflects downtime from third parties' infrastructure, partially offset by development capital spending. The increase in average daily production volumes in the Williston/Powder River Basin region reflects the impact of the joint-venture agreement entered into with Anadarko Petroleum Corporation in April 2012 and development capital spending in the Williston Basin. The Michigan/Illinois and California regions consist of low-decline asset bases and continue to produce at consistent levels. Average daily production volumes in the East Texas region reflect the impact of the acquisition in May 2012.

Gains on Oil and Natural Gas Derivatives

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

	Six Months Ended June 30, 2013 (in thousands)	2012	Variance
Cash settlements on commodity derivatives [1]	$139,429	$156,039	$(16,610)
Cash settlements on bankruptcy claim [2]	5,073	18,277	(13,204)
Total cash settlements	144,502	174,316	(29,814)
Oil derivative contracts related to current production period [3]	(8,995)	16,956	(25,951)
Changes in fair value on unsettled commodity derivatives [4]	82,856	250,406	(167,550)
Gains on oil and natural gas derivatives	$218,363	$441,678	$(223,315)

(1) Exclude the cost of any premiums paid for put option contracts.

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(2) Represent the recoveries of a bankruptcy claim against Lehman Brothers.

(3) Represent the timing difference related to contracts that have settled (contract terms have expired) but cash has not been received at the end of the reporting period.

(4) Represent changes in fair value of the derivatives contracts from period to period and include the reduction of put option premium value over time. The Company pays cash for put options at the time of execution and no additional amounts are payable in the future under the contracts. The premiums paid for put options that settled during the six months ended June 30, 2013, and June 30, 2012, were approximately \$86 million and \$62 million, respectively.

Gains on oil and natural gas derivatives decreased by approximately \$224 million to gains of approximately \$218 million for the six months ended June 30, 2013, from gains of approximately \$442 million for the six months ended June 30, 2012. Gains on oil and natural gas derivatives decreased primarily due to changes in fair value on unsettled derivatives contracts. The results for 2013 and 2012 also include gains of approximately \$5 million and \$18 million, respectively, related to the recoveries of a bankruptcy claim (see Note 10). The fair value on unsettled derivatives contracts changes as future commodity price expectations change compared to the contract prices on the derivatives. If the expected future commodity prices increase compared to the contract prices on the derivatives, losses are recognized; and if the expected future commodity prices decrease compared to the contract prices on the derivatives, gains are recognized.

During the six months ended June 30, 2013, the Company had commodity derivative contracts for approximately 109% of its natural gas production, including natural gas put options used to indirectly hedge NGL revenues, and 133% of its oil production. During the six months ended June 30, 2012, the Company had commodity derivative contracts for approximately 117% of its natural gas production, including natural gas put options used to indirectly hedge NGL revenues, and 107% of its oil production.

The Company determines the fair value of its oil and natural gas derivatives utilizing pricing models that use a variety of techniques, including market quotes and pricing analysis. See Item 3. "Quantitative and Qualitative Disclosures About Market Risk" and Note 7 and Note 8 for additional information about the Company's commodity derivatives. For information about the Company's credit risk related to derivative contracts, see "Counterparty Credit Risk" in "Liquidity and Capital Resources" below.

Marketing and Other Revenues

Marketing revenues represent third-party activities associated with company-owned gathering systems and plants. Marketing and other revenues increased by approximately \$22 million or 128% to approximately \$39 million for the six months ended June 30, 2013, from approximately \$17 million for the six months ended June 30, 2012, primarily due to higher revenues generated from the Jayhawk natural gas processing plant.

Expenses

Lease Operating Expenses

Lease operating expenses include expenses such as labor, field office, vehicle, supervision, maintenance, tools and supplies and workover expenses. Lease operating expenses increased by approximately \$30 million or 22% to approximately \$172 million for the six months ended June 30, 2013, from approximately \$142 million for the six months ended June 30, 2012. Lease operating expenses increased primarily due to costs associated with properties acquired during 2012 (see Note 2) and also higher costs associated with horizontal wells drilled in the Mid-Continent region during the second half of 2012. Lease operating expenses per Mcfe decreased to \$1.21 per Mcfe for the six months ended June 30, 2013, from \$1.42 per Mcfe for the six months ended June 30, 2012, primarily due to lower rates on newly acquired properties and cost saving initiatives.

Transportation Expenses

Transportation expenses increased by approximately \$24 million or 74% to approximately \$56 million for the six months ended June 30, 2013, from approximately \$32 million for the six months ended June 30, 2012, primarily due to the BP acquisitions in 2012.

Marketing Expenses

Marketing expenses represent third-party activities associated with company-owned gathering systems and plants. Marketing expenses increased by approximately \$10 million or 134% to approximately \$17 million for the six months ended June 30, 2013, from approximately $7 million for the six months ended June 30, 2012, primarily due to higher expenses associated with the Jayhawk natural gas processing plant.

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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 $20 million or 24% to approximately $105 million for the six months ended June 30, 2013, from approximately $85 million for the six months ended June 30, 2012. The increase was primarily due to an increase in salaries and benefits related expenses of approximately $14 million, driven primarily by increased employee headcount, an increase in professional services expenses of approximately $3 million and an increase in acquisition related expenses of approximately $2 million due primarily to the pending transaction with Berry (see Note 2). Although general and administrative expenses increased, the unit rate decreased to $0.74 per Mcfe for the six months ended June 30, 2013, from $0.84 per Mcfe for the six months ended June 30, 2012, as a result of efficiencies gained from being a larger, more scalable organization.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization increased by approximately $135 million or 52% to approximately $396 million for the six months ended June 30, 2013, from approximately $261 million for the six months ended June 30, 2012. Higher depletion rates and higher total production volumes were the primary reasons for the increased expense. Depreciation, depletion and amortization per Mcfe also increased to $2.78 per Mcfe for the six months ended June 30, 2013, from $2.60 per Mcfe for the six months ended June 30, 2012, primarily due to negative reserve revisions from the prior year, partially offset by lower rates on properties acquired in 2012.

Impairment of Long-Lived Assets

During the six months ended June 30, 2013, the Company recorded a noncash impairment charge, before and after tax, of approximately $42 million associated with the write-down of the carrying value of the Panther Properties sold in May 2013 (see Note 2). During the six months ended June 30, 2012, the Company recorded a noncash impairment charge, before and after tax, of approximately $146 million associated with proved oil and natural gas properties related to a decline in commodity prices.

Taxes, Other Than Income Taxes

Taxes, other than income taxes, which consist primarily of severance and ad valorem taxes, increased by approximately $16 million or 29% to approximately $72 million for the six months ended June 30, 2013, from approximately $56 million for the six months ended June 30, 2012. Severance taxes, which are a function of revenues generated from production, increased by approximately $7 million compared to the six months ended June 30, 2012, primarily due to higher production volumes and higher natural gas prices partially offset by lower NGL and oil prices. Ad valorem taxes, which are based on the value of reserves and production equipment and vary by location, increased by approximately $10 million compared to the six months ended June 30, 2012, primarily due to property acquisitions in 2012 and higher rates on the Company’s base properties partially offset by an adjustment related to the properties acquired in the Green River Basin region.

Other Income and (Expenses)

	Six Months Ended June 30, 2013	2012	Variance
	(in thousands)		
Interest expense, net of amounts capitalized	$(204,206)	$(171,909)	$(32,297)
Loss on extinguishment of debt	(4,187)	—	(4,187)
Other, net	(3,825)	(11,225)	7,400
	$(212,218)	$(183,134)	$(29,084)

Other income and (expenses) increased by approximately $29 million for the six months ended June 30, 2013, compared to the six months ended June 30, 2012. Interest expense increased primarily due to higher outstanding debt during the period and higher amortization of financing fees and expenses associated with the November 2019 Senior Notes, as defined in Note 6, and amendments made to the Company’s Credit Facility during 2012 and 2013. In addition, for the six months ended June 30, 2013, the Company recorded a loss on extinguishment of debt of approximately $4 million as a result of the redemption of the remaining outstanding 2017 Senior Notes. See “Debt” in “Liquidity and Capital Resources” below for additional details. Other expenses decreased primarily due to no write-offs of deferred financing fees related to the amendment of the Credit Facility for the six months ended June 30, 2013, compared to approximately $8 million for the six months ended June 30, 2012.

Income Tax Expense (Benefit)

The Company is a limited liability company treated as a partnership for federal and state income tax purposes, with the exception of the state of Texas, in which income tax liabilities and/or benefits of the Company are passed through to its unitholders. Limited liability companies are subject to Texas margin tax. In addition, certain of the Company's subsidiaries are Subchapter C-corporations subject to federal and state income taxes. The Company recognized income tax expense of approximately $6 million for the six months ended June 30, 2013, compared to income tax expense of approximately $9 million for the six months ended June 30, 2012. Income tax expense decreased primarily due to lower income from the Company's taxable subsidiaries during the six months ended June 30, 2013, compared to the same period in 2012.

Net Income

Net income decreased by approximately $108 million to approximately $123 million for the six months ended June 30, 2013, from approximately $231 million for the six months ended June 30, 2012. The decrease was primarily due to lower gains on oil and natural gas derivatives and higher expenses, including interest, partially offset by higher production revenues. See discussions above for explanations of variances.

Liquidity and Capital Resources

The Company utilizes funds from debt and equity offerings, borrowings under its Credit Facility 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 six months ended June 30, 2013, the Company's capital expenditures, excluding acquisitions, were approximately $606 million. For 2013, the Company estimates its total capital expenditures, excluding acquisitions, will be approximately $1.15 billion, including approximately $1 billion related to the Company's oil and natural gas capital program and approximately $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 adjustment. The Company expects to fund these capital expenditures primarily with cash flow from operations and borrowings under its Credit Facility.

As the Company pursues growth, it continually monitors the capital resources available to meet future financial obligations and planned capital expenditures. The Company's future success in growing reserves and production volumes will be highly dependent on the capital resources available and its success in drilling for or acquiring additional reserves. The Company actively reviews acquisition opportunities on an ongoing basis. If the Company were to make significant additional acquisitions for cash, it would need to borrow additional amounts under its Credit 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 and 2010 Issued Senior Notes impose certain restrictions on the Company's ability to obtain additional debt financing. Based upon current expectations, the Company believes liquidity and capital resources will be sufficient to conduct its business and operations. For additional information about the risk that the Company may not have sufficient distributable cash flow to maintain its distribution and other risk factors that could affect the Company, see Item 1A. "Risk Factors."

Statements of Cash Flows

The following is a comparative cash flow summary:

	Six Months Ended June 30, 2013	2012	Variance
	(in thousands)		
Net cash:			
Provided by (used in) operating activities [1]	$561,356	$(122,429)	$683,785
Used in investing activities	(404,528)	(2,265,931)	1,861,403
Provided by (used in) financing activities	(156,919)	2,389,129	(2,546,048)
Net increase (decrease) in cash and cash equivalents	$(91)	$769	$(860)

(1)

The six months ended June 30, 2012, are net of payments made for commodity derivative premiums of approximately $583 million.

Operating Activities

Cash provided by operating activities for the six months ended June 30, 2013, was approximately $561 million, compared to cash used in operating activities of approximately $122 million for the six months ended June 30, 2012. The increase was primarily due to no premiums paid for derivatives during the six months ended June 30, 2013, compared to approximately $583 million in premiums paid during the same period in 2012. Premiums paid for commodity derivatives decreased primarily due to reduced acquisition activity during the six months ended June 30, 2013, as compared to the six months ended June 30, 2012. Lower premiums and higher revenues primarily due to increased production volumes were partially offset by higher expenses.

Premiums paid during the six months ended June 30, 2012, were for commodity derivative contracts that hedge future production. The Company hedges a substantial portion of its production to reduce exposure to fluctuations in the prices of oil and natural gas and provide long-term cash flow predictability to manage its business, service debt and pay distributions. The majority of the Company's hedges are in the form of fixed price swaps, which are entered into on market terms and without cost. The Company's ability to enter into swaps is governed by covenants under its Credit Facility which limit the maximum percentage of forecasted future production that may be hedged using swaps to 80% for the current calendar year and the following four calendar years and 70% thereafter. In prior years, the Company has chosen to purchase put options, primarily in connection with acquisitions, to hedge certain volumes in excess of volumes already hedged with swaps to achieve greater downside commodity price protection. Put options require the payment of a premium, which the Company pays in cash at the time of execution and no additional amounts are payable in the future under the contracts.

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

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

Investing Activities

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

	Six Months Ended June 30, 2013	2012
	(in thousands)	
Cash flow from investing activities:		
Acquisition of oil and natural gas properties and joint-venture funding	$(64,381)	$(1,762,933)
Capital expenditures	(551,046)	(503,573)
Proceeds from sale of properties and equipment and other	210,899	575
	$(404,528)	$(2,265,931)

The primary use of cash in investing activities is for capital spending, including acquisitions and the development of the Company's oil and natural gas properties. The decrease was primarily due to no significant acquisitions consummated during the six months ended June 30, 2013, compared to a total of three acquisitions of properties in the Hugoton Basin, Williston/Powder River Basin and East Texas regions during the same period in 2012. See Note 2 for additional details of acquisitions. Capital expenditures increased primarily due to capital additions for pipelines and supporting facilities in the Granite Wash formation, as well as development activities of properties acquired in 2012 in the Hugoton Basin, Williston/Powder River Basin and Green River Basin regions. Proceeds from sale of properties and equipment and other for the six months ended June 30, 2013, include approximately $219 million in net proceeds received for the sale of the Panther Properties in May 2013 (see Note 2).

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Financing Activities

Cash used in financing activities for the six months ended June 30, 2013, was approximately $157 million, compared to cash provided by financing activities of approximately $2.4 billion for the six months ended June 30, 2012. The decrease in financing cash flow needs was primarily attributable to reduced acquisition activity during the six months ended June 30, 2013. The following provides a comparative summary of proceeds from borrowings and repayments of debt:

	Six Months Ended June 30,	
	2013	2012
	(in thousands)	
Proceeds from borrowings:		
Credit facility	$775,000	$2,155,000
Senior notes	—	1,799,802
	$775,000	$3,954,802
Repayments of debt:		
Credit facility	$(520,000)	$(1,945,000)
Senior notes	(40,737)	—
	$(560,737)	$(1,945,000)

Debt

In April 2013, the Company entered into a Sixth Amended and Restated Credit Agreement ("Credit Facility"), which provides for a revolving credit facility up to the lesser of: (i) the then-effective borrowing base and (ii) the maximum commitment amount of $4.0 billion. The borrowing base remained unchanged at $4.5 billion and does not include any assets to be acquired in the pending transaction with Berry (see Note 2). The maturity date is April 2018. The amended and restated agreement is substantially similar to the previous Credit Facility with revisions to permit the transactions related to the acquisition of Berry and to designate Berry as an unrestricted subsidiary under the agreement. At June 30, 2013, the borrowing capacity under the Credit Facility was approximately $2.6 billion, which includes a $5 million reduction in availability for outstanding letters of credit.

The Company's Credit Facility contains customary representations and warranties and covenants for facilities of this type, including a covenant that the Company maintain a ratio of EBITDA (calculated in the same manner as adjusted EBITDA as set forth below in "Reconciliation of EBITDA, Adjusted EBITDA and Distributable Cash Flow") to Interest Expense (as defined in the Credit Facility) of 2.5 to 1.0. If an event of default occurs and is continuing, including with respect to the covenant regarding the ratio of EBITDA to Interest Expense, the Company would be unable to make borrowings and its financial condition and liquidity would be adversely affected. For information related to the Credit Facility, see Note 6.

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 cash distribution payments. Absent such borrowings, the Company would have at times experienced a shortfall in cash available to pay the declared cash distribution. For additional information, see "Distribution Practices" in "Non-GAAP Financial Measures" below. 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."

In accordance with the provisions of the indenture related to the 2017 Senior Notes, in June 2013, the Company redeemed the remaining outstanding principal amount of $41 million. In accordance with the provisions of the indenture related to the 2018 Senior Notes, in July 2013, the Company redeemed the remaining outstanding principal amount of $14 million.

Counterparty Credit Risk

The Company accounts for its commodity derivatives at fair value. The Company's counterparties are current participants or affiliates of participants in its Credit 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 are subject to counterparty netting under agreements governing such derivatives and therefore the risk of loss due to counterparty nonperformance is somewhat mitigated.

Distributions

Under the Company's limited liability company agreement, the Company's unitholders are entitled to receive a distribution of available cash, which includes cash on hand plus borrowings less any reserves established by the Board of Directors to provide for the proper conduct of the Company's business (including reserves for future capital expenditures, including drilling, acquisitions and anticipated future credit needs) or to fund distributions over the next four quarters. The following provides a summary of distributions paid by the Company during the six months ended June 30, 2013:

Date Paid	Distribution Per Unit	Total Distributions (in millions)
May 2013	$0.725	$170
February 2013	$0.725	$171

In April 2013, the Company's Board of Directors approved a change in its distribution policy that provides a distribution with respect to any quarter may be made, at the discretion of the Board of Directors, (i) within 45 days following the end of each quarter or (ii) in three equal installments within 15, 45 and 75 days following the end of each quarter. On July 1, 2013, the Company's Board of Directors declared a cash distribution of $0.725 per unit with respect to the second quarter of 2013, to be paid in three equal monthly installments of $0.2416 per unit. The first monthly distribution, totaling approximately $57 million, was paid on July 15, 2013, to unitholders of record as of the close of business on July 10, 2013.

Off-Balance Sheet Arrangements

The Company does not currently have any off-balance sheet arrangements.

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.

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

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On April 12, 2013, a purported stockholder class action captioned David Hall v. Berry Petroleum Co., et al. was filed in the Delaware Court of Chancery, C.A. No. 8476-VCG. The complaint names as defendants Berry, the members of its board of directors, HoldCo, Bacchus Merger Sub, LinnCo, LINN Energy and LinnCo Merger Sub. The complaint alleges that the individual defendants breached their fiduciary duties in connection with the transactions by engaging in an unfair sales process that resulted in an unfair price for Berry, by failing to disclose all material information regarding the transactions, and that the entity defendants aided and abetted those breaches of fiduciary duty. The complaint seeks a declaration that the transactions are unlawful and unenforceable, an order directing the individual defendants to comply with their fiduciary duties, an injunction against consummation of the transactions, or, in the event they are completed, rescission of the transactions, an award of fees and costs, including attorneys' and experts' fees and expenses, and other relief. After expedited discovery, the plaintiffs in this case made a settlement proposal and the parties are currently engaged in settlement discussions. The Company is unable to estimate a possible loss, or range of possible loss, if any, at this time.

On July 9, 2013, Anthony Booth, individually and on behalf of all other persons similarly situated, filed a class action complaint in the United States District Court, Southern District of Texas, against LINN Energy, Mark E. Ellis, Kolja Rockov, and David B. Rottino (the "Booth Action"). On July 18, 2013, the Catherine A. Fisher Trust, individually and on behalf of all other persons similarly situated, filed a class action complaint in the United States District Court, Southern District of Texas, against the same defendants (the "Fisher Action"). On July 17, 2013, Don Gentry, individually and on behalf of all other persons similarly situated, filed a class action complaint in the United States District Court, Southern District of Texas, against LINN Energy, LinnCo, Mark E. Ellis, Kolja Rockov, David B. Rottino, George A. Alcorn, David D. Dunlap, Terrence S. Jacobs, Michael C. Linn, Joseph P. McCoy, Jeffrey C. Swoveland, and the various underwriters for LinnCo's initial public offering (the "Gentry Action") (the Booth Action, Fisher Action, and Gentry Action together, the "Texas Federal Actions"). The Texas Federal Actions each assert claims under Sections 10(b) and 20(a) of the Securities Exchange Act of 1934 (the "Exchange Act") based on allegations that the Company made false or misleading statements relating to its hedging strategy, the cash flow available for distribution to unitholders, and the Company's energy production. The Gentry Action asserts additional claims under Sections 11 and 15 of the Securities Act of 1933 based on alleged misstatements relating to these issues in the prospectus and registration statement for LinnCo's initial public offering. The cases are in their preliminary stages and it is possible that additional similar actions could be filed. As a result, the Company is unable to estimate a possible loss, or range of possible loss, if any.

On July 10, 2013, David Adrian Luciano, individually and on behalf of all other persons similarly situated, filed a class action complaint in the United States District Court, Southern District of New York, against LINN Energy, LinnCo, Mark E. Ellis, Kolja Rockov, David B. Rottino, George A. Alcorn, David D. Dunlap, Terrence S. Jacobs, Michael C. Linn, Joseph P. McCoy, Jeffrey C. Swoveland, and the various underwriters for LinnCo's initial public offering (the "Luciano Action"). On July 12, 2013, Frank Donio, individually and on behalf of all other persons similarly situated, filed a class action complaint in the United States District Court, Southern District of New York, against the same defendants (the "Donio Action"). On July 19, 2013, John Cottrell, individually and on behalf of all other persons similarly situated, filed a class action complaint in the United States District Court, Southern District of New York, against LINN Energy, Mark E. Ellis, Kolja Rockov, and David B. Rottino (the "Cottrell Action"). On July 23, 2013, Kevin Feldman, individually and on behalf of all other persons similarly situated, filed a class action complaint in the United States District Court, Southern District of New York, against the same defendants as in the Luciano Action (the "Feldman Action") (the Luciano Action, Donio Action, Cottrell Action, and Feldman Action together, the "New York Federal Actions"). The Donio Action and the Cottrell Action assert claims under Sections 10(b) and 20(a) of the Exchange Act based on allegations that the Company made false or misleading statements relating to its hedging strategy, the cash flow available for distribution to unitholders, and the Company's energy production. The Luciano Action and the Feldman Action assert claims under Sections 11 and 15 of the Securities Act of 1933 based on alleged misstatements relating to these issues in the prospectus and registration statement for LinnCo's initial public offering. The cases are in their preliminary stages and it is possible that additional similar actions could be filed. As a result, the Company is unable to estimate a possible loss, or range of possible loss, if any.

On July 10, 2013, Judy Mesirov, derivatively on behalf of nominal defendant LINN Energy, filed a shareholder derivative petition against Mark E. Ellis, Kolja Rockov, David B. Rottino, Arden L. Walker, Jr., Charlene A. Ripley, Michael C. Linn, Joseph P. McCoy, George A. Alcorn, Terrence S. Jacobs, David D. Dunlap, Jeffrey C. Swoveland, and Linda M. Stephens in the District Court of Harris County, Texas (the “Mesirov Action”). On July 12, 2013, John Peters, derivatively on behalf of nominal defendant LINN Energy, filed a shareholder derivative petition against many of the same defendants in the District Court of Harris County, Texas (the “Peters Action”) (the Mesirov Action and Peters Action together, the “Texas Derivative Actions”). The Texas Derivative Actions assert derivative claims on behalf of LINN Energy against the individual defendants for alleged breaches of fiduciary duty, waste of corporate assets, mismanagement, abuse of control, and unjust enrichment based on factual allegations similar to those in the Texas Federal Actions and the New York Federal Actions. The cases are in

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their preliminary stages and it is possible that additional similar actions could be filed in the District Court of Harris County, Texas, or in other jurisdictions. As a result, the Company is unable to estimate a possible loss, or range of possible loss, if any.

During the six months ended June 30, 2013, and June 30, 2012, the Company made no significant payments to settle any legal, environmental or tax proceedings. The Company regularly analyzes current information and accrues for probable liabilities on the disposition of certain matters as necessary. Liabilities for loss contingencies arising from claims, assessments, litigation or other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated.

Commitments and Contractual Obligations

The Company has contractual obligations for long-term debt, operating leases and other long-term liabilities that were summarized in the table of contractual obligations in the 2012 Annual Report on Form 10-K. With the exception of the Company's redemption of the remaining outstanding principal amount of the 2017 Senior Notes and 2018 Senior Notes, there have been no significant changes to the Company's contractual obligations from December 31, 2012. See Note 6 for additional information about the Company's debt instruments.

Non-GAAP Financial Measures

The non-GAAP financial measures of adjusted EBITDA and distributable cash flow, 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 measures prepared in accordance with GAAP, such as net income, operating income or cash flow from operating activities. Adjusted EBITDA and distributable cash flow should not be considered in isolation or as a substitute for GAAP measures, such as net income, operating income, cash flow from operating activities or any other GAAP measure of liquidity or financial performance.

EBITDA, Adjusted EBITDA and Distributable Cash Flow (Non-GAAP Measures)

EBITDA and adjusted EBITDA are supplemental financial measures used by Company management and by external users of the Company's financial statements such as investors, lenders under the Company's Credit Facility, research analysts, rating agencies and others to assess:

- the Company's operating performance as compared to other companies in the upstream energy sector, without regard to financing methods, historical cost basis or capital structure;
- the ability of the Company's assets to generate sufficient cash to support its decision to make distributions to its unitholders;
- the Company's ability to incur and service debt and fund capital expenditures;
- the viability of acquisitions and other capital expenditure projects and the returns on investment of various investment opportunities; and
- the Company's ability to comply with financial covenants in its Credit Facility that are calculated using adjusted EBITDA.

The Company believes the presentations of EBITDA and adjusted EBITDA provide useful information to investors to evaluate the operations of its business excluding certain items and for the reasons set forth above. Adjusted EBITDA is also a quantitative measure commonly used throughout the investment community with respect to publicly traded partnerships and limited liability companies.

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

- Interest expense;
- Income tax expense (benefit); and
- Depreciation, depletion and amortization.

The Company defines adjusted EBITDA as EBITDA plus the following adjustments:

- Net operating cash flow from acquisitions and divestitures, effective date through closing date;
- Impairment of long-lived assets;
- Write-off of deferred financing fees;
- (Gains) losses on sale of assets and other, net;
- Loss on extinguishment of debt;

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- Changes in fair value on unsettled commodity derivatives;
- Changes in fair value on unsettled interest rate derivatives;
- Cash settlements on interest rate derivatives;
- Cash settlements on canceled derivatives;
- Cash recoveries of bankruptcy claim;
- Unit-based compensation expenses;
- Exploration costs; and
- Merger transaction costs.

Distributable cash flow ("DCF") is a supplemental financial measure used by Company management in determining (prior to the establishment of any reserves by its Board of Directors) the amount of cash available for distribution to the Company's unitholders. Specifically, this financial measure indicates to investors whether or not the Company is generating cash flow at a level that can sustain or support an increase in its distribution rates and serves as an indicator of the Company's success in providing a return on investments.

The Company defines DCF as adjusted EBITDA with the following adjustments:

- Interest expense;
- Maintenance capital expenditures; and
- Provision for legal matters.

Distribution Practices

The amount of cash that the Company distributes is determined in accordance with the provisions of the Company's limited liability company agreement, including with respect to the establishment of reserves for capital expenditures and other purposes and based on the discretion of the Board of Directors. It is the Company's intention to fund interest expense, maintenance capital expenditures and distributions from adjusted EBITDA and to fund acquisitions and other capital expenditures with proceeds from debt or equity offerings, borrowings under its Credit Facility or other external sources of funding. While DCF is reported on a quarterly basis, management must consider the timing and size of planned capital expenditures and long-term views about expected results in determining the sustainability of its distributions. Capital spending and resulting production and cash flows do not typically occur evenly throughout the year due to a variety of factors which are difficult to predict, including rig availability, weather, well performance, the timing of completions and the commodity price environment. Consistent with practices common to publicly traded partnerships and limited liability companies, the Company's Board of Directors historically has not varied the distribution it declares from period to period based on uneven cash flows. As a result, DCF may be higher or lower than the declared distribution amounts for individual quarters. Historically, there have been periods in which the Company's distributions were less than DCF, and there have been periods in which the Company's distributions were more than DCF. To the extent DCF was insufficient in a particular period to pay the distribution amount, the Company funded the shortfall with borrowings under its Credit Facility.

Reconciliation of EBITDA, Adjusted EBITDA and Distributable Cash Flow

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(in thousands)			
Net income	$345,157	$237,086	$123,272	$230,884
Plus:				
Interest expense	103,847	94,390	204,206	171,909
Income tax expense (benefit)	(1,129)	512	6,407	9,430
Depreciation, depletion and amortization	198,629	143,506	396,070	260,782
EBITDA	646,504	475,494	729,955	673,005
Plus:				
Net operating cash flow from acquisitions and divestitures, effective date through closing date (1)	(6,790)	6,034	(6,790)	45,127
Impairment of long-lived assets	(14,851)	146,499	42,202	146,499
Write-off of deferred financing fees	—	6,229	—	7,889
(Gains) losses on sale of assets and other, net (2)	(1,288)	(444)	1,010	991
Loss on extinguishment of debt	4,187	—	4,187	—
Changes in fair value on unsettled commodity derivatives (3)	(271,483)	(303,630)	(82,856)	(250,406)
Cash recoveries of bankruptcy claim (4)	(5,073)	(18,277)	(5,073)	(18,277)
Unit-based compensation expenses	8,313	6,663	19,575	14,834
Exploration costs	818	407	3,044	817
Merger transaction costs (5)	1,975	—	13,114	—
Adjusted EBITDA	362,312	318,975	718,368	620,479
Adjustments to distributable cash flow:				
Interest expense (6)	(98,281)	(91,347)	(193,505)	(164,979)
Maintenance capital expenditures (7)	(111,912)	(88,269)	(222,210)	(155,638)
Provision for legal matters (8)	—	160	—	795
Distributable cash flow	$152,119	$139,519	$302,653	$300,657
Distributions to unitholders	$170,163	$144,576	$341,117	$282,166
Excess (shortfall) of distributable cash flow (9)	$(18,044)	$(5,057)	$(38,464)	$18,491

(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) Represent changes in fair value of the derivatives contracts from period to period and include the reduction of put option premium value over time. The premiums paid for put options that settled during the three months ended June 30, 2013, and June 30, 2012, and during the six months ended June 30, 2013, and June 30, 2012, were approximately $43 million, $36 million, $86 million and $62 million, respectively. Deducting the premiums paid for put options would reduce the Company's adjusted EBITDA and DCF; however, the Company pays cash for put options at the time of execution and no additional amounts are payable in the future under the contracts. Therefore, the Company's calculation of adjusted EBITDA and DCF is more representative of the cash available for distribution during the period. The Company considers the cost of premiums paid for put options as an investment related to its underlying oil and natural gas properties only for the purpose of calculating the non-GAAP financial measures of adjusted EBITDA and DCF.

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

(5) Represent transaction costs incurred by LinnCo and reimbursable by LINN Energy including investment banking, legal, accounting and other professional service fees associated with the pending acquisition of Berry.

(6) Interest expense deducted from DCF is less than interest expense added to EBITDA due to the exclusion of amortization of financing fees, discounts and premiums on senior notes and imputed interest.

(7) Maintenance capital expenditures, a component of total capital expenditures, is a non-GAAP calculation established at the beginning of each calendar year that represents the estimated capital investment required to approximately maintain production levels from the prior year and replace proved developed producing reserves that are forecasted to be produced as a result of maintaining production levels from the prior year. Management makes estimates of maintenance capital expenditures as part of the annual budget process, ranks the most efficient projects by production replacement and proved developed producing reserves replacement and allocates the total planned expenditures across the four quarters of each calendar year. While the Company believes its estimates and assumptions to be reasonable under the circumstances, they are subject to, among other things, risks and uncertainties including production rates, reserve quantities and capital costs estimates. At the end of each calendar year, the Company evaluates the performance of its annual capital program, re-ranks its most efficient projects and incorporates the results of this analysis in its subsequent calendar year estimated maintenance capital expenditures. The calculation includes the cost to convert nonproducing reserves to producing status and does not include the initial cost to acquire the underlying asset as that amount has already been spent in a prior period and therefore does not impact the ability to make distributions in future periods.

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

(9) Represents the difference between DCF and actual distributions to unitholders. Any excess of DCF over actual distributions was retained by the Company. Any shortfall of DCF compared to actual distributions was funded with borrowings under the Company's Credit Facility.

EBITDA

EBITDA (a non-GAAP financial measure) increased by approximately $172 million or 36% to approximately $647 million for the three months ended June 30, 2013, from approximately $475 million for the three months ended June 30, 2012, and by approximately $57 million or 8% to approximately $730 million for the six months ended June 30, 2013, from approximately $673 million for the six months ended June 30, 2012. The increases were primarily due to higher revenues and lower impairment charges.

Adjusted EBITDA

Adjusted EBITDA (a non-GAAP financial measure) increased by approximately $43 million or 14% to approximately $362 million for the three months ended June 30, 2013, from approximately $319 million for the three months ended June 30, 2012, and by approximately $98 million or 16% to approximately $718 million for the six months ended June 30, 2013, from approximately $620 million for the six months ended June 30, 2012. The increases were primarily due to higher revenues partially offset by higher expenses.

Distributable Cash Flow

Distributable cash flow (a non-GAAP financial measure) increased by approximately $12 million or 9% to approximately $152 million for the three months ended June 30, 2013, from approximately $140 million for the three months ended June 30, 2012, and by approximately $2 million or 1% to approximately $303 million for the six months ended June 30, 2013, from approximately $301 million for the six months ended June 30, 2012. The increases were primarily due to higher revenues partially offset by higher expenses including higher interest expense and higher maintenance capital expenditures associated with increased estimated spending necessary to maintain production levels from the prior year and replace proved developed producing reserves that are forecasted to be produced as a result of maintaining production levels from the prior year.

See discussions elsewhere in "Management's Discussion and Analysis of Financial Condition and Results of Operations" for explanations of variances.

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Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations - Continued

	Six Months Ended June 30, 2013	2012
	(in thousands)	
Net cash provided by (used in) operating activities	$561,356	$(122,429)
Plus:		
Net operating cash flow from acquisitions and divestitures, effective date through closing date	(6,790)	45,127
Cash payments for interest, net of amounts capitalized	192,517	128,617
Cash recoveries of bankruptcy claim	(5,073)	(18,277)
Premiums paid for derivatives	—	583,434
Changes in operating assets and liabilities and other, net	(23,642)	4,007
Adjusted EBITDA	718,368	620,479
Adjustments to distributable cash flow:		
Interest expense	(193,505)	(164,979)
Maintenance capital expenditures	(222,210)	(155,638)
Provision for legal matters	—	795
Distributable cash flow	$302,653	$300,657
Distributions to unitholders	$341,117	$282,166
Excess (shortfall) of distributable cash flow	$(38,464)	$18,491

Regulatory Matters

On August 15, 2012, the Environmental Protection Agency (“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 the Company’s operations, including the installation of new equipment to control emissions.

The Company cannot predict how future environmental laws and regulations may impact its properties or operations. For the six months ended June 30, 2013, the Company did not incur any material capital expenditures for installation of remediation or pollution control equipment at any of its facilities. The Company is not aware of any environmental issues or claims that will require material capital expenditures during 2013 or that will otherwise have a material impact on its financial position, results of operations or cash flows.

Critical Accounting Policies and Estimates

The discussion and analysis of the Company’s financial condition and results of operations is based upon the condensed 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 disclosure 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

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations - Continued

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.

Recently Issued Accounting Standards

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

Cautionary Statement

This Quarterly Report on Form 10-Q 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 content about the Company's:

- business strategy;
- acquisition strategy;
- ability to consummate the pending merger with Berry;
- effects of the pending SEC inquiry and other legal proceedings;
- 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 Quarterly Report on Form 10-Q, are forward-looking statements. These forward-looking statements may be found in Item 2. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expect," "plan," "project," "intend," "anticipate," "believe," "estimate," "predict," "potential," "pursue," "target," "continue," the negative of su other comparable terminology.

The forward-looking statements contained in this Quarterly Report on Form 10-Q 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 Quarterly Report on Form 10-Q 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 set forth in Item 1A. "Risk Factors" in this Quarterly Report on Form 10-Q and in the Annual Report on Form 10-K for the year ended December 31, 2012, and elsewhere in the Annual Report. 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 3. 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 Quarterly Report on Form 10-Q and in the Company’s 2012 Annual Report on Form 10-K. A reference to a “Note” herein refers to the accompanying Notes to Condensed Consolidated Financial Statements contained in Item 1. “Financial Statements.”

Commodity Price Risk

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

The Company enters into commodity hedging transactions primarily in the form of (i) swap contracts that are designed to provide a fixed price and (ii) from time to time, put options that are designed to provide a fixed price floor with the opportunity for upside. The Company enters into these transactions with respect to a portion of its projected production to provide an economic hedge of the risk related to the future commodity prices received. The Company does not enter into derivative contracts for trading purposes. There have been no significant changes to the Company’s objectives, general strategies or instruments used to manage the Company’s commodity price risk exposures from the year ended December 31, 2012.

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

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

At June 30, 2013, the fair value of fixed price swaps and put contracts was a net asset of approximately $958 million. A 10% increase in the index oil and natural gas prices above the June 30, 2013, prices would result in a net asset of approximately $205 million, which represents a decrease in the fair value of approximately $753 million; conversely, a 10% decrease in the index oil and natural gas prices below June 30, 2013, prices would result in a net asset of approximately $1.8 billion, which represents an increase in the fair value of approximately $821 million.

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

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Item 3. Quantitative and Qualitative Disclosures About Market Risk - Continued

The Company determines the fair value of its oil and natural gas derivatives utilizing pricing models that use a variety of techniques, including market quotes and pricing analysis. Inputs to the pricing models include publicly available prices and forward price curves generated from a compilation of data gathered from third parties. Company management validates the data provided by third parties by understanding the pricing models used, obtaining market values from other pricing sources, analyzing pricing data in certain situations and confirming that those securities trade in active markets.

The prices of oil, natural gas and NGL have been extremely volatile, and the Company expects this volatility to continue. Prices for these commodities may fluctuate widely in response to relatively minor changes in the supply of and demand for such commodities, market uncertainty and a variety of additional factors that are beyond its control. Actual gains or losses recognized related to the Company’s derivative contracts will likely differ from those estimated at June 30, 2013, and December 31, 2012, and will depend exclusively on the price of the commodities on the specified settlement dates provided by the derivative contracts.

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

Interest Rate Risk

At June 30, 2013, the Company had long-term debt outstanding under its Credit Facility of approximately $1.4 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 $14 million increase in annual interest expense.

At December 31, 2012, the Company had long-term debt outstanding under its Credit Facility of approximately $1.2 billion, which incurred interest at floating rates. A 1% increase in the LIBOR would result in an estimated $12 million increase in annual interest expense.

Counterparty Credit Risk

The Company accounts for its commodity derivatives 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 June 30, 2013, the average public bond yield spread utilized to estimate the impact of the Company’s credit risk on derivative liabilities was approximately 1.92%. A 1% increase in the average public bond yield spread would result in no significant increase or decrease in net income for the six months ended June 30, 2013. At June 30, 2013, the credit default swap spreads utilized to estimate the impact of counterparties’ credit risk on derivative assets ranged between 0% and 2.24%. A 1% increase in each of the counterparties’ credit default swap spreads would result in an estimated $15 million decrease in net income for the six months ended June 30, 2013.

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

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Item 4. 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 June 30, 2013.

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 condensed 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 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 second quarter of 2013 that materially affected, or were reasonably likely to materially affect, the Company's internal control over financial reporting.

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Part II - Other Information

Item 1. Legal Proceedings

For a discussion of legal proceedings, see Note 10 of Notes to Condensed Consolidated Financial Statements.

Item 1A. Risk Factors

Our business has many risks. Factors that could materially adversely affect our business, financial position, results of operations, liquidity or the trading price of our units are described in Item 1A. "Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2012. Except as set forth below, as of the date of this report, these risk factors have not changed materially. This information should be considered carefully, together with other information in this report and other reports and materials we file with the United States Securities and Exchange Commission ("SEC").

We may not have sufficient distributable cash flow to maintain our distribution at the current distribution level, or at all, and future distributions to our unitholders may be reduced or eliminated.

For the quarters ended March 31, 2013, and June 30, 2013, our distributable cash flow was less than cash distributions to our unitholders. While the Board of Directors considers estimates of distributable cash flow both historically and prospectively when declaring a distribution for the current period, if we continue to generate distributable cash flow that is insufficient to maintain our current distribution to unitholders, our Board of Directors may determine to reduce or eliminate our distribution to unitholders. Any such reduction in distributions may cause the trading price of our units to decline. Factors that may cause us to generate distributable cash flow that is insufficient to maintain our current distribution to unitholders include, among other things, the following:

- Production from existing assets: Our revenues are dependent on how much oil, natural gas and NGLs we produce. For the quarter ended June 30, 2013, our oil production volumes fell short of our expectations. If our existing assets continue to under-perform with respect to expected production, our revenues may be lower than expected, which could result in distributable cash flow that is insufficient to maintain our current distribution to unitholders.
- NGL commodity prices: We have been and continue to be limited in our ability to effectively hedge our NGL production. As a result, we are subject to the current depressed price environment for NGLs, and in particular, ethane prices. If current price levels for NGLs continue into the future, our revenues and results of operations will be affected, which could result in distributable cash flow that is insufficient to maintain our current distribution to unitholders.
- Access to and cost of capital: Accretive acquisitions are an integral component of our business strategy. When revenues are expected to be lower as a result of under-performance of assets, weakening commodity prices on unhedged volumes or declining contract prices on unhedged volumes, we seek to make accretive acquisitions of oil and natural gas properties to cover potential shortfalls in distributable cash flow in order to maintain our distribution level. As a result of the pending SEC inquiry, we may be limited in our ability to access the capital markets at an acceptable cost; thus our ability to make accretive acquisitions may be limited.

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

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

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

If we underestimate the appropriate level of estimated maintenance capital expenditures or the estimated maintenance capital expenditures do not produce the expected results, we may have less cash available for distribution in future periods.

Maintenance capital expenditures, a component of total capital expenditures, is a non-GAAP calculation established at the beginning of each calendar year that represents the estimated capital investment required to approximately maintain production levels from the prior year and replace proved developed producing reserves that are forecasted to be produced as a result of maintaining production levels from the prior year. In determining cash available for distribution, we deduct estimated maintenance capital expenditures. Management evaluates historical results based on continually revised and updated information from past years and future assumptions made during the annual budget process to estimate maintenance capital expenditures. As a result, results from historical time periods are reflected in our estimates of maintenance capital expenditures for future periods. If we underestimate the appropriate level of estimated maintenance capital expenditures or the estimated maintenance capital expenditures do not produce the expected results, we may have less cash available for distribution in future periods when adjustments from the previous year are included in future estimates. Over time, if we do not set aside sufficient cash reserves or have available sufficient sources of financing and make sufficient expenditures to maintain our asset base, we may be unable to pay distributions at the anticipated level and could be required to reduce our distributions.

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

We, LinnCo and our and LinnCo's current and former directors and officers are the subject of a number of purported class action lawsuits and derivative lawsuits, and there is an ongoing private SEC inquiry regarding us and LinnCo. We cannot predict the outcome or impact of these pending matters, but the lawsuits could result in judgments against us and LinnCo and directors and officers named as defendants and there could be one or more enforcement actions in respect of the SEC inquiry, which may result in fines, penalties, damages, sanctions, administrative remedies and modifications to our business practices. Furthermore, our legal expenses incurred in defending the lawsuits and responding to the SEC inquiry have been significant and we expect them to continue to be significant in the future. In addition, members of our senior management have been required to divert significant attention and resources to these matters, reducing the time, attention and resources they have available to devote to managing our business. These additional expenses and diversion of attention and resources, along with any reputational issues raised by these lawsuits and inquiry, may materially affect our business and results of operations and consequently reduce our distributable cash flow.

Failure to complete or delays in completing LinnCo's pending merger with Berry could have an adverse impact on our unit price and our business.

Due to the pending SEC inquiry, the timing of LinnCo's pending merger with Berry is uncertain. If the merger is not completed, or there are delays in completing the merger, our unit price and our business could be adversely affected and we would be subject to a number of risks, including the following:

- the current trading price of our units may reflect a market assumption that the merger will be completed and a failure to complete or delays in completing the merger could result in a further decline in the price of our units;
- we may not realize the benefits expected from the merger, including cost savings, increased production, enhanced financial and competitive position and diversification of operating locations and assets;
- we will be required to pay certain costs relating to the merger, including certain investment banking, financing, legal and accounting fees and expenses, whether or not the merger is completed; and
- we may be responsible, under certain circumstances, for the net losses resulting from the termination of the derivatives transactions entered into by Berry at our request on or after the date of the merger agreement, which net losses could be significant.

There can be no assurance that these risks will not materialize, and if any of them do, they may have an adverse effect on our financial position, results of operations and operating cash flows.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

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

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units during the six months ended June 30, 2013. At June 30, 2013, approximately $56 million was available for unit repurchase under the program.

Item 3. Defaults Upon Senior Securities

None

Item 4. Mine Safety Disclosures

Not applicable

Item 5. Other Information

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 Quarterly Report on Form 10-Q.

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Item 6. Exhibits

Exhibit Number		Description
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
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

* Filed herewith.

** Furnished herewith.

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SIGNATURE

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 (Registrant)
Date: August 8, 2013	/s/ David B. Rottino David B. Rottino Senior Vice President of Finance, Business Development and Chief Accounting Officer (As Duly Authorized Officer and Chief Accounting Officer)