LINN ENERGY, LLC
Form 10-Q
July 28, 2011

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, 2011

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 (Address of principal executive offices)	77002 (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 June 30, 2011, there were 176,980,978 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, 2011 (Unaudited)	December 31, 2010
	(in thousands, except unit amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$69,768	$ 236,001
Accounts receivable – trade, net	264,279	184,624
Derivative instruments	141,143	234,675
Other current assets	56,757	55,609
Total current assets	531,947	710,909
Noncurrent assets:		
Oil and natural gas properties (successful efforts method)	6,740,667	5,664,503
Less accumulated depletion and amortization	(855,314)	(719,035)
	5,885,353	4,945,468
Other property and equipment	164,120	139,903
Less accumulated depreciation	(41,033)	(35,151)
	123,087	104,752
Derivative instruments	29,473	56,895
Other noncurrent assets	112,955	115,124
	142,428	172,019
Total noncurrent assets	6,150,868	5,222,239
Total assets	$6,682,815	$ 5,933,148
LIABILITIES AND UNITHOLDERS' CAPITAL		
Current liabilities:		
Accounts payable and accrued expenses	$305,014	$ 219,830
Derivative instruments	8,750	12,839
Other accrued liabilities	67,674	82,439
Total current liabilities	381,438	315,108
Noncurrent liabilities:		
Senior notes, net	3,052,888	2,742,902
Derivative instruments	191,405	39,797
Other noncurrent liabilities	57,886	47,125
Total noncurrent liabilities	3,302,179	2,829,824
Commitments and contingencies (Note 10)		

Unitholders’ capital:		
176,980,978 units and 159,009,795 units issued and outstanding at June 30, 2011, and December 31, 2010, respectively	2,969,654	2,549,099
Accumulated income	29,544	239,117
	2,999,198	2,788,216
Total liabilities and unitholders’ capital	$6,682,815	$ 5,933,148

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, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(in thousands, except per unit amounts)			
Revenues and other:				
Oil, natural gas and natural gas liquids sales	$302,390	$153,195	$543,097	$302,581
Gains (losses) on oil and natural gas derivatives	205,515	123,791	(163,961)	219,794
Marketing revenues	1,509	1,223	2,682	2,617
Other revenues	1,157	195	2,280	448
	510,571	278,404	384,098	525,440
Expenses:				
Lease operating expenses	56,363	38,367	102,264	69,589
Transportation expenses	6,476	5,256	12,331	9,876
Marketing expenses	1,044	772	1,853	1,741
General and administrative expenses	31,543	23,306	62,103	47,794
Exploration costs	550	155	995	4,016
Bad debt expenses	33	(208)	(5)	(19)
Depreciation, depletion and amortization	79,345	57,941	145,711	107,132
Taxes, other than income taxes	20,318	10,391	36,045	20,591
(Gains) losses on sale of assets and other, net	977	(52)	1,591	(374)
	196,649	135,928	362,888	260,346
Other income and (expenses):				
Loss on extinguishment of debt	(9,810)	—	(94,372)	—
Interest expense, net of amounts capitalized	(62,361)	(45,969)	(125,825)	(73,622)
Losses on interest rate swaps	—	(33,245)	—	(56,407)
Other, net	(2,972)	(3,691)	(4,718)	(4,292)
	(75,143)	(82,905)	(224,915)	(134,321)
Income (loss) before income taxes	238,779	59,571	(203,705)	130,773
Income tax benefit (expense)	(1,670)	215	(5,868)	(5,677)
Net income (loss)	$237,109	$59,786	$(209,573)	$125,096
Net income (loss) per unit:				
Basic	$1.34	$0.41	$(1.25)	$0.90
Diluted	$1.33	$0.40	$(1.25)	$0.90
Weighted average units outstanding:				
Basic	175,035	146,124	169,104	137,874
Diluted	175,797	146,462	169,104	138,234
Distributions declared per unit	$0.66	$0.63	$1.32	$1.26

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 (Loss)	Total Unitholders' Capital
		(in thousands)		
December 31, 2010	159,010	$2,549,099	$239,117	$2,788,216
Sale of units, net of underwriting discounts and expenses of $26,315	16,726	622,656	—	622,656
Issuance of units	1,245	4,452	—	4,452
Distributions to unitholders		(222,391)	—	(222,391)
Unit-based compensation expenses		11,181	—	11,181
Excess tax benefit from unit-based compensation		4,657	—	4,657
Net loss		—	(209,573)	(209,573)
June 30, 2011	176,981	$2,969,654	$29,544	$2,999,198

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, 2011	2010
	(in thousands)	
Cash flow from operating activities:		
Net income (loss)	$(209,573)	$125,096
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	145,711	107,132
Unit-based compensation expenses	11,181	7,400
Loss on extinguishment of debt	94,372	
Amortization and write-off of deferred financing fees and other	12,413	15,711
Gains on sale of assets and other, net	(156)	(515)
Bad debt expenses	(5)	(19)
Deferred income tax	2,790	2,702
Mark-to-market on derivatives:		
Total (gains) losses	163,961	(163,387)
Cash settlements	104,512	135,594
Cash settlements on canceled derivatives		(74,275)
Premiums paid for derivatives		(91,028)
Changes in assets and liabilities:		
Increase in accounts receivable – trade, net	(82,202)	(22,791)
Decrease in other assets	2,333	11,859
Increase in accounts payable and accrued expenses	74,348	3,108
Increase (decrease) in other liabilities	(15,923)	18,596
Net cash provided by operating activities	303,762	75,183
Cash flow from investing activities:		
Acquisition of oil and natural gas properties	(847,780)	(771,189)
Development of oil and natural gas properties	(225,889)	(62,357)
Purchases of other property and equipment	(18,657)	(8,125)
Proceeds from sale of properties and equipment and other	10,590	586
Net cash used in investing activities	(1,081,736)	(841,085)
Cash flow from financing activities:		
Proceeds from sale of units	648,971	431,250
Proceeds from borrowings	1,359,240	2,188,176
Repayments of debt	(1,064,679)	(1,420,000)
Distributions to unitholders	(222,391)	(175,435)
Financing fees, offering expenses and other, net	(111,987)	(60,488)
Excess tax benefit from unit-based compensation	2,587	1,741
Purchase of units		(11,832)
Net cash provided by financing activities	611,741	953,412
Net increase (decrease) in cash and cash equivalents	(166,233)	187,510

Cash and cash equivalents:		
Beginning	236,001	22,231
Ending	$69,768	$209,741

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

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."), primarily in the Mid-Continent, the Permian Basin, the Williston Basin, Michigan and California.

Principles of Consolidation and Reporting

The condensed consolidated financial statements at June 30, 2011, and for the three months and six months ended June 30, 2011, and June 30, 2010, 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, and 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, 2010. 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.

Use of Estimates

The preparation of the accompanying condensed consolidated financial statements in conformity with GAAP requires management of the Company to make estimates and assumptions about future events. These estimates and the underlying assumptions affect the amount of assets and liabilities reported, disclosures about contingent assets and liabilities, and reported amounts of revenues and expenses. The estimates that are particularly significant to the financial statements include estimates of the Company's reserves of oil, natural gas and natural gas liquids ("NGL"), future cash flows from oil and natural gas properties, depreciation, depletion and amortization, asset retirement obligations, certain revenues and operating expenses, fair values of commodity derivatives and, when applicable, interest rate 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.

Note 2 – Acquisitions and Divestitures

Acquisitions – 2011

On June 1, 2011, the Company completed the acquisitions of certain oil and natural gas properties in the Cleveland play, located in the Texas Panhandle, from Panther Energy Company, LLC and Red Willow Mid-Continent, LLC (collectively referred to as "Panther"). The results of operations of these properties have been included in the condensed consolidated financial statements since the acquisition date. The Company paid approximately $222 million in total consideration for these properties. The transaction was financed primarily with proceeds from the Company's May 2011 debt offering, as described below.

On May 2, 2011, and May 11, 2011, the Company completed two acquisitions of certain oil and natural gas properties in the Williston Basin. The results of operations of these properties have been included in the condensed consolidated financial statements since the acquisition dates. The Company paid $153 million in cash and recorded a receivable of $3 million and a payable of $1 million, resulting in total consideration for the acquisitions of approximately $151 million. The transactions were financed initially with borrowings under the Company's Credit Facility, as defined in Note 6.

On April 1, 2011, and April 5, 2011, the Company completed two acquisitions of certain oil and natural gas properties located in the Permian Basin, including properties from SandRidge Exploration and Production, LLC ("SandRidge"). The results of operations of these properties have been included in the condensed consolidated financial statements since the acquisition dates. The Company paid $238 million in cash and recorded a payable of $1 million, resulting in total consideration for the acquisitions of approximately $239 million. The transactions were financed initially with borrowings under the Company's Credit Facility.

On March 31, 2011, the Company completed the acquisition of certain oil and natural gas properties in the Williston Basin from an affiliate of Concho Resources Inc. ("Concho"). The results of operations of these properties have been included in the condensed consolidated financial statements since the acquisition date. The Company paid $196 million in cash and recorded a receivable from Concho of $2 million, resulting in total consideration for the acquisition of approximately $194 million. The transaction was financed primarily with proceeds from the Company's March 2011 public offering of units, as described below.

During the six months ended June 30, 2011, the Company completed other smaller acquisitions of oil and natural gas properties located in its various operating regions. The results of operations of these properties have been included in the condensed consolidated financial statements since the acquisition dates. The Company, in the aggregate, paid approximately $41 million in total consideration for these properties.

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

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

Assets:		
Current	$	(1,481)
Noncurrent		54
Oil and natural gas properties		851,740
Total assets acquired	$	850,313
Liabilities:		
Current	$	(3,819)

Asset retirement obligations		6,966
Total liabilities assumed	$	3,147
Net assets acquired	$	847,166

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LINN ENERGY, LLC

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – Continued

(Unaudited)

Current assets include receivables, prepaids and inventory of oil produced but not yet sold and noncurrent assets include other property and equipment. Current liabilities include payables, ad valorem taxes payable and environmental liabilities.

The fair values of oil and natural gas properties and asset retirement obligations were measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation of oil and natural gas properties include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; (iv) estimated future cash flows; and (v) a market-based weighted average cost of capital rate.

The revenues and expenses related to the properties acquired from Panther, SandRidge and Concho are included in the condensed consolidated results of operations of the Company as of June 1, 2011, April 1, 2011, and March 31, 2011, respectively. The following unaudited pro forma financial information presents a summary of the Company's condensed consolidated results of operations for the three months and six months ended June 30, 2011, and June 30, 2010, assuming the acquisitions of Panther, SandRidge and Concho had been completed as of January 1, 2010, including adjustments to reflect the values assigned to the net assets acquired. The pro forma financial information is not necessarily indicative of the results of operations if the acquisitions had been effective as of this date.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(in thousands, except per unit amounts)			
Total revenues and other	$ 521,386	$ 305,436	$ 423,314	$ 574,507
Total operating expenses	$ 201,393	$ 152,638	$ 383,409	$ 292,691
Net income (loss)	$ 240,428	$ 65,980	$ (197,756)	$ 133,563
Net income (loss) per unit:				
Basic	$ 1.36	$ 0.42	$ (1.16)	$ 0.89
Diluted	$ 1.35	$ 0.42	$ (1.16)	$ 0.89

Other

In July 2010, the Company entered into a definitive purchase and sale agreement ("PSA") to acquire certain oil and natural gas properties for a contract price of $95 million. Upon the execution of the PSA, the Company paid a deposit of approximately $9 million. In September 2010, in accordance with the terms of the PSA, the Company terminated the PSA as a result of certain conditions to closing not being met. On March 28, 2011, an arbitration panel granted a favorable final ruling to the Company with regard to the termination of the PSA and the return of the deposit. On April 27, 2011, the deposit plus interest was received by the Company.

Acquisitions – 2010

On May 27, 2010, the Company completed the acquisition of interests in Henry Savings LP and Henry Savings Management LLC (collectively referred to as "Henry") that primarily hold oil and natural gas properties located in the Permian Basin. The results of operations of these properties have been included in the condensed consolidated financial statements since the acquisition date. The Company paid $330 million in cash and recorded a receivable from Henry of $7 million, resulting in total consideration for the acquisition of approximately $323 million. The transaction was financed with borrowings under the Company's Credit Facility.

On April 30, 2010, the Company completed the acquisition of interests in two wholly owned subsidiaries of HighMount Exploration & Production LLC ("HighMount") that hold oil and natural gas properties in the Antrim

LINN ENERGY, LLC

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – Continued

(Unaudited)

Shale located in northern Michigan. The results of operations of these properties have been included in the condensed consolidated financial statements since the acquisition date. The Company paid $327 million in cash. The transaction was financed with a portion of the net proceeds from the Company's March 2010 public offering of units.

On January 29, 2010, the Company completed the acquisition of certain oil and natural gas properties located in the Anadarko Basin in Oklahoma and Kansas and the Permian Basin in Texas and New Mexico from certain affiliates of Merit Energy Company ("Merit"). The results of operations of these properties have been included in the condensed consolidated financial statements since the acquisition date. The Company paid $152 million in cash and recorded a receivable from Merit of $1 million, resulting in total consideration for the acquisition of approximately $151 million. The transaction was financed with borrowings under the Company's Credit Facility.

Note 3 – Unitholders' Capital

Public Offering of Units

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

Distributions

Under the Company's limited liability company agreement, the Company's unitholders are entitled to receive a quarterly distribution of available cash to the extent there is sufficient cash from operations after establishment of cash reserves and payment of fees and expenses. Distributions paid by the Company during the six months ended June 30, 2011, are presented on the condensed consolidated statement of unitholders' capital. On July 26, 2011, the Company's Board of Directors declared a cash distribution of $0.69 per unit with respect to the second quarter of 2011, which represents a 5% increase over the previous quarter. The distribution, totaling approximately $122 million, will be paid on August 12, 2011, to unitholders of record as of the close of business on August 5, 2011.

Note 4 – 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, 2011	December 31, 2010
	(in thousands)	
Proved properties:		
Leasehold acquisition	$ 5,505,535	$ 4,695,704
Development	1,066,039	840,175

Unproved properties		169,093		128,624
		6,740,667		5,664,503
Less accumulated depletion and amortization		(855,314)		(719,035)
	$	5,885,353	$	4,945,468

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LINN ENERGY, LLC

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – Continued

(Unaudited)

Note 5 – Unit-Based Compensation

During the six months ended June 30, 2011, the Company granted an aggregate 1,071,002 restricted units to employees, primarily as part of its annual review of employee compensation, with an aggregate fair value of approximately $41 million. The restricted 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,	
	2011	2010	2011	2010
	(in thousands)			
General and administrative expenses	$ 5,290	$ 3,196	$ 10,694	$ 7,210
Lease operating expenses	253	69	487	190
Total unit-based compensation expenses	$ 5,543	$ 3,265	$ 11,181	$ 7,400
Income tax benefit	$ 2,408	$ 1,291	$ 4,132	$ 2,927

Note 6 – Debt

The following summarizes debt outstanding:

	June 30, 2011			December 31, 2010		
	Carrying Value	Fair Value (1)	Interest Rate (2)	Carrying Value	Fair Value (1)	Interest Rate (2)
	(in millions, except percentages)					
11.75% senior notes due 2017	$ 41	$ 49	12.73 %	$ 250	$ 288	12.73 %
9.875% senior notes due 2018	16	18	10.25 %	256	279	10.25 %
6.50% senior notes due 2019	750	740	6.62 %			
8.625% senior notes due 2020	1,300	1,402	9.00 %	1,300	1,396	9.00 %
7.75% senior notes due 2021	1,000	1,039	8.00 %	1,000	1,021	8.00 %
Less current maturities						
	3,107	$ 3,248		2,806	$ 2,984	
Unamortized discount	(54)			(63)		

Total debt, net of discount	$ 3,053	$ 2,743

(1) Fair values of the senior notes were estimated based on prices quoted from third-party financial institutions.

(2) Represents effective interest rates for the senior notes.

Credit Facility

On May 2, 2011, the Company entered into a Fifth 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 $1.5 billion. The initial borrowing base under the Credit Facility was $2.5 billion, but was reduced to $2.3 billion as a result of the issuance of the 2019 Senior Notes, as described below. The maturity date was extended from April 2015 to April 2016.

LINN ENERGY, LLC

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – Continued

(Unaudited)

During 2011, in connection with amendments to its Credit Facility, the Company incurred financing fees and expenses of approximately $4 million, which will be amortized over the life of the Credit Facility. Such amortized expenses are recorded in “interest expense, net of amounts capitalized” on the condensed consolidated statements of operations. At June 30, 2011, available borrowing capacity under the Credit Facility was $1.5 billion, which includes a $4 million reduction in availability for outstanding letters of credit.

Redetermination of the borrowing base under the Credit Facility, based primarily on reserve reports that reflect commodity prices at such time, occurs semi-annually, in April and October, as well as upon requested interim redeterminations, by the lenders at their sole discretion. The Company also has the right to request one additional borrowing base redetermination per year at its discretion, as well as the right to an additional redetermination each year in connection with certain acquisitions. Significant declines in commodity prices may result in a decrease in the borrowing base. The Company’s obligations under the Credit Facility are secured by mortgages on its and certain of its material subsidiaries’ oil and natural gas properties and other personal property as well as a pledge of all ownership interests in its direct and indirect material subsidiaries. The Company and its subsidiaries are required to maintain the mortgages on properties representing at least 80% of the total value of its and its subsidiaries’ oil and natural gas properties. 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 1.75% and 2.75% 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 0.75% and 1.75% 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 equal to 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 2019

On May 13, 2011, the Company issued $750 million in aggregate principal amount of 6.50% senior notes due 2019 (“2019 Senior Notes”) at a price of 99.232%. The 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 $729 million (after deducting the initial purchasers’ discount and offering expenses). The Company used a portion of the net proceeds to repay all of the outstanding indebtedness under its Credit Facility and to fund the Panther acquisition (see Note 2). The remaining proceeds will be used for general corporate purposes. In connection with the 2019 Senior Notes, the Company incurred financing fees and expenses of approximately $15 million, which will be amortized over the life of the 2019 Senior Notes. The discount on the 2019 Senior Notes, which totaled approximately $6 million, will also be amortized over the life of the 2019 Senior Notes. Such amortized expenses are recorded in “interest expense, net of amounts capitalized” on the condensed consolidated statements of operations.

The 2019 Senior Notes were issued under an indenture dated May 13, 2011 (“2019 Indenture”), mature May 15, 2019, and bear interest at 6.50%. Interest is payable semi-annually on May 15 and November 15, beginning November 15,

2011. The 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 2019 Senior Notes on a senior unsecured basis. The 2019 Indenture provides that the Company may redeem: (i) on or prior to May 15, 2014, up to 35% of the aggregate principal amount of the 2019 Senior Notes at a redemption price of 106.50% of the principal amount redeemed, plus accrued and unpaid interest, with the net cash proceeds of one or more equity offerings; (ii) prior to May 15, 2015, all or part of the 2019 Senior Notes at a redemption price equal to the principal amount redeemed, plus a make-whole premium (as defined in the 2019 Indenture) and accrued and unpaid interest; and (iii) on or after May 15, 2015, all or part of the 2019 Senior Notes at a redemption price equal to 103.250%, and decreasing percentages thereafter, of the principal amount redeemed, plus accrued and unpaid interest. The 2019 Indenture also provides that, if a change of control (as defined in the 2019 Indenture) occurs, the holders have a right to require the Company to repurchase all or part of the 2019 Senior Notes at a redemption price equal to 101%, plus accrued and unpaid interest.

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

In connection with the issuance and sale of the 2019 Senior Notes, the Company entered into a Registration Rights Agreement ("2019 Registration Rights Agreement") with the initial purchasers. Under the 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 2019 Senior Notes in exchange for outstanding 2019 Senior Notes within 400 days after the notes were issued. In certain circumstances, the Company may be required to file a shelf registration statement to cover resales of the 2019 Senior Notes. If the Company fails to satisfy these obligations, the Company may be required to pay additional interest to holders of the 2019 Senior Notes under certain circumstances.

Senior Notes Due 2020 and Senior Notes Due 2021

On April 6, 2010, the Company issued $1.30 billion in aggregate principal amount of 8.625% senior notes due 2020 (the "2020 Senior Notes"). On September 13, 2010, the Company issued $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 2019 Senior Notes.

Senior Notes Due 2017 and Senior Notes Due 2018

The Company also has $41 million (originally $250 million) in aggregate principal amount of 11.75% senior notes due 2017 (the "2017 Senior Notes") and $16 million (originally $256 million) in aggregate principal amount of 9.875% senior notes due 2018 (the "2018 Senior Notes" and together with the 2017 Notes, the "Original Senior Notes"). The indentures related to the Original Senior Notes originally contained redemption provisions and covenants that are substantially similar to those of the 2010 Issued Senior Notes; however, in connection with the tender offers described below, the indentures were amended and most of the covenants and certain default provisions were eliminated.

Redemptions of Original Senior Notes

In March 2011, in accordance with the provisions of the indentures related to the 2017 Senior Notes and the 2018 Senior Notes, the Company redeemed 35%, or $87 million and $90 million, respectively, of each of the original aggregate principal amount of the 2017 Senior Notes and 2018 Senior Notes. After the redemptions, $163 million and $166 million, respectively, of the 2017 Senior Notes and 2018 Senior Notes remained outstanding.

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Tender Offers for and Repurchase of Original Senior Notes

On February 28, 2011, the Company commenced cash tender offers ("Offers") and related consent solicitations to purchase any and all of its outstanding 2017 Senior Notes and 2018 Senior Notes. The Offers expired on March 25, 2011. Holders who validly tendered 2017 Senior Notes and 2018 Senior Notes on or before March 14, 2011, received the total consideration of $1,212.50 and $1,172.50, respectively, for each $1,000 principal amount of such notes accepted for purchase. Total consideration included a consent payment of $30.00 per $1,000 principal amount of notes accepted for purchase. Holders who validly tendered 2017 Senior Notes and 2018 Senior Notes after March 14, 2011, but before March 25, 2011, received $1,182.50 and $1,142.50, respectively, for each $1,000 principal amount of such notes accepted for purchase.

During March 2011, the Company accepted and purchased: 1) $105 million of the aggregate principal amount of the outstanding 2017 Senior Notes (or 65% of the remaining outstanding principal amount of the 2017 Senior Notes), and 2) $126 million of the aggregate principal amount of the outstanding 2018 Senior Notes (or 76% of the remaining outstanding principal amount of the 2018 Senior Notes).

In conjunction with each tender offer, the Company received consents to amendments to the indentures to the 2017 Senior Notes and 2018 Senior Notes, which eliminated most of the covenants and certain default provisions applicable to the series of notes issued under such indentures. The amendments became effective upon the execution of the supplemental indentures to the indentures governing each of the 2017 Senior Notes and the 2018 Senior Notes.

In June 2011, the Company repurchased an additional portion of its remaining outstanding 2017 Senior Notes and 2018 Senior Notes for $17 million (or 29% of the remaining outstanding principal amount of the 2017 Senior Notes) and $24 million (or 61% of the remaining outstanding principal amount of the 2018 Senior Notes), respectively. After giving effect to the tender offers and subsequent repurchases of the 2017 Senior Notes and the 2018 Senior Notes, aggregate principal amounts of $41 million and $16 million, respectively, remain outstanding at June 30, 2011.

In connection with the redemptions, cash tender offers and additional repurchases of a portion of the Original Senior Notes, the Company recorded a loss on extinguishment of debt of approximately $10 million and $94 million for the three months and six months ended June 30, 2011, respectively.

Note 7 – Derivatives

Commodity Derivatives

The Company utilizes derivative instruments to minimize the variability in cash flow due to commodity price movements. The Company enters 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.

LINN ENERGY, LLC

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – Continued

(Unaudited)

The following table summarizes open positions as of June 30, 2011, and represents, as of such date, derivatives in place through December 31, 2016, on annual production volumes:

	July 1 – December 31, 2011	2012	2013	2014	2015	2016
Natural gas positions:						
Fixed price swaps:						
Hedged volume (MMMBtu)	15,950	49,410	57,067	66,156	75,190	18,300
Average price ($/MMBtu)	$ 9.50	$ 5.97	$ 5.88	$ 5.86	$ 5.90	$ 6.01
Puts:						
Hedged volume (MMMBtu)	9,699	25,364	25,295	23,178	23,178	—
Average price ($/MMBtu)	$ 5.97	$ 6.25	$ 6.25	$ 5.00	$ 5.00	$ —
PEPL puts: (1)						
Hedged volume (MMMBtu)	6,630	—	—	—	—	—
Average price ($/MMBtu)	$ 8.50	$ —	$ —	$ —	$ —	$ —
Total:						
Hedged volume (MMMBtu)	32,279	74,774	82,362	89,334	98,368	18,300
Average price ($/MMBtu)	$ 8.24	$ 6.07	$ 6.00	$ 5.64	$ 5.69	$ 6.01
Oil positions:						
Fixed price swaps: (2)						
Hedged volume (MBbls)	2,932	7,741	8,413	9,034	9,216	549
Average price ($/Bbl)	$ 91.82	$ 94.67	$ 98.27	$ 95.39	$ 98.18	$ 100.58
Puts:						
Hedged volume (MBbls)	1,176	2,196	2,190	—	—	—
Average price ($/Bbl)	$ 75.00	$ 75.00	$ 75.00	$ —	$ —	$ —
Collars:						
Hedged volume (MBbls)	138	—	—	—	—	—
Average floor price ($/Bbl)	$ 90.00	$ —	$ —	$ —	$ —	$ —
Average ceiling price ($/Bbl)	$ 112.25	$ —	$ —	$ —	$ —	$ —

Total:						
Hedged volume (MBbls)	4,246	9,937	10,603	9,034	9,216	549
Average price ($/Bbl)	$ 87.10	$ 90.33	$ 93.46	$ 95.39	$ 98.18	$ 100.58
Natural gas basis differential positions:						
PEPL basis swaps: (1)						
Hedged volume (MMMBtu)	17,770	37,735	38,854	42,194	42,194	—
Hedged differential ($/MMBtu)	$ (0.96)	$ (0.89)	$ (0.89)	$ (0.39)	$ (0.39)	$ —
Oil timing differential positions:						
Trade month roll swaps: (3)						
Hedged volume (MBbls)	1,380	5,490	5,475	5,475	—	—
Hedged differential ($/Bbl)	$ 0.22	$ 0.22	$ 0.22	$ 0.22	$ —	$ —

(1) Settle on the Panhandle Eastern Pipeline (“PEPL”) spot price of natural gas to hedge basis differential associated with natural gas production in the Mid-Continent Deep and Mid-Continent Shallow regions.

(2) As presented in the table above, the Company has certain outstanding fixed price oil swaps on 1,000 Bbls of daily production for the year ending December 31, 2015, 14,750 Bbls of daily production for the years ending December 31,

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2016, and December 31, 2017, and 13,750 Bbls of daily production for the year ending December 31, 2018, which may be extended annually at a price of $100.00 per Bbl 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) The Company hedges the timing risk associated with the sales price of oil in the Mid-Continent Deep, Mid-Continent Shallow 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 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"). The 2011 swaps hedge production volumes for October through December.

During the six months ended June 30, 2011, the Company entered into commodity derivative contracts consisting of oil and natural gas swaps for certain years through 2016 and oil trade month roll swaps for October 2011 through December 2014.

Settled derivatives on natural gas production for the three months and six months ended June 30, 2011, included volumes of 16,106 MMMBtu and 32,178 MMMBtu, respectively, at average contract prices of $8.24 per MMBtu and $8.25 per MMBtu. Settled derivatives on oil production for the three months and six months ended June 30, 2011, included volumes of 1,839 MBbls and 3,671 MBbls, respectively, at an average contract price of $84.08 per Bbl. The natural gas derivatives are settled based on the closing NYMEX future price of natural gas or the published PEPL spot price of natural gas on the settlement date, which occurs on the third day preceding the production month. The oil derivatives are settled based on the month's average daily NYMEX price of light oil and settlement occurs on the final day of the production month.

In July 2011, the Company entered into commodity derivative contracts consisting of oil swaps for 2015 and 2016. At July 15, 2011, the Company had derivative contracts in place for 2011 and 2012 at average prices of $87.10 per Bbl and $90.33 per Bbl for oil and $8.24 per MMBtu and $6.07 per MMBtu for natural gas, respectively. Additionally, the Company has derivative contracts in place covering a substantial portion of its exposure to the Mid-Continent natural gas basis differential through 2015.

Interest Rate Swaps

The Company may from time to time enter into interest rate swap agreements based on LIBOR to minimize the effect of fluctuations in interest rates. If LIBOR is lower than the fixed rate in the contract, the Company is required to pay the counterparty the difference, and conversely, the counterparty is required to pay the Company if LIBOR is higher than the fixed rate in the contract. The Company does not designate interest rate swap agreements as cash flow hedges; therefore, the changes in fair value of these instruments are recorded in current earnings. At June 30, 2011, the Company had no outstanding interest rate swap agreements.

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LINN ENERGY, LLC

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – Continued

(Unaudited)

Balance Sheet Presentation

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

	June 30, 2011	December 31, 2010
	(in thousands)	
Assets:		
Commodity derivatives	$ 440,485	$ 637,836
Liabilities:		
Commodity derivatives	$ 470,024	$ 398,902

By using derivative instruments to economically hedge exposures to changes in commodity prices and interest rates, when applicable, the Company exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes the Company, which creates credit risk. The Company's counterparties are current participants or affiliates of participants in its Credit Facility or were participants or affiliates of participants in its Credit Facility at the time it originally entered into the derivatives. The Credit Facility is secured by the Company's oil and natural gas reserves; therefore, the Company is not required to post any collateral. The Company does not require 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 $440 million at June 30, 2011. The Company minimizes the credit risk in derivative instruments by: (i) limiting its exposure to any single counterparty; (ii) entering into derivative instruments only with counterparties that meet the Company's minimum credit quality standard, or have a guarantee from an affiliate that meets the Company's minimum credit quality standard; and (iii) monitoring the creditworthiness of the Company's counterparties on an ongoing basis. In accordance with the Company's standard practice, its commodity derivatives and, when applicable, its interest rate derivatives are subject to counterparty netting under agreements governing such derivatives and therefore the risk of such loss is somewhat mitigated.

Gains (Losses) on Derivatives

Gains and losses on derivatives, including realized and unrealized gains and losses, are reported on the condensed consolidated statements of operations in "gains (losses) on oil and natural gas derivatives" and "losses on interest rate swaps." Realized gains (losses), excluding canceled derivatives, represent amounts related to the settlement of derivative instruments, and for commodity derivatives, are aligned with the underlying production. Unrealized gains (losses) represent the change in fair value of the derivative instruments and are noncash items.

LINN ENERGY, LLC

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – Continued

(Unaudited)

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

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(in thousands)			
Realized gains (losses):				
Commodity derivatives	$ 42,081	$ 83,160	$ 97,890	$ 145,663
Interest rate swaps				(8,021)
Canceled derivatives		(74,275)		(74,275)
	$ 42,081	$ 8,885	$ 97,890	$ 63,367
Unrealized gains (losses):				
Commodity derivatives	$ 163,434	$ 40,631	$ (261,851)	$ 74,131
Interest rate swaps		41,030		25,889
	$ 163,434	$ 81,661	$ (261,851)	$ 100,020
Total gains (losses):				
Commodity derivatives	$ 205,515	$ 123,791	$ (163,961)	$ 219,794
Interest rate swaps		(33,245)		(56,407)
	$ 205,515	$ 90,546	$ (163,961)	$ 163,387

Note 8 – Fair Value Measurements on a Recurring Basis

The Company accounts for its commodity derivatives and, when applicable, its interest rate derivatives at fair value (see Note 7) on a recurring basis. The fair value of derivative instruments is determined utilizing pricing models for significantly similar instruments. Inputs to the pricing models include publicly available prices and forward price curves generated from a compilation of data gathered from third parties. Assumed credit risk adjustments, based on published credit ratings, public bond yield spreads and credit default swap spreads, are applied to the Company's commodity derivatives and, when applicable, its interest rate derivatives.

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

	June 30, 2011 Level 2	June 30, 2011 Netting (1)	June 30, 2011 Total
	(in thousands)		
Assets:			
Commodity derivatives	$ 440,485	$ (269,869)	$ 170,616
Liabilities:			
Commodity derivatives	$ 470,024	$ (269,869)	$ 200,155

(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 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

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existing regulatory requirements; (ii) remaining life per well; (iii) future inflation factors (2.0% for the six months ended June 30, 2011); and (iv) a credit-adjusted risk-free interest rate (average of 7.4% for the six months ended June 30, 2011).

The following presents a reconciliation of the asset retirement obligations (in thousands):

Asset retirement obligations at December 31, 2010	$42,945
Liabilities added from acquisitions	6,966
Liabilities added from drilling	630
Current year accretion expense	1,817
Settlements	(1,028)
Revision of estimate	784
Asset retirement obligations at June 30, 2011	$52,114

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 in this dispute is ongoing and is not complete. 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.

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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LINN ENERGY, LLC

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – Continued

(Unaudited)

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

	Net Income (Loss) (Numerator)	Units (Denominator)	Per Unit Amount
	(in thousands)		
Three months ended June 30, 2011:			
Net income:			
Allocated to units	$ 237,109		
Allocated to unvested restricted units	(2,475)		
	$ 234,634		
Net income per unit:			
Basic net income per unit		175,035	$ 1.34
Dilutive effect of unit equivalents		762	(0.01)
Diluted net income per unit		175,797	$ 1.33
Three months ended June 30, 2010:			
Net income:			
Allocated to units	$ 59,786		
Allocated to unvested restricted units	(592)		
	$ 59,194		
Net income per unit:			
Basic net income per unit		146,124	$ 0.41
Dilutive effect of unit equivalents		338	(0.01)
Diluted net income per unit		146,462	$ 0.40
Six months ended June 30, 2011:			
Net loss:			
Allocated to units	$ (209,573)		
Allocated to unvested restricted units	(2,439)		
	$ (212,012)		
Net loss per unit:			
Basic net loss per unit		169,104	$ (1.25)
Dilutive effect of unit equivalents		—	—
Diluted net loss per unit		169,104	$ (1.25)
Six months ended June 30, 2010:			
Net income:			
Allocated to units	$ 125,096		
Allocated to unvested restricted units	(1,336)		
	$ 123,760		
Net income per unit:			
Basic net income per unit		137,874	$ 0.90
Dilutive effect of unit equivalents		360	—

Diluted net income per unit	138,234	$	0.90

There were no anti-dilutive unit equivalents for the three months ended June 30, 2011. Basic units outstanding excludes the effect of weighted average anti-dilutive unit equivalents related to 2 million unit options and warrants

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LINN ENERGY, LLC

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – Continued

(Unaudited)

for the six months ended June 30, 2011. All equivalent units were anti-dilutive for the six months ended June 30, 2011. Basic units outstanding excludes the effect of weighted average anti-dilutive unit equivalents related to 1 million unit options and warrants for the three months and six months ended June 30, 2010.

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 states of Texas and Michigan, with income tax liabilities and/or benefits of the Company passed through to unitholders. Limited liability companies are subject to state income taxes in Texas and Michigan and certain of the Company's subsidiaries are Subchapter C-corporations subject to federal and state income taxes. As such, with the exception of the states of Texas and Michigan 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 these taxes are reported in "income tax benefit (expense)" 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, 2011 (in thousands)	December 31, 2010 (in thousands)
Accrued compensation	$ 12,735	$ 18,931
Accrued interest	54,368	62,999
Other	571	509
	$ 67,674	$ 82,439

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

	Six Months Ended June 30, 2011 (in thousands)	Six Months Ended June 30, 2010 (in thousands)
Cash payments for interest, net of amounts capitalized	$ 124,173	$ 39,492
Cash payments for income taxes	$ 476	$ 1,681
Noncash investing activities:		
In connection with the acquisition of oil and natural gas properties, liabilities were assumed as follows:		
Fair value of assets acquired	$ 850,313	$ 792,242

Cash paid, net of cash acquired	(847,780)	(771,189)
Receivables from sellers	5,855	10,391
Payables to sellers	(5,241)	—
Liabilities assumed	$ 3,147	$ 31,444

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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 $3 million is included in “other noncurrent assets” on the condensed consolidated balance sheets at June 30, 2011, and December 31, 2010, and represents cash deposited by the Company into a separate account and designated for asset retirement obligations in accordance with contractual agreements.

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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, 2010, 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, 2010. 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 IPO in January 2006. The Company's properties are located in six operating regions in the United States ("U.S."):

- Mid-Continent Deep, which includes the Texas Panhandle Deep Granite Wash formation and deep formations in Oklahoma and Kansas;
- Mid-Continent Shallow, which includes the Texas Panhandle Brown Dolomite formation and shallow formations in Oklahoma, Louisiana and Illinois;
- Permian Basin, which includes areas in West Texas and Southeast New Mexico;
- Williston Basin, which includes the Bakken formation in North Dakota;
- Michigan, which includes the Antrim Shale formation in the northern part of the state; and
- California, which includes the Brea Olinda Field of the Los Angeles Basin.

Results for the three months ended June 30, 2011, included the following:

- oil, natural gas and NGL sales of approximately $302 million compared to $153 million for the second quarter of 2010;
- average daily production of 358 MMcfe/d compared to 256 MMcfe/d for the second quarter of 2010;
- realized gains on commodity derivatives of approximately $42 million compared to $83 million for the second quarter of 2010;
- adjusted EBITDA of approximately $264 million compared to $175 million for the second quarter of 2010;
- adjusted net income of approximately $83 million compared to $53 million for the second quarter of 2010;
- capital expenditures, excluding acquisitions, of approximately $137 million compared to $46 million for the second quarter of 2010; and
- 55 wells drilled (all successful) compared to 26 wells drilled (all successful) for the second quarter of 2010.

Results for the six months ended June 30, 2011, included the following:

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oil, natural gas and NGL sales of approximately $543 million compared to $303 million for the six months ended June 30, 2010;

- average daily production of 335 MMcfe/d compared to 235 MMcfe/d for the six months ended June 30, 2010;

- realized gains on commodity derivatives of approximately $98 million compared to $146 million for the six months ended June 30, 2010;
- adjusted EBITDA of approximately $474 million compared to $326 million for the six months ended June 30, 2010;
- adjusted net income of approximately $146 million compared to $100 million for the six months ended June 30, 2010;
- capital expenditures, excluding acquisitions, of approximately $250 million compared to $73 million for the six months ended June 30, 2010; and
- 101 wells drilled (99 successful) compared to 39 wells drilled (all successful) for the six months ended June 30, 2010.

Adjusted EBITDA and adjusted net income are non-GAAP financial measures used by management to analyze Company performance. Adjusted EBITDA is a measure used by Company management to evaluate cash flow and the Company's ability to sustain or increase distributions. The most significant reconciling items between net income (loss) and adjusted EBITDA are interest expense and noncash items, including the change in fair value of derivatives, and depreciation, depletion and amortization. Adjusted net income is used by Company management to evaluate its operational performance from oil and natural gas properties, prior to unrealized (gains) losses on derivatives, realized (gains) losses on canceled derivatives, impairment of goodwill and long-lived assets, loss on extinguishment of debt and (gains) losses on sale of assets, net. See "Non-GAAP Financial Measures" on page 40 for a reconciliation of each non-GAAP financial measure to its most directly comparable financial measure calculated and presented in accordance with GAAP.

Acquisitions – 2011

On June 1, 2011, the Company completed the acquisition of certain oil and natural gas properties in the Cleveland play, located in the Texas Panhandle, from Panther Energy Company, LLC and Red Willow Mid-Continent, LLC (collectively referred to as "Panther") for total consideration of approximately $222 million. The acquisition included approximately 9 MMBoe (54 Bcfe) of proved reserves as of the acquisition date.

On May 2, 2011, and May 11, 2011, the Company completed two acquisitions of certain oil and natural gas properties in the Williston Basin for total consideration of approximately $151 million. The acquisitions included approximately 6 MMBoe (36 Bcfe) of proved reserves as of the acquisition date.

On April 1, 2011, and April 5, 2011, the Company completed two acquisitions of certain oil and natural gas properties located in the Permian Basin for total consideration of approximately $239 million. The acquisitions included approximately 13 MMBoe (79 Bcfe) of proved reserves as of the acquisition date.

On March 31, 2011, the Company completed the acquisition of certain oil and natural gas properties in the Williston Basin from an affiliate of Concho Resources Inc. ("Concho") for total consideration of approximately $194 million. The acquisition included approximately 8 MMBoe (50 Bcfe) of proved reserves as of the acquisition date.

During the six months ended June 30, 2011, the Company completed other smaller acquisitions of oil and natural gas properties located in its various operating regions. The Company, in the aggregate, paid approximately $41 million in total consideration for these properties.

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Financing and Liquidity

In March 2011, in accordance with the provisions of the indentures related to the 2017 Senior Notes and the 2018 Senior Notes, the Company redeemed 35%, or $87 million and $90 million, respectively, of each of the original aggregate principal amount of the Original Senior Notes, as defined in Note 6.

On February 28, 2011, the Company commenced cash tender offers and related consent solicitations to purchase any and all of its outstanding 2017 Senior Notes and 2018 Senior Notes. In March 2011, the Company accepted and purchased: 1) $105 million of the aggregate principal amount of the outstanding 2017 Senior Notes (or 65% of the remaining outstanding principal amount of 2017 Senior Notes), and 2) $126 million aggregate principal amount of the outstanding 2018 Senior Notes (or 76% of the remaining outstanding principal amount of 2018 Senior Notes).

In March 2011, the Company also completed a public offering of units for net proceeds of approximately $623 million. The Company used the net proceeds from the sale of these units to fund the March 2011 redemptions of a portion of the outstanding 2017 Senior Notes and 2018 Senior Notes and to fund the cash tender offers and related expenses for a portion of the remaining 2017 Senior Notes and 2018 Senior Notes (see Note 6). The Company used the remaining net proceeds from the sale of units to finance a portion of the March 31, 2011, acquisition in the Williston Basin.

On May 2, 2011, the Company entered into a Fifth 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 $1.5 billion. The initial borrowing base under the Credit Facility was $2.5 billion, but was reduced to $2.3 billion as a result of the issuance of the 2019 Senior Notes (see Note 6). The maturity date was extended from April 2015 to April 2016.

In May 2011, the Company also issued $750 million in aggregate principal amount of 6.50% senior notes due 2019 (see Note 6) and used net proceeds of approximately $729 million to repay all of the outstanding indebtedness under its Credit Facility, fund or partially fund acquisitions and for general corporate purposes.

In June 2011, the Company repurchased an additional portion of its remaining outstanding 2017 Senior Notes and 2018 Senior Notes for $17 million (or 29% of the remaining outstanding principal amount of the 2017 Senior Notes) and $24 million (or 61% of the remaining outstanding principal amount of the 2018 Senior Notes), respectively.

Commodity Derivatives

The Company hedges a significant portion of its forecasted production to reduce exposure to fluctuations in the prices of oil and natural gas and provide long-term cash flow predictability to pay distributions, service debt and manage its business. By removing a significant portion of the price volatility associated with future production, the Company expects to mitigate, but not eliminate, the potential effects of variability in cash flow from operations due to fluctuations in commodity prices.

In July 2011, the Company entered into commodity derivative contracts consisting of oil swaps for 2015 and 2016. The following table summarizes open positions as of July 15, 2011, and represents, as of such date, derivatives in place through December 31, 2016, on annual production volumes:

	July 16 – December 31, 2011	2012	2013	2014	2015	2016
Natural gas positions:						
Fixed price swaps:						
Hedged volume (MMMBtu)	13,292	49,410	57,067	66,156	75,190	18,300
Average price ($/MMBtu)	$ 9.50	$ 5.97	$ 5.88	$ 5.86	$ 5.90	$ 6.01
Puts:						
Hedged volume (MMMBtu)	8,071	25,364	25,295	23,178	23,178	—
Average price ($/MMBtu)	$ 5.98	$ 6.25	$ 6.25	$ 5.00	$ 5.00	$ —
PEPL puts: (1)						
Hedged volume (MMMBtu)	5,525	—	—	—	—	—
Average price ($/MMBtu)	$ 8.50	$ —	$ —	$ —	$ —	$ —
Total:						
Hedged volume (MMMBtu)	26,888	74,774	82,362	89,334	98,368	18,300
Average price ($/MMBtu)	$ 8.24	$ 6.07	$ 6.00	$ 5.64	$ 5.69	$ 6.01
Oil positions:						
Fixed price swaps: (2)						
Hedged volume (MBbls)	2,932	7,741	8,413	9,034	9,581	1,830
Average price ($/Bbl)	$ 91.82	$ 94.67	$ 98.27	$ 95.39	$ 98.25	$ 101.00
Puts:						
Hedged volume (MBbls)	1,176	2,196	2,190	—	—	—
Average price ($/Bbl)	$ 75.00	$ 75.00	$ 75.00	$ —	$ —	$ —
Collars:						
Hedged volume (MBbls)	138	—	—	—	—	—
Average floor price ($/Bbl)	$ 90.00	$ —	$ —	$ —	$ —	$ —
Average ceiling price ($/Bbl)	$ 112.25	$ —	$ —	$ —	$ —	$ —
Total:						
Hedged volume (MBbls)	4,246	9,937	10,603	9,034	9,581	1,830

Average price ($/Bbl)	$ 87.10	$ 90.33	$ 93.46	$ 95.39	$ 98.25	$ 101.00
Natural gas basis differential positions:						
PEPL basis swaps: (1)						
Hedged volume (MMMBtu)	14,809	37,735	38,854	42,194	42,194	—
Hedged differential ($/MMBtu)	$ (0.96)	$ (0.89)	$ (0.89)	$ (0.39)	$ (0.39)	$ —
Oil timing differential positions:						
Trade month roll swaps: (3)						
Hedged volume (MBbls)	1,380	5,490	5,475	5,475	—	—
Hedged differential ($/Bbl)	$ 0.22	$ 0.22	$ 0.22	$ 0.22	$ —	$ —

(1) Settle on the Panhandle Eastern Pipeline (“PEPL”) spot price of natural gas to hedge basis differential associated with natural gas production in the Mid-Continent Deep and Mid-Continent Shallow regions.

(2) As presented in the table above, the Company has certain outstanding fixed price oil swaps on 14,750 Bbls of daily production which may be extended annually at a price of $100.00 per Bbl for each of the years ending December 31, 2016, December 31, 2017, and December 31, 2018, 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) The Company hedges the timing risk associated with the sales price of oil in the Mid-Continent Deep, Mid-Continent Shallow 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 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"). The 2011 swaps hedge production volumes for October through December.

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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, 2011, Compared to Three Months Ended June 30, 2010

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Variance
		(in thousands)	
Revenues and other:			
Natural gas sales	$ 70,800	$ 51,451	$ 19,349
Oil sales	191,454	76,250	115,204
NGL sales	40,136	25,494	14,642
Total oil, natural gas and NGL sales	302,390	153,195	149,195
Gains on oil and natural gas derivatives	205,515	123,791	81,724
Marketing revenues	1,509	1,223	286
Other revenues	1,157	195	962
	$ 510,571	$ 278,404	$ 232,167
Expenses:			
Lease operating expenses	$ 56,363	$ 38,367	$ 17,996
Transportation expenses	6,476	5,256	1,220
Marketing expenses	1,044	772	272
General and administrative expenses (1)	31,543	23,306	8,237
Exploration costs	550	155	395
Bad debt expenses	33	(208)	241
Depreciation, depletion and amortization	79,345	57,941	21,404
Taxes, other than income taxes	20,318	10,391	9,927
Gains (losses) on sale of assets and other, net	977	(52)	1,029
	$ 196,649	$ 135,928	$ 60,721
Other income and (expenses)	$ (75,143)	$ (82,905)	$ 7,762
Income before income taxes	$ 238,779	$ 59,571	$ 179,208
Adjusted EBITDA (2)	$ 263,606	$ 174,973	$ 88,633
Adjusted net income (2)	$ 83,357	$ 52,633	$ 30,724

(1) General and administrative expenses for the three months ended June 30, 2011, and June 30, 2010, include approximately $5 million and $3 million, respectively, of noncash unit-based compensation expenses.

(2) This is a non-GAAP measure used by management to analyze the Company's performance. See "Non-GAAP Financial Measures" on page 40 for a reconciliation of the non-GAAP financial measure to its most directly comparable financial measure calculated and presented in accordance with GAAP.

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

	Three Months Ended June 30, 2011	2010	Variance
Average daily production:			
Natural gas (MMcf/d)	169	140	21 %
Oil (MBbls/d)	21.4	11.6	84 %
NGL (MBbls/d)	10.1	7.7	31 %
Total (MMcfe/d)	358	256	40 %
Weighted average prices (hedged): (1)			
Natural gas (Mcf)	$ 8.39	$ 8.58	(2)%
Oil (Bbl)	$ 90.03	$ 96.03	(6)%
NGL (Bbl)	$ 43.77	$ 36.32	21 %
Weighted average prices (unhedged): (2)			
Natural gas (Mcf)	$ 4.61	$ 4.04	14 %
Oil (Bbl)	$ 98.23	$ 72.21	36 %
NGL (Bbl)	$ 43.77	$ 36.32	21 %
Average NYMEX prices:			
Natural gas (MMBtu)	$ 4.31	$ 4.09	5 %
Oil (Bbl)	$ 102.56	$ 78.03	31 %
Costs per Mcfe of production:			
Lease operating expenses	$ 1.73	$ 1.65	5 %
Transportation expenses	$ 0.20	$ 0.23	(13)%
General and administrative expenses (3)	$ 0.97	$ 1.00	(3)%
Depreciation, depletion and amortization	$ 2.44	$ 2.49	(2)%
Taxes, other than income taxes	$ 0.62	$ 0.45	38 %

(1) Includes the effect of realized gains on derivatives of approximately $42 million and approximately $83 million for the three months ended June 30, 2011, and June 30, 2010, respectively.

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

(3) General and administrative expenses for the three months ended June 30, 2011, and June 30, 2010, include approximately $5 million and $3 million, respectively, of noncash unit-based compensation expenses. Excluding these amounts, general and administrative expenses for the three months ended June 30, 2011, and June 30, 2010, were $0.81 per Mcfe and $0.86 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 $149 million or 97% to approximately $302 million for the three months ended June 30, 2011, from approximately $153 million for the three months ended June 30, 2010, due to higher commodity prices and higher production volumes. Higher oil, natural gas and NGL prices resulted in an increase in revenues of approximately $51 million, $9 million and $7 million, respectively.

Average daily production volumes increased to 358 MMcfe/d during the three months ended June 30, 2011, from 256 MMcfe/d during the three months ended June 30, 2010. Higher oil, natural gas and NGL production volumes resulted in an increase in revenues of approximately $64 million, $10 million and $8 million, respectively.

The following sets forth average daily production by region:

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Variance			
Average daily production (MMcfe/d):						
Mid-Continent Deep	162	135	27		20	%
Mid-Continent Shallow	62	68	(6	)	(10	)%
Permian Basin	75	19	56		293	%
Williston Basin	11	—	11		—	
Michigan	34	20	14		70	%
California	14	14	—		—	
	358	256	102		40	%

The 20% increase in average daily production volumes in the Mid-Continent Deep region primarily reflects the Company's 2010 and 2011 capital drilling programs in the Deep Granite Wash formation. The 10% decrease in average daily production volumes in the Mid-Continent Shallow region reflects downtime related to weather and third-party plant maintenance, and the effects of natural declines, partially offset by the results of the Company's drilling and optimization programs. Average daily production volumes in the Permian Basin region reflect the impact of the acquisitions in 2010 and 2011 and subsequent development capital spending. Average daily production volumes in the Williston Basin region reflect the impact of the acquisitions in 2011. Average daily production volumes in the Michigan region reflect the impact of the acquisitions in the second quarter and fourth quarter of 2010. The California region consists of a low-decline asset base and continues to produce at a consistent level.

Gains (Losses) on Oil and Natural Gas Derivatives
The Company determines the fair value of its oil and natural gas derivatives utilizing pricing models that use a variety of techniques, including market quotes and pricing analysis. See Item 7A. "Quantitative and Qualitative Disclosures About Market Risk," Note 7 and Note 8 for additional information about the Company's commodity derivatives. During the three months ended June 30, 2011, the Company had commodity derivative contracts for approximately 105% of its natural gas production and 94% of its oil production and recognized realized gains of approximately $42 million. During the three months ended June 30, 2010, the Company had commodity derivative contracts for approximately 112% of its natural gas production and 66% of its oil and NGL production and recognized realized gains of approximately $83 million. Unrealized gains and losses result from changes in market valuations of derivatives 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, unrealized losses are recognized; and if the expected future commodity prices decrease compared to the contract prices on the derivatives,

unrealized gains are recognized. During the second quarter of 2011 and 2010, expected future oil and natural gas prices decreased, which resulted in net unrealized gains on derivatives of approximately $163 million and $41 million, respectively, for the three months ended June 30, 2011 and June 30, 2010. For information about the Company's credit risk related to derivative contracts, see "Counterparty Credit Risk" in "Liquidity and Capital Resources" below.

Expenses

Lease Operating Expenses
Lease operating expenses include expenses such as labor, field office, vehicle, supervision, maintenance, tools and supplies and workover expenses. Lease operating expenses increased approximately $18 million or 47% to approximately $56 million for the three months ended June 30, 2011, from approximately $38 million for the three months ended June 30, 2010. Lease operating expenses per Mcfe also increased to $1.73 per Mcfe for the three months ended June 30, 2011, from $1.65 per Mcfe for the three months ended June 30, 2010. Lease operating expenses increased primarily due to costs associated with properties acquired in the Permian Basin, Williston Basin and Michigan regions during 2010 and during the first two quarters of 2011 (see Note 2).

Transportation Expenses
Transportation expenses increased approximately $1 million or 23% to approximately $6 million for the three months ended June 30, 2011, from approximately $5 million for the three months ended June 30, 2010, primarily due to higher production volumes.

General and Administrative Expenses
General and administrative expenses are costs not directly associated with field operations and include costs of employees including executive officers, related benefits, office leases and professional fees. General and administrative expenses increased approximately $9 million or 35% to approximately $32 million for the three months ended June 30, 2011, from approximately $23 million for the three months ended June 30, 2010. The increase was primarily due to an increase in salaries and benefits expense of approximately $4 million, driven primarily by increased employee headcount due to recent acquisitions activity, an increase in unit-based compensation expense of approximately $2 million and an increase in professional services expense of approximately $1 million. General and administrative expenses per Mcfe decreased to $0.97 per Mcfe for the three months ended June 30, 2011, from $1.00 per Mcfe for the three months ended June 30, 2010.

Exploration Costs
Exploration costs increased approximately $0.4 million to approximately $0.6 million for the three months ended June 30, 2011, from approximately $0.2 million for the three months ended June 30, 2010. The increase was primarily due to higher amortization and impairment expense on unproved properties.

Depreciation, Depletion and Amortization
Depreciation, depletion and amortization increased approximately $21 million or 37% to approximately $79 million for the three months ended June 30, 2011, from approximately $58 million for the three months ended June 30, 2010. Higher total production levels and oil and natural gas property acquisitions were the primary reasons for the increased expense. Depreciation, depletion and amortization per Mcfe decreased to $2.44 per Mcfe for the three months ended June 30, 2011, from $2.49 per Mcfe for the three months ended June 30, 2010.

Taxes, Other Than Income Taxes
Taxes, other than income taxes, which consist primarily of severance and ad valorem taxes, increased approximately $10 million or 96% to approximately $20 million for the three months ended June 30, 2011, from approximately $10 million for the three months ended June 30, 2010. Severance taxes, which are a function of revenues generated from production, increased approximately $9 million compared to the three months ended June 30, 2010, primarily due to higher commodity prices and production volumes. Ad valorem taxes, which are based on the value of reserves and

production equipment and vary by location, were essentially flat compared to the three months ended June 30, 2010.

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

Other Income and (Expenses)

	Three Months Ended June 30, 2011	2010	Variance
		(in thousands)	
Loss on extinguishment of debt	$ (9,810)	$ —	$ (9,810)
Interest expense, net of amounts capitalized	(62,361)	(45,969)	(16,392)
Realized losses on canceled interest rate swaps	—	(74,275)	74,275
Unrealized gains on interest rate swaps	—	41,030	(41,030)
Other, net	(2,972)	(3,691)	719
	$ (75,143)	$ (82,905)	$ 7,762

Other income and (expenses) decreased approximately $8 million for the three months ended June 30, 2011, compared to the three months ended June 30, 2010. Interest expense increased primarily due to higher interest rates and higher amortization of financing fees associated with the 2019 Senior Notes and the 2010 Issued Senior Notes, as defined in Note 6. Also during the three months ended June 30, 2011, the Company entered into a Fifth Amended and Restated Credit Facility, which also resulted in higher amortization of financing fees. In addition, for the three months ended June 30, 2011, the Company recorded a loss on extinguishment of debt of approximately $10 million as a result of the additional repurchases of a portion of the Original Senior Notes, as defined in Note 6. See “Debt” in “Liquidity and Capital Resources” below for additional details.

Income Tax Benefit (Expense)

The Company is a limited liability company treated as a partnership for federal and state income tax purposes, with the exception of the states of Texas and Michigan, with income tax liabilities and/or benefits of the Company passed through to unitholders. Limited liability companies are subject to state income taxes in Texas and Michigan. 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 expense of approximately $2 million and income tax benefit of approximately $0.2 million for the three months ended June 30, 2011, and June 30, 2010, respectively. Income tax expense increased primarily due to an increase in income at the Company’s taxable subsidiary and a higher Texas margin tax expense resulting from higher pre-tax income during the three months ended June 30, 2011, compared to the same period in 2010.

Adjusted EBITDA

Adjusted EBITDA (a non-GAAP financial measure) increased approximately $89 million or 51% to approximately $264 million for the three months ended June 30, 2011, from approximately $175 million for the three months ended June 30, 2010. The increase was primarily due to higher production revenues resulting from higher production volumes and higher commodity prices, partially offset by higher expenses. 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.

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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, 2011, Compared to Six Months Ended June 30, 2010

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010	Variance
		(in thousands)	
Revenues and other:			
Natural gas sales	$ 137,598	$ 104,313	$ 33,285
Oil sales	330,092	142,190	187,902
NGL sales	75,407	56,078	19,329
Total oil, natural gas and NGL sales	543,097	302,581	240,516
Gains (losses) on oil and natural gas derivatives	(163,961)	219,794	(383,755)
Marketing revenues	2,682	2,617	65
Other revenues	2,280	448	1,832
	$ 384,098	$ 525,440	$ (141,342)
Expenses:			
Lease operating expenses	$ 102,264	$ 69,589	$ 32,675
Transportation expenses	12,331	9,876	2,455
Marketing expenses	1,853	1,741	112
General and administrative expenses (1)	62,103	47,794	14,309
Exploration costs	995	4,016	(3,021)
Bad debt expenses	(5)	(19)	14
Depreciation, depletion and amortization	145,711	107,132	38,579
Taxes, other than income taxes	36,045	20,591	15,454
(Gains) losses on sale of assets and other, net	1,591	(374)	1,965
	$ 362,888	$ 260,346	$ 102,542
Other income and (expenses)	$ (224,915)	$ (134,321)	$ (90,594)
Income (loss) before income taxes	$ (203,705)	$ 130,773	$ (334,478)
Adjusted EBITDA (2)	$ 473,602	$ 326,482	$ 147,120
Adjusted net income (2)	$ 145,664	$ 99,998	$ 45,666

(1) General and administrative expenses for the six months ended June 30, 2011, and June 30, 2010, include approximately $11 million and $7 million, respectively, of noncash unit-based compensation expenses.

(2) This is a non-GAAP measure used by management to analyze the Company's performance. See "Non-GAAP Financial Measures" on page 40 for a reconciliation of the non-GAAP financial measure to its most directly comparable financial measure calculated and presented in accordance with GAAP.

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

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010	Variance
Average daily production:			
Natural gas (MMcf/d)	163	125	30 %
Oil (MBbls/d)	19.3	10.7	80 %
NGL (MBbls/d)	9.3	7.6	22 %
Total (MMcfe/d)	335	235	43 %
Weighted average prices (hedged): (1)			
Natural gas (Mcf)	$ 8.68	$ 8.86	(2)%
Oil (Bbl)	$ 88.35	$ 98.93	(11)%
NGL (Bbl)	$ 44.70	$ 40.81	10 %
Weighted average prices (unhedged): (2)			
Natural gas (Mcf)	$ 4.66	$ 4.61	1 %
Oil (Bbl)	$ 94.34	$ 73.37	29 %
NGL (Bbl)	$ 44.70	$ 40.81	10 %
Average NYMEX prices:			
Natural gas (MMBtu)	$ 4.22	$ 4.70	(10)%
Oil (Bbl)	$ 98.33	$ 78.37	25 %
Costs per Mcfe of production:			
Lease operating expenses	$ 1.69	$ 1.64	3 %
Transportation expenses	$ 0.20	$ 0.23	(13)%
General and administrative expenses (3)	$ 1.02	$ 1.12	(9)%
Depreciation, depletion and amortization	$ 2.40	$ 2.52	(5)%
Taxes, other than income taxes	$ 0.59	$ 0.48	23 %

(1) Includes the effect of realized gains on derivatives of approximately $98 million and approximately $146 million for the six months ended June 30, 2011, and June 30, 2010, respectively.

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

(3) General and administrative expenses for the six months ended June 30, 2011, and June 30, 2010, include approximately $11 million and $7 million, respectively, of noncash unit-based compensation expenses. Excluding these amounts, general and administrative expenses for the six months ended June 30, 2011, and June 30, 2010, were $0.85 per Mcfe and $0.95 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 $240 million or 80% to approximately $543 million for the six months ended June 30, 2011, from approximately $303 million for the six months ended June 30, 2010, due to higher commodity prices and higher production volumes. Higher oil, natural gas and NGL prices resulted in an increase in revenues of approximately $73 million, $1 million and $7 million, respectively.

Average daily production volumes increased to 335 MMcfe/d during the six months ended June 30, 2011, from 235 MMcfe/d during the six months ended June 30, 2010. Higher oil, natural gas and NGL production volumes resulted in an increase in revenues of approximately $114 million, $32 million and $13 million, respectively.

The following sets forth average daily production by region:

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010	Variance	
Average daily production (MMcfe/d):				
Mid-Continent Deep	152	129	23	18 %
Mid-Continent Shallow	62	66	(4)	(6)%
Permian Basin	67	16	51	328 %
Williston Basin	6	—	6	—
Michigan	34	10	24	242 %
California	14	14	—	2 %
	335	235	100	43 %

The 18% increase in average daily production volumes in the Mid-Continent Deep region primarily reflects the Company's 2010 and 2011 capital drilling programs in the Deep Granite Wash formation. The 6% decrease in average daily production volumes in the Mid-Continent Shallow region reflects downtime related to weather and third-party plant maintenance, and the effects of natural declines, partially offset by the results of the Company's drilling and optimization programs. Average daily production volumes in the Permian Basin region reflect the impact of the acquisitions in 2010 and 2011 and subsequent development capital spending. Average daily production volumes in the Williston Basin region reflect the impact of the acquisitions in 2011. Average daily production volumes in the Michigan region reflect the impact of the acquisitions in the second quarter and fourth quarter of 2010. The California region consists of a low-decline asset base and continues to produce at a consistent level.

Gains (Losses) on Oil and Natural Gas Derivatives
The Company determines the fair value of its oil and natural gas derivatives utilizing pricing models that use a variety of techniques, including market quotes and pricing analysis. See Item 7A. "Quantitative and Qualitative Disclosures About Market Risk," Note 7 and Note 8 for additional information about the Company's commodity derivatives. During the six months ended June 30, 2011, the Company had commodity derivative contracts for approximately 109% of its natural gas production and 105% of its oil production and recognized realized gains of approximately $98 million. During the six months ended June 30, 2010, the Company had commodity derivative contracts for approximately 126% of its natural gas production and 70% of its oil and NGL production and recognized realized gains of approximately $146 million. Unrealized gains and losses result from changes in market valuations of derivatives 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, unrealized losses are recognized; and if the expected future commodity prices decrease compared to the contract prices on the derivatives,

unrealized gains are recognized. During the first two quarters of 2011, expected future oil and natural gas prices increased, which resulted in net unrealized losses on derivatives of approximately $262 million for the six months ended June 30, 2011. During the first two quarters of 2010, expected future oil and natural gas prices decreased, which resulted in net unrealized gains on derivatives of approximately $74 million for the six months ended June 30, 2010. For information about the Company's credit risk related to derivative contracts, see "Counterparty Credit Risk" in "Liquidity and Capital Resources" below.

Expenses

Lease Operating Expenses
Lease operating expenses include expenses such as labor, field office, vehicle, supervision, maintenance, tools and supplies and workover expenses. Lease operating expenses increased approximately $32 million or 47% to approximately $102 million for the six months ended June 30, 2011, from approximately $70 million for the six months ended June 30, 2010. Lease operating expenses per Mcfe also increased to $1.69 per Mcfe for the six months ended June 30, 2011, from $1.64 per Mcfe for the six months ended June 30, 2010. Lease operating expenses increased primarily due to costs associated with properties acquired in the Permian Basin, Williston Basin and Michigan regions during 2010 and during the first two quarters of 2011 (see Note 2).

Transportation Expenses
Transportation expenses increased approximately $2 million or 25% to approximately $12 million for the six months ended June 30, 2011, from approximately $10 million for the six months ended June 30, 2010, primarily due to higher production volumes.

General and Administrative Expenses
General and administrative expenses are costs not directly associated with field operations and include costs of employees including executive officers, related benefits, office leases and professional fees. General and administrative expenses increased approximately $14 million or 30% to approximately $62 million for the six months ended June 30, 2011, from approximately $48 million for the six months ended June 30, 2010. The increase was primarily due to an increase in salaries and benefits expense of approximately $8 million, driven primarily by increased employee headcount due to recent acquisitions activity, an increase in unit-based compensation expense of approximately $3 million and an increase in professional services expense of approximately $2 million. General and administrative expenses per Mcfe decreased to $1.02 per Mcfe for the six months ended June 30, 2011, from $1.12 per Mcfe for the six months ended June 30, 2010.

Exploration Costs
Exploration costs decreased approximately $3 million or 75% to approximately $1 million for the six months ended June 30, 2011, from approximately $4 million for the six months ended June 30, 2010. The decrease was primarily due to lower impairment expense on unproved properties.

Depreciation, Depletion and Amortization
Depreciation, depletion and amortization increased approximately $39 million or 36% to approximately $146 million for the six months ended June 30, 2011, from approximately $107 million for the six months ended June 30, 2010. Higher total production levels and oil and natural gas property acquisitions were the primary reasons for the increased expense. Depreciation, depletion and amortization per Mcfe decreased to $2.40 per Mcfe for the six months ended June 30, 2011, from $2.52 per Mcfe for the six months ended June 30, 2010. The decrease per Mcfe is primarily due to higher reserves resulting from higher commodity prices and drilling activity in the Mid-Continent Deep region, including the Deep Granite Wash formation.

Taxes, Other Than Income Taxes
Taxes, other than income taxes, which consist primarily of severance and ad valorem taxes, increased approximately $15 million or 75% to approximately $36 million for the six months ended June 30, 2011, from approximately $21

million for the six months ended June 30, 2010. Severance taxes, which are a function of revenues generated from production, increased approximately $15 million compared to the six months ended June 30, 2010, primarily due to higher commodity prices and production volumes. Ad valorem taxes, which are based on the value of reserves and production equipment and vary by location, were essentially flat compared to the six months ended June 30, 2010.

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

Other Income and (Expenses)

	Six Months Ended June 30, 2011	2010	Variance
		(in thousands)	
Loss on extinguishment of debt	$ (94,372)	$ —	$ (94,372)
Interest expense, net of amounts capitalized	(125,825)	(73,622)	(52,203)
Realized losses on interest rate swaps	—	(8,021)	8,021
Realized losses on canceled interest rate swaps	—	(74,275)	74,275
Unrealized gains on interest rate swaps	—	25,889	(25,889)
Other, net	(4,718)	(4,292)	(426)
	$ (224,915)	$ (134,321)	$ (90,594)

Other income and (expenses) increased approximately $91 million for the six months ended June 30, 2011, compared to the six months ended June 30, 2010. Interest expense increased primarily due to higher interest rates and higher amortization of financing fees associated with the 2019 Senior Notes and the 2010 Issued Senior Notes, as defined in Note 6. Also during the six months ended June 30, 2011, the Company entered into a Fifth Amended and Restated Credit Facility, which also resulted in higher amortization of financing fees. In addition, for the six months ended June 30, 2011, the Company recorded a loss on extinguishment of debt of approximately $94 million as a result of the redemptions, cash tender offers and additional repurchases of a portion of the Original Senior Notes, as defined in Note 6. See "Debt" in "Liquidity and Capital Resources" below for additional details.

Income Tax Benefit (Expense)

The Company is a limited liability company treated as a partnership for federal and state income tax purposes, with the exception of the states of Texas and Michigan, with income tax liabilities and/or benefits of the Company passed through to unitholders. Limited liability companies are subject to state income taxes in Texas and Michigan. 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 expense of approximately $6 million for the six months ended June 30, 2011, and June 30, 2010.

Adjusted EBITDA

Adjusted EBITDA (a non-GAAP financial measure) increased approximately $148 million or 45% to approximately $474 million for the six months ended June 30, 2011, from approximately $326 million for the six months ended June 30, 2010. The increase was primarily due to higher production revenues resulting from higher production volumes and higher commodity prices, partially offset by higher expenses. 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.

Liquidity and Capital Resources

The Company utilizes funds from equity and debt offerings, bank borrowings and cash generated 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, 2011, the Company's capital expenditures, excluding acquisitions, were approximately $250 million. For 2011, the Company estimates its total capital expenditures, excluding acquisitions, will be approximately $630 million. Total capital expenditures include approximately $590 million related to the Company’s oil and natural gas capital program and $27 million related to its plant and pipeline capital. This estimate reflects amounts for the development of properties associated with

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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 cash on hand.

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 2019 Senior Notes, 2010 Issued Senior Notes and Original Senior Notes impose certain restrictions on the Company's ability to obtain additional debt financing. Based upon current expectations, the Company believes liquidity and capital resources will be sufficient to conduct its business and operations.

Statements of Cash Flows

The following is a comparative cash flow summary:

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010	Variance
		(in thousands)	
Net cash:			
Provided by operating activities (1)	$ 303,762	$ 75,183	$ 228,579
Used in investing activities	(1,081,736)	(841,085)	(240,651)
Provided by financing activities	611,741	953,412	(341,671)
Net increase (decrease) in cash and cash equivalents	$ (166,233)	$ 187,510	$ (353,743)

(1) The six months ended June 30, 2010, includes premiums paid for commodity derivatives of approximately $91 million.

Operating Activities

Cash provided by operating activities for the six months ended June 30, 2011, was approximately $304 million, compared to approximately $75 million for the six months ended June 30, 2010. The increase was primarily due to higher net income, excluding noncash mark-to-market activities related to derivatives contracts and other noncash items, partially offset by higher working capital needs. During the six months ended June 30, 2011, no premiums were paid for derivative contracts; however, approximately $91 million of premiums were paid for derivative contracts during the same period in 2010.

Premiums paid during the six months ended June 30, 2010, related to commodity derivative contracts that hedge future production and were primarily funded through the Company's Credit Facility. These derivative contracts provide the Company long-term cash flow predictability to manage its business, service debt and pay distributions. The production volumes attributed to the derivative contracts the Company enters into in the future will be directly related to expected future production. See Note 7 and Note 8 for additional details about the Company's commodity derivatives.

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

Investing Activities

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

	Six Months Ended June 30, 2011	2010
	(in thousands)	
Cash flow from investing activities:		
Acquisition of oil and natural gas properties, net of cash acquired	$ (847,780)	$ (771,189)
Capital expenditures	(244,546)	(70,482)
Proceeds from sale of properties and equipment and other	10,590	586
	$ (1,081,736)	$ (841,085)

The primary use of cash in investing activities is for capital spending. Cash used in investing activities for the six months ended June 30, 2011, primarily relates to the acquisitions of properties in the Williston Basin, Permian Basin and Mid-Continent Deep regions. The six months ended June 30, 2011, also includes the returned deposit of approximately $9 million related to a terminated purchase and sale agreement. See Note 2 for additional details.

Capital expenditures were higher for the six months ended June 30, 2011, compared to the same period in 2010, primarily due to an increase in drilling activities in the Mid-Continent Deep and Permian Basin regions. Excluding acquisitions, capital expenditures for full year 2011 are expected to be approximately $630 million.

Financing Activities

Cash provided by financing activities was approximately $612 million for the six months ended June 30, 2011, compared to approximately $953 million for the six months ended June 30, 2010. The decrease in financing cash flows was primarily attributable to lower proceeds from borrowings, higher financing and offering expenses, including expenses related to the extinguishment of debt, and higher distributions to unitholders, partially offset by higher proceeds from the sale of units by the Company in March 2011, as described below, and lower repayments of debt. The following provides a comparative summary of proceeds from borrowings and repayments of debt:

	Six Months Ended June 30, 2011	2010
	(in thousands)	
Proceeds from borrowings:		
Credit facility	$ 615,000	$ 920,000
Senior notes	744,240	1,268,176
	$ 1,359,240	$ 2,188,176
Repayments of debt:		
Credit facility	$ (615,000)	$ (1,420,000)
Senior notes	(449,679)	
	$ (1,064,679)	$ (1,420,000)

Debt

On May 2, 2011, the Company entered into a Fifth 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 $1.5 billion. The initial borrowing base under the Credit Facility was $2.5 billion, and was reduced to $2.3 billion as a result of the issuance of the 2019 Senior Notes (see Note 6), and the maturity date has been extended from April 2015 to April 2016. At June 30, 2011, available borrowing capacity was $1.5 billion, which includes a $4 million reduction in availability for outstanding letters of credit. In addition, on May 13, 2011, the Company issued $750 million in aggregate principal amount of 6.50% senior notes due 2019 and received net proceeds of approximately $729 million. In March 2011, in accordance with the provisions of the indentures related to the 2017 Senior Notes and the 2018 Senior Notes, the Company redeemed 35%, or $87 million and $90 million, respectively, of each of the original aggregate principal amount of the 2017 Senior Notes and 2018 Senior Notes.

On February 28, 2011, the Company commenced cash tender offers and related consent solicitations to purchase any and all of its outstanding 2017 Senior Notes and 2018 Senior Notes. In March 2011, the Company accepted and purchased: 1) $105 million of the aggregate principal amount of the outstanding 2017 Senior Notes (or 65% of the remaining outstanding principal amount of 2017 Senior Notes), and 2) $126 million of the aggregate principal amount of the outstanding 2018 Senior Notes (or 76% of the remaining outstanding principal amount of 2018 Senior Notes).

In June 2011, the Company repurchased an additional portion of its remaining outstanding 2017 Senior Notes and 2018 Senior Notes for $17 million (or 29% of the remaining outstanding principal amount of the 2017 Senior Notes) and $24 million (or 61% of the remaining outstanding principal amount of the 2018 Senior Notes), respectively. After giving effect to the tender offers and subsequent repurchases of the 2017 Senior Notes and the 2018 Senior Notes, aggregate principal amounts of $41 million and $16 million, respectively, remain outstanding at June 30, 2011.

The Company depends, in part, on its Credit Facility for future capital needs. In addition, the Company has drawn on the Credit Facility to fund or partially fund quarterly cash distribution payments, since it uses operating cash flow primarily for investing activities and borrows as cash is needed. Absent such borrowings, the Company would have at times experienced a shortfall in cash available to pay the declared quarterly cash distribution amount. If an event of default occurs and is continuing under the Credit Facility, the Company would be unable to make borrowings to fund distributions. For additional information about this matter and other risk factors that could affect the Company, see Item 1A. "Risk Factors."

Counterparty Credit Risk

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

Public Offering of Units

In March 2011, the Company sold 16,726,067 units representing limited liability company interests at $38.80 per unit ($37.248 per unit, net of underwriting discount) for net proceeds of approximately $623 million (after underwriting discount and offering expenses of approximately $26 million). The Company used the net proceeds from the sale of these units to fund the March 2011 redemptions of a portion of the outstanding 2017 Senior Notes and 2018 Senior

Notes and to fund the cash tender offers and related expenses for a portion of the remaining 2017 Senior Notes and 2018 Senior Notes (see Note 6). The Company used the remaining net proceeds from the sale of units to finance a portion of the March 31, 2011, acquisition in the Williston Basin.

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

Distributions

Under the Company's limited liability company agreement, the Company's unitholders are entitled to receive a quarterly distribution of available cash to the extent there is sufficient cash from operations after establishment of cash reserves and payment of fees and expenses. The following provides a summary of distributions paid by the Company during the six months ended June 30, 2011:

Date Paid	Period Covered by Distribution	Distribution Per Unit	Total Distribution (in millions)
February 2011	October 1 – December 31, 2010	$ 0.66	$ 106
May 2011	January 1 – March 31, 2011	$ 0.66	$ 116

On July 26, 2011, the Company's Board of Directors declared a cash distribution of $0.69 per unit, or $2.76 per unit on an annualized basis, with respect to the second quarter of 2011, which represents a 5% increase over the previous quarter. The distribution, totaling approximately $122 million, will be paid on August 12, 2011, to unitholders of record as of the close of business on August 5, 2011.

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 in this dispute is ongoing and is not complete. As a result, the Company is unable to estimate a possible loss, or range of possible loss, if any. In addition, the Company is involved in various other disputes arising in the ordinary course of business. The Company is not currently a party to any litigation or pending claims that it believes would have a material adverse effect on its overall business, financial position, results of operations or liquidity; however, cash flow could be significantly impacted in the reporting periods in which such matters are resolved.

During the six months ended June 30, 2011, and June 30, 2010, the Company made no significant payments to settle any legal, environmental or tax proceedings. The Company regularly analyzes current information and accrues for probable liabilities on the disposition of certain matters as necessary. Liabilities for loss contingencies arising from claims, assessments, litigation or other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated.

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 2010 Annual Report on Form 10-K. With the exception of: (i) entering into the Fifth Amended and Restated Credit Agreement that provides a $1.5 billion maximum commitment amount and extends the maturity from April 2015 to April 2016; (ii) the issuance of $750 million in aggregate principal amount of 6.50% Senior Notes due 2019; and (iii) the redemptions, cash tender offers and related consent solicitations and additional repurchases in which the Company purchased 84% and 94% of the outstanding principal amounts of 2017 Senior Notes and 2018 Senior Notes, respectively, there have been no significant changes to the Company's contractual obligations from December 31, 2010. 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 adjusted net income, as defined by the Company, may not be comparable to similarly titled measures used by other companies. Therefore, these non-GAAP measures should be considered in conjunction with net income and other performance measures prepared in accordance with GAAP, such as operating income or cash flow from operating activities. Adjusted EBITDA and adjusted net income should not be considered in isolation or as a substitute for GAAP measures, such as net income, operating income or any other GAAP measure of liquidity or financial performance.

Adjusted EBITDA (Non-GAAP Measure)

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

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

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

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

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

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(in thousands)			
Net income (loss)	$ 237,109	$ 59,786	$ (209,573)	$ 125,096
Plus:				
Net operating cash flow from acquisitions and divestitures, effective date through closing date	29,308	13,126	36,359	18,517
Interest expense, cash	61,591	17,941	125,181	39,693
Interest expense, noncash	770	28,028	644	33,929
Depreciation, depletion and amortization	79,345	57,941	145,711	107,132
Write-off of deferred financing fees and other	1,189	2,076	1,189	2,076
(Gains) losses on sale of assets and other, net	(93)	256	(916)	670
Provision for legal matters	248	—	740	—
Loss on extinguishment of debt	9,810	—	94,372	—
Unrealized (gains) losses on commodity derivatives	(163,434)	(40,631)	261,851	(74,131)
Unrealized gains on interest rate derivatives	—	(41,030)	—	(25,889)
Realized losses on interest rate derivatives	—	—	—	8,021
Realized losses on canceled derivatives	—	74,275	—	74,275
Unit-based compensation expenses	5,543	3,265	11,181	7,400
Exploration costs	550	155	995	4,016
Income tax (benefit) expense	1,670	(215)	5,868	5,677
Adjusted EBITDA	$ 263,606	$ 174,973	$ 473,602	$ 326,482

The following presents a reconciliation of net cash provided by operating activities to adjusted EBITDA:

Net cash provided by operating activities for the three months ended June 30, 2011, was approximately $196 million and includes cash interest payments of approximately $61 million and other items totaling approximately $7 million that are not included in adjusted EBITDA. Net cash used in operating activities for the three months ended June 30, 2010, was approximately $(5) million and includes cash interest payments of approximately $18 million, premiums paid for commodity derivatives of approximately $76 million, realized losses on canceled derivatives of approximately $74 million and other items totaling approximately $12 million that are not included in adjusted EBITDA. Net cash provided by operating activities for the six months ended June 30, 2011, was approximately $304 million and includes cash interest payments of approximately $124 million and other items totaling approximately $46 million that are not included in adjusted EBITDA. Net cash provided by operating activities for the six months ended June 30, 2010, was approximately $75 million and includes cash interest payments of approximately $39 million, cash settlements on interest rate derivatives of approximately $11 million, premiums paid for commodity derivatives of approximately $91 million, realized losses on canceled derivatives of approximately $74 million and other items totaling approximately $36 million that are not included in adjusted EBITDA.

Adjusted Net Income (Non-GAAP Measure)

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

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

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

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(in thousands, except per unit amounts)			
Net income (loss)	$ 237,109	$ 59,786	$ (209,573)	$ 125,096
Plus:				
Unrealized (gains) losses on commodity derivatives	(163,434)	(40,631)	261,851	(74,131)
Unrealized gains on interest rate derivatives	—	(41,030)	—	(25,889)
Realized losses on canceled derivatives	—	74,275	—	74,275
Loss on extinguishment of debt	9,810		94,372	
(Gains) losses on sale of assets, net	(128)	233	(986)	647
Adjusted net income	$ 83,357	$ 52,633	$ 145,664	$ 99,998
Net income (loss) per unit – basic	$ 1.34	$ 0.41	$ (1.25)	$ 0.90
Plus, per unit:				
Unrealized (gains) losses on commodity derivatives	(0.93)	(0.27)	1.56	(0.52)
Unrealized gains on interest rate derivatives	—	(0.28)	—	(0.19)
Realized losses on canceled derivatives	—	0.50	—	0.53
Loss on extinguishment of debt	0.06		0.56	
(Gains) losses on sale of assets, net	—		(0.01)	
Adjusted net income per unit – basic	$ 0.47	$ 0.36	$ 0.86	$ 0.72

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 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 Not Yet Adopted

There are no recently issued accounting standards not yet adopted that the Company expects will have a material impact to its results of operations or financial position.

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

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;
- financial strategy;
- 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, 2010, 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.

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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 2010 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

The Company enters into derivative contracts with respect to a portion of its projected production through various transactions that provide an economic hedge of the risk related to the future prices received. The Company does not enter into derivative contracts for trading purposes (see Note 7). At June 30, 2011, the fair value of contracts that settle during the next 12 months was an asset of approximately $124 million and a liability of $6 million for a net asset of approximately $118 million. A 10% increase in the index oil and natural gas prices above the June 30, 2011, prices for the next 12 months would result in a net asset of approximately $19 million which represents a decrease in the fair value of approximately $99 million; conversely, a 10% decrease in the index oil and natural gas prices would result in a net asset of approximately $219 million which represents an increase in the fair value of approximately $101 million.

Counterparty Credit Risk

The Company accounts for its commodity derivatives and, when applicable, 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, 2011, the average public bond yield spread utilized to estimate the impact of the Company’s credit risk on derivative liabilities was approximately 3.28%. A 1% increase in the average public bond yield spread would result in an estimated $14 million increase in net income (loss) for the six months ended June 30, 2011. At June 30, 2011, the credit default swap spreads utilized to estimate the impact of counterparties’ credit risk on derivative assets ranged between 0% and 2.58%. A 1% increase in each of the counterparties’ credit default swap spreads would result in an estimated $1 million decrease in net income (loss) for the six months ended June 30, 2011.

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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, 2011.

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 2011 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 general 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, 2010. 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 SEC.

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 units during the six months ended June 30, 2011. At June 30, 2011, approximately $74 million was available for unit repurchase under the program.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Reserved

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
2.1*†	—	Purchase and Sale Agreement, dated May 4, 2011, between Linn Energy Holdings, LLC, as purchaser, and Panther Energy Company, LLC and Red Willow Mid-Continent, LLC, as sellers
4.1	—	Indenture, dated May 13, 2011, among Linn Energy, LLC, Linn Energy Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.1 to Current Report on Form 8-K filed on May 16, 2011)
4.2	—	Registration Rights Agreement, dated May 13, 2011, among Linn Energy, LLC, Linn Energy Finance Corp., the Subsidiary Guarantors named therein and the representatives of the Initial Purchasers named therein (incorporated herein by reference to Exhibit 4.2 to Current Report on Form 8-K filed on May 16, 2011)
10.1*	—	Fifth Amended and Restated Credit Agreement dated as of May 2, 2011, among Linn Energy, LLC as Borrower, BNP Paribas, as Administrative Agent, and the Lenders and agents Party thereto
10.2*	—	Fifth Amended and Restated Guaranty and Pledge Agreement, dated as of May 2, 2011, made by Linn Energy, LLC and each of the other Obligors in favor of BNP Paribas, as Administrative Agent thereto
31.1*	—	Section 302 Certification of Mark E. Ellis, 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, 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.

† The schedules to this agreement have been omitted from this filing pursuant to Item 601(b)(2) of Regulation S-K. The Company will furnish copies of such schedules to the Securities and Exchange Commission upon request.

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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: July 28, 2011

/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)