LINN ENERGY, LLC
Form 10-K
February 23, 2012

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

Form 10-K

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

For the fiscal year ended December 31, 2011

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

Commission file number: 000-51719

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

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

Registrant's telephone number, including area code
(281) 840-4000
Securities registered pursuant to Section 12(b) of the Act:

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

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes x No o

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 o

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

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 o Non-accelerated filer o Smaller reporting company o

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

The aggregate market value of voting and non-voting common equity held by non-affiliates of the registrant was approximately $6.8 billion on June 30, 2011, based on $39.07 per unit, the last reported sales price of the units on The NASDAQ Global Select Market on such date.

As of January 31, 2012, there were 199,366,666 units outstanding.

Documents Incorporated By Reference:

Certain information called for in Items 10, 11, 12, 13 and 14 of Part III are incorporated by reference from the registrant's definitive proxy statement for the annual meeting of unitholders to be held on April 24, 2012.

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GLOSSARY OF TERMS

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

Basin. A large area with a relatively thick accumulation of sedimentary rocks.

Bbl. One stock tank barrel or 42 United States (“U.S.”) gallons liquid volume.

Bcf. One billion cubic feet.

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

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

Development well. A well drilled within the proved area of a reservoir to the depth of a stratigraphic horizon known to be productive.

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

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

Formation. A stratum of rock that is recognizable from adjacent strata consisting mainly of a certain type of rock or combination of rock types with thickness that may range from less than two feet to hundreds of feet.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

MBbls. One thousand barrels of oil or other liquid hydrocarbons.

MBbls/d. MBbls per day.

Mcf. One thousand cubic feet.

Mcfe. One thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of oil, condensate or natural gas liquids.

MMBbls. One million barrels of oil or other liquid hydrocarbons.

MMBoe. One million barrels of oil equivalent, determined using a ratio of one Bbl of oil, condensate or natural gas liquids to six Mcf.

MMBtu. One million British thermal units.

MMcf. One million cubic feet.

MMcf/d. MMcf per day.

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

MMcfe/d. MMcfe per day.

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GLOSSARY OF TERMS - Continued

MMMBtu. One billion British thermal units.

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

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

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

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

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

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

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

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

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

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

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

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GLOSSARY OF TERMS - Continued

Standardized measure of discounted future net cash flows. The present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with the regulations of the Securities and Exchange Commission, without giving effect to non-property related expenses such as general and administrative expenses, debt service, future income tax expenses or depreciation, depletion and amortization; discounted using an annual discount rate of 10%.

Tcfe. One trillion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of oil, condensate or natural gas liquids.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil, natural gas and NGL regardless of whether such acreage contains proved reserves.

Unproved reserves. Reserves that are considered less certain to be recovered than proved reserves. Unproved reserves may be further sub-classified to denote progressively increasing uncertainty of recoverability and include probable reserves and possible reserves.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.

Workover. Maintenance on a producing well to restore or increase production.

Zone. A stratigraphic interval containing one or more reservoirs.

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Part I

Item 1. Business

This Annual Report on Form 10-K contains forward-looking statements based on expectations, estimates and projections as of the date of this filing. These statements by their nature are subject to risks, uncertainties and assumptions and are influenced by various factors. As a consequence, actual results may differ materially from those expressed in the forward-looking statements. For more information, see "Forward-Looking Statements" included at the end of this Item 1. "Business" and see also Item 1A. "Risk Factors."

References

When referring to Linn Energy, LLC ("LINN Energy" or the "Company"), the intent is to refer to LINN Energy and its consolidated subsidiaries as a whole or on an individual basis, depending on the context in which the statements are made.

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

Overview

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

Proved reserves at December 31, 2011, were 3,370 Bcfe, of which approximately 34% were oil, 50% were natural gas and 16% were natural gas liquids ("NGL"). Approximately 60% were classified as proved developed, with a total standardized measure of discounted future net cash flows of $6.6 billion. At December 31, 2011, the Company operated 7,759 or 69% of its 11,230 gross productive wells and had an average proved reserve-life index of approximately 22 years, based on the December 31, 2011, reserve report and fourth quarter 2011 annualized production.

Strategy

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

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

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

Grow Through Acquisition of Long-Life, High Quality Properties

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

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Since January 1, 2007, excluding three acquisitions of Appalachian Basin properties sold in July 2008, the Company has completed 33 acquisitions of working and royalty interests in oil and natural gas properties and related gathering and pipeline assets. Total acquired proved reserves were approximately 2.8 Tcfe at the date of acquisition with acquisition costs of approximately $2.26 per Mcfe. The Company finances acquisitions with a combination of funds from equity and debt offerings, bank borrowings and cash flow from operations. See Note 2 for additional details about the Company's acquisitions and divestitures.

Efficiently Operate and Develop Acquired Properties

The Company has centralized the operation of its acquired properties into defined operating regions to minimize operating costs and maximize production and capital efficiency. The Company maintains a large inventory of drilling and optimization projects within each region to achieve organic growth from its capital development program. The Company generally seeks to be the operator of its properties so that it can develop drilling programs and optimization projects that not only replace production, but add value through reserve and production growth and future operational synergies. The development program is focused on lower-risk, repeatable drilling opportunities to maintain and/or grow cash flow. Many of the wells are completed in multiple producing zones with commingled production and long economic lives. In addition, the Company seeks to deliver attractive financial returns by leveraging its experienced workforce and scalable infrastructure. For 2012, the Company estimates its total capital expenditures, excluding acquisitions, will be approximately $940 million, including $880 million related to its oil and natural gas capital program and $40 million related to its plant and pipeline capital. This estimate is under continuous review and is subject to ongoing adjustments. The Company expects to fund these capital expenditures primarily with cash flow from operations and bank borrowings.

Reduce Cash Flow Volatility Through Hedging

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

These commodity hedging transactions are primarily in the form of swap contracts and put options that are designed to provide a fixed price (swap contracts) or fixed price floor with the opportunity for upside (put options) that the Company will receive as compared to floating market prices. The Company has derivative contracts in place for 2011 through 2016 at average prices ranging from a low of $95.39 per Bbl to a high of $98.44 per Bbl for oil and from a low of $5.00 per MMBtu to a high of $5.84 per MMBtu for natural gas. See Note 7 for the specific years and the related commodity prices. 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 and its timing risk exposure on Mid-Continent and Permian Basin oil sales through 2014. For additional details about the Company's commodity derivative contracts, see Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Item 7A. "Quantitative and Qualitative Disclosures About Market Risk." See also Note 7 and Note 8.

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

Recent Developments

Acquisitions

On December 15, 2011, the Company completed the acquisition of certain oil and natural gas properties located primarily in the Granite Wash of Texas and Oklahoma from Plains Exploration & Production Company ("Plains") for total consideration of approximately $544 million. The acquisition included approximately 51 MMBoe (306 Bcfe) of proved reserves as of the acquisition date.

On November 1, 2011, and November 18, 2011, the Company completed two acquisitions of certain oil and natural gas properties located in the Permian Basin for total consideration of approximately $110 million. The acquisitions included approximately 7 MMBoe (42 Bcfe) of proved reserves as of the acquisition dates.

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 $223 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 located in the Williston Basin for total consideration of approximately $153 million. The acquisitions included approximately 6 MMBoe (35 Bcfe) of proved reserves as of the acquisition dates.

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 dates.

On March 31, 2011, the Company completed the acquisition of certain oil and natural gas properties located in the Williston Basin from an affiliate of Concho Resources Inc. ("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 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 $38 million in total consideration for these properties.

Proved reserves as of the acquisition date for all of the above referenced acquisitions were estimated using the average oil and natural gas prices during the preceding 12-month period, determined as an unweighted average of the first-day-of-the-month prices for each month.

The Company regularly engages in discussions with potential sellers regarding acquisition opportunities. Such acquisition efforts may involve its participation in auction processes, as well as situations in which the Company believes it is the only party or one of a very limited number of potential buyers in negotiations with the potential seller. These acquisition efforts can involve assets that, if acquired, would have a material effect on its financial condition and results of operations.

Distributions

On January 27, 2012, 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 fourth quarter of 2011. The distribution, totaling approximately $138 million, was paid on February 14, 2012, to unitholders of record as of the close of business on February 7, 2012.

Operating Regions

The Company's properties are located in six operating regions in the 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;
- Michigan, which includes the Antrim Shale formation in the northern part of the state;
- California, which includes the Brea Olinda Field of the Los Angeles Basin; and
- Williston Basin, which includes the Bakken formation in North Dakota.

Mid-Continent Deep

The Mid-Continent Deep region includes properties in the Deep Granite Wash formation in the Texas Panhandle, which produces at depths ranging from 10,000 feet to 16,000 feet, as well as properties in Oklahoma and Kansas, which produce at depths of more than 8,000 feet. Mid-Continent Deep proved reserves represented approximately 47% of total proved reserves at December 31, 2011, of which 49% were classified as proved developed reserves. This region produced 172 MMcfe/d or 47% of the Company's 2011 average daily production. During 2011, the Company invested approximately $268 million to drill in this region. During 2012, the Company anticipates spending approximately 65% of its total oil and natural gas capital budget for development activities in the Mid-Continent Deep region, primarily in the Deep Granite Wash formation.

To more efficiently transport its natural gas in the Mid-Continent Deep region to market, the Company owns and operates a network of natural gas gathering systems comprised of approximately 285 miles of pipeline and associated compression and metering facilities that connect to numerous sales outlets in the Texas Panhandle.

Mid-Continent Shallow

The Mid-Continent Shallow region includes properties producing from the Brown Dolomite formation in the Texas Panhandle, which produces at depths of approximately 3,200 feet, as well as properties in Oklahoma, Louisiana and Illinois, which produce at depths of less than 8,000 feet. Mid-Continent Shallow proved reserves represented approximately 20% of total proved reserves at December 31, 2011, of which 70% were classified as proved developed reserves. This region produced 63 MMcfe/d or 17% of the Company's 2011 average daily production. During 2011, the Company invested approximately $9 million to drill in this region. During 2012, the Company anticipates spending approximately 2% of its total oil and natural gas capital budget for development activities in the Mid-Continent Shallow region.

To more efficiently transport its natural gas in the Mid-Continent Shallow region to market, the Company owns and operates a network of natural gas gathering systems comprised of approximately 665 miles of pipeline and associated compression and metering facilities that connect to numerous sales outlets in the Texas Panhandle.

Permian Basin

The Permian Basin is one of the largest and most prolific oil and natural gas basins in the U.S. The Company's properties are located in West Texas and Southeast New Mexico and produce at depths ranging from 2,000 feet to 12,000 feet. Permian Basin proved reserves represented approximately 16% of total proved reserves at December 31, 2011, of which 56% were classified as proved developed reserves. This region produced 73 MMcfe/d or 20% of the Company's 2011 average daily production. During 2011, the Company invested approximately $255 million to drill in this region. During 2012, the Company anticipates spending approximately 25% of its total oil and natural gas capital budget for development activities in the Permian Basin region, primarily in the Wolfberry trend.

Michigan

The Michigan region includes properties producing from the Antrim Shale formation in the northern part of the state, which produces at depths ranging from 600 feet to 2,200 feet. Michigan proved reserves represented approximately 9% of total proved reserves at December 31, 2011, of which 90% were classified as proved developed reserves. This region produced 35 MMcfe/d or 9% of the Company's 2011 average daily production. During 2011, the Company invested approximately $3 million to drill in this region. During 2012, the Company anticipates spending approximately 1% of its total oil and natural gas capital budget for development activities in the Michigan region.

California

The California region consists of the Brea Olinda Field of the Los Angeles Basin. The Brea Olinda Field was discovered in 1880 and produces from the shallow Pliocene formation to the deeper Miocene formation at depths ranging from 1,000 feet to 7,500 feet. California proved reserves represented approximately 6% of total proved reserves at December 31, 2011, of which 93% were classified as proved developed reserves. This region produced 14 MMcfe/d or 4% of the Company's 2011 average daily production. During 2011, the Company invested approximately $6 million to drill in this region. During 2012, the Company anticipates spending approximately 1% of its total oil and natural gas capital budget for development activities in the California region.

Williston Basin

The Williston Basin is one of the premier oil basins in the U.S. The Company's properties are located in North Dakota and produce at depths ranging from 9,000 feet to 12,000 feet. Williston Basin proved reserves represented approximately 2% of total proved reserves at December 31, 2011, of which 48% were classified as proved developed reserves. This region produced 12 MMcfe/d or 3% of the Company's 2011 average daily production. During 2011, the Company invested approximately $39 million to drill in this region. During 2012, the Company anticipates spending approximately 6% of its total oil and natural gas capital budget for development activities in the Williston Basin region.

Drilling and Acreage

The following sets forth the wells drilled in the Mid-Continent Deep, Mid-Continent Shallow, Permian Basin, Michigan, California and Williston Basin operating regions during the periods indicated ("gross" refers to the total wells in which the Company had a working interest and "net" refers to gross wells multiplied by the Company's working interest):

	Year Ended December 31,		
	2011	2010	2009
Gross wells:			
Productive	292	138	72
Dry	2	1	1
	294	139	73
Net development wells:			
Productive	186	116	35
Dry	2	1	1
	188	117	36
Net exploratory wells:			
Productive	—	—	—
Dry	—	—	—
	—	—	—

The totals above do not include 8 and 25 lateral segments added to existing vertical wellbores in the Mid-Continent Shallow region during the years ended December 31, 2010, and December 31, 2009, respectively. There were no lateral segments added to existing vertical wellbores during the year ended December 31, 2011. At December 31, 2011, the Company had 85 gross (51 net) wells in process (no wells were temporarily suspended).

This information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled and the quantities or economic value of

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reserves found. Productive wells are those that produce commercial quantities of oil, natural gas or NGL, regardless of whether they generate a reasonable rate of return.

The following sets forth information about the Company’s drilling locations and net acres of leasehold interests as of December 31, 2011:

	Total (1)
Proved undeveloped	2,302
Other locations	4,154
Total drilling locations	6,456
Leasehold interests – net acres (in thousands)	1,116

(1) Does not include optimization projects.

As shown in the table above, as of December 31, 2011, the Company had 2,302 proved undeveloped drilling locations (specific drilling locations as to which the independent engineering firm, DeGolyer and MacNaughton, assigned proved undeveloped reserves as of such date) and the Company had identified 4,154 additional unproved drilling locations (specific drilling locations as to which DeGolyer and MacNaughton has not assigned any proved reserves) on acreage that the Company has under existing leases. As successful development wells frequently result in the reclassification of adjacent lease acreage from unproved to proved, the Company expects that a significant number of its unproved drilling locations will be reclassified as proved drilling locations prior to the actual drilling of these locations.

Productive Wells

The following sets forth information relating to the productive wells in which the Company owned a working interest as of December 31, 2011. Productive wells consist of producing wells and wells capable of production, including wells awaiting pipeline or other connections to commence deliveries. “Gross” wells refers to the total number of producing wells in which the Company has an interest, and “net” wells refers to the sum of its fractional working interests owned in gross wells. The number of wells below does not include approximately 2,500 productive wells in which the Company owns a royalty interest only.

	Natural Gas Wells		Oil Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Operated (1)	3,889	2,925	3,870	3,578	7,759	6,503
Nonoperated (2)	1,843	369	1,628	207	3,471	576
	5,732	3,294	5,498	3,785	11,230	7,079

(1) The Company had 12 operated wells with multiple completions at December 31, 2011.

(2) The Company had no nonoperated wells with multiple completions at December 31, 2011.

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Developed and Undeveloped Acreage

The following sets forth information relating to leasehold acreage as of December 31, 2011:

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
	(in thousands)					
Leasehold acreage	2,352	1,060	133	56	2,485	1,116

Production, Price and Cost History

The Company's natural gas production is primarily sold under market sensitive price contracts, which typically sell at a differential to the New York Mercantile Exchange ("NYMEX"), Panhandle Eastern Pipeline ("PEPL"), El Paso Permian Basin, or Mich Con city-gate natural gas prices due to the Btu content and the proximity to major consuming markets. The Company's natural gas production is sold to purchasers under percentage-of-proceeds contracts, percentage-of-index contracts or spot price contracts. By the terms of the percentage-of-proceeds contracts, the Company receives a percentage of the resale price received by the purchaser for sales of residual natural gas and NGL recovered after transportation and processing of natural gas. These purchasers sell the residual natural gas and NGL based primarily on spot market prices. Under percentage-of-index contracts, the price per MMBtu the Company receives for natural gas is tied to indexes published in Gas Daily or Inside FERC Gas Market Report. Although exact percentages vary daily, as of December 31, 2011, approximately 90% of the Company's natural gas and NGL production was sold under short-term contracts at market-sensitive or spot prices. At December 31, 2011, the Company had natural gas throughput delivery commitments under long-term contracts of approximately 784 MMcf for the year ended December 31, 2012, and approximately 31 Bcf to be delivered by August 2015.

The Company's oil production is primarily sold under market sensitive contracts, which typically sell at a differential to NYMEX, and as of December 31, 2011, approximately 90% of its oil production was sold under short-term contracts. At December 31, 2011, the Company had no delivery commitments for oil production.

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

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

	Year Ended December 31,		
	2011	2010	2009
Average daily production:			
Natural gas (MMcf/d)	175	137	125
Oil (MBbls/d)	21.5	13.1	9.0
NGL (MBbls/d)	10.8	8.3	6.5
Total (MMcfe/d)	369	265	218
Weighted average prices (hedged): (1)			
Natural gas (Mcf)	$ 8.20	$ 8.52	$ 8.27
Oil (Bbl)	$ 89.21	$ 94.71	$ 110.94
NGL (Bbl)	$ 42.88	$ 39.14	$ 28.04
Weighted average prices (unhedged): (2)			
Natural gas (Mcf)	$ 4.35	$ 4.24	$ 3.51
Oil (Bbl)	$ 91.24	$ 75.16	$ 55.25
NGL (Bbl)	$ 42.88	$ 39.14	$ 28.04
Average NYMEX prices:			
Natural gas (MMBtu)	$ 4.05	$ 4.40	$ 3.99
Oil (Bbl)	$ 95.12	$ 79.53	$ 61.94
Costs per Mcfe of production:			
Lease operating expenses	$ 1.73	$ 1.64	$ 1.67
Transportation expenses	$ 0.21	$ 0.20	$ 0.23
General and administrative expenses (3)	$ 0.99	$ 1.02	$ 1.08
Depreciation, depletion and amortization	$ 2.48	$ 2.46	$ 2.53
Taxes, other than income taxes	$ 0.58	$ 0.47	$ 0.35

(1) Includes the effect of realized gains on derivatives of approximately $230 million (excluding $27 million realized gains on canceled contracts), $308 million and $401 million (excluding $49 million realized net gains on canceled contracts) for the years ended December 31, 2011, December 31, 2010, and December 31, 2009, respectively.

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

(3) General and administrative expenses for the years ended December 31, 2011, December 31, 2010, and December 31, 2009, include approximately $21 million, $13 million and $15 million, respectively, of noncash unit-based compensation expenses. Excluding these amounts, general and administrative expenses for the years ended December 31, 2011, December 31, 2010, and December 31, 2009, were $0.83 per Mcfe, $0.88 per Mcfe and $0.90 per Mcfe, respectively. This measure is not in accordance with U.S. Generally Accepted Accounting Principles ("GAAP") and thus is a non-GAAP measure, used by management to analyze the Company's performance.

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Reserve Data

Proved Reserves

The following sets forth estimated proved oil, natural gas and NGL reserves and the standardized measure of discounted future net cash flows at December 31, 2011, based on reserve reports prepared by independent engineers, DeGolyer and MacNaughton:

Estimated proved developed reserves:			
Natural gas (Bcf)		998	
Oil (MMBbls)		125	
NGL (MMBbls)		48	
Total (Bcfe)		2,034	
Estimated proved undeveloped reserves:			
Natural gas (Bcf)		677	
Oil (MMBbls)		64	
NGL (MMBbls)		46	
Total (Bcfe)		1,336	
Estimated total proved reserves (Bcfe)		3,370	
Proved developed reserves as a percentage of total proved reserves		60	%
Standardized measure of discounted future net cash flows (in millions) (1)	$	6,615	
Representative NYMEX prices: (2)			
Natural gas (MMBtu)	$	4.12	
Oil (Bbl)	$	95.84	

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

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

During the year ended December 31, 2011, the Company’s proved undeveloped reserves (“PUDs”) increased to 1,336 Bcfe from 935 Bcfe at December 31, 2010, representing an increase of 401 Bcfe. The increase was primarily due to 364 Bcfe added as a result of the Company’s acquisitions in the Mid-Continent Deep, Permian Basin and Williston Basin regions and 346 Bcfe added as a result of its drilling activities in the Texas Panhandle Granite Wash, partially offset by PUDs developed during 2011.

During the year ended December 31, 2011, the Company incurred approximately $307 million in capital expenditures to convert 178 Bcfe of reserves classified as PUDs at December 31, 2010. Based on the December 31, 2011 reserve report, the amounts of capital expenditures estimated to be incurred in 2012, 2013 and 2014 to develop the Company’s PUDs are approximately $765 million, $836 million and $556 million, respectively. The amount and timing of these expenditures will depend on a number of factors, including actual drilling results, service costs and product prices. Of the 1,336 Bcfe of PUDs at December 31, 2011, seven Bcfe remained undeveloped for five years or more; however, the property is included in the Company's 2012 development plan. All PUD properties are included in the Company's current five-year development plan.

Reserve engineering is inherently a subjective process of estimating underground accumulations of oil, natural gas and NGL that cannot be measured exactly. The accuracy of any reserve estimate is a function of the quality of available data and engineering and geological interpretation and judgment. Accordingly, reserve estimates may vary from the quantities of oil, natural gas and NGL that are ultimately recovered. Future prices received for production may vary, perhaps significantly, from the prices assumed for the purposes of estimating the standardized measure of discounted future net cash flows. The standardized measure of discounted future net cash flows should not be construed as the market value of the reserves at the dates shown. The 10% discount factor required to be used under the provisions of applicable accounting standards may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with the Company or the oil and natural gas industry. The standardized measure of discounted future net cash flows is materially affected by assumptions about the timing of future production, which may prove to be inaccurate.

The reserve estimates reported herein were prepared by independent engineers, DeGolyer and MacNaughton. The process performed by the independent engineers to prepare reserve amounts included their estimation of reserve quantities, future producing rates, future net revenue and the present value of such future net revenue, is based in part on data provided by the Company. When preparing the reserve estimates, the independent engineering firm did not independently verify the accuracy and completeness of the information and data furnished by the Company with respect to ownership interests, production, well test data, historical costs of operation and development, product prices, or any agreements relating to current and future operations of the properties and sales of production. However, if in the course of their work, something came to their attention that brought into question the validity or sufficiency of any such information or data, they did not rely on such information or data until they had satisfactorily resolved their questions relating thereto. The estimates of reserves conform to the guidelines of the SEC, including the criteria of "reasonable certainty," as it pertains to expectations about the recoverability of reserves in future years. The independent engineering firm also prepared estimates with respect to reserve categorization, using the definitions for proved reserves set forth in Regulation S-X Rule 4-10(a) and subsequent SEC staff interpretations and guidance.

The Company's internal control over the preparation of reserve estimates is a process designed to provide reasonable assurance regarding the reliability of the Company's reserve estimates in accordance with SEC regulations. The preparation of reserve estimates was overseen by the Company's Reservoir Engineering Advisor, who has Master of Petroleum Engineering and Master of Business Administration degrees and more than 25 years of oil and natural gas industry experience. The reserve estimates were reviewed and approved by the Company's senior engineering staff and management, with final approval by its Executive Vice President and Chief Operating Officer. For additional information regarding estimates of reserves, including the standardized measure of discounted future net cash flows, see "Supplemental Oil and Natural Gas Data (Unaudited)" in Item 8. "Financial Statements and Supplementary Data." The Company has not filed reserve estimates with any federal authority or agency, with the exception of the SEC.

Operational Overview

General

The Company generally seeks to be the operator of its properties so that it can develop drilling programs and optimization projects that not only replace production, but add value through reserve and production growth and future operational synergies. Many of the Company's wells are completed in multiple producing zones with commingled production and long economic lives.

Principal Customers

For the year ended December 31, 2011, sales of oil, natural gas and NGL to Enbridge Energy Partners, L.P. and DCP Midstream Partners, LP accounted for approximately 21% and 19%, respectively, of the Company's total production volumes, or 40% in the aggregate. If the Company were to lose any one of its major oil and natural gas purchasers, the loss could temporarily cease or delay production and sale of its oil and natural gas in that particular purchaser's service area. If the Company were to lose a purchaser, it believes it could identify a substitute purchaser. However, if one or more of these large purchasers ceased purchasing oil and natural gas altogether, it could have a detrimental effect on the oil and natural gas market in general and on the volume of oil and natural gas that the Company is able to sell.

Competition

The oil and natural gas industry is highly competitive. The Company encounters strong competition from other independent operators and master limited partnerships in acquiring properties, contracting for drilling and other related services and securing trained personnel. The Company is also affected by competition for drilling rigs and the availability of related equipment. In the past, the oil and natural gas industry has experienced shortages of drilling rigs, equipment, pipe and personnel, which has delayed development drilling and has caused significant price increases. The Company is unable to predict when, or if, such shortages may occur or how they would affect its drilling program.

Operating Hazards and Insurance

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

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

Title to Properties

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

Seasonal Nature of Business

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

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

Environmental Matters and Regulation

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

- require the acquisition of various permits before drilling commences;
- require the installation of expensive pollution control equipment;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities;
- limit or prohibit drilling activities on lands lying within wilderness, wetlands, areas inhabited by endangered species and other protected areas;
- require remedial measures to prevent pollution from former operations, such as pit closure and plugging of abandoned wells;
- impose substantial liabilities for pollution resulting from operations; and
- with respect to operations affecting federal lands or leases, require preparation of a Resource Management Plan, an Environmental Assessment, and/or an Environmental Impact Statement.

These laws, rules and regulations may also restrict the production rate of oil, natural gas and NGL below the rate that would otherwise be possible. The regulatory burden on the industry increases the cost of doing business and consequently affects profitability. Additionally, Congress and federal and state agencies frequently revise environmental laws and regulations, and any changes that result in more stringent and costly waste handling, disposal and cleanup requirements for the oil and natural gas industry could have a significant impact on operating costs.

The environmental laws and regulations applicable to the Company and its operations include, among others, the following U.S. federal laws and regulations:

- Clean Air Act, and its amendments, which governs air emissions;
- Clean Water Act, which governs discharges to and excavations within the waters of the U.S.;
- Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), which imposes liability where hazardous releases have occurred or are threatened to occur (commonly known as "Superfund");
- Energy Independence and Security Act of 2007, which prescribes new fuel economy standards and other energy saving measures;
- National Environmental Policy Act, which governs oil and natural gas production activities on federal lands;
- Resource Conservation and Recovery Act ("RCRA"), which governs the management of solid waste;
- Safe Drinking Water Act, which governs the underground injection and disposal of wastewater; and
- U.S. Department of Interior regulations, which impose liability for pollution cleanup and damages.

Various states regulate the drilling for, and the production, gathering and sale of, oil, natural gas and NGL, including imposing production taxes and requirements for obtaining drilling permits. States also regulate the method of developing new fields, the spacing and operation of wells and the prevention of waste of resources. States may regulate rates of production and may establish maximum daily production allowables from natural gas wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulations, but there can be no assurance that they will not do so in the future. The effect of these regulations may be to limit the amounts of oil, natural gas and NGL that may be produced from the Company's wells and to limit the number of wells or locations it can drill. The oil and natural gas industry is also subject to compliance with various other federal, state and local regulations and laws. Some of those laws relate to occupational safety, resource conservation and equal opportunity employment.

The Company believes that it substantially complies with all current applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on its financial condition or results of operations. Future regulatory issues that could impact the Company include new rules or legislation regulating greenhouse gas emissions, hydraulic fracturing and air emissions.

Climate Change

In response to recent studies suggesting that emissions of carbon dioxide and certain other gases may be contributing to warming of the Earth's atmosphere, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that would require a reduction in emissions of greenhouse gases ("GHG") from motor vehicles and also may trigger construction and operating permit review for GHG emissions from certain stationary sources. The EPA has asserted that the final motor vehicle GHG emission standards triggered construction and operating permit requirements for stationary sources. Thus, on June 3, 2010, the EPA issued a final rule to address permitting of GHG emissions from stationary sources under the Clean Air Act's Prevention of Significant Deterioration ("PSD") and Title V programs. This final rule "tailors" the PSD and Title V programs to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. In addition, on November 8, 2010, the EPA finalized new GHG reporting requirements for upstream petroleum and natural gas systems, which will be added to the EPA's existing GHG reporting rule published in 2009. Facilities containing petroleum and natural gas systems that emit 25,000 metric tons or more of CO2 equivalent per year will now be required to report annual GHG emissions to the EPA, with the first report due on September 28, 2012. In addition, both houses of Congress have considered legislation to reduce emissions of GHGs, and almost one-half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Any laws or regulations that may be adopted to restrict or reduce emissions of U.S. greenhouse gases could require the Company to incur increased operating costs, and could have an adverse effect on demand for oil and natural gas.

Hydraulic Fracturing

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. Hydraulic fracturing operations have historically been overseen by state regulators as part of their oil and gas regulatory programs. However, the EPA has asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the Safe Drinking Water Act's Underground Injection Control Program and has begun the process of drafting guidance documents related to this newly asserted regulatory authority. Moreover, on November 23, 2011, the EPA announced that it was granting, in part, a petition to initiate rulemaking under the Toxic Substances Control Act ("TSCA"), relating to chemical substances and mixtures used in oil and gas exploration or production. In addition, legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. If adopted, these bills could result in additional permitting requirements for hydraulic fracturing operations as well as various restrictions on those operations. These permitting requirements and restrictions could result in delays in operations at well sites and also increased costs to make wells productive.

There are also certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic-fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic-fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic-fracturing practices. Furthermore, a number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with initial results expected to be available by late 2012 and final results by

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2014. In addition, the U.S. Department of Energy is conducting an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic-fracturing completion methods. Also, the U.S. Department of the Interior is considering disclosure requirements or other mandates for hydraulic fracturing on federal lands. These on-going or proposed studies, depending on their course and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the Safe Drinking Water Act or other regulatory mechanisms. Moreover, some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances. For example, both Texas and Louisiana have adopted disclosure regulations requiring varying degrees of disclosure of the constituents in hydraulic fracturing fluids. Any such added regulation in states where the Company operates could lead to operational delays, increased operating costs and additional regulatory burdens, and reduced production of oil and natural gas, which could adversely affect the Company's revenues and results of operations.

Endangered Species Act

The federal Endangered Species Act ("ESA") restricts activities that may affect endangered and threatened species or their habitats. Some of the Company's operations may be located in areas that are designated as habitat for endangered or threatened species. The Company believes that it is currently in substantial compliance with the ESA. However, the designation of previously unprotected species as being endangered or threatened could cause the Company to incur additional costs or become subject to operating restrictions in areas where the species are known to exist.

Air Emissions

On July 28, 2011, the EPA issued proposed rules that would subject all oil and gas operations (production, processing, transmission, storage and distribution) to regulation under the New Source Performance Standards ("NSPS") and National Emissions Standards for Hazardous Air Pollutants ("NESHAP") programs. The EPA's proposed rules also include NSPS standards for completions of hydraulically fractured gas wells, applicable to newly drilled and fractured wells and also existing wells that are refractured. These standards include the reduced emission completion ("REC") techniques developed in EPA's Natural Gas STAR program along with pit flaring of gas not sent to the gathering line. Further, the proposed regulations under NESHAP include maximum achievable control technology ("MACT") standards for certain equipment not currently subject to such standards. The Company is currently evaluating the effect these proposed rules could have on its business. Final action on the proposed rules is expected no later than April 3, 2012. If these or other initiatives result in an increase in regulation, it could increase the Company's costs or reduce its production, which could have a material adverse effect on its results of operations and cash flows.

The Company cannot predict how future environmental laws and regulations may impact its properties or operations. For the year ended December 31, 2011, the Company did not incur any material capital expenditures for installation of remediation or pollution control equipment at any of the Company's facilities. The Company is not aware of any environmental issues or claims that will require material capital expenditures during 2012 or that will otherwise have a material impact on its financial position or results of operations.

Employees

As of December 31, 2011, the Company employed approximately 824 personnel. None of the employees are represented by labor unions or covered by any collective bargaining agreement. The Company believes that its relationship with its employees is satisfactory.

Principal Executive Offices

The Company is a Delaware limited liability company with headquarters in Houston, Texas. The principal executive offices are located at 600 Travis, Suite 5100, Houston, Texas 77002. The main telephone number is (281) 840-4000.

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Company Website

The Company's internet website is www.linnenergy.com. The Company makes available free of charge on or through its website Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and any amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after the Company electronically files such material with, or furnishes it to, the SEC. Information on the Company's website should not be considered a part of, or incorporated by reference into, this Annual Report on Form 10-K.

The SEC maintains an internet website that contains these reports at www.sec.gov. Any materials that the Company files with the SEC may be read or copied at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. Information concerning the operation of the Public Reference Room may be obtained by calling the SEC at (800) 732-0330.

Forward-Looking Statements

This Annual Report on Form 10-K contains forward-looking statements that are subject to a number of risks and uncertainties, many of which are beyond the Company's control. These statements may include discussions about the Company's:

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

All of these types of statements, other than statements of historical fact included in this Annual Report on Form 10-K, are forward-looking statements. These forward-looking statements may be found in Item 1. "Business;" Item 1A. "Risk Factors;" Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" and other items within this Annual Report on Form 10-K. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expect," "plan," "project," "intend," "anticipate," "believe," "estimate," "potential," "pursue," "target," "continue," the negative of such terms or other comparable terminology.

The forward-looking statements contained in this Annual Report on Form 10-K are largely based on Company expectations, which reflect estimates and assumptions made by Company management. These estimates and assumptions reflect management's best judgment based on currently known market conditions and other factors. Although the Company believes such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties beyond its control. In addition, management's assumptions may prove to be inaccurate. The Company cautions that the forward-looking statements contained in this Annual Report on Form 10-K are not guarantees of future performance, and it cannot assure any reader that such statements will be realized or the forward-looking statements or events will occur. Actual results may differ materially from those anticipated or implied in forward-looking statements due to factors listed in the "Risk Factors" section and elsewhere in this Annual Report on Form 10-K. The forward-looking statements speak only as of the date made, and other than as required by law, the Company undertakes no obligation to publicly update or revise any forward-looking statement, whether as a result of new information, future events or otherwise.

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Item 1A. Risk Factors

Our business has many risks. Factors that could materially adversely affect our business, financial position, operating results or liquidity and the trading price of our units are described below. This information should be considered carefully, together with other information in this report and other reports and materials we file with the SEC.

We may not have sufficient cash flow from operations to pay the quarterly distribution at the current distribution level, or at all, and future distributions to our unitholders may fluctuate from quarter to quarter.

We may not have sufficient cash flow from operations each quarter to pay the quarterly distribution at the current distribution level or at all. Under the terms of our limited liability company agreement, the amount of cash otherwise available for distribution will be reduced by our operating expenses and any cash reserve amounts that our Board of Directors establishes to provide for future operations, future capital expenditures, future debt service requirements and future cash distributions to our unitholders. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

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

In addition, the actual amount of cash we will have available for distribution will depend on other factors, some of which are beyond our control, including:

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

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

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

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

- the risk that reserves expected to support the acquired assets may not be of the anticipated magnitude or may not be developed as anticipated;
- the risk of title defects discovered after closing;
- inaccurate assumptions about revenues and costs, including synergies;
- significant increases in our indebtedness and working capital requirements;

- an inability to transition and integrate successfully or timely the businesses we acquire;
- the cost of transition and integration of data systems and processes;

- the potential environmental problems and costs;
- the assumption of unknown liabilities;
- limitations on rights to indemnity from the seller;
- the diversion of management's attention from other business concerns;
- increased demands on existing personnel and on our corporate structure;
- disputes arising out of acquisitions;
- customer or key employee losses of the acquired businesses; and
- the failure to realize expected growth or profitability.

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

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

Our ability to grow and to increase distributions to our unitholders is partially dependent on our ability to make acquisitions that result in an increase in available cash flow per unit. We may be unable to make such acquisitions because we are:

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

In any such case, our future growth and ability to increase distributions will be limited. Furthermore, even if we do make acquisitions that we believe will increase available cash flow per unit, these acquisitions may nevertheless result in a decrease in available cash flow per unit.

We have significant indebtedness under our 2019 Senior Notes, 2010 Issued Senior Notes, and Original Senior Notes (collectively, "Senior Notes") and from time to time, our Credit Facility. For a discussion of our Senior Notes, see Note 6. The Indentures governing our Senior Notes have substantial restrictions and financial covenants and we may have difficulty obtaining additional credit, which could adversely affect our operations, our ability to make acquisitions and our ability to pay distributions to our unitholders.

As of January 31, 2012, we had an aggregate of approximately $3.3 billion outstanding under Senior Notes and our Credit Facility (with additional borrowing capacity of approximately $1.3 billion under our Credit Facility). As a result of our indebtedness, we will use a portion of our cash flow to pay interest and principal when due, which will reduce the cash available to finance our operations and other business activities and could limit our flexibility in planning for or reacting to changes in our business and the industry in which we operate.

The Credit Facility restricts our ability to obtain additional financing, make investments, lease equipment, sell assets, enter into commodity and interest rate derivative contracts and engage in business combinations. We are also required to comply with certain financial covenants and ratios under our Credit Facility and the Indentures governing our Senior Notes. Our ability to comply with these restrictions and covenants in the future is uncertain and will be affected by the levels of cash flow from our operations and events or circumstances beyond our control. Our failure to comply with any of the restrictions and covenants could result in an event of default, which, if it continues beyond any applicable cure periods, could cause all of our existing indebtedness to be immediately due and payable.

We depend, in part, on our Credit Facility for future capital needs. We have drawn on our Credit Facility to fund or partially fund quarterly cash distribution payments, since we use operating cash flow primarily for drilling and development of oil and natural gas properties and acquisitions and borrow as cash is needed. Absent such borrowing, we would have at times experienced a shortfall in cash available to pay our declared quarterly cash distribution amount. If there is a default by us under our Credit Facility that continues beyond any applicable cure period, we would be unable to make borrowings to fund distributions. In addition, we may finance acquisitions through borrowings under our Credit Facility or the incurrence of additional debt. To the extent that we are unable to incur additional debt under our Credit Facility or otherwise because we are not in compliance with the financial covenants in the Credit Facility, we may not be able to complete acquisitions, which could adversely affect our ability to maintain or increase distributions. Furthermore, to the extent we are unable to refinance our Credit Facility on terms that are as favorable as those in our existing Credit Facility, or at all, our ability to fund our operations and our ability to pay distributions could be affected.

The borrowing base under our Credit Facility is determined semi-annually at the discretion of the lenders and is based in part on oil, natural gas and NGL prices. Significant declines in oil, natural gas or NGL prices may result in a decrease in our borrowing base. The lenders can unilaterally adjust the borrowing base and therefore the borrowings permitted to be outstanding under the Credit Facility. Any increase in the borrowing base requires the consent of all the lenders. Outstanding borrowings in excess of the borrowing base must be repaid immediately, or we must pledge other properties as additional collateral. We do not currently have substantial unpledged properties, and we may not have the financial resources in the future to make any mandatory principal prepayments required under the Credit Facility. Significant declines in our production or significant declines in realized oil, natural gas or NGL prices for prolonged periods and resulting decreases in our borrowing base may force us to reduce or suspend distributions to our unitholders.

Our ability to access the capital and credit markets to raise capital and borrow on favorable terms will be affected by disruptions in the capital and credit markets, which could adversely affect our operations, our ability to make acquisitions and our ability to pay distributions to our unitholders.

Disruptions in the capital and credit markets could limit our ability to access these markets or significantly increase our cost to borrow. Some lenders may increase interest rates, enact tighter lending standards, refuse to refinance existing debt at maturity on favorable terms or at all and may reduce or cease to provide funding to borrowers. If we are unable to access the capital and credit markets on favorable terms, our ability to make acquisitions and pay distributions could be affected.

Our variable rate indebtedness subjects us to interest rate risk, which could cause our debt service obligations to increase significantly.

Borrowings under our Credit Facility bear interest at variable rates and expose us to interest rate risk. If interest rates increase and we are unable to effectively hedge our interest rate risk, our debt service obligations on the variable rate indebtedness would increase even though the amount borrowed remained the same, and our net income and cash available for servicing our indebtedness would decrease.

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

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

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

To achieve more predictable cash flow and to reduce our exposure to adverse fluctuations in the prices of oil and natural gas, we enter into commodity derivative contracts for a significant portion of our production. Commodity derivative arrangements expose us to the risk of financial loss in some circumstances, including situations when production is less than expected. If we experience a sustained material interruption in our production or if we are unable to perform our drilling activity as planned, we might be forced to satisfy all or a portion of our derivative obligations without the benefit of the cash flow from our sale of the underlying physical commodity, resulting in a substantial reduction of our liquidity, which may adversely affect our ability to pay distributions to our unitholders.

Counterparty failure may adversely affect our derivative positions.

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

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

Our revenue, profitability and cash flow depend upon the prices of and demand for oil, natural gas and NGL. The oil, natural gas and NGL market is very volatile and a drop in prices can significantly affect our financial results and impede our growth. Changes in oil, natural gas and NGL prices have a significant impact on the value of our reserves and on our cash flow. Prices for these commodities may fluctuate widely in response to relatively minor changes in the supply of and demand for them, market uncertainty and a variety of additional factors that are beyond our control, such as:

- the domestic and foreign supply of and demand for oil, natural gas and NGL;
- the price and level of foreign imports;
- the level of consumer product demand;
- weather conditions;
- overall domestic and global economic conditions;
- political and economic conditions in oil and natural gas producing countries, including those in the Middle East and South America;
- the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain price and production controls;
- the impact of the U.S. dollar exchange rates on oil, natural gas and NGL prices;
- technological advances affecting energy consumption;
- domestic and foreign governmental regulations and taxation;
- the impact of energy conservation efforts;
- the proximity and capacity of pipelines and other transportation facilities; and
- the price and availability of alternative fuels.

In the past, the prices of oil, natural gas and NGL have been extremely volatile, and we expect this volatility to continue. If commodity prices decline significantly for a prolonged period, our cash flow from operations will decline, and we may have to lower our distribution or may not be able to pay distributions at all.

Future price declines or downward reserve revisions may result in a write down of our asset carrying values, which could adversely affect our results of operations and limit our ability to borrow funds.

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

Unless we replace our reserves, our reserves and production will decline, which would adversely affect our cash flow from operations and our ability to make distributions to our unitholders.

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

Our estimated reserves are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

No one can measure underground accumulations of oil, natural gas and NGL in an exact manner. Reserve engineering requires subjective estimates of underground accumulations of oil, natural gas and NGL and assumptions concerning future oil, natural gas and NGL prices, production levels and operating and development costs. As a result, estimated quantities of proved reserves and projections of future production rates and the timing of development expenditures may prove to be inaccurate. Independent petroleum engineering firms prepare estimates of our proved reserves. Some of our reserve estimates are made without the benefit of a lengthy production history, which are less reliable than estimates based on a lengthy production history. Also, we make certain assumptions regarding future oil, natural gas and NGL prices, production levels and operating and development costs that may prove incorrect. Any significant variance from these assumptions by actual amounts could greatly affect our estimates of reserves, the economically recoverable quantities of oil, natural gas and NGL attributable to any particular group of properties, the classifications of reserves based on risk of recovery and estimates of the future net cash flows. Numerous changes over time to the assumptions on which our reserve estimates are based, as described above, often result in the actual quantities of oil, natural gas and NGL we ultimately recover being different from our reserve estimates.

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

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

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

Our development operations require substantial capital expenditures, which will reduce our cash available for distribution. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our reserves.

The oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business for the development and production of oil, natural gas and NGL reserves. These expenditures will reduce our cash available for distribution. We intend to finance our future capital expenditures with cash flow from operations and to the extent necessary, with equity and debt offerings or bank borrowings. Our cash flow from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the level of oil, natural gas and NGL we are able to produce from existing wells;
- the prices at which we are able to sell our oil, natural gas and NGL; and
- our ability to acquire, locate and produce new reserves.

If our revenues or the borrowing base under our Credit Facility decrease as a result of lower oil, natural gas and NGL prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. Our Credit Facility restricts our ability to obtain new financing. If additional capital is needed, we may not be able to obtain debt or equity financing on terms favorable to us, or at all. If cash flow from operations or cash available under our Credit Facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our development operations, which in turn could lead to a possible decline in our reserves.

We may decide not to drill some of the prospects we have identified, and locations that we decide to drill may not yield oil, natural gas and NGL in commercially viable quantities.

Our prospective drilling locations are in various stages of evaluation, ranging from a prospect that is ready to drill to a prospect that will require additional geological and engineering analysis. Based on a variety of factors, including future oil, natural gas and NGL prices, the generation of additional seismic or geological information, the availability of drilling rigs and other factors, we may decide not to drill one or more of these prospects. As a result, we may not be able to increase or maintain our reserves or production, which in turn could have an adverse effect on our business, financial position, results of operations and our ability to pay distributions. In addition, the SEC’s reserve reporting rules include a general requirement that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. At December 31, 2011, we had 2,302 proved undeveloped drilling locations. To the extent that we do not drill these locations within five years of initial booking, they may not continue to qualify for classification as proved reserves, and we may be required to reclassify such reserves as unproved reserves. The reclassification of such reserves could also have a negative effect on the borrowing base under our Credit Facility.

The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a well. Our efforts will be uneconomic if we drill dry holes or wells that are productive but do not produce enough oil, natural gas and NGL to be commercially viable after drilling, operating and other costs. If we drill future wells that we identify as dry holes, our drilling success rate would decline, which could have an adverse effect on our business, financial position or results of operations.

Our business depends on gathering and transportation facilities. Any limitation in the availability of those facilities would interfere with our ability to market the oil, natural gas and NGL we produce, and could reduce our cash available for distribution and adversely impact expected increases in oil, natural gas and NGL production from our drilling program.

The marketability of our oil, natural gas and NGL production depends in part on the availability, proximity and capacity of gathering and pipeline systems. The amount of oil, natural gas and NGL that can be produced and sold is subject to limitation in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage to the gathering or transportation system, or lack of contracted capacity on such systems. The curtailments arising from these and similar circumstances may last from a few days to several months. In many cases, we are provided only with limited, if any, notice as to when these circumstances will arise and their duration. In addition, some of our wells are drilled in locations that are not serviced by gathering and transportation pipelines, or the gathering and transportation pipelines in the area may not have sufficient capacity to transport additional production. As a result, we may not be able to sell the oil, natural gas and NGL production from these wells until the necessary gathering and transportation systems are constructed. Any significant curtailment in gathering system or pipeline capacity, or significant delay in the construction of necessary gathering and transportation facilities, would interfere with our ability to market the oil, natural gas and NGL we produce, and could reduce our cash available for distribution and adversely impact expected increases in oil, natural gas and NGL production from our drilling program.

We depend on certain key customers for sales of our oil, natural gas and NGL. To the extent these and other customers reduce the volumes they purchase from us or delay payment, our revenues and cash available for distribution could decline. Further, a general increase in nonpayment could have an adverse impact on our financial position and results of operations.

For the year ended December 31, 2011, Enbridge Energy Partners, L.P. and DCP Midstream Partners, LP accounted for approximately 21% and 19%, respectively, of our total production volumes, or 40% in the aggregate. For the year ended December 31, 2010, DCP Midstream Partners, LP, Enbridge Energy Partners, L.P. and ConocoPhillips accounted for approximately 19%, 17% and 12%, respectively, of our total volumes, or 48% in the aggregate. To the extent these and other customers reduce the volumes of oil, natural gas or NGL that they purchase from us, our revenues and cash available for distribution could decline.

Many of our leases are in areas that have been partially depleted or drained by offset wells.

Our key project areas are located in some of the most active drilling areas of the producing basins in the U.S. As a result, many of our leases are in areas that have already been partially depleted or drained by earlier offset drilling. This may inhibit our ability to find economically recoverable quantities of reserves in these areas.

Our identified drilling location inventories are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling, resulting in temporarily lower cash from operations, which may impact our ability to pay distributions.

Our management has specifically identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. As of December 31, 2011, we had identified 6,456 drilling locations, of which 2,302 were proved undeveloped locations and 4,154 were other locations. These identified drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of factors, including the availability of capital, seasonal conditions, regulatory approvals, oil, natural gas and NGL prices, costs and drilling results. In addition, DeGolyer and MacNaughton has not estimated proved reserves for the 4,154 other drilling locations we have identified and scheduled for drilling, and therefore there may be greater uncertainty with respect to the success of drilling wells at these drilling locations. Our final determination on whether to drill any of these drilling locations will be dependent upon the factors described above as well as, to some degree, the results of our drilling activities with respect to our proved drilling locations. Because of these uncertainties, we do not know if the numerous drilling locations we have identified will be drilled within our expected timeframe or will ever be drilled or if we will be able to produce oil, natural gas and NGL from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

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

Our drilling activities are subject to many risks, including the risk that we will not discover commercially productive reservoirs. Drilling for oil, natural gas and NGL can be uneconomic, not only from dry holes, but also from productive wells that do not produce sufficient revenues to be commercially viable. In addition, our drilling and producing operations may be curtailed, delayed or canceled as a result of other factors, including:

- the high cost, shortages or delivery delays of equipment and services;
- unexpected operational events;
- adverse weather conditions;
- facility or equipment malfunctions;
- title problems;
- pipeline ruptures or spills;
- compliance with environmental and other governmental requirements;
- unusual or unexpected geological formations;
- loss of drilling fluid circulation;
- formations with abnormal pressures;
- fires;
- blowouts, craterings and explosions; and
- uncontrollable flows of oil, natural gas and NGL or well fluids.

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

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

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

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

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

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

Part of the regulatory environment in which we operate includes, in some cases, legal requirements for obtaining environmental assessments, environmental impact studies and/or plans of development before commencing drilling and production activities. In addition, our activities are subject to the regulations regarding conservation practices and protection of correlative rights. These regulations affect our operations and limit the quantity of oil, natural gas and NGL we may produce and sell. A major risk inherent in our drilling plans is the need to obtain drilling permits from state and local authorities. Delays in obtaining regulatory approvals or drilling permits, the failure to obtain a drilling permit for a well or the receipt of a permit with unreasonable conditions or costs could have a material adverse effect on our ability to develop our properties. Additionally, the regulatory environment could change in ways that might substantially increase the financial and managerial costs of compliance with these laws and regulations and, consequently, adversely affect our ability to pay distributions to our unitholders. For a description of the laws and regulations that affect us, see Item 1. "Business - Environmental Matters and Regulation."

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

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations. Due to concerns raised relating to potential impacts of hydraulic fracturing on groundwater quality, legislative and regulatory efforts at the federal level and in some states have been initiated to render permitting and compliance requirements more stringent for hydraulic fracturing or prohibit the activity altogether. For example, the EPA has asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the Safe Drinking Water Act's Underground Injection Control Program and has begun the process of drafting guidance documents related to this newly asserted regulatory authority. In addition, both Texas and Louisiana have adopted disclosure regulations requiring varying degrees of disclosure of the constituents in hydraulic fracturing fluids. Such efforts could have an adverse effect on our oil and natural gas production activities. For a more detailed discussion of hydraulic fracturing matters impacting our business, see Item 1. "Business - Environmental Matters and Regulation."

We may issue additional units without unitholder approval, which would dilute existing ownership interests.

We may issue an unlimited number of limited liability company interests of any type, including units, without the approval of our unitholders.

The issuance of additional units or other equity securities may have the following effects:

- an individual unitholder’s proportionate ownership interest in us may decrease;
- the relative voting strength of each previously outstanding unit may be reduced;

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- the amount of cash available for distribution per unit may decrease; and
- the market price of the units may decline.

Our management may have conflicts of interest with the unitholders. Our limited liability company agreement limits the remedies available to our unitholders in the event unitholders have a claim relating to conflicts of interest.

Conflicts of interest may arise between our management on one hand, and the Company and our unitholders on the other hand, related to the divergent interests of our management. Situations in which the interests of our management may differ from interests of our nonaffiliated unitholders include, among others, the following situations:

- our limited liability company agreement gives our Board of Directors broad discretion in establishing cash reserves for the proper conduct of our business, which will affect the amount of cash available for distribution. For example, our management will use its reasonable discretion to establish and maintain cash reserves sufficient to fund our drilling program;
- our management team, subject to oversight from our Board of Directors, determines the timing and extent of our drilling program and related capital expenditures, asset purchases and sales, borrowings, issuances of additional units and reserve adjustments, all of which will affect the amount of cash that we distribute to our unitholders; and
- affiliates of our directors are not prohibited from investing or engaging in other businesses or activities that compete with the Company.

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

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

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of entity level taxation by individual states. If the Internal Revenue Service ("IRS") were to treat us as a corporation for federal income tax purposes or we were to become subject to entity level taxation for state tax purposes, taxes paid, if any, would reduce the amount of cash available for distribution.

The anticipated after-tax economic benefit of an investment in our units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this or any other tax matter that affects us.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rates, currently at a maximum rate of 35%. Distributions would generally be taxed again as corporate distributions, and no income, gain, loss, deduction or credit would flow through to unitholders. Because a tax may be imposed on us as a corporation, our cash available for distribution to our unitholders could be reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to our unitholders, likely causing a substantial reduction in the value of our units.

Current law or our business may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity level taxation. Any modification to current law or interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible to meet the requirements for

partnership status, affect or cause us to change our business activities, affect the tax considerations of an investment in us, change the character or treatment of portions of our income and adversely affect an investment in our units.

In addition, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships and limited liability companies to entity level taxation through the imposition of state income, franchise or other forms of taxation. For example, we are required to pay Texas franchise tax at a maximum effective rate of 0.7% of our total revenue apportioned to Texas in the prior year. Imposition of a tax on us by any other state would reduce the amount of cash available for distribution to our unitholders.

The value of an investment in our units could be affected by recent and potential federal tax increases.

Absent new legislation extending the current rates, in taxable years beginning after December 31, 2012, the highest marginal U.S. federal income tax rate applicable to ordinary income and long-term capital gains of individuals will increase to 39.6% and 20%, respectively. Moreover, these rates are subject to change by new legislation at any time.

The Health Care and Education Reconciliation Act of 2010 includes a provision that, in taxable years beginning after December 31, 2012, subjects certain individuals, estates and trusts to an Unearned Income Medicare Contribution tax of 3.8% on certain income. In the case of an individual having a modified adjusted gross income in excess of $200,000 (or $250,000 for married taxpayers filing joint returns), the provision imposes a tax equal to 3.8% of the lesser of such excess and the individual’s “net investment income,” which will include net income and gains from the ownership or disposition of our units.

A successful IRS contest of the federal income tax positions we take may adversely affect the market for our units, and the cost of an IRS contest will reduce our cash available for distribution to our unitholders.

The IRS may adopt tax positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS may materially and adversely impact the market for our units and the price at which they trade.

Unitholders are required to pay taxes on their share of our taxable income, including their share of ordinary income and capital gain upon dispositions of properties by us, even if they do not receive any cash distributions from us. A unitholder’s share of our taxable income, gain, loss and deduction, or specific items thereof, may be substantially different than the unitholder’s interest in our economic profits.

Our unitholders are required to pay federal income taxes and, in some cases, state and local income taxes on their share of our taxable income, whether or not they receive cash distributions from us. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from their share of our taxable income. For example, we may sell a portion of our properties and use the proceeds to pay down debt or acquire other properties rather than distributing the proceeds to our unitholders, and some or all of our unitholders may be allocated substantial taxable income with respect to that sale.

A unitholder’s share of our taxable income upon a disposition of property by us may be ordinary income or capital gain or some combination thereof. Even where we dispose of properties that are capital assets, what otherwise would be capital gains may be recharacterized as ordinary income in order to “recapture” ordinary deductions that were previously allocated to that unitholder related to the same property.

A unitholder’s share of our taxable income and gain (or specific items thereof) may be substantially greater than, or our tax losses and deductions (or specific items thereof) may be substantially less than, the unitholder’s interest in our economic profits. This may occur, for example, in the case of a unitholder who purchases units at a time when the value of our units or of one or more of our properties is relatively low or a unitholder who acquires units directly from us in exchange for property whose fair market value exceeds its tax basis at the time of the exchange.

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Item 1A.   Risk Factors - Continued

A unitholder's taxable gain or loss on the disposition of our units could be more or less than expected.

If unitholders sell their units, they will recognize a gain or loss equal to the difference between the amount realized and their tax basis in those units. Prior distributions to our unitholders in excess of the total net taxable income they were allocated for a unit, which decreases their tax basis, will become taxable income to our unitholders if the unit is sold at a price greater than their tax basis in that unit, even if the price received is less than their original cost.

A substantial portion of the amount realized, whether or not representing gain, may be ordinary income. In addition, if unitholders sell their units, they may incur a tax liability in excess of the amount of cash they receive from the sale. If the IRS successfully contests some positions we take, unitholders could recognize more gain on the sale of units than would be the case under those positions, without the benefit of decreased income in prior years.

Tax-exempt entities and non-U.S. persons face unique tax issues from owning our units that may result in adverse tax consequences to them.

Investment in units by tax-exempt entities, such as individual retirement accounts (known as IRAs) and other retirement plans, and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file U.S. federal tax returns and pay tax on their share of our taxable income.

We treat each purchaser of units as having the same economic and tax characteristics without regard to the units purchased. The IRS may challenge this treatment, which could adversely affect the value of the units.

Because we cannot match transferors and transferees of units, we must maintain uniformity of the economic and tax characteristics of our units to a purchaser of units. We take depletion, depreciation and amortization and other positions that are intended to maintain such uniformity. These positions may not conform with all aspects of existing Treasury regulations and may affect the amount or timing of income, gain, loss or deduction allocable to a unitholder or the amount of gain from a unitholder's sale of units. A successful IRS challenge to those positions could also adversely affect the amount or timing of income, gain, loss or deduction allocable to a unitholder, or the amount of gain from a unitholder's sale of units and could have a negative impact on the value of our units or result in audit adjustments to unitholder tax returns.

The sale or exchange of 50% or more of our capital and profits interests within a 12-month period will result in the deemed termination of our tax partnership for federal income tax purposes.

We will be considered to have terminated for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a 12-month period. Our termination would, among other things, result in the closing of our taxable year for all unitholders and could result in a deferral of depreciation deductions allowable in computing our taxable income. If this occurs, our unitholders will be allocated an increased amount of federal taxable income for the year in which we are considered to be terminated as a percentage of the cash distributed to the unitholders with respect to that period.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month (or in some cases for periods shorter than a month) based upon the ownership of our units on the first day of each month (or shorter period), instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month (or in some cases for periods shorter than a month) based upon the ownership of our units on the first day of each month (or shorter period), instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury regulations. If the IRS were to challenge this method or new Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of those units. If so, the unitholder would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition.

Because a unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of the loaned units, the unitholder may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss, or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

Unitholders may be subject to state and local taxes and return filing requirements in states and jurisdictions where they do not live as a result of investing in our units.

In addition to federal income taxes, our unitholders will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property now or in the future, even if they do not reside in any of those jurisdictions. Our unitholders will likely be required to file foreign, state and local income tax returns and pay state and local income taxes in some or all of these jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. In 2011, we have been registered to do business or have owned assets in Pennsylvania, California, Oklahoma, Kansas, New Mexico, Illinois, Indiana, Arkansas, Colorado, Louisiana, Michigan, Mississippi, Montana, North Dakota, South Dakota and Texas. As we make acquisitions or expand our business, we may do business or own assets in other states in the future. It is the responsibility of each unitholder to file all U.S. federal, state and local tax returns that may be required of such unitholder.

Changes to current federal tax laws may affect unitholders' ability to take certain tax deductions.

Substantive changes to the existing federal income tax laws have been proposed that, if adopted, would affect, among other things, the ability to take certain operations-related deductions, including deductions for intangible drilling and percentage depletion and deductions for U.S. production activities. Other proposed changes may affect our ability to remain taxable as a partnership for federal income tax purposes. We are unable to predict whether any changes, or other proposals to such laws, ultimately will be enacted. Any such changes could negatively impact the value of an investment in our units.

Derivatives legislation enacted in 2010 could have an adverse impact on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

New comprehensive financial reform legislation was signed into law by the President on July 21, 2010. The legislation calls for the Commodity Futures Trading Commission (the "CFTC") to regulate certain markets for over-the-counter ("OTC") derivative products. Currently, rulemakings are pending at the CFTC, the product of which would be rules that implement the mandates in the new legislation to cause significant portions of derivatives to clear through clearinghouses. The significance of the effect on our business will depend in part on whether we are determined to be a major swap participant or swap dealer or a qualifying end-user, as those terms are defined in the final rules. Depending on those determinations, we may be required to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivatives activities. The CFTC has proposed regulations that, if adopted, may provide to us the certainty that we will not be required to comply with margin requirements or clearing requirements, but the timing of any adoption of any such regulations, and their

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scope, are uncertain. Even if we are not deemed a major swap participant or swap dealer, the rules could impose burdens on market participants to such an extent that liquidity in the bilateral OTC derivative market decreases substantially. The legislation and new regulations may also require counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The new legislation and any new regulations, including determinations with respect to the applicability of margin requirements and other trading structures, could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures and to generate sufficient cash flow to pay quarterly distributions at the current levels or at all. Our revenues could be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material, adverse effect on us, our financial condition, and our results of operations.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

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

The Company's obligations under its Credit Facility are secured by mortgages on a substantial majority of its oil and natural gas properties. See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 6 for additional information concerning the Credit Facility.

Offices

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

Item 3. Legal Proceedings

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

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Executive Officers of the Company

Name	Age	Position with the Company
Mark E. Ellis	56	Chairman, President and Chief Executive Officer
Kolja Rockov	41	Executive Vice President and Chief Financial Officer
Arden L. Walker, Jr.	52	Executive Vice President and Chief Operating Officer
Charlene A. Ripley	48	Senior Vice President and General Counsel
David B. Rottino	46	Senior Vice President of Finance, Business Development and Chief Accounting Officer

Mark E. Ellis is the Chairman, President and Chief Executive Officer and has served in such capacity since December 2011. He previously served as President, Chief Executive Officer and Director from January 2010 to December 2011. From December 2007 to January 2010, Mr. Ellis served as President and Chief Operating Officer and from December 2006 to December 2007, Mr. Ellis served as Executive Vice President and Chief Operating Officer of the Company. Mr. Ellis serves on the boards of America's Natural Gas Alliance, Houston Museum of Natural Science, The Cynthia Woods Mitchell Pavilion, Industry Board of Petroleum Engineering at Texas A&M University and the Visiting Committee of Petroleum Engineering at the Colorado School of Mines.

Kolja Rockov is the Executive Vice President and Chief Financial Officer and has served in such capacity since March 2005. Mr. Rockov serves on the Board of Small Steps Nurturing Center in Houston.

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

Charlene A. Ripley is the Senior Vice President and General Counsel and has served in such capacity since September 2011. She served as Senior Vice President, General Counsel and Corporate Secretary from April 2007 to September 2011. Ms. Ripley currently serves on the board of the Texas General Counsel Forum and on the advisory board of the Women's Energy Network. She also serves on several nonprofit boards, including the Impact Youth Development Center, Girls Inc. and the American Heart Association of Houston. She is a member of the United Way of Greater Houston Women's Initiative.

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

Item 4. Mine Safety Disclosures

Not applicable

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Part II

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

Market Information

The Company's units are listed on The NASDAQ Global Select Market ("NASDAQ") under the symbol "LINE" and began trading on January 13, 2006, after pricing of its IPO. At the close of business on January 31, 2012, there were approximately 192 unitholders of record.

The following sets forth the range of high and low last reported sales prices per unit, as reported by NASDAQ, for the quarters indicated. In addition, distributions declared during each quarter are presented.

Quarter	Unit Price Range High	Unit Price Range Low	Cash Distributions Declared Per Unit
2011:			
October 1 – December 31	$ 39.05	$ 32.80	$ 0.69
July 1 – September 30	$ 40.90	$ 31.91	$ 0.69
April 1 – June 30	$ 40.38	$ 36.65	$ 0.66
January 1 – March 31	$ 39.94	$ 37.34	$ 0.66
2010:			
October 1 – December 31	$ 37.49	$ 31.94	$ 0.66
July 1 – September 30	$ 31.96	$ 26.15	$ 0.63
April 1 – June 30	$ 27.18	$ 22.69	$ 0.63
January 1 – March 31	$ 28.80	$ 24.80	$ 0.63

Distributions

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

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

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

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

Unitholder Return Performance Presentation

The performance graph below compares the total unitholder return on the Company's units, with the total return of the Standard & Poor's 500 Index (the "S&P 500 Index") and the Alerian MLP Index, a weighted composite of 50 prominent energy master limited partnerships. Total return includes the change in the market price, adjusted for reinvested dividends or distributions, for the period shown on the performance graph and assumes that $100 was

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

invested in the Company on December 31, 2006, and the S&P 500 Index and the Alerian MLP Index on the same date. The results shown in the graph below are not necessarily indicative of future performance.

	December 31, 2006	December 31, 2007	December 31, 2008	December 31, 2009	December 31, 2010	December 31, 2011
LINN Energy	$ 100	$ 84	$ 57	$ 121	$ 177	$ 193
Alerian MLP Index	$ 100	$ 113	$ 71	$ 126	$ 171	$ 195
S&P 500 Index	$ 100	$ 105	$ 66	$ 84	$ 97	$ 99

Notwithstanding anything to the contrary set forth in any of the Company’s previous or future filings under the Securities Act of 1933 or the Securities Exchange Act of 1934 that might incorporate this Annual Report on Form 10-K or future filings with the SEC, in whole or in part, the preceding performance information shall not be deemed to be “soliciting material” or to be “filed” with the SEC or incorporated by reference into any filing except to the extent this performance presentation is specifically incorporated by reference therein.

Securities Authorized for Issuance Under Equity Compensation Plans

See the information incorporated by reference under Item 12. “Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters” regarding securities authorized for issuance under the Company’s equity compensation plans, which information is incorporated by reference into this Item 5.

Sales of Unregistered Securities

None.

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

Issuer Purchases of Equity Securities

The following sets forth information with respect to the Company's repurchases of its units during the fourth quarter of 2011:

Period	Total Number of Units Purchased	Average Price Paid Per Unit	Total Number of Units Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Units that May Yet be Purchased Under the Plans or Programs (1) (in millions)
October 1 – 31	129,734	$ 32.08	129,734	$ 56

(1) 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.

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Item 6. Selected Financial Data

The selected financial data set forth below should be read in conjunction with Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Item 8. "Financial Statements and Supplementary Data."

Because of rapid growth through acquisitions and development of properties, the Company's historical results of operations and period-to-period comparisons of these results and certain other financial data may not be meaningful or indicative of future results. The results of the Company's Appalachian Basin and Mid Atlantic Well Service, Inc. operations, which were disposed of in 2008, are classified as discontinued operations for years ended December 31, 2007, through December 31, 2009 (see Note 2). Unless otherwise indicated, results of operations information presented herein relates only to continuing operations.

	At or for the Year Ended December 31,				
	2011	2010	2009	2008	2007
	(in thousands, except per unit amounts)				
Statement of operations data:					
Oil, natural gas and natural gas liquids sales	$ 1,162,037	$ 690,054	$ 408,219	$ 755,644	$ 255,927
Gains (losses) on oil and natural gas derivatives	449,940	75,211	(141,374)	662,782	(345,537)
Depreciation, depletion and amortization	334,084	238,532	201,782	194,093	69,081
Interest expense, net of amounts capitalized	259,725	193,510	92,701	94,517	38,974
Income (loss) from continuing operations	438,439	(114,288)	(295,841)	825,657	(356,194)
Income (loss) from discontinued operations, net of taxes (1)			(2,351)	173,959	(8,155)
Net income (loss)	438,439	(114,288)	(298,192)	999,616	(364,349)
Income (loss) per unit – continuing operations:					
Basic	2.52	(0.80)	(2.48)	7.18	(5.17)
Diluted	2.51	(0.80)	(2.48)	7.18	(5.17)
Income (loss) per unit – discontinued operations:					
Basic			(0.02)	1.52	(0.12)
Diluted			(0.02)	1.52	(0.12)
Net income (loss) per unit:					
Basic	2.52	(0.80)	(2.50)	8.70	(5.29)
Diluted	2.51	(0.80)	(2.50)	8.70	(5.29)
Distributions declared per unit	2.70	2.55	2.52	2.52	2.18
Weighted average units outstanding	172,004	142,535	119,307	114,140	68,916
Cash flow data:					
Net cash provided by (used in):					
Operating activities (2)	$ 518,706	$ 270,918	$ 426,804	$ 179,515	$ (44,814)

Investing activities	(2,130,360)	(1,581,408)	(282,273)	(35,550)	(2,892,420)
Financing activities	1,376,767	1,524,260	(150,968)	(116,738)	2,932,080
Balance sheet data:					
Total assets	$ 8,000,137	$ 5,933,148	$ 4,340,256	$ 4,722,020	$ 3,807,703
Long-term debt	3,993,657	2,742,902	1,588,831	1,653,568	1,443,830
Unitholders' capital	3,428,910	2,788,216	2,452,004	2,760,686	2,026,641

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

(2) Includes premiums paid for derivatives of approximately $134 million, $120 million, $94 million, $130 million and $279 million for the years ended December 31, 2011, December 31, 2010, December 31, 2009, December 31, 2008, and December 31, 2007, respectively.

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Item 6. Selected Financial Data - Continued

	At or for the Year Ended December 31,				
	2011	2010	2009	2008	2007
Production data:					
Average daily production – continuing operations:					
Natural gas (MMcf/d)	175	137	125	124	51
Oil (MBbls/d)	21.5	13.1	9.0	8.6	3.4
NGL (MBbls/d)	10.8	8.3	6.5	6.2	2.7
Total (MMcfe/d)	369	265	218	212	87
Average daily production – discontinued operations:					
Total (MMcfe/d)				12	24
Estimated proved reserves – continuing operations: (1)					
Natural gas (Bcf)	1,675	1,233	774	851	833
Oil (MMBbls)	189	156	102	84	55
NGL (MMBbls)	94	71	54	51	43
Total (Bcfe)	3,370	2,597	1,712	1,660	1,419
Estimated proved reserves – discontinued operations: (1)					
Total (Bcfe)					197

(1) In accordance with SEC regulations, reserves at December 31, 2011, December 31, 2010, and December 31, 2009, were estimated using the average price during the 12-month period, determined as an unweighted average of the first-day-of-the-month price for each month, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. In accordance with SEC regulations, reserves for all prior years were estimated using year-end prices. The price used to estimate reserves is held constant over the life of the reserves.

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

The following discussion and analysis should be read in conjunction with the "Consolidated Financial Statements" and "Notes to Consolidated Financial Statements," which are included in this Annual Report on Form 10-K in Item 8. "Financial Statements and Supplementary Data." The following discussion contains forward-looking statements that reflect the Company's future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside the Company's control. The Company's actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, market prices for oil, natural gas and NGL, production volumes, estimates of proved reserves, capital expenditures, economic and competitive conditions, credit and capital market conditions, regulatory changes and other uncertainties, as well as those factors discussed below and elsewhere in this Annual Report on Form 10-K, particularly in Item 1A. "Risk Factors." In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur.

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

Executive Overview

LINN Energy's mission is to acquire, develop and maximize cash flow from a growing portfolio of long-life oil and natural gas assets. LINN Energy is an independent oil and natural gas company that began operations in March 2003 and completed its 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;
- Michigan, which includes the Antrim Shale formation in the northern part of the state;
- California, which includes the Brea Olinda Field of the Los Angeles Basin; and
- Williston Basin, which includes the Bakken formation in North Dakota.

Results for the year ended December 31, 2011, included the following:

- oil, natural gas and NGL sales of approximately $1.2 billion compared to $690 million in 2010;
- average daily production of 369 MMcfe/d compared to 265 MMcfe/d in 2010;
- realized gains on commodity derivatives of approximately $257 million compared to $308 million in 2010;
- adjusted EBITDA of approximately $998 million compared to $732 million in 2010;
- adjusted net income of approximately $313 million compared to $219 million in 2010;
- capital expenditures, excluding acquisitions, of approximately $697 million compared to $263 million in 2010; and
- 294 wells drilled (292 successful) compared to 139 wells drilled (138 successful) in 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 income (loss) from continuing operations 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 long-lived assets, loss on extinguishment of debt and (gains) losses on sale of assets, net. See “Non-GAAP Financial Measures” on page 58 for a reconciliation of each non-GAAP financial measure to its most directly comparable financial measure calculated and presented in accordance with GAAP.

Acquisitions

On December 15, 2011, the Company completed the acquisition of certain oil and natural gas properties located primarily in the Granite Wash of Texas and Oklahoma from Plains Exploration & Production Company ("Plains") for total consideration of approximately $544 million. The acquisition included approximately 51 MMBoe (306 Bcfe) of proved reserves as of the acquisition date.

On November 1, 2011, and November 18, 2011, the Company completed two acquisitions of certain oil and natural gas properties located in the Permian Basin for total consideration of approximately $110 million. The acquisitions included approximately 7 MMBoe (42 Bcfe) of proved reserves as of the acquisition dates.

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 $223 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 located in the Williston Basin for total consideration of approximately $153 million. The acquisitions included approximately 6 MMBoe (35 Bcfe) of proved reserves as of the acquisition dates.

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 dates.

On March 31, 2011, the Company completed the acquisition of certain oil and natural gas properties located in the Williston Basin from an affiliate of Concho Resources Inc. ("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 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 $38 million in total consideration for these properties.

Proved reserves as of the acquisition date for all of the above referenced acquisitions were estimated using the average oil and natural gas prices during the preceding 12-month period, determined as an unweighted average of the first-day-of-the-month prices for each month.

Financing and Liquidity

The Company's Credit Facility has a borrowing base of $3.0 billion with a maximum commitment amount of $1.5 billion. The maturity date is April 2016. At January 31, 2012, the borrowing capacity under the Credit Facility was approximately $1.3 billion, which includes a $4 million reduction in availability for outstanding letters of credit.

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, 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 its Original Senior Notes, as defined in Note 6.

In March 2011, in connection with its cash tender offers and related consent solicitations, the Company also accepted and purchased: 1) $105 million of the aggregate principal amount of its outstanding 2017 Senior Notes (or

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65% of the remaining outstanding principal amount of its 2017 Senior Notes), and 2) $126 million aggregate principal amount of its outstanding 2018 Senior Notes (or 76% of the remaining outstanding principal amount of its 2018 Senior Notes).

In March 2011, the Company completed a public offering of units for net proceeds of approximately $623 million. The Company used a portion of the net proceeds from the sale of these units to fund the March 2011 redemptions of a portion of its outstanding 2017 Senior Notes and 2018 Senior Notes and to fund the cash tender offers and related expenses for a portion of its 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.

In May 2011, the Company 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 approximately $17 million (or 29% of the remaining outstanding principal amount of its 2017 Senior Notes) and approximately $24 million (or 61% of the remaining outstanding principal amount of its 2018 Senior Notes), respectively. In December 2011, the Company also repurchased an additional portion of its remaining outstanding 2018 Senior Notes for approximately $2 million (or 9% of the remaining outstanding principal amount of its 2018 Senior Notes).

On August 23, 2011, the Company entered into an equity distribution agreement, pursuant to which it may from time to time issue and sell units representing limited liability company interests having an aggregate offering price of up to $500 million. In September 2011, the Company issued and sold 16,060 units representing limited liability company interests at an average unit price of $38.25 for proceeds of approximately $602,000 (net of approximately $12,000 in commissions). In December 2011, the Company issued and sold 772,104 units representing limited liability company interests at an average unit price of $38.03 for proceeds of approximately $29 million (net of approximately $587,000 in commissions). The Company used the net proceeds for general corporate purposes including the repayment of a portion of the indebtedness outstanding under its Credit Facility. At December 31, 2011, units equaling approximately $470 million in aggregate offering price remained available to be issued and sold under the agreement.

In January 2012, the Company, under its equity distribution agreement, issued and sold 1,539,651 units representing limited liability company interests at an average unit price of $38.02 for proceeds of approximately $57 million (net of approximately $1 million in commissions). The Company used the net proceeds for general corporate purposes including the repayment of a portion of the indebtedness outstanding under its Credit Facility. At January 31, 2012, units equaling approximately $411 million in aggregate offering price remained available to be issued and sold under the agreement.

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

Commodity Derivatives

During the year ended December 31, 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 2015. In September 2011, the Company canceled its oil and natural gas swaps for the year 2016 and used the realized gains of approximately $27 million to increase prices on its existing oil and natural gas swaps for the year 2012. In September 2011, the Company also paid premiums of approximately $33 million to increase prices on its existing oil puts for the years 2012 and 2013. In addition, during the fourth quarter of 2011, the Company paid premiums of approximately $52 million for put options and approximately $22 million to increase prices on its existing oil puts for 2012 and 2013.

Operating Regions

Following is a discussion of the Company's six operating regions.

Mid-Continent Deep

The Mid-Continent Deep region includes properties in the Deep Granite Wash formation in the Texas Panhandle, which produces at depths ranging from 10,000 feet to 16,000 feet, as well as properties in Oklahoma and Kansas, which produce at depths of more than 8,000 feet. Mid-Continent Deep proved reserves represented approximately 47% of total proved reserves at December 31, 2011, of which 49% were classified as proved developed reserves. This region produced 172 MMcfe/d or 47% of the Company's 2011 average daily production. During 2011, the Company invested approximately $268 million to drill in this region. During 2012, the Company anticipates spending approximately 65% of its total oil and natural gas capital budget for development activities in the Mid-Continent Deep region, primarily in the Deep Granite Wash formation.

To more efficiently transport its natural gas in the Mid-Continent Deep region to market, the Company owns and operates a network of natural gas gathering systems comprised of approximately 285 miles of pipeline and associated compression and metering facilities that connect to numerous sales outlets in the Texas Panhandle.

Mid-Continent Shallow

The Mid-Continent Shallow region includes properties producing from the Brown Dolomite formation in the Texas Panhandle, which produces at depths of approximately 3,200 feet, as well as properties in Oklahoma, Louisiana and Illinois, which produce at depths of less than 8,000 feet. Mid-Continent Shallow proved reserves represented approximately 20% of total proved reserves at December 31, 2011, of which 70% were classified as proved developed reserves. This region produced 63 MMcfe/d or 17% of the Company's 2011 average daily production. During 2011, the Company invested approximately $9 million to drill in this region. During 2012, the Company anticipates spending approximately 2% of its total oil and natural gas capital budget for development activities in the Mid-Continent Shallow region.

To more efficiently transport its natural gas in the Mid-Continent Shallow region to market, the Company owns and operates a network of natural gas gathering systems comprised of approximately 665 miles of pipeline and associated compression and metering facilities that connect to numerous sales outlets in the Texas Panhandle.

Permian Basin

The Permian Basin is one of the largest and most prolific oil and natural gas basins in the U.S. The Company's properties are located in West Texas and Southeast New Mexico and produce at depths ranging from 2,000 feet to 12,000 feet. Permian Basin proved reserves represented approximately 16% of total proved reserves at December 31, 2011, of which 56% were classified as proved developed reserves. This region produced 73 MMcfe/d or 20% of the Company's 2011 average daily production. During 2011, the Company invested approximately $255 million to drill in this region. During 2012, the Company anticipates spending approximately 25% of its total oil and natural gas capital budget for development activities in the Permian Basin region, primarily in the Wolfberry trend.

Michigan

The Michigan region includes properties producing from the Antrim Shale formation in the northern part of the state, which produces at depths ranging from 600 feet to 2,200 feet. Michigan proved reserves represented approximately 9% of total proved reserves at December 31, 2011, of which 90% were classified as proved developed reserves. This region produced 35 MMcfe/d or 9% of the Company's 2011 average daily production. During 2011, the Company invested approximately $3 million to drill in this region. During 2012, the Company anticipates spending approximately 1% of its total oil and natural gas capital budget for development activities in the Michigan region.

California

The California region consists of the Brea Olinda Field of the Los Angeles Basin. The Brea Olinda Field was discovered in 1880 and produces from the shallow Pliocene formation to the deeper Miocene formation at depths ranging from 1,000 feet to 7,500 feet. California proved reserves represented approximately 6% of total proved reserves at December 31, 2011, of which 93% were classified as proved developed reserves. This region produced 14 MMcfe/d or 4% of the Company's 2011 average daily production. During 2011, the Company invested approximately $6 million to drill in this region. During 2012, the Company anticipates spending approximately 1% of its total oil and natural gas capital budget for development activities in the California region.

Williston Basin

The Williston Basin is one of the premier oil basins in the U.S. The Company's properties are located in North Dakota and produce at depths ranging from 9,000 feet to 12,000 feet. Williston Basin proved reserves represented approximately 2% of total proved reserves at December 31, 2011, of which 48% were classified as proved developed reserves. This region produced 12 MMcfe/d or 3% of the Company's 2011 average daily production. During 2011, the Company invested approximately $39 million to drill in this region. During 2012, the Company anticipates spending approximately 6% of its total oil and natural gas capital budget for development activities in the Williston Basin region.

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

Results of Operations

Year Ended December 31, 2011, Compared to Year Ended December 31, 2010

	Year Ended December 31, 2011	2010	Variance
		(in thousands)	
Revenues and other:			
Natural gas sales	$ 278,714	$ 211,596	$ 67,118
Oil sales	714,385	359,996	354,389
NGL sales	168,938	118,462	50,476
Total oil, natural gas and NGL sales	1,162,037	690,054	471,983
Gains on oil and natural gas derivatives (1)	449,940	75,211	374,729
Marketing revenues	5,868	3,966	1,902
Other revenues	4,609	3,049	1,560
	$ 1,622,454	$ 772,280	$ 850,174
Expenses:			
Lease operating expenses	$ 232,619	$ 158,382	$ 74,237
Transportation expenses	28,358	19,594	8,764
Marketing expenses	3,681	2,716	965
General and administrative expenses (2)	133,272	99,078	34,194
Exploration costs	2,390	5,168	(2,778)
Bad debt expenses	(22)	(46)	24
Depreciation, depletion and amortization	334,084	238,532	95,552
Impairment of long-lived assets	—	38,600	(38,600)
Taxes, other than income taxes	78,522	45,182	33,340
Losses on sale of assets and other, net	3,516	6,536	(3,020)
	$ 816,420	$ 613,742	$ 202,678
Other income and (expenses)	$ (362,129)	$ (268,585)	$ (93,544)
Income (loss) before income taxes	$ 443,905	$ (110,047)	$ 553,952
Adjusted EBITDA (3)	$ 997,621	$ 732,131	$ 265,490
Adjusted net income (3)	$ 313,331	$ 219,489	$ 93,842

(1) During the year ended December 31, 2011, the Company canceled (before the contract settlement date) derivative contracts on estimated future oil and natural gas production resulting in realized gains of approximately $27 million.

(2) General and administrative expenses for the years ended December 31, 2011, and December 31, 2010, include approximately $21 million and $13 million, respectively, of noncash unit-based compensation expenses.

(3) This is a non-GAAP measure used by management to analyze the Company's performance. See "Non-GAAP Financial Measures" on page 58 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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	Year Ended December 31, 2011	Year Ended December 31, 2010	Variance
Average daily production:			
Natural gas (MMcf/d)	175	137	28 %
Oil (MBbls/d)	21.5	13.1	64 %
NGL (MBbls/d)	10.8	8.3	30 %
Total (MMcfe/d)	369	265	39 %
Weighted average prices (hedged): (1)			
Natural gas (Mcf)	$ 8.20	$ 8.52	(4)%
Oil (Bbl)	$ 89.21	$ 94.71	(6)%
NGL (Bbl)	$ 42.88	$ 39.14	10 %
Weighted average prices (unhedged): (2)			
Natural gas (Mcf)	$ 4.35	$ 4.24	3 %
Oil (Bbl)	$ 91.24	$ 75.16	21 %
NGL (Bbl)	$ 42.88	$ 39.14	10 %
Average NYMEX prices:			
Natural gas (MMBtu)	$ 4.05	$ 4.40	(8)%
Oil (Bbl)	$ 95.12	$ 79.53	20 %
Costs per Mcfe of production:			
Lease operating expenses	$ 1.73	$ 1.64	5 %
Transportation expenses	$ 0.21	$ 0.20	5 %
General and administrative expenses (3)	$ 0.99	$ 1.02	(3)%
Depreciation, depletion and amortization	$ 2.48	$ 2.46	1 %
Taxes, other than income taxes	$ 0.58	$ 0.47	23 %

(1) Includes the effect of realized gains on derivatives of approximately $230 million (excluding $27 million realized gains on canceled contracts) and $308 million for the years ended December 31, 2011, and December 31, 2010, respectively.

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

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

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Revenues and Other

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

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

The following sets forth average daily production by region:

	Year Ended December 31, 2011	2010	Variance	
Average daily production (MMcfe/d):				
Mid-Continent Deep	172	133	39	30 %
Mid-Continent Shallow	63	66	(3)	(5)%
Permian Basin	73	31	42	134 %
Michigan	35	21	14	67 %
California	14	14	—	—
Williston Basin	12	—	12	—
	369	265	104	39 %

The 30% increase in average daily production volumes in the Mid-Continent Deep region is primarily due to the Company's 2010 and 2011 capital drilling programs in the Deep Granite Wash formation, as well as the impact of the acquisition in the Cleveland Play in June 2011. The 5% 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. The 134% increase in average daily production volumes in the Permian Basin region reflects the impact of acquisitions in 2010 and 2011 and subsequent development capital spending. The 67% increase in average daily production volumes in the Michigan region reflects the full year impact of acquisitions in the second and fourth quarters of 2010. The California region consists of a low-decline asset base and continues to produce at a consistent level. Average daily production volumes in the Williston Basin region reflect the impact of the Company's acquisitions in this region in 2011.

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 year ended December 31, 2011, the Company had commodity derivative contracts for approximately 101% of its natural gas production and 101% of its oil production, which resulted in realized gains of approximately $257 million (including realized gains on canceled contracts of approximately $27 million). During the year ended December 31, 2010, the Company had commodity derivative contracts for approximately 114% of its natural gas production and 97% of its oil production, which resulted in realized gains of approximately $308 million. Unrealized gains and losses 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 2011, expected future oil and natural gas prices decreased, which resulted in net unrealized gains on derivatives of approximately $193 million for the year ended December 31, 2011. During 2010, expected future oil prices increased and expected future natural gas prices decreased, which resulted in net unrealized losses on derivatives of approximately $232 million for the year ended December 31, 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 by approximately $75 million or 47% to approximately $233 million for the year ended December 31, 2011, from approximately $158 million for the year ended December 31, 2010. Lease operating expenses per Mcfe also increased to $1.73 per Mcfe for the year ended December 31, 2011, from $1.64 per Mcfe for the year ended December 31, 2010. Lease operating expenses increased primarily due to costs associated with properties acquired during 2010 and 2011 (see Note 2). Temporary oil handling costs in the Granite Wash formation and higher post-acquisition maintenance costs in the Permian Basin also contributed to the increase.

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

General and Administrative Expenses
General and administrative expenses are costs not directly associated with field operations and include costs of employees including executive officers, related benefits, office leases and professional fees. General and administrative expenses increased by approximately $34 million or 35% to approximately $133 million for the year ended December 31, 2011, from approximately $99 million for the year ended December 31, 2010. The increase was primarily due to an increase in salaries and benefits expense of approximately $18 million, driven primarily by increased employee headcount, an increase in unit-based compensation expense of approximately $8 million, an increase in professional services expense of approximately $3 million and an increase in acquisition integration expenses of approximately $3 million. General and administrative expenses per Mcfe decreased to $0.99 per Mcfe for the year ended December 31, 2011, from $1.02 per Mcfe for the year ended December 31, 2010, due to higher production volumes.

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

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

Impairment of Long-Lived Assets

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

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

Other Income and (Expenses)

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

Other income and (expenses) increased by approximately $94 million during the year ended December 31, 2011, compared to the year ended December 31, 2010. Interest expense increased primarily due to higher outstanding debt during the period and higher amortization of financing fees associated with the 2019 Senior Notes and the 2010 Issued Senior Notes, as defined in Note 6. In addition, in May 2011, the Company entered into a Fifth Amended and Restated Credit Facility, which also resulted in higher amortization of financing fees. For the year ended December 31, 2011, the Company also recorded a loss on extinguishment of debt of approximately $95 million as a result of the redemptions, 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 income tax expense of approximately $5 million for the year ended December 31, 2011, compared to approximately $4 million for the same period in 2010. Income tax expense increased primarily due to higher income in 2011 from the Company's taxable subsidiaries.

Adjusted EBITDA

Adjusted EBITDA (a non-GAAP financial measure) increased by approximately $266 million or 36% to approximately $998 million for the year ended December 31, 2011, from approximately $732 million for the year ended December 31, 2010. The increase was primarily due to higher production revenues resulting from higher production volumes and higher commodity prices, partially offset by higher expenses. See "Non-GAAP Financial Measures" on page 58 for a reconciliation of adjusted EBITDA to its most directly comparable financial measure calculated and presented in accordance with GAAP.

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Results of Operations – Continuing Operations

Year Ended December 31, 2010, Compared to Year Ended December 31, 2009

	Year Ended December 31, 2010	2009	Variance
		(in thousands)	
Revenues and other:			
Natural gas sales	$ 211,596	$ 160,470	$ 51,126
Oil sales	359,996	181,619	178,377
NGL sales	118,462	66,130	52,332
Total oil, natural gas and NGL sales	690,054	408,219	281,835
Gains (losses) on oil and natural gas derivatives (1)	75,211	(141,374)	216,585
Marketing revenues	3,966	4,380	(414)
Other revenues	3,049	1,924	1,125
	$ 772,280	$ 273,149	$ 499,131
Expenses:			
Lease operating expenses	$ 158,382	$ 132,647	$ 25,735
Transportation expenses	19,594	18,202	1,392
Marketing expenses	2,716	2,154	562
General and administrative expenses (2)	99,078	86,134	12,944
Exploration costs	5,168	7,169	(2,001)
Bad debt expenses	(46)	401	(447)
Depreciation, depletion and amortization	238,532	201,782	36,750
Impairment of long-lived assets	38,600		38,600
Taxes, other than income taxes	45,182	27,605	17,577
(Gains) losses on sale of assets and other, net	6,536	(24,598)	31,134
	$ 613,742	$ 451,496	$ 162,246
Other income and (expenses)	$ (268,585)	$ (121,715)	$ (146,870)
Loss from continuing operations before income taxes	$ (110,047)	$ (300,062)	$ 190,015
Adjusted EBITDA (3)	$ 732,131	$ 566,235	$ 165,896
Adjusted net income (3)	$ 219,489	$ 206,922	$ 12,567

(1) During the year ended December 31, 2009, the Company canceled (before the contract settlement date) derivative contracts on estimated future oil and natural gas production resulting in realized net gains of approximately $49 million, primarily associated with the Company's commodity derivative repositioning in July 2009 (see Note 7).

(2) General and administrative expenses for the years ended December 31, 2010, and December 31, 2009, include approximately $13 million and $15 million, respectively, of noncash unit-based compensation expenses.

(3) This is a non-GAAP measure used by management to analyze the Company's performance. See "Non-GAAP Financial Measures" on page 58 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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	Year Ended December 31, 2010	Year Ended December 31, 2009	Variance
Average daily production:			
Natural gas (MMcf/d)	137	125	10 %
Oil (MBbls/d)	13.1	9.0	46 %
NGL (MBbls/d)	8.3	6.5	28 %
Total (MMcfe/d)	265	218	22 %
Weighted average prices (hedged): (1)			
Natural gas (Mcf)	$ 8.52	$ 8.27	3 %
Oil (Bbl)	$ 94.71	$ 110.94	(15)%
NGL (Bbl)	$ 39.14	$ 28.04	40 %
Weighted average prices (unhedged): (2)			
Natural gas (Mcf)	$ 4.24	$ 3.51	21 %
Oil (Bbl)	$ 75.16	$ 55.25	36 %
NGL (Bbl)	$ 39.14	$ 28.04	40 %
Average NYMEX prices:			
Natural gas (MMBtu)	$ 4.40	$ 3.99	10 %
Oil (Bbl)	$ 79.53	$ 61.94	28 %
Costs per Mcfe of production:			
Lease operating expenses	$ 1.64	$ 1.67	(2)%
Transportation expenses	$ 0.20	$ 0.23	(13)%
General and administrative expenses (3)	$ 1.02	$ 1.08	(6)%
Depreciation, depletion and amortization	$ 2.46	$ 2.53	(3)%
Taxes, other than income taxes	$ 0.47	$ 0.35	34 %

(1) Includes the effect of realized gains on derivatives of approximately $308 million and $401 million (excluding $49 million realized net gains on canceled contracts) for the years ended December 31, 2010, and December 31, 2009, respectively.

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

(3) General and administrative expenses for the years ended December 31, 2010, and December 31, 2009, include approximately $13 million and $15 million, respectively, of noncash unit-based compensation expenses. Excluding these amounts, general and administrative expenses for the years ended December 31, 2010, and December 31, 2009, were $0.88 per Mcfe and $0.90 per Mcfe, respectively. This is a non-GAAP measure used by management to analyze the Company's performance.

Revenues and Other

Oil, Natural Gas and NGL Sales
Oil, natural gas and NGL sales increased by approximately $282 million or 69% to approximately $690 million for the year ended December 31, 2010, from approximately $408 million for the year ended December 31, 2009, due to higher commodity prices and higher production volumes. Higher oil, natural gas and NGL prices resulted in an increase in revenues of approximately $95 million, $36 million and $34 million, respectively.

Average daily production volumes increased to 265 MMcfe/d during the year ended December 31, 2010, from 218 MMcfe/d during the year ended December 31, 2009. Higher oil, natural gas and NGL production volumes resulted in an increase in revenues of approximately $83 million, $15 million and $19 million, respectively.

The following sets forth average daily production by region:

	Year Ended December 31,			
	2010	2009	Variance	
Average daily production (MMcfe/d):				
Mid-Continent Deep	133	135	(2)	(1)%
Mid-Continent Shallow	66	67	(1)	(1)%
Permian Basin	31	2	29	1,450 %
Michigan	21	—	21	—
California	14	14	—	—
	265	218	47	22 %

The 1% decrease in average daily production volumes in the Mid-Continent Deep region primarily reflects natural declines, in addition to minimal capital development during the second half of 2009 due to low commodity prices, partially offset by the impact of the Company’s 2010 capital drilling program in the Deep Granite Wash formation. Average daily production volumes in the Mid-Continent Shallow region reflect the impact of drilling and optimization programs which offset the effects of natural declines. Average daily production volumes in the Permian Basin region reflect the impact of the acquisitions in 2010 and the third quarter of 2009 and subsequent development capital spending. Average daily production volumes in the Michigan region reflect the impact of the Company’s acquisitions in this area in 2010 (see Note 2). The California region consists of a low-decline asset base and continues to produce at levels consistent with prior year.

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 year ended December 31, 2010, the Company had commodity derivative contracts for approximately 114% of its natural gas production and 97% of its oil production, which resulted in realized gains of approximately $308 million. During the year ended December 31, 2009, the Company recorded realized gains of approximately $450 million (including realized net gains on canceled contracts of approximately $49 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 2010, expected future oil prices increased and expected future natural gas prices decreased, which

resulted in net unrealized losses on derivatives of approximately $232 million for the year ended December 31, 2010. During 2009, expected future oil prices increased and expected future natural gas prices decreased, which resulted in net unrealized losses on derivatives of approximately $591 million for the year ended December 31, 2009. For information about the Company’s credit risk related to derivative contracts, see “Counterparty Credit Risk” in “Liquidity and Capital Resources” below.

Expenses

Lease Operating Expenses

Lease operating expenses include expenses such as labor, field office, vehicle, supervision, maintenance, tools and supplies and workover expenses. Lease operating expenses increased by approximately $25 million or 19% to approximately $158 million for the year ended December 31, 2010, from approximately $133 million for the year ended December 31, 2009. Lease operating expenses increased primarily due to costs associated with properties acquired in the Permian Basin and Michigan regions in 2010 and the second half of 2009 (see Note 2). Lease operating expenses per Mcfe decreased to $1.64 per Mcfe for the year ended December 31, 2010, from $1.67 per Mcfe for the year ended December 31, 2009.

Transportation Expenses

Transportation expenses increased by approximately $1 million or 8% to approximately $19 million for the year ended December 31, 2010, from approximately $18 million for the year ended December 31, 2009, primarily due to higher total production volume levels from the Company's acquisitions in the Permian Basin and Michigan regions in 2010 and the second half of 2009, partially offset by lower rates associated with owned facilities.

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 by approximately $13 million or 15% to approximately $99 million for the year ended December 31, 2010, from approximately $86 million for the year ended December 31, 2009. The increase was primarily due to an increase in salaries and benefits expense of approximately $10 million, driven primarily by increased employee headcount, and acquisition integration expenses of approximately $4 million. General and administrative expenses per Mcfe decreased to $1.02 per Mcfe for the year ended December 31, 2010, from $1.08 per Mcfe for the year ended December 31, 2009.

Exploration Costs

Exploration costs decreased by approximately $2 million or 28% to approximately $5 million for the year ended December 31, 2010, from approximately $7 million for the year ended December 31, 2009. The decrease was primarily due to fewer lease-term expirations related to unproved leasehold costs.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization increased by approximately $37 million or 18% to approximately $239 million for the year ended December 31, 2010, from approximately $202 million for the year ended December 31, 2009. Higher total production volume levels, primarily due to the Company's acquisitions in the Permian Basin and Michigan regions in 2010 and in the Permian Basin region in the second half of 2009, were the main reason for the increase. Depreciation, depletion and amortization per Mcfe decreased to $2.46 per Mcfe for the year ended December 31, 2010, from $2.53 per Mcfe for the year ended December 31, 2009.

Impairment of Long-Lived Assets

During the year ended December 31, 2010, the Company recorded a noncash impairment charge of approximately $39 million primarily associated with the impairment of proved oil and natural gas properties related to an unfavorable marketing contract. The Company recorded no impairment charge for the year ended December 31, 2009. See Note 1 and "Critical Accounting Policies and Estimates" below for additional information.

Taxes, Other Than Income Taxes

Taxes, other than income taxes, which consist primarily of severance and ad valorem taxes, increased by approximately $17 million or 64% to approximately $45 million for the year ended December 31, 2010, from approximately $28 million for the year ended December 31, 2009. Severance taxes, which are a function of revenues generated from production, increased by approximately $14 million compared to the year ended December 31, 2009, primarily due to higher commodity prices and higher total production volume levels. Ad valorem taxes, which are based on the value of reserves and production equipment and vary by location, increased

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by approximately $2 million compared to the year ended December 31, 2009, primarily due to property acquisitions in the Permian Basin region.

Other Income and (Expenses)

	Year Ended December 31, 2010	2009	Variance
		(in thousands)	
Interest expense, net of amounts capitalized	$ (193,510)	$ (92,701)	$ (100,809)
Realized losses on interest rate swaps	(8,021)	(42,881)	34,860
Realized losses on canceled interest rate swaps	(123,865)	(60)	(123,805)
Unrealized gains on interest rate swaps	63,978	16,588	47,390
Other, net	(7,167)	(2,661)	(4,506)
	$ (268,585)	$ (121,715)	$ (146,870)

Other income and (expenses) increased by approximately $147 million during the year ended December 31, 2010, compared to the year ended December 30, 2009. During the year ended December 31, 2010, the Company canceled (before the contract settlement date) all of its interest rate swap agreements, resulting in higher realized losses of approximately $124 million. These losses were partially offset by an increase in unrealized gains on interest rate swaps and a decrease in realized losses on interest rate swaps during the year ended December 31, 2010, compared to the year ended December 31, 2009. Additionally, in the second and third quarters of 2010, the Company entered into an amendment to its Credit Facility and issued the 2010 Issued Senior Notes, as defined in Note 6, which resulted in increased interest expense due to higher interest rates and higher amortization of financing fees. 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 $4 million for the year ended December 31, 2010, compared to an income tax benefit of approximately $4 million for the same period in 2009. Income tax expense increased primarily due to an increase in income in 2010 from the Company's taxable subsidiaries. In 2009, the Company released a valuation allowance on a significant portion of the deferred tax assets at the Company's taxable subsidiaries.

Adjusted EBITDA

Adjusted EBITDA (a non-GAAP financial measure) increased by approximately $166 million or 29% to approximately $732 million for the year ended December 31, 2010, from approximately $566 million for the year ended December 31, 2009. The increase was primarily due to higher production revenues resulting from higher commodity prices and higher total production volume levels, partially offset by lower realized gains on commodity derivatives. See "Non-GAAP Financial Measures" on page 58 for a reconciliation of adjusted EBITDA to its most directly comparable financial measure calculated and presented in accordance with GAAP.

Reserve Replacement Metrics

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

$$\text{Reserve replacement cost per Mcfe} = \frac{\text{Oil and natural gas capital costs expended (1)}}{\text{Sum of reserve additions (2)}}$$

$$\text{Reserve replacement ratio} = \frac{\text{Sum of reserve additions (2)}}{\text{Annual production}}$$

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

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

The reserve replacement metrics are presented separately, both: (i) including and excluding the impact of price revisions on reserves, to demonstrate the effectiveness of the Company's drilling program exclusive of economic factors (such as price) outside of its control and (ii) including and excluding acquisitions, to demonstrate the Company's ability to add reserves through its drilling program and through acquisitions. Reserve replacement cost and reserve replacement ratio are non-GAAP financial measures. The methods used by the Company to calculate these measures may differ from methods used by other companies to compute similar measures. As a result, the Company's measures may not be comparable to similar measures provided by other companies. The Company believes that providing such measures is useful in evaluating the cost to add proved reserves; however, these measures should not be considered in isolation or as a substitute for GAAP measures. The reserve replacement cost per Mcfe and reserve replacement ratio are statistical indicators that have limitations, including their predictive and comparative value. The reserve replacement ratio is limited because it may vary widely based on the extent and timing of new discoveries, project sanctioning and property acquisitions. In addition, since the reserve replacement ratio does not consider the development cost or timing of future production of new reserves, it should not be used as a measure of value creation.

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The following presents reserve replacement cost and reserve replacement ratio including and excluding the effect of price revisions on reserves:

	Including Price Revisions Year Ended December 31,			Excluding Price Revisions Year Ended December 31,		
	2011	2010	2009	2011	2010	2009
Costs per Mcfe of production:						
Reserve replacement cost, including acquisitions	$2.37	$1.63	$1.96	$2.46	$1.94	$1.71
Reserve replacement cost, excluding acquisitions (finding and development cost)	$1.94	$0.79	$2.03	$2.15	$1.57	$1.59
Percentage of production:						
Reserve replacement ratio, including acquisitions	674 %	1,014 %	165 %	651 %	854 %	189 %
Reserve replacement ratio, excluding acquisitions	244 %	321 %	88 %	221 %	161 %	112 %

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

	Year Ended December 31,		
	2011	2010	2009
		(in thousands)	
Costs incurred in oil and natural gas property acquisition, exploration and development	$ 2,158,639	$ 1,602,086	$ 258,105
Less:			
Asset retirement costs	(2,427)	(748)	(371)
Property acquisition costs	(1,516,737)	(1,356,430)	(115,929)
Oil and natural gas capital costs expended, excluding acquisitions	$ 639,475	$ 244,908	$ 141,805

Liquidity and Capital Resources

The Company utilizes funds from equity and debt offerings, bank borrowings and cash flow from operations for capital resources and liquidity. To date, the primary use of capital has been for acquisitions and the development of oil and natural gas properties. For the year ended December 31, 2011, the Company's total capital expenditures, excluding acquisitions, were approximately $697 million. For 2012, the Company estimates its total capital expenditures, excluding acquisitions, will be approximately $940 million, including $880 million related to its oil and natural gas capital program and $40 million related to its plant and pipeline capital. This estimate reflects amounts for the development of properties associated with acquisitions (see Note 2), is under continuous review and subject to ongoing adjustments. The Company expects to fund these capital expenditures primarily with cash flow from operations and bank borrowings.

As the Company pursues growth, it continually monitors the capital resources available to meet future financial obligations and planned capital expenditures. The Company's future success in growing reserves and production volumes will be highly dependent on the capital resources available and its success in drilling for or acquiring additional reserves. The Company actively reviews acquisition opportunities on an ongoing basis. If the Company were to make significant additional acquisitions for cash, it would need to borrow additional amounts under its Credit Facility, if available, or obtain additional debt or equity financing. The Company's Credit Facility and

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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:

	Year Ended December 31,		
	2011	2010	2009
		(in thousands)	
Net cash:			
Provided by operating activities (1)	$ 518,706	$ 270,918	$ 426,804
Used in investing activities	(2,130,360)	(1,581,408)	(282,273)
Provided by (used in) financing activities	1,376,767	1,524,260	(150,968)
Net increase (decrease) in cash and cash equivalents	$ (234,887)	$ 213,770	$ (6,437)

(1) The years ended December 31, 2011, December 31, 2010, and December 31, 2009, include premiums paid for derivatives of approximately $134 million, $120 million and $94 million, respectively.

Operating Activities

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

Cash provided by operating activities was approximately $271 million for the year ended December 31, 2010, compared to approximately $427 million for the year ended December 31, 2009. The decrease was primarily due to approximately $124 million in realized losses on canceled interest rate derivatives during the year ended December 31, 2010, compared to approximately $49 million in realized net gains on canceled commodity derivatives during the year ended December 31, 2009.

Premiums paid during 2011, 2010 and 2009 were for commodity derivative contracts that hedge future production. These derivative contracts provide the Company long-term cash flow predictability to manage its business, service debt and pay distributions and are primarily funded through the Company's Credit Facility. The amount of derivative contracts the Company enters into in the future will be directly related to expected future production. See Note 7 and Note 8 for additional details about the Company's commodity derivatives.

Investing Activities

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

	Year Ended December 31,		
	2011	2010	2009
		(in thousands)	
Cash flow from investing activities:			
Acquisition of oil and natural gas properties, net of cash acquired	$ (1,500,193)	$ (1,351,033)	$ (130,735)

Capital expenditures		(629,864)		(223,013)		(178,242)
Proceeds from sale of properties and equipment and other		(303)		(7,362)		26,704
	$	(2,130,360)	$	(1,581,408)	$	(282,273)

The primary use of cash in investing activities is for capital spending, including acquisitions and the development of the Company's oil and natural gas properties. Cash used in investing activities for the year ended December 31, 2011, primarily relates to acquisitions of properties in the Williston Basin, Permian Basin and Mid-Continent Deep regions. See Note 2 for additional details of acquisitions. The year ended December 31, 2011, also includes the deposit of approximately $9 million returned to the Company by the other party to the purchase and sale agreement ("PSA") terminated by the Company in 2010.

Cash used in investing activities for the year ended December 31, 2010, primarily relates to acquisitions and the development of properties in the Permian Basin, Mid-Continent Deep and Michigan regions (see Note 2). Proceeds from the sale of properties were lower for the year ended December 31, 2010, compared to the year ended December 31, 2009, primarily due to the proceeds received in 2009 related to the sale of acreage in central Oklahoma. The year ended December 31, 2010, also includes the deposit made by the Company of approximately $9 million and held by the other party to the PSA terminated by the Company (see Note 2). Cash used in investing activities for the year ended December 31, 2009, includes approximately $114 million for the acquisition of properties in the Permian Basin region (see Note 2).

Financing Activities

Cash provided by financing activities for the year ended December 31, 2011, was approximately $1.4 billion compared to approximately $1.5 billion for the year ended December 31, 2010. The decrease in financing cash flow needs was primarily attributable to the increase in cash provided by operating activities and the utilization of cash on hand. In comparison, cash used in financing activities was approximately $151 million for the year ended December 31, 2009. The following provides a comparative summary of proceeds from borrowings and repayments of debt:

	Year Ended December 31,		
	2011	2010	2009
		(in thousands)	
Proceeds from borrowings:			
Credit facility	$ 1,790,000	$ 1,050,000	$ 401,500
Senior notes	744,240	2,250,816	237,703
	$ 2,534,240	$ 3,300,816	$ 639,203
Repayments of debt:			
Credit facility	$ (850,000)	$ (2,150,000)	$ (704,893)
Senior notes	(451,029)	—	—
	$ (1,301,029)	$ (2,150,000)	$ (704,893)

Debt

The Company's Credit Facility has a borrowing base of $3.0 billion with a maximum commitment amount of $1.5 billion. The maturity date is April 2016. At January 31, 2012, the borrowing capacity under the Credit Facility was approximately $1.3 billion, which includes a $4 million reduction in availability for outstanding letters of credit.

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, 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.

In March 2011, in connection with its cash tender offers and related consent solicitations, the Company also accepted and purchased: 1) $105 million of the aggregate principal amount of its outstanding 2017 Senior Notes (or 65% of the remaining outstanding principal amount of its 2017 Senior Notes), and 2) $126 million aggregate principal amount of its outstanding 2018 Senior Notes (or 76% of the remaining outstanding principal amount of its 2018 Senior Notes).

In May 2011, the Company 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 approximately $17 million (or 29% of the remaining outstanding principal amount of its 2017 Senior Notes) and approximately $24 million (or 61% of the remaining outstanding principal amount of its 2018 Senior Notes), respectively. In December 2011, the Company also repurchased an additional portion of its remaining outstanding 2018 Senior Notes for approximately $2 million (or 9% of the remaining outstanding principal amount of the 2018 Senior Notes). 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 $14 million, respectively, remained outstanding at December 31, 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 drilling and development of oil and natural gas properties and acquisitions and borrows as cash is needed. Absent such borrowings, the Company would have at times experienced a shortfall in cash available to pay the declared quarterly cash distribution amount. If an event of default occurs and is continuing under the Credit Facility, the Company would be unable to make borrowings to fund distributions. For additional information about this matter and other risk factors that could affect the Company, see Item 1A. “Risk Factors.”

Counterparty Credit Risk

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

Equity Distribution Agreement

On August 23, 2011, the Company entered into an equity distribution agreement, pursuant to which it may from time to time issue and sell units representing limited liability company interests having an aggregate offering price of up to $500 million. In connection with entering into the agreement, the Company incurred expenses of approximately $423,000. Sales of units, if any, will be made through a sales agent by means of ordinary brokers’ transactions, in block transactions, or as otherwise agreed with the agent. The Company expects to use the net proceeds from any sale of the units for general corporate purposes, which may include, among other things, capital expenditures, acquisitions and the repayment of debt.

In September 2011, the Company issued and sold 16,060 units representing limited liability company interests at an average unit price of $38.25 for proceeds of approximately $602,000 (net of approximately $12,000 in commissions). In December 2011, the Company issued and sold 772,104 units representing limited liability company interests at an average unit price of $38.03 for proceeds of approximately $29 million (net of approximately $587,000 in commissions). In connection with the issue and sale of these units, the Company incurred professional service expenses of approximately $139,000. The Company used the net proceeds for general corporate purposes including the repayment of a portion of the indebtedness outstanding under its Credit Facility. At December 31, 2011, units equaling approximately $470 million in aggregate offering price remained available to be issued and sold under the agreement.

In January 2012, the Company issued and sold 1,539,651 units representing limited liability company interests at an average unit price of $38.02 for proceeds of approximately $57 million (net of approximately $1 million in commissions). The net proceeds were used for general corporate purposes including the repayment of a portion of the indebtedness outstanding under the Company's Credit Facility. At January 31, 2012, units equaling approximately $411 million in aggregate offering price remained available to be issued and sold under the agreement.

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

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

Unit Repurchase Plan

In October 2008, the Board of Directors of the Company authorized the repurchase of up to $100 million of the Company's outstanding units from time to time on the open market or in negotiated purchases. In August 2011, the Company repurchased 400,000 units at an average unit price of $32.98 for a total cost of approximately $13 million. In addition, in October 2011, the Company repurchased 129,734 units at an average unit price of $32.08 for a total cost of approximately $4 million.

Distributions

Under the Company's limited liability company agreement, unitholders are entitled to receive a quarterly distribution of available cash to the extent there is sufficient cash from operations after establishment of cash reserves and payment of fees and expenses. The following provides a summary of distributions paid by the Company during the year ended December 31, 2011:

Date Paid	Period Covered by Distribution	Distribution Per Unit	Total Distribution (in millions)
November 2011	July 1 – September 30, 2011	$ 0.69	$ 122
August 2011	April 1 – June 30, 2011	$ 0.69	$ 123
May 2011	January 1 – March 31, 2011	$ 0.66	$ 116
February 2011	October 1 – December 31, 2010	$ 0.66	$ 106

On July 26, 2011, the Company's Board of Directors approved an increase in the quarterly cash distribution from $0.66 per unit to $0.69 per unit, representing an increase of 5%. On January 27, 2012, 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 fourth quarter of 2011. The distribution, totaling approximately $138 million, was paid on February 14, 2012, to unitholders of record as of the close of business on February 7, 2012.

Contingencies

The Company has been named as a defendant in a number of lawsuits and is involved in various other disputes arising in the ordinary course of business, 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. The Company is not currently a party to any litigation or pending claims that it believes would have a material adverse effect on its overall business, financial position, results of operations or liquidity; however, cash flow could be significantly impacted in the reporting periods in which such matters are resolved.

During the years ended December 31, 2011, December 31, 2010, and December 31, 2009, the Company made no significant payments to settle any legal, environmental or tax proceedings. The Company regularly analyzes current information and accrues for probable liabilities on the disposition of certain matters as necessary. Liabilities for loss contingencies arising from claims, assessments, litigation or other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated.

In 2008, Lehman Brothers Holdings Inc. ("Lehman Holdings") and Lehman Brothers Commodity Services Inc. ("Lehman Commodity Services") filed voluntary petitions for reorganization under Chapter 11 of the U.S. Bankruptcy Code. At December 31, 2011, and December 31, 2010, the Company had a net receivable of approximately $7 million from Lehman Commodity Services for canceled derivative contracts, which is included in "other current assets" on the consolidated balance sheets. The value of the receivable was estimated based on market expectations. In March 2011, the Company, Lehman Holdings and Lehman Commodity Services entered into Termination Agreements under which the Company was granted general unsecured claims against Lehman Holdings and Lehman Commodity Services in the amount of $51 million each, provided that the aggregate value of the distributions to the Company on account of both such claims will not exceed $51 million (collectively, the "Company Claim"). On December 6, 2011, a Chapter 11 Plan ("Plan") was approved by the Bankruptcy Court. Initial distributions under the Plan to creditors, including the Company, are expected to occur after January 31, 2012. Based on the recovery estimates described in the approved disclosure statement relating to the Plan, the Company expects to ultimately receive a substantial portion of the Company Claim.

Commitments and Contractual Obligations

The following summarizes, as of December 31, 2011, certain long-term contractual obligations that are reflected in the consolidated balance sheets and/or disclosed in the accompanying notes thereto:

			Payments Due		
Contractual Obligations	Total	2012	2013 – 2014	2015 – 2016	2017 and Beyond
			(in thousands)		
Long-term debt obligations:					
Credit facility	$940,000	$—	$—	$940,000	$—
Senior notes	3,104,898	—	—	—	3,104,898
Interest (1)	2,130,681	268,718	537,436	519,317	805,210
Operating lease obligations:					
Office, property and equipment leases	31,477	5,652	9,367	7,405	9,053
Other noncurrent liabilities:					
Asset retirement obligations	71,142	2,847	3,353	3,438	61,504
Other:					
Commodity derivatives	17,563	14,060	1,772	1,731	—

Charitable contributions	222	111	111	—	—
	$6,295,983	$291,388	$552,039	$1,471,891	$3,980,665

(1) Represents interest on the Credit Facility computed at the weighted average LIBOR of 2.57% through maturity in April 2016 and interest on the 2019 Senior Notes, 2010 Issued Senior Notes, and the Original Senior Notes, as defined in Note 6, computed at fixed rates of 11.75%, 9.875%, 6.50%, 8.625% and 7.75% through maturities in May 2017, July 2018, May 2019, April 2020 and February 2021, respectively.

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Capital Structure

The Company's capitalization is presented below:

	December 31, 2011	December 31, 2010
	(in thousands)	
Cash and cash equivalents	$ 1,114	$ 236,001
Credit facility	$ 940,000	$
Senior notes due 2017, net	39,183	239,301
Senior notes due 2018, net	13,913	250,974
Senior notes due 2019, net	744,593	—
Senior notes due 2020, net	1,271,856	1,269,661
Senior notes due 2021, net	984,112	982,966
	3,993,657	2,742,902
Total unitholders' capital	3,428,910	2,788,216
	$ 7,422,567	$ 5,531,118

Non-GAAP Financial Measures

The non-GAAP financial measures of adjusted EBITDA and adjusted net income, as defined by the Company, may not be comparable to similarly titled measures used by other companies. Therefore, these non-GAAP measures should be considered in conjunction with income from continuing operations 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 income (loss) from continuing operations plus the following adjustments:

- Net operating cash flow from acquisitions and divestitures, effective date through closing date;
- Interest expense;
- Depreciation, depletion and amortization;
- Impairment of long-lived assets;
- Write-off of deferred financing fees 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;

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- Exploration costs; and
- Income tax (benefit) expense.

The following presents a reconciliation of income (loss) from continuing operations to adjusted EBITDA:

	Year Ended December 31,		
	2011	2010	2009
		(in thousands)	
Income (loss) from continuing operations	$ 438,439	$ (114,288)	$ (295,841)
Plus:			
Net operating cash flow from acquisitions and divestitures, effective date through closing date	57,966	42,846	3,708
Interest expense, cash	249,085	129,691	74,185
Interest expense, noncash	10,640	63,819	18,516
Depreciation, depletion and amortization	334,084	238,532	201,782
Impairment of long-lived assets		38,600	
Write-off of deferred financing fees and other	1,189	2,076	204
(Gains) losses on sale of assets and other, net	124	3,008	(23,051)
Provision for legal matters	1,086	4,362	
Loss on extinguishment of debt	94,612		
Unrealized (gains) losses on commodity derivatives	(192,951)	232,376	591,379
Unrealized gains on interest rate derivatives		(63,978)	(16,588)
Realized losses on interest rate derivatives		8,021	42,881
Realized (gains) losses on canceled derivatives	(26,752)	123,865	(48,977)
Unit-based compensation expenses	22,243	13,792	15,089
Exploration costs	2,390	5,168	7,169
Income tax (benefit) expense	5,466	4,241	(4,221)
Adjusted EBITDA from continuing operations	$ 997,621	$ 732,131	$ 566,235

Net cash provided by operating activities for the year ended December 31, 2011, was approximately $519 million and includes cash interest payments of approximately $247 million, premiums paid for commodity derivatives of approximately $134 million, realized gains on canceled derivatives of approximately $(27) million and other items totaling approximately $125 million that are not included in adjusted EBITDA. Net cash provided by operating activities for the year ended December 31, 2010, was approximately $271 million and includes cash interest payments of approximately $129 million, premiums paid for commodity derivatives of approximately $120 million, cash settlements on interest rate derivatives of approximately $11 million, realized losses on canceled derivatives of approximately $124 million and other items totaling approximately $77 million that are not included in adjusted EBITDA. Net cash provided by operating activities for the year ended December 31, 2009, was approximately $427 million and includes cash interest payments of approximately $74 million, premiums paid for commodity derivatives of approximately $94 million, cash settlements on interest rate derivatives of approximately $42 million, realized gains on canceled derivatives of approximately $(49) million and other items totaling approximately $(22) 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 long-lived assets, loss on extinguishment of debt and (gains) losses on sale of assets, net.

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

	Year Ended December 31,		
	2011	2010	2009
	(in thousands, except per unit amounts)		
Income (loss) from continuing operations	$ 438,439	$ (114,288)	$ (295,841)
Plus:			
Unrealized (gains) losses on commodity derivatives	(192,951)	232,376	591,379
Unrealized gains on interest rate derivatives		(63,978)	(16,588)
Realized (gains) losses on canceled derivatives	(26,752)	123,865	(48,977)
Impairment of long-lived assets		38,600	
Loss on extinguishment of debt	94,612		
(Gains) losses on sale of assets, net	(17)	2,914	(23,051)
Adjusted net income from continuing operations	$ 313,331	$ 219,489	$ 206,922
Income (loss) from continuing operations per unit – basic	$ 2.52	$ (0.80)	$ (2.48)
Plus, per unit:			
Unrealized (gains) losses on commodity derivatives	(1.11)	1.63	4.95
Unrealized gains on interest rate derivatives		(0.45)	(0.14)
Realized (gains) losses on canceled derivatives	(0.15)	0.87	(0.41)
Impairment of long-lived assets		0.27	
Loss on extinguishment of debt	0.54		
(Gains) losses on sale of assets, net		0.02	(0.19)
Adjusted net income from continuing operations per unit – basic	$ 1.80	$ 1.54	$ 1.73

Critical Accounting Policies and Estimates

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

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

Recently Issued Accounting Standards Not Yet Adopted

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

In May 2011, the FASB issued an ASU that further addresses fair value measurement accounting and related disclosure requirements. The ASU clarifies the FASB's intent regarding the application of existing fair value measurement and disclosure requirements, changes the fair value measurement requirements for certain financial instruments, and sets forth additional disclosure requirements for other fair value measurements. The ASU will be applied prospectively and is effective for periods beginning after December 15, 2011. The Company is currently evaluating the impact, if any, of the adoption of this ASU on its consolidated financial statements and related disclosures.

Oil and Natural Gas Reserves

Proved reserves are based on the quantities of oil, natural gas and NGL that by analysis of geoscience and engineering data can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain. The independent engineering firm, DeGolyer and MacNaughton, prepared a reserve and economic evaluation of all of the Company properties on a well-by-well basis as of December 31, 2011, and the reserve estimates reported herein were prepared by DeGolyer and MacNaughton. The reserve estimates were reviewed and approved by the Company's senior engineering staff and management, with final approval by its Executive Vice President and Chief Operating Officer.

Reserves and their relation to estimated future net cash flows impact the Company's depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. The process performed by the independent engineers to prepare reserve amounts included their estimation of reserve quantities, future producing rates, future net revenue and the present value of such future net revenue, based in part on data provided by the Company. The estimates of reserves conform to the guidelines of the SEC, including the criteria of "reasonable certainty," as it pertains to expectations about the recoverability of reserves in future years.

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

Oil and Natural Gas Properties

Proved Properties
The Company accounts for oil and natural gas properties in accordance with the successful efforts method. In accordance with this method, all leasehold and development costs of proved properties are capitalized and amortized

on a unit-of-production basis over the remaining life of the proved reserves and proved developed reserves, respectively.

The Company evaluates the impairment of its proved oil and natural gas properties on a field-by-field basis whenever events or changes in circumstances indicate that the carrying value may not be recoverable. The carrying values of proved properties are reduced to fair value when the expected undiscounted future cash flows are less than net book value. The fair values of proved properties are measured using valuation techniques consistent with the income approach, converting future cash flows to a single discounted amount. Significant inputs used to determine the fair values of proved properties include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; and (iv) a market-based weighted average cost of capital rate. The underlying commodity prices embedded in the Company's estimated cash flows are the product of a process that begins with New York Mercantile Exchange ("NYMEX") forward curve pricing, adjusted for estimated location and quality differentials, as well as other factors that Company management believes will impact realizable prices. Costs of retired, sold or abandoned properties that constitute a part of an amortization base are charged or credited, net of proceeds, to accumulated depreciation, depletion and amortization unless doing so significantly affects the unit-of-production amortization rate, in which case a gain or loss is recognized currently. Gains or losses from the disposal of other properties are recognized currently. Expenditures for maintenance and repairs necessary to maintain properties in operating condition are expensed as incurred. Estimated dismantlement and abandonment costs are capitalized, net of salvage, at their estimated net present value and amortized on a unit-of-production basis over the remaining life of the related proved developed reserves. The Company capitalizes interest on borrowed funds related to its share of costs associated with the drilling and completion of new oil and natural gas wells. Interest is capitalized only during the periods in which these assets are brought to their intended use. The Company capitalized interest costs of approximately $2 million, $1 million and $300,000 for the years ended December 31, 2011, December 31, 2010, and December 31, 2009, respectively.

Impairment of Proved Properties

Based on the analysis described above, the Company recorded no impairment charge of proved oil and natural gas properties for the years ended December 31, 2011, and December 31, 2009. For the year ended December 31, 2010, the Company recorded a noncash impairment charge, before and after tax, of approximately $39 million primarily associated with proved oil and natural gas properties related to an unfavorable marketing contract. The carrying values of the impaired proved properties were reduced to fair value, estimated using inputs characteristic of a Level 3 fair-value measurement. The charges are included in "impairment of long-lived assets" on the consolidated statements of operations.

Unproved Properties

Costs related to unproved properties include costs incurred to acquire unproved reserves. Because these reserves do not meet the definition of proved reserves, the related costs are not classified as proved properties. The fair values of unproved properties are measured using valuation techniques consistent with the income approach, converting future cash flows to a single discounted amount. Significant inputs used to determine the fair values of unproved properties include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; and (iv) a market-based weighted average cost of capital rate. The market-based weighted average cost of capital rate is subjected to additional project-specific risking factors. Unproved leasehold costs are capitalized and amortized on a composite basis if individually insignificant, based on past success, experience and average lease-term lives. Individually significant leases are reclassified to proved properties if successful and expensed on a lease by lease basis if unsuccessful or the lease term expires. Unamortized leasehold costs related to successful exploratory drilling are reclassified to proved properties and depleted on a unit-of-production basis. The Company assesses unproved properties for impairment quarterly on the basis of its experience in similar situations and other factors such as the primary lease terms of the properties, the average holding period of unproved properties, and the relative proportion of such properties on which proved reserves have been found in the past.

Exploration Costs

Geological and geophysical costs, delay rentals, amortization and impairment of unproved leasehold costs and costs to drill exploratory wells that do not find proved reserves are expensed as exploration costs. The costs of any exploratory wells are carried as an asset if the well finds a sufficient quantity of reserves to justify its capitalization as a producing well and as long as the Company is making sufficient progress towards assessing the reserves and the economic and operating viability of the project. The Company recorded noncash leasehold impairment expenses related to unproved properties of approximately $2 million, $5 million and $7 million for the years ended December 31, 2011, December 31, 2010, and December 31, 2009, which are included in “exploration costs” on the consolidated statements of operations.

Revenue Recognition

Sales of oil, natural gas and NGL are recognized when the product has been delivered to a custody transfer point, persuasive evidence of a sales arrangement exists, the rights and responsibility of ownership pass to the purchaser upon delivery, collection of revenue from the sale is reasonably assured, and the sales price is fixed or determinable.

The Company has elected the entitlements method to account for natural gas production imbalances. Imbalances occur when the Company sells more or less than its entitled ownership percentage of total natural gas production. In accordance with the entitlements method, any amount received in excess of the Company’s share is treated as a liability. If the Company receives less than its entitled share, the underproduction is recorded as a receivable. At December 31, 2011, and December 31, 2010, the Company had natural gas production imbalance receivables of approximately $19 million and $18 million, respectively, which are included in “accounts receivable – trade, net” on the consolidated balance sheets and natural gas production imbalance payables of approximately $9 million and $8 million, respectively, which are included in “accounts payable and accrued expenses” on the consolidated balance sheets.

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

Asset Retirement Obligations

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

Derivative Instruments

The Company uses derivative financial instruments to reduce exposure to fluctuations in the prices of oil and natural gas. By removing a significant portion of the price volatility associated with future production, the Company expects to mitigate, but not eliminate, the potential effects of variability in cash flow from operations due to fluctuations in commodity prices. These transactions are primarily in the form of swap contracts and put options. A swap contract specifies a fixed price that the Company will receive from the counterparty as compared to floating market prices, and on the settlement date the Company will receive or pay the difference between the swap price and the market price. A put option requires the Company to pay the counterparty a premium equal to the fair value of the option at the purchase date and receive from the counterparty the excess, if any, of the fixed price floor over the market price at the settlement date. In addition, the Company may from time to time enter into derivative contracts in the form of interest rate swaps to minimize the effects of fluctuations in interest rates. Currently, the Company has no outstanding derivative contracts in the form of interest rate swaps.

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

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

Acquisition Accounting

The Company accounts for business combinations under the acquisition method of accounting (see Note 2). Accordingly, the Company recognizes amounts for identifiable assets acquired and liabilities assumed equal to their estimated acquisition date fair values. Transaction and integration costs associated with business combinations are expensed as incurred.

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

Any excess of the acquisition price over the estimated fair value of net assets acquired is recorded as goodwill while any excess of the estimated fair value of net assets acquired over the acquisition price is recorded in current earnings as a gain. Deferred taxes are recorded for any differences between the assigned values and the tax basis of assets and liabilities. Estimated deferred taxes are based on available information concerning the tax basis of assets acquired and liabilities assumed and loss carryforwards at the acquisition date, although such estimates may change in the future as additional information becomes known.

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

Legal, Environmental and Other Contingencies

A provision for legal, environmental and other contingencies is charged to expense when the loss is probable and the cost can be reasonably estimated. Determining when expenses should be recorded for these contingencies and the appropriate amounts of the accrual is subject to an estimation process that requires subjective judgment of management. In many cases, management's judgment is based on the advice and opinions of legal counsel and other advisers, the interpretation of laws and regulations which can be interpreted differently by regulators and/or courts of law, the experience of the Company and other companies dealing with similar matters, and management's decision on how it intends to respond to a particular matter; for example, a decision to contest it vigorously or a decision to seek a negotiated settlement. The Company's management closely monitors known and potential legal, environmental and other contingencies and periodically determines when it should record losses for these items based on information available to the Company.

Unit-Based Compensation

The Company recognizes expense for unit-based compensation over the requisite service period in an amount equal to the fair value of unit-based payments granted to employees and nonemployee directors. See Note 1 and Note 5 for additional details about the Company's accounting for unit-based compensation.

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Item 7A. Quantitative and Qualitative Disclosures About Market Risk

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

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

Commodity Price Risk

The Company enters into derivative contracts with respect to a portion of its projected production through various transactions that provide an economic hedge of the risk related to the future commodity prices received. The Company does not enter into derivative contracts for trading purposes (see Note 7). At December 31, 2011, the fair value of contracts that settle during the next 12 months was an asset of approximately $232 million and a liability of $11 million for a net asset of approximately $221 million. A 10% increase in the index oil and natural gas prices above the December 31, 2011, prices for the next 12 months would result in a net asset of approximately $80 million which represents a decrease in the fair value of approximately $141 million; conversely, a 10% decrease in the index oil and natural gas prices would result in a net asset of approximately $369 million which represents an increase in the fair value of approximately $148 million.

Interest Rate Risk

At December 31, 2011, the Company had long-term debt outstanding under its Credit Facility of $940 million, which incurred interest at floating rates (see Note 6). A 1% increase in the London Interbank Offered Rate (“LIBOR”) would result in an estimated $9 million increase in annual interest expense.

Counterparty Credit Risk

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

At December 31, 2011, the average public bond yield spread utilized to estimate the impact of the Company’s credit risk on derivative liabilities was approximately 4.52%. A 1% increase in the average public bond yield spread would result in an estimated $100,000 increase in net income for the year ended December 31, 2011. At December 31, 2011, the credit default swap spreads utilized to estimate the impact of counterparties’ credit risk on derivative assets ranged between 0% and 4.99%. A 1% increase in each of the counterparties’ credit default swap spreads would result in an estimated $3 million decrease in net income for the year ended December 31, 2011.

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Item 8. Financial Statements and Supplementary Data

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

As of December 31, 2011, our management assessed the effectiveness of the Company's internal control over financial reporting based on the criteria for effective internal control over financial reporting established in Internal Control – Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the assessment, management determined that we maintained effective internal control over financial reporting as of December 31, 2011, based on those criteria. KPMG LLP, the independent registered public accounting firm that audited the consolidated financial statements of the Company included in this Annual Report on Form 10-K, has issued an attestation report on the effectiveness of the Company's internal control over financial reporting as of December 31, 2011, which is included herein.

/s/ Linn Energy, LLC

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Unitholders
Linn Energy, LLC:

We have audited the accompanying consolidated balance sheets of Linn Energy, LLC and subsidiaries as of December 31, 2011 and 2010, and the related consolidated statements of operations, unitholders' capital, and cash flows for each of the years in the three-year period ended December 31, 2011. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Linn Energy, LLC and subsidiaries as of December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2011, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Linn Energy, LLC's internal control over financial reporting as of December 31, 2011, based on criteria established in Internal Control–Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 23, 2012, expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

Houston, Texas
February 23, 2012

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Unitholders
Linn Energy, LLC:

We have audited Linn Energy, LLC's internal control over financial reporting as of December 31, 2011, based on criteria established in Internal Control–Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Linn Energy, LLC's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, Linn Energy, LLC maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on criteria established in Internal Control–Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Linn Energy, LLC and subsidiaries as of December 31, 2011 and 2010, and the related consolidated statements of operations, unitholders' capital, and cash flows for each of the years in the three-year period ended December 31, 2011, and our report dated February 23, 2012, expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Houston, Texas

February 23, 2012

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LINN ENERGY, LLC

CONSOLIDATED BALANCE SHEETS

	December 31, 2011	December 31, 2010
	(in thousands, except unit amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$1,114	$236,001
Accounts receivable – trade, net	284,565	184,624
Derivative instruments	255,063	234,675
Other current assets	80,734	55,609
Total current assets	621,476	710,909
Noncurrent assets:		
Oil and natural gas properties (successful efforts method)	7,835,650	5,664,503
Less accumulated depletion and amortization	(1,033,617)	(719,035)
	6,802,033	4,945,468
Other property and equipment	197,235	139,903
Less accumulated depreciation	(48,024)	(35,151)
	149,211	104,752
Derivative instruments	321,840	56,895
Other noncurrent assets	105,577	115,124
	427,417	172,019
Total noncurrent assets	7,378,661	5,222,239
Total assets	$8,000,137	$5,933,148
LIABILITIES AND UNITHOLDERS' CAPITAL		
Current liabilities:		
Accounts payable and accrued expenses	$403,450	$219,830
Derivative instruments	14,060	12,839
Other accrued liabilities	75,898	82,439
Total current liabilities	493,408	315,108
Noncurrent liabilities:		
Credit facility	940,000	
Senior notes, net	3,053,657	2,742,902
Derivative instruments	3,503	39,797
Other noncurrent liabilities	80,659	47,125
Total noncurrent liabilities	4,077,819	2,829,824
Commitments and contingencies (Note 11)		
Unitholders' capital:		
177,364,558 units and 159,009,795 units issued and outstanding at December 31, 2011, and December 31, 2010, respectively	2,751,354	2,549,099

Accumulated income	677,556	239,117
	3,428,910	2,788,216
Total liabilities and unitholders' capital	$8,000,137	$5,933,148

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

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LINN ENERGY, LLC

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31, 2011	2010	2009
	(in thousands, except per unit amounts)		
Revenues and other:			
Oil, natural gas and natural gas liquids sales	$1,162,037	$690,054	$408,219
Gains (losses) on oil and natural gas derivatives	449,940	75,211	(141,374)
Marketing revenues	5,868	3,966	4,380
Other revenues	4,609	3,049	1,924
	1,622,454	772,280	273,149
Expenses:			
Lease operating expenses	232,619	158,382	132,647
Transportation expenses	28,358	19,594	18,202
Marketing expenses	3,681	2,716	2,154
General and administrative expenses	133,272	99,078	86,134
Exploration costs	2,390	5,168	7,169
Bad debt expenses	(22)	(46)	401
Depreciation, depletion and amortization	334,084	238,532	201,782
Impairment of long-lived assets	—	38,600	
Taxes, other than income taxes	78,522	45,182	27,605
(Gains) losses on sale of assets and other, net	3,516	6,536	(24,598)
	816,420	613,742	451,496
Other income and (expenses):			
Loss on extinguishment of debt	(94,612)	—	—
Interest expense, net of amounts capitalized	(259,725)	(193,510)	(92,701)
Losses on interest rate swaps	—	(67,908)	(26,353)
Other, net	(7,792)	(7,167)	(2,661)
	(362,129)	(268,585)	(121,715)
Income (loss) from continuing operations before income taxes	443,905	(110,047)	(300,062)
Income tax benefit (expense)	(5,466)	(4,241)	4,221
Income (loss) from continuing operations	438,439	(114,288)	(295,841)
Discontinued operations:			
Losses on sale of assets, net of taxes			(158)
Loss from discontinued operations, net of taxes			(2,193)
			(2,351)
Net income (loss)	$ 438,439	$(114,288)	$(298,192)
Income (loss) per unit – continuing operations:			
Basic	$2.52	$(0.80)	$(2.48)
Diluted	$2.51	$(0.80)	$(2.48)
Loss per unit – discontinued operations:			
Basic	$—	$	$(0.02)
Diluted	$—	$	$(0.02)
Net income (loss) per unit:			
Basic	$2.52	$(0.80)	$(2.50)
Diluted	$2.51	$(0.80)	$(2.50)

Weighted average units outstanding:			
Basic	172,004	142,535	119,307
Diluted	172,729	142,535	119,307
Distributions declared per unit	$2.70	$2.55	$2.52

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

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LINN ENERGY, LLC

CONSOLIDATED STATEMENTS OF UNITHOLDERS' CAPITAL

	Units	Unitholders' Capital	Accumulated Income (Deficit) (in thousands)	Treasury Units (at Cost)	Total Unitholders' Capital
December 31, 2008	114,080	$2,109,089	$651,597	$	$2,760,686
Sale of units, net of underwriting discounts and expenses of $12,369	14,950	279,299			279,299
Issuance of units	1,098	494			494
Cancellation of units	(187)	(2,696)		2,696	
Purchase of units				(2,696)	(2,696)
Distributions to unitholders		(303,316)			(303,316)
Unit-based compensation expenses		15,089			15,089
Reclassification of distributions paid on forfeited restricted units		63			63
Excess tax benefit from unit-based compensation		577			577
Net loss			(298,192)		(298,192)
December 31, 2009	129,941	2,098,599	353,405		2,452,004
Sale of units, net of underwriting discounts and expenses of $34,556	28,750	809,774	—	—	809,774
Issuance of units	815	4,418	—	—	4,418
Cancellation of units	(496)	(11,832)	—	11,832	—
Purchase of units		—	—	(11,832)	(11,832)
Distributions to unitholders		(365,711)	—	—	(365,711)
Unit-based compensation expenses		13,792	—	—	13,792
Reclassification of distributions paid on forfeited restricted units		59			59
Net loss		—	(114,288)	—	(114,288)
December 31, 2010	159,010	2,549,099	239,117	—	2,788,216
Sale of units, net of underwriting discounts and expenses of $27,427	17,514	651,522	—	—	651,522
Issuance of units	1,371	7,446	—	—	7,446
Cancellation of units	(530)	(17,352)	—	17,352	—
Purchase of units		—	—	(17,352)	(17,352)
Distributions to unitholders		(466,488)	—	—	(466,488)
Unit-based compensation expenses		22,243	—	—	22,243
Reclassification of distributions paid on forfeited restricted units		79			79
Excess tax benefit from unit-based compensation		4,805			4,805
Net income		—	438,439	—	438,439
December 31, 2011	177,365	$2,751,354	$677,556	$—	$3,428,910

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

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LINN ENERGY, LLC

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2011	2010	2009
		(in thousands)	
Cash flow from operating activities:			
Net income (loss)	$438,439	$(114,288)	$(298,192)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	334,084	238,532	201,782
Impairment of long-lived assets		38,600	
Unit-based compensation expenses	22,243	13,792	15,089
Loss on extinguishment of debt	94,612	—	—
Amortization and write-off of deferred financing fees and other	23,828	27,014	21,824
(Gains) losses on sale of assets and other, net	(281)	1,718	(22,842)
Deferred income tax	310	3,088	(6,436)
Mark-to-market on derivatives:			
Total (gains) losses	(449,940)	(7,303)	167,727
Cash settlements	237,134	302,875	362,936
Cash settlements on canceled derivatives	26,752	(123,865)	48,977
Premiums paid for derivatives	(134,352)	(120,376)	(93,606)
Changes in assets and liabilities:			
(Increase) decrease in accounts receivable – trade, net	(120,055)	(66,283)	29,117
(Increase) decrease in other assets	(2,951)	2,926	(3,051)
Increase (decrease) in accounts payable and accrued expenses	58,216	25,457	(4,675)
Increase (decrease) in other liabilities	(9,333)	49,031	8,154
Net cash provided by operating activities	518,706	270,918	426,804
Cash flow from investing activities:			
Acquisition of oil and natural gas properties, net of cash acquired	(1,500,193)	(1,351,033)	(130,735)
Development of oil and natural gas properties	(574,635)	(204,832)	(170,458)
Purchases of other property and equipment	(55,229)	(18,181)	(7,784)
Proceeds from sale of properties and equipment and other	(303)	(7,362)	26,704
Net cash used in investing activities	(2,130,360)	(1,581,408)	(282,273)
Cash flow from financing activities:			
Proceeds from sale of units	678,949	844,330	291,668
Proceeds from borrowings	2,534,240	3,300,816	639,203
Repayments of debt	(1,301,029)	(2,150,000)	(704,893)
Distributions to unitholders	(466,488)	(365,711)	(303,316)
Financing fees, offering expenses and other, net	(56,358)	(93,343)	(71,511)
Excess tax benefit from unit-based compensation	4,805		577
Purchase of units	(17,352)	(11,832)	(2,696)
Net cash provided by (used in) financing activities	1,376,767	1,524,260	(150,968)
Net increase (decrease) in cash and cash equivalents	(234,887)	213,770	(6,437)
Cash and cash equivalents:			
Beginning	236,001	22,231	28,668

Ending	$1,114	$236,001	$22,231

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

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LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 – Basis of Presentation and Significant Accounting Policies

Nature of Business

Linn Energy, LLC ("LINN Energy" or the "Company") is an independent oil and natural gas company that began operations in March 2003 and was formed as a Delaware limited liability company in April 2005. The Company completed its initial public offering ("IPO") in January 2006 and its units representing limited liability company interests ("units") are listed on The NASDAQ Global Select Market under the symbol "LINE." LINN Energy's mission is to acquire, develop and maximize cash flow from a growing portfolio of long-life oil and natural gas assets. The Company's properties are located in the United States ("U.S."), primarily in the Mid-Continent, the Permian Basin, Michigan, California and the Williston Basin.

The operations of the Company are governed by the provisions of a limited liability company agreement executed by and among its members. The agreement includes specific provisions with respect to the maintenance of the capital accounts of each of the Company's unitholders. Pursuant to applicable provisions of the Delaware Limited Liability Company Act (the "Delaware Act") and the Third Amended and Restated Limited Liability Company Agreement of Linn Energy, LLC (the "Agreement"), unitholders have no liability for the debts, obligations and liabilities of the Company, except as expressly required in the Agreement or the Delaware Act. The Company will remain in existence unless and until dissolved in accordance with the terms of the Agreement.

Principles of Consolidation and Reporting

The Company presents its financial statements in accordance with U.S. generally accepted accounting principles ("GAAP"). The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries. All significant intercompany transactions and balances have been eliminated upon consolidation. Investments in noncontrolled entities over which the Company exercises significant influence are accounted for under the equity method. Subsequent events were evaluated through the issuance date of the financial statements.

The consolidated financial statements for previous periods include certain reclassifications that were made to conform to current presentation. Such reclassifications have no impact on previously reported net income (loss) or unitholders' capital.

Discontinued Operations

Discontinued operations in 2009 primarily represent activity related to post-closing adjustments associated with the Company's Appalachian Basin and Mid Atlantic Well Service, Inc. operations disposed of in 2008.

Use of Estimates

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

LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Recently Issued Accounting Standards Not Yet Adopted

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

In May 2011, the FASB issued an ASU that further addresses fair value measurement accounting and related disclosure requirements. The ASU clarifies the FASB's intent regarding the application of existing fair value measurement and disclosure requirements, changes the fair value measurement requirements for certain financial instruments, and sets forth additional disclosure requirements for other fair value measurements. The ASU will be applied prospectively and is effective for periods beginning after December 15, 2011. The Company is currently evaluating the impact, if any, of the adoption of this ASU on its consolidated financial statements and related disclosures.

Cash Equivalents

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

Accounts Receivable – Trade, Net

Trade accounts receivable are recorded at the invoiced amount and do not bear interest. The Company maintains an allowance for doubtful accounts for estimated losses inherent in its accounts receivable portfolio. In establishing the required allowance, management considers historical losses, current receivables aging, and existing industry and national economic data. The Company reviews its allowance for doubtful accounts monthly. Past due balances over 90 days and over a specified amount are reviewed individually for collectibility. Account balances are charged off against the allowance after all means of collection have been exhausted and the potential recovery is remote. The balance in the Company's allowance for doubtful accounts related to trade accounts receivable was approximately $1 million at December 31, 2011, and December 31, 2010.

Inventories

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

Oil and Natural Gas Properties

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

respectively.

The Company evaluates the impairment of its proved oil and natural gas properties on a field-by-field basis whenever events or changes in circumstances indicate that the carrying value may not be recoverable. The carrying values of proved properties are reduced to fair value when the expected undiscounted future cash flows are less than net book value. The fair values of proved properties are measured using valuation techniques consistent with the income approach, converting future cash flows to a single discounted amount. Significant inputs used to determine

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the fair values of proved properties include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; and (iv) a market-based weighted average cost of capital rate. The underlying commodity prices embedded in the Company's estimated cash flows are the product of a process that begins with New York Mercantile Exchange ("NYMEX") forward curve pricing, adjusted for estimated location and quality differentials, as well as other factors that Company management believes will impact realizable prices. Costs of retired, sold or abandoned properties that constitute a part of an amortization base are charged or credited, net of proceeds, to accumulated depreciation, depletion and amortization unless doing so significantly affects the unit-of-production amortization rate, in which case a gain or loss is recognized currently. Gains or losses from the disposal of other properties are recognized currently. Expenditures for maintenance and repairs necessary to maintain properties in operating condition are expensed as incurred. Estimated dismantlement and abandonment costs are capitalized, net of salvage, at their estimated net present value and amortized on a unit-of-production basis over the remaining life of the related proved developed reserves. The Company capitalizes interest on borrowed funds related to its share of costs associated with the drilling and completion of new oil and natural gas wells. Interest is capitalized only during the periods in which these assets are brought to their intended use. The Company capitalized interest costs of approximately $2 million, $1 million and $300,000 for the years ended December 31, 2011, December 31, 2010, and December 31, 2009, respectively.

Impairment of Proved Properties

Based on the analysis described above, the Company recorded no impairment charge of proved oil and natural gas properties for the years ended December 31, 2011, and December 31, 2009. For the year ended December 31, 2010, the Company recorded a noncash impairment charge, before and after tax, of approximately $39 million primarily associated with proved oil and natural gas properties related to an unfavorable marketing contract. The carrying values of the impaired proved properties were reduced to fair value, estimated using inputs characteristic of a Level 3 fair-value measurement. The charges are included in "impairment of long-lived assets" on the consolidated statements of operations.

Unproved Properties

Costs related to unproved properties include costs incurred to acquire unproved reserves. Because these reserves do not meet the definition of proved reserves, the related costs are not classified as proved properties. The fair values of unproved properties are measured using valuation techniques consistent with the income approach, converting future cash flows to a single discounted amount. Significant inputs used to determine the fair values of unproved properties include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; and (iv) a market-based weighted average cost of capital rate. The market-based weighted average cost of capital rate is subjected to additional project-specific risking factors. Unproved leasehold costs are capitalized and amortized on a composite basis if individually insignificant, based on past success, experience and average lease-term lives. Individually significant leases are reclassified to proved properties if successful and expensed on a lease by lease basis if unsuccessful or the lease term expires. Unamortized leasehold costs related to successful exploratory drilling are reclassified to proved properties and depleted on a unit-of-production basis. The Company assesses unproved properties for impairment quarterly on the basis of its experience in similar situations and other factors such as the primary lease terms of the properties, the average holding period of unproved properties, and the relative proportion of such properties on which proved reserves have been found in the past.

Exploration Costs

Geological and geophysical costs, delay rentals, amortization and impairment of unproved leasehold costs and costs to drill exploratory wells that do not find proved reserves are expensed as exploration costs. The costs of any exploratory wells are carried as an asset if the well finds a sufficient quantity of reserves to justify its capitalization as a producing well and as long as the Company is making sufficient progress towards assessing the reserves and the economic and operating viability of the project. The Company recorded noncash leasehold impairment expenses related to unproved properties of approximately $2 million, $5 million and $7 million for the years ended December 31, 2011, December 31, 2010, and December 31, 2009, which are included in “exploration costs” on the consolidated statements of operations.

LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Other Property and Equipment

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

Revenue Recognition

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

The Company has elected the entitlements method to account for natural gas production imbalances. Imbalances occur when the Company sells more or less than its entitled ownership percentage of total natural gas production. In accordance with the entitlements method, any amount received in excess of the Company's share is treated as a liability. If the Company receives less than its entitled share, the underproduction is recorded as a receivable. At December 31, 2011, and December 31, 2010, the Company had natural gas production imbalance receivables of approximately $19 million and $18 million, respectively, which are included in "accounts receivable – trade, net" on the consolidated balance sheets and natural gas production imbalance payables of approximately $9 million and $8 million, respectively, which are included in "accounts payable and accrued expenses" on the consolidated balance sheets.

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

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

Restricted Cash

Restricted cash of approximately $4 million and $3 million is included in "other noncurrent assets" on the consolidated balance sheets at December 31, 2011, and December 31, 2010, respectively, and represents cash the Company has deposited into a separate account and designated for asset retirement obligations in accordance with contractual agreements.

Derivative Instruments

The Company uses derivative financial instruments to reduce exposure to fluctuations in the prices of oil and natural gas. By removing a significant portion of the price volatility associated with future production, the Company expects to mitigate, but not eliminate, the potential effects of variability in cash flow from operations due to fluctuations in commodity prices. These transactions are primarily in the form of swap contracts and put options. In addition, the Company may from time to time enter into derivative contracts in the form of interest rate swaps to minimize the effects of fluctuations in interest rates. At December 31, 2011, the Company had no outstanding interest rate swap agreements.

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

Unit-Based Compensation

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

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

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

Deferred Financing Fees

The Company incurred legal and bank fees related to the issuance of debt (see Note 6). At December 31, 2011, and December 31, 2010, net deferred financing fees of approximately $94 million and $102 million, respectively, are included in "other noncurrent assets" on the consolidated balance sheets. These debt issuance costs are amortized over the life of the debt agreement. For the years ended December 31, 2011, December 31, 2010, and December 31, 2009, amortization expense of approximately $16 million, $17 million and $14 million, respectively, is included in "interest expense, net of amounts capitalized" on the consolidated statements of operations.

Fair Value of Financial Instruments

The carrying values of the Company's receivables, payables and Credit Facility (as defined in Note 6) are estimated to be substantially the same as their fair values at December 31, 2011, and December 31, 2010. See Note 6 for fair value disclosures related to the Company's other outstanding debt. As noted above, the Company carries its derivative financial instruments at fair value. See Note 8 for details about the fair value of the Company's derivative financial instruments.

Income Taxes

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

Limited liability companies are subject to 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, which are accounted for using the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and

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liabilities and their respective tax basis and operating loss and tax credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. See Note 14 for detail of amounts recorded in the consolidated financial statements.

Note 2 – Acquisitions, Divestitures and Discontinued Operations

Acquisitions – 2011

On December 15, 2011, the Company completed the acquisition of certain oil and natural gas properties located primarily in the Granite Wash of Texas and Oklahoma from Plains Exploration & Production Company (“Plains”). The results of operations of these properties have been included in the consolidated financial statements since the acquisition date. The Company paid approximately $544 million in total consideration for these properties. The transaction was financed initially with borrowings under the Company’s Credit Facility, as defined in Note 6.

On November 1, 2011, and November 18, 2011, the Company completed two acquisitions of certain oil and natural gas properties located in the Permian Basin. The results of operations of these properties have been included in the consolidated financial statements since the acquisition dates. The Company paid approximately $108 million in cash and recorded a payable of approximately $2 million, resulting in total consideration for the acquisitions of approximately $110 million. The transactions were financed initially with borrowings under the Company’s Credit Facility.

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”). The results of operations of these properties have been included in the consolidated financial statements since the acquisition date. The Company paid approximately $223 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 located in the Williston Basin. The results of operations of these properties have been included in the consolidated financial statements since the acquisition dates. The Company paid approximately $154 million in cash and recorded a receivable of approximately $1 million, resulting in total consideration for the acquisitions of approximately $153 million. The transactions were financed initially with borrowings under the Company’s Credit Facility.

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 consolidated financial statements since the acquisition dates. The Company paid approximately $239 million in total consideration for the acquisitions. 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 located in the Williston Basin from an affiliate of Concho Resources Inc. (“Concho”). The results of operations of these properties have been included in the consolidated financial statements since the acquisition date. The Company paid $196 million in cash and recorded a receivable from Concho of approximately $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 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 consolidated financial statements since the acquisition dates. The Company, in the aggregate, paid approximately $38 million in total consideration for these properties.

LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

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	$	5,981
Noncurrent		748
Oil and natural gas properties		1,516,737
Total assets acquired	$	1,523,466
Liabilities:		
Current	$	2,130
Asset retirement obligations		19,853
Total liabilities assumed	$	21,983
Net assets acquired	$	1,501,483

Current assets include receivables, prepaids and inventory and noncurrent assets include other property and equipment. Current liabilities include payables, ad valorem taxes payable and other 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 Plains, Panther, SandRidge and Concho are included in the condensed consolidated results of operations of the Company as of December 15, 2011, 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 years ended December 31, 2011, and December 31, 2010, assuming the acquisitions of Plains, Panther, SandRidge and Concho had been completed as of January 1, 2010, including adjustments to reflect the values assigned to the net assets acquired. The pro forma financial information is not necessarily indicative of the results of operations if the acquisitions had been effective as of this date.

	Year Ended December 31,			
	2011		2010	
	(in thousands, except per unit amounts)			
Total revenues and other	$	1,819,878	$	939,572
Total operating expenses	$	901,967	$	720,360

Net income (loss)	$	528,046	$	(86,952)
Net income (loss) per unit:				
Basic	$	3.01	$	(0.57)
Diluted	$	3.00	$	(0.57)

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LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

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. The other party to the PSA disputed the termination of the PSA and held the deposit. 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. The deposit plus interest was received by the Company in April 2011.

Acquisitions – 2010 and 2009

The following is a summary of certain significant acquisitions completed by the Company during the years ended December 31, 2010, and December 31, 2009:

- On November 16, 2010, the Company completed the acquisition of certain oil and natural gas properties located in the Wolfberry trend of the Permian Basin from Element Petroleum, LP for approximately $118 million.
- On October 14, 2010, the Company completed two acquisitions of certain oil and natural gas properties located in the Wolfberry trend of the Permian Basin from Crownrock, LP and Patriot Resources Partners LLC for approximately $260 million.
- On August 16, 2010, the Company completed the acquisition of certain oil and natural gas properties located in the Permian Basin from Crownrock, LP and Element Petroleum, LP for approximately $95 million.
- On May 27, 2010, the Company completed the acquisition of interests in Henry Savings LP and Henry Savings Management LLC that primarily hold oil and natural gas properties located in the Permian Basin for approximately $323 million.
- On April 30, 2010, the Company completed the acquisition of interests in two wholly owned subsidiaries of HighMount Exploration & Production LLC that hold oil and natural gas properties in the Antrim Shale located in northern Michigan for approximately $327 million.
- On January 29, 2010, the Company completed the acquisition of certain oil and natural gas properties located in the Anadarko Basin in Oklahoma and Kansas and the Permian Basin in Texas and New Mexico from certain affiliates of Merit Energy Company for approximately $151 million.
- On August 31, 2009, and September 30, 2009, the Company completed two acquisitions of certain oil and natural gas properties located in the Permian Basin in Texas and New Mexico from Forest Oil Corporation and Forest Oil Permian Corporation for approximately $114 million.

Divestitures

In 2009, certain post-closing matters related to the 2008 sale of the deep rights interests in certain central Oklahoma acreage were resolved and the Company recorded a gain of approximately $25 million, which is included in "(gains) losses on sale of assets and other, net" on the consolidated statements of operations for the year ended December 31, 2009.

Discontinued Operations

Discontinued operations of approximately $2 million in 2009 primarily represent activity related to post-closing adjustments associated with the Company's Appalachian Basin and Mid Atlantic Well Service, Inc. operations disposed of in 2008.

Note 3 – Unitholders' Capital

Equity Distribution Agreement

On August 23, 2011, the Company entered into an equity distribution agreement, pursuant to which it may from time to time issue and sell units representing limited liability company interests having an aggregate offering price of up to $500 million. In connection with entering into the agreement, the Company incurred expenses of approximately $423,000. Sales of units, if any, will be made through a sales agent by means of ordinary brokers' transactions, in block transactions, or as otherwise agreed with the agent. The Company expects to use the net proceeds from any sale of the units for general corporate purposes, which may include, among other things, capital expenditures, acquisitions and the repayment of debt.

In September 2011, the Company issued and sold 16,060 units representing limited liability company interests at an average unit price of $38.25 for proceeds of approximately $602,000 (net of approximately $12,000 in commissions). In December 2011, the Company issued and sold 772,104 units representing limited liability company interests at an average unit price of $38.03 for proceeds of approximately $29 million (net of approximately $587,000 in commissions). In connection with the issue and sale of these units, the Company incurred professional service expenses of approximately $139,000. The Company used the net proceeds for general corporate purposes including the repayment of a portion of the indebtedness outstanding under its Credit Facility. At December 31, 2011, units equaling approximately $470 million in aggregate offering price remained available to be issued and sold under the agreement.

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

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

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

In October 2009, the Company sold 8,625,000 units representing limited liability company interests at $21.90 per unit ($21.024 per unit, net of underwriting discount) for net proceeds of approximately $181 million (after underwriting discount and offering expenses of approximately $8 million). The Company used the net proceeds from the sale of these units to reduce indebtedness under the Credit Facility.

In May 2009, the Company sold 6,325,000 units representing limited liability company interests at $16.25 per unit ($15.60 per unit, net of underwriting discount) for net proceeds of approximately $98 million (after underwriting discount and offering expenses of approximately $4 million). The Company used the net proceeds from the sale of these units to reduce indebtedness under the Credit Facility.

Equity Distribution Agreement and Public Offering of Units – Subsequent Events

In January 2012, the Company, under its equity distribution agreement, issued and sold 1,539,651 units representing limited liability company interests at an average unit price of $38.02 for proceeds of approximately $57 million (net of approximately $1 million in commissions). The Company used the net proceeds for general corporate purposes including the repayment of a portion of the indebtedness outstanding under its Credit Facility. At January 31, 2012, units equaling approximately $411 million in aggregate offering price remained available to be issued and sold under the agreement.

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

Unit Repurchase Plan

In October 2008, the Board of Directors of the Company authorized the repurchase of up to $100 million of the Company's outstanding units from time to time on the open market or in negotiated purchases. During the year ended December 31, 2011, 529,734 units were repurchased at an average unit price of $32.76 for a total cost of approximately $17 million. During the year ended December 31, 2010, 486,700 units were repurchased at an average unit price of $23.79 for a total cost of approximately $12 million. During the year ended December 31, 2009, 123,800 units were repurchased at an average unit price of $12.99 for a total cost of approximately $2 million. All units were subsequently canceled.

At December 31, 2011, approximately $56 million was available for unit repurchase under the program. The timing and amounts of any such repurchases will be at the discretion of management, subject to market conditions and other factors, and in accordance with applicable securities laws and other legal requirements. The repurchase plan does not obligate the Company to acquire any specific number of units and may be discontinued at any time. Units are repurchased at fair market value on the date of repurchase.

Issuance and Cancellation of Units

During the years ended December 31, 2010, and December 31, 2009, the Company purchased 9,055 units and 63,031 units for approximately $300,000 and $1 million, respectively, in conjunction with units received by the Company for the payment of minimum withholding taxes due on units issued under its equity compensation plan (see Note 5). All units were subsequently canceled. The Company purchased no units during the year ended December 31, 2011.

Distributions

Under the Agreement, Company unitholders are entitled to receive a quarterly distribution of available cash to the extent there is sufficient cash from operations after establishment of cash reserves and payment of fees and expenses. Distributions paid by the Company are presented on the consolidated statements of unitholders' capital. On January 27, 2012, the Company's Board of Directors declared a cash distribution of $0.69 per unit with respect to the fourth quarter of 2011. The distribution, totaling approximately $138 million, was paid February 14, 2012, to unitholders of record as of the close of business February 7, 2012.

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LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Note 4 – Business and Credit Concentrations

Cash

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

Revenue and Trade Receivables

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

For the year ended December 31, 2011, the Company's three largest customers represented 13%, 10% and 10%, respectively, of the Company's sales. For the year ended December 31, 2010, the Company's three largest customers represented 17%, 14% and 13%, respectively, of the Company's sales. For the year ended December 31, 2009, the Company's three largest customers represented 22%, 18% and 15%, respectively, of the Company's sales.

At December 31, 2011, trade accounts receivable from three customers represented approximately 12%, 10% and 10%, respectively, of the Company's receivables. At December 31, 2010, trade accounts receivable from three customers represented approximately 16%, 12% and 11%, respectively, of the Company's receivables.

Note 5 – Unit-Based Compensation and Other Benefit Plans

Incentive Plan Summary

The Linn Energy, LLC Amended and Restated Long-Term Incentive Plan, as amended (the "Plan"), originally became effective in December 2005. The Plan, which is administered by the Compensation Committee of the Board of Directors ("Compensation Committee"), permits granting unit grants, unit options, restricted units, phantom units and unit appreciation rights to employees, consultants and nonemployee directors under the terms of the Plan. The unit options and restricted units vest ratably over three years. The contractual life of unit options is 10 years. Unit awards were initially issued in conjunction with the Company's IPO in January 2006.

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

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

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

Unit Options – A unit option is a right to purchase a unit at a specified price at terms determined by the Compensation Committee. Unit options will have an exercise price that will not be less than the fair

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market value of the units on the date of grant, and in general, will become exercisable over a vesting period but may accelerate upon a change in control of the Company. If a grantee's employment or service relationship terminates for any reason other than death, the grantee's unvested unit options will be automatically forfeited unless the option agreement or the Compensation Committee provides otherwise.

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

Phantom Units/Unit Appreciation Rights – These awards may be settled in units, cash or a combination thereof. Such grants contain terms as determined by the Compensation Committee, including the period or terms over which phantom units vest. If a grantee's employment or service relationship terminates for any reason other than death, the grantee's phantom units or unit appreciation rights will be automatically forfeited unless, and to the extent, the Compensation Committee or the terms of the award agreement provide otherwise. While phantom units require no payment from the grantee, unit appreciation rights will have an exercise price that will not be less than the fair market value of the units on the date of grant. At December 31, 2011, the Company had 36,784 phantom units issued and outstanding. To date, the Company has not issued unit appreciation rights.

Securities Authorized for Issuance Under the Plan

As of December 31, 2011, approximately 1.4 million units were issuable under the Plan pursuant to outstanding award or other agreements, and 5.2 million additional units were reserved for future issuance under the Plan.

Accounting for Unit-Based Compensation

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

	Year Ended December 31,		
	2011	2010	2009
		(in thousands)	
General and administrative expenses	$ 21,131	$ 13,450	$ 14,743
Lease operating expenses	1,112	342	346
Total unit-based compensation expenses	$ 22,243	$ 13,792	$ 15,089
Income tax benefit	$ 8,219	$ 5,096	$ 5,968

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LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Restricted/Unrestricted Units

The fair value of unrestricted unit grants and restricted units issued is determined based on the fair market value of the Company units on the date of grant. A summary of the status of the nonvested units as of December 31, 2011, is presented below:

	Number of Nonvested Units	Weighted Average Grant-Date Fair Value
Nonvested units at December 31, 2010	1,451,556	$ 21.16
Granted	1,110,502	$ 38.54
Vested	(651,760)	$ 20.22
Forfeited	(50,636)	$ 33.32
Nonvested units at December 31, 2011	1,859,662	$ 31.54

The weighted average grant-date fair value of unrestricted unit grants and restricted units granted was $25.89 and $16.11 during the years ended December 31, 2010, and December 31, 2009, respectively.

As of December 31, 2011, there was approximately $38 million of unrecognized compensation cost related to nonvested restricted units. The cost is expected to be recognized over a weighted average period of approximately 1.5 years. The total fair value of units that vested was approximately $13 million, $14 million and $11 million for the years ended December 31, 2011, December 31, 2010, and December 31, 2009, respectively.

In January 2012, the Company granted 913,663 restricted units as part of its annual review of its employees, including executives, compensation.

Changes in Unit Options and Unit Options Outstanding

The following provides information related to unit option activity for the year ended December 31, 2011:

	Number of Units Underlying Options	Weighted Average Exercise Price Per Unit	Weighted Average Grant-Date Fair Value	Weighted Average Remaining Contractual Life in Years
Outstanding at December 31, 2010	1,720,393	$ 22.48	$ 3.05	6.71
Exercised	(310,400)	$ 23.99	$ 3.83	
Outstanding at December 31, 2011	1,409,993	$ 22.14	$ 2.87	5.83
Exercisable at December 31, 2011	1,282,526	$ 22.76	$ 3.11	5.70

No unit options were granted during the years ended December 31, 2011, or December 31, 2010. The weighted average grant-date fair value of options granted was $0.55 during the year ended December 31, 2009. The total intrinsic value of options exercised was approximately $5 million, $2 million and $124,000, during the years ended December 31, 2011, December 31, 2010, and December 31, 2009, respectively. The Company received approximately $7 million from the exercise of options during the year ended December 31, 2011.

As of December 31, 2011, total unrecognized compensation cost related to nonvested unit options was approximately $4,000. The cost is expected to be recognized over a weighted average period of approximately one month. In addition, the exercisable unit options at December 31, 2011, have an aggregate intrinsic value of approximately $19 million and all outstanding unit options have an aggregate intrinsic value of approximately $22 million. The total fair value of all options that vested during the years ended December 31, 2011, December 31, 2010, and December 31, 2009, was approximately $500,000, $1 million and $2 million, respectively. No options expired during the years ended December 31, 2011, December 31, 2010, or December 31, 2009.

The fair value of unit-based compensation for unit options was estimated on the date of grant using a Black-Scholes pricing model based on certain assumptions. The Company's determination of the fair value of unit-based payment awards is affected by the Company's unit price as well as assumptions regarding a number of complex and subjective variables. The Company's employee unit options have various restrictions including vesting provisions and restrictions on transfers and hedging, among others, and often are expected to be exercised prior to their contractual maturity.

Expected volatilities used in the estimation of fair value have been determined using available volatility data for the Company as well as an average of volatility computations of other identified peer companies in the oil and natural gas industry. Expected distributions are estimated based on the Company's distribution rate at the date of grant. Historical data of the Company and other identified peer companies is used to estimate expected term because, due to the limited period of time its equity units have been publicly traded, the Company does not have sufficient historical exercise data to compute a reasonable estimate. Forfeitures are estimated using historical Company data and are revised, if necessary, in subsequent periods if actual forfeitures differ from estimates. All employees granted awards have been determined to have similar behaviors for purposes of determining the expected term used to estimate fair value. The risk-free rate for periods within the expected term of the unit option is based on the U.S. Treasury yield curve in effect at the time of grant. The fair values of the 2009 unit option grants were based upon the following assumptions:

	2009
Expected volatility	30.59%
Expected distributions	15.80% – 16.79%
Risk-free rate	1.24 % – 1.91 %
Expected term	5 years

Although the fair value of unit option grants is determined in accordance with applicable accounting standards, using a Black-Scholes pricing model, that value may not be indicative of the fair value observed in a willing buyer/willing seller market transaction.

Nonemployee Grants

During the year ended December 31, 2007, the Company granted an aggregate 150,000 unit warrants to certain individuals in connection with an acquisition transition services agreement. The unit warrants, all of which remain outstanding, have an exercise price of $25.50 per unit warrant, are fully exercisable at December 31, 2011, and expire 10 years from the date of issuance.

Defined Contribution Plan

The Company sponsors a 401(k) defined contribution plan for eligible employees. Company contributions to the 401(k) plan consisted of a discretionary matching contribution equal to 100% of the first 4% of eligible compensation contributed by the employee on a before-tax basis for the year ending December 31, 2009. For the years ended December 31, 2011, and December 31, 2010, the Company contribution was equal to 100% of the first 6% of eligible employee compensation. The Company contributed approximately $4 million, $3 million and $2 million during the years ended December 31, 2011, December 31, 2010, and December 31, 2009, respectively, to the 401(k) plan's trustee account. The 401(k) plan funds are held in a trustee account on behalf of the plan participants.

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LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Note 6 – Debt

The following summarizes debt outstanding:

	December 31, 2011			December 31, 2010		
	Carrying Value	Fair Value (1)	Interest Rate (2)	Carrying Value	Fair Value (1)	Interest Rate (2)
	(in millions, except percentages)					
Credit facility	$ 940	$ 940	2.57 %	$	$	
11.75% senior notes due 2017	41	46	12.73 %	250	288	12.73 %
9.875% senior notes due 2018	14	16	10.25 %	256	279	10.25 %
6.50% senior notes, due 2019	750	742	6.62 %			
8.625% senior notes due 2020	1,300	1,406	9.00 %	1,300	1,396	9.00 %
7.75% senior notes due 2021	1,000	1,036	8.00 %	1,000	1,021	8.00 %
Less current maturities						
	4,045	$ 4,186		2,806	$ 2,984	
Unamortized discount	(51)			(63)		
Total debt, net of discount	$ 3,994			$ 2,743		

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

(2) Represents variable interest rate for the Credit Facility and 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. In October 2011, as part of the semi-annual redetermination, a borrowing base of $3.0 billion was approved by the lenders with the maximum commitment amount remaining unchanged at $1.5 billion. The maturity date is April 2016.

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 consolidated statements of operations. At December 31, 2011, available borrowing capacity under the Credit Facility was $556 million, 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 (the “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, fund or partially fund acquisitions and 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 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, 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 2019 Registration Rights Agreement, the Company agreed to use 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 $14 million (originally $256 million) in aggregate principal amount of 9.875% senior notes due 2018 (the “2018 Senior Notes” and together with the 2017 Senior Notes, the “Original Senior Notes”). The indentures related to the Original Senior Notes originally contained redemption provisions and covenants that were 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 its 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.

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 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.

In March 2011, in connection with its Offers and related consent solicitations, the Company accepted and purchased: 1) $105 million of the aggregate principal amount of its outstanding 2017 Senior Notes (or 65% of the remaining outstanding principal amount of its 2017 Senior Notes), and 2) $126 million of the aggregate principal amount of its outstanding 2018 Senior Notes (or 76% of the remaining outstanding principal amount of its 2018 Senior Notes).

In conjunction with each tender offer, the Company received consents to amendments to the indentures of 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 approximately $17 million (or 29% of the remaining outstanding principal amount of its 2017 Senior Notes) and approximately $24 million (or 61% of the remaining outstanding principal amount of its 2018

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Senior Notes), respectively. In December 2011, the Company also repurchased an additional portion of its remaining outstanding 2018 Senior Notes for approximately $2 million (or 9% of the remaining outstanding principal amount of its 2018 Senior Notes). 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 $14 million, respectively, remain outstanding at December 31, 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 $95 million for the year ended December 31, 2011.

Note 7 – Derivatives

Commodity Derivatives

The Company utilizes derivative instruments to minimize the variability in cash flow due to commodity price movements. The Company has historically entered into derivative instruments such as swap contracts, put options and collars to economically hedge its forecasted oil, natural gas and NGL sales. At December 31, 2011, the Company had no outstanding collars. 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.

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

	2012	2013	2014	2015	2016
Natural gas positions:					
Fixed price swaps:					
Hedged volume (MMMBtu)	56,730	64,367	73,456	82,490	2,745
Average price ($/MMBtu)	$ 5.85	$ 5.69	$ 5.69	$ 5.75	$ 5.00
Puts:					
Hedged volume (MMMBtu)	38,357	37,340	30,660	32,850	—
Average price ($/MMBtu)	$ 5.83	$ 5.85	$ 5.00	$ 5.00	$ —
Total:					
Hedged volume (MMMBtu)	95,087	101,707	104,116	115,340	2,745
Average price ($/MMBtu)	$ 5.84	$ 5.75	$ 5.49	$ 5.54	$ 5.00
Oil positions:					
Fixed price swaps: (1)					
Hedged volume (MBbls)	8,171	9,033	9,034	9,581	—
Average price ($/Bbl)	$ 97.37	$ 98.05	$ 95.39	$ 98.25	$ —
Puts:					
Hedged volume (MBbls)	2,196	2,300	—	—	—
Average price ($/Bbl)	$ 100.00	$ 100.00	$ —	$ —	$ —
Total:					
Hedged volume (MBbls)	10,367	11,333	9,034	9,581	—
Average price ($/Bbl)	$ 97.93	$ 98.44	$ 95.39	$ 98.25	$ —
Natural gas basis differential positions:					
PEPL basis swaps: (2)					
Hedged volume (MMMBtu)	37,735	38,854	42,194	42,194	—
Hedged differential ($/MMBtu)	$ (0.89)	$ (0.89)	$ (0.39)	$ (0.39)	$ —
Oil timing differential positions:					
Trade month roll swaps: (3)					
Hedged volume (MBbls)	5,982	6,315	6,315	840	—
Hedged differential ($/Bbl)	$ 0.21	$ 0.21	$ 0.21	$ 0.17	$ —

(1) 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.

(2) 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.

(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 crude oil during that month, plus an adjustment calculated as a spread between the weighted average prices of the delivery month, the next month and the following month during the period when the delivery month is prompt (the "trade month roll").

During the year ended December 31, 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 2015. In September 2011, the Company canceled its oil and natural gas swaps for the year 2016 and used the realized gains of approximately $27 million to increase prices on its existing oil and natural gas swaps for the year 2012. Also, in September 2011, the Company paid premiums of approximately $33 million to increase prices on its existing oil puts for the years 2012 and 2013. In addition, during the fourth quarter of 2011, the Company paid premiums of approximately $52 million for put options and approximately $22 million to increase prices on its existing oil puts for 2012 and 2013, respectively.

Settled derivatives on natural gas production for the year ended December 31, 2011, included volumes of 64,457 MMMBtu at an average contract price of $8.24. Settled derivatives on oil production for the year ended December 31, 2011, included volumes of 7,917 MBbls at an average contract price of $85.70. Settled derivatives on natural gas production for the year ended December 31, 2010, included volumes of 57,160 MMMBtu at an average contract price of $8.66. Settled derivatives on oil production for the year ended December 31, 2010, included volumes of 4,650 MBbls at an average contract price of $99.68. 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 crude oil and settlement occurs on the final day of the production month.

Interest Rate Swaps

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

In April 2010, the Company restructured its interest rate swap portfolio in conjunction with the repayment of all of the outstanding indebtedness under its Credit Facility with net proceeds from the issuance of the 2020 Senior Notes (see Note 6). In conjunction with the repayment of borrowings under its Credit Facility with proceeds from the issuance of 2020 Senior Notes, the Company canceled (before the contract settlement date) certain interest rate swap agreements for 2010 through 2013, resulting in realized losses of approximately $74 million. In September 2010, the Company canceled (before the contract settlement date) all of its remaining interest rate swap agreements in conjunction with the repayment of all of the outstanding indebtedness under its Credit Facility with net proceeds from the issuance of 2021 Senior Notes (see Note 6). The cancellation of the interest rate swap agreements in September 2010 resulted in a realized loss of approximately $50 million. At December 31, 2011, and December 31, 2010, the Company had no outstanding interest rate swap agreements.

Balance Sheet Presentation

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

	December 31, 2011	December 31, 2010
	(in thousands)	
Assets:		
Commodity derivatives	$ 880,175	$ 637,836
Liabilities:		
Commodity derivatives	$ 320,835	$ 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

LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Credit Facility at the time it originally entered into the derivatives. The Credit Facility is secured by the Company's oil and natural gas reserves; therefore, the Company is not required to post any collateral. The Company does not receive collateral from its counterparties. The maximum amount of loss due to credit risk that the Company would incur if its counterparties failed completely to perform according to the terms of the contracts, based on the gross fair value of financial instruments, was approximately $880 million at December 31, 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 loss is somewhat mitigated.

Gains (Losses) on Derivatives

Gains and losses on derivatives, including realized and unrealized gains and losses, are reported on the 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.

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

	Year Ended December 31,		
	2011	2010	2009
		(in thousands)	
Realized gains (losses):			
Commodity derivatives	$ 230,237	$ 307,587	$ 400,968
Interest rate swaps	—	(8,021)	(42,881)
Canceled derivatives	26,752	(123,865)	48,977
	$ 256,989	$ 175,701	$ 407,064
Unrealized gains (losses):			
Commodity derivatives	$ 192,951	$ (232,376)	$ (591,379)
Interest rate swaps	—	63,978	16,588
	$ 192,951	$ (168,398)	$ (574,791)
Total gains (losses):			
Commodity derivatives	$ 449,940	$ 75,211	$ (141,374)
Interest rate swaps	—	(67,908)	(26,353)
	$ 449,940	$ 7,303	$ (167,727)

During the year ended December 31, 2011, the Company canceled (before the contract settlement date) its oil and natural gas swaps for the year 2016 and used the realized gains of approximately $27 million to increase prices on its existing oil and natural gas swaps for the year 2012. During the year ended December 31, 2010, the Company canceled (before the contract settlement date) all of its interest rate swap agreements resulting in realized losses of approximately $124 million.

During the year ended December 31, 2009, the Company canceled (before the contract settlement date) derivative contracts on estimated future oil and natural gas production resulting in realized net gains of approximately $49 million. Of this amount, realized net gains of approximately $45 million, along with an incremental premium payment of approximately $49 million, were used to reposition the Company’s commodity derivative portfolio in July 2009, when the Company canceled oil and natural gas derivative contracts for years 2012 through 2014 to raise prices for oil and natural gas derivative contracts in years 2010 and 2011.

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Note 8 – Fair Value Measurements on a Recurring Basis

The Company accounts for its commodity derivatives and, when applicable, its interest rate derivatives at fair value (see Note 7) on a recurring basis. The Company uses certain pricing models to determine the fair value of its derivative financial instruments. Inputs to the pricing models include publicly available prices and forward price curves generated from a compilation of data gathered from third parties. Company management validates the data provided by third parties by understanding the pricing models used, obtaining market values from other pricing sources, analyzing pricing data in certain situations and confirming that those securities trade in active markets. Assumed credit risk adjustments, based on published credit ratings, public bond yield spreads and credit default swap spreads, are applied to the Company's commodity derivatives and, when applicable, its interest rate derivatives.

Fair Value Hierarchy

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

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

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

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

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

	Fair Value Measurements on a Recurring Basis December 31, 2011		
	Level 2	Netting (1)	Total
		(in thousands)	
Assets:			

Commodity derivatives	$ 880,175	$ (303,272)	$ 576,903
Liabilities:			
Commodity derivatives	$ 320,835	$ (303,272)	$ 17,563

(1) Represents counterparty netting under agreements governing such derivatives.

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Note 9 – Other Property and Equipment

Other property and equipment consists of the following:

	December 31, 2011	December 31, 2010
	(in thousands)	
Natural gas compression plant and pipeline	$ 129,863	$ 96,624
Buildings and leasehold improvements	16,158	10,874
Vehicles	13,653	10,127
Drilling and other equipment	3,645	1,827
Furniture and office equipment	29,972	17,529
Land	3,944	2,922
	197,235	139,903
Less accumulated depreciation	(48,024)	(35,151)
	$ 149,211	$ 104,752

Note 10 – Asset Retirement Obligations

Asset retirement obligations associated with retiring tangible long-lived assets are recognized as a liability in the period in which a legal obligation is incurred and becomes determinable and are included in “other noncurrent liabilities” on the consolidated balance sheets. Accretion expense is included in “depreciation, depletion and amortization” on the consolidated statements of operations. The fair value of additions to the asset retirement obligations is estimated using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation include estimates of: (i) plug and abandon costs per well based on existing regulatory requirements; (ii) remaining life per well; (iii) future inflation factors (2.0% for each of the years in the three-year period ended December 31, 2011); and (iv) a credit-adjusted risk-free interest rate (average of 7.5%, 8.6% and 9.6% for the years ended December 31, 2011, December 31, 2010, and December 31, 2009, respectively).

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

	December 31, 2011	December 31, 2010
	(in thousands)	
Asset retirement obligations at beginning of year	$ 42,945	$ 33,135
Liabilities added from acquisitions	19,853	6,976
Liabilities added from drilling	1,277	309
Current year accretion expense	4,140	2,694
Settlements	(2,218)	(169)
Revision of estimates	5,145	
Asset retirement obligations at end of year	$ 71,142	$ 42,945

Note 11 – Commitments and Contingencies

The Company has been named as a defendant in a number of lawsuits and is involved in various other disputes arising in the ordinary course of business, 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. The Company is not currently a party to any litigation or pending claims that it believes would have a material adverse effect on its overall business, financial position, results of operations or liquidity; however, cash flow could be significantly impacted in the reporting periods in which such matters are resolved.

On September 15, 2008, and October 3, 2008, Lehman Brothers Holdings Inc. ("Lehman Holdings") and Lehman Brothers Commodity Services Inc. ("Lehman Commodity Services"), respectively, filed voluntary petitions for reorganization under Chapter 11 of the U.S. Bankruptcy Code with the U.S. Bankruptcy Court for the Southern District of New York. At December 31, 2011, and December 31, 2010, the Company had a net receivable of approximately $7 million from Lehman Commodity Services related to canceled derivative contracts, which is included in "other current assets" on the consolidated balance sheets. The value of the receivable was estimated based on market expectations. In March 2011, the Company, Lehman Holdings and Lehman Commodity Services entered into Termination Agreements under which the Company was granted general unsecured claims against Lehman Holdings and Lehman Commodity Services in the amount of $51 million each, provided that the aggregate value of the distributions to the Company on account of both such claims will not exceed $51 million (collectively, the "Company Claim"). On December 6, 2011, a Chapter 11 Plan ("Plan") was approved by the Bankruptcy Court. Initial distributions under the Plan to creditors, including the Company, are expected to occur after January 31, 2012. Based on the recovery estimates described in the approved disclosure statement relating to the Plan, the Company expects to ultimately receive a substantial portion of the Company Claim.

Note 12 – Earnings Per Unit

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

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LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

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

	Income (Loss) (Numerator) (in thousands)	Units (Denominator)	Per Unit Amount
Year ended December 31, 2011:			
Income from continuing operations:			
Allocated to units	$ 438,439		
Allocated to unvested restricted units	(4,739)		
	$ 433,700		
Income per unit:			
Basic income per unit		172,004	$ 2.52
Dilutive effect of unit equivalents		725	(0.01)
Diluted income per unit		172,729	$ 2.51
Year ended December 31, 2010:			
Loss from continuing operations:			
Allocated to units	$ (114,288)		
Allocated to unvested restricted units			
	$ (114,288)		
Loss per unit:			
Basic loss per unit		142,535	$ (0.80)
Dilutive effect of unit equivalents			
Diluted loss per unit		142,535	$ (0.80)
Year ended December 31, 2009:			
Loss from continuing operations:			
Allocated to units	$ (295,841)		
Allocated to unvested restricted units	—		
	$ (295,841)		
Loss per unit:			
Basic loss per unit		119,307	$ (2.48)
Dilutive effect of unit equivalents		—	—
Diluted loss per unit		119,307	$ (2.48)

There were no anti-dilutive unit equivalents for the year ended December 31, 2011. Basic units outstanding excludes the effect of weighted average anti-dilutive unit equivalents related to approximately 2 million unit options and warrants for each of the years ended December 31, 2010, and December 31, 2009. All equivalent units were anti-dilutive for the years ended December 31, 2010, and December 31, 2009, respectively.

Note 13 – Operating Leases

The Company leases office space and other property and equipment under lease agreements expiring on various dates through 2019. The Company recognized expense under operating leases of approximately $5 million, $5 million, and $4 million, for the years ended December 31, 2011, December 31, 2010, and December 31, 2009, respectively.

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As of December 31, 2011, future minimum lease payments were as follows (in thousands):

2012	$5,652
2013	4,769
2014	4,598
2015	4,455
2016	2,950
Thereafter	9,053
	$31,477

Note 14 – Income Taxes

The Company is a limited liability company treated as a partnership for federal and state income tax purposes, with the exception of the states of Texas and Michigan, with income tax liabilities and/or benefits of the Company passed through to its 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, except as set forth in the tables below.

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

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

	Year Ended December 31,		
	2011	2010	2009
		(in thousands)	
Current taxes:			
Federal	$ (4,551)	$ (65)	$ (1,063)
State	(605)	(1,088)	(678)
Deferred taxes:			
Federal	1,148	(2,862)	5,307
State	(1,458)	(226)	655
	$ (5,466)	$ (4,241)	$ 4,221

As of December 31, 2011, the Company's taxable entities had approximately $8 million of net operating loss carryforwards for federal income tax purposes which will begin expiring in 2031.

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LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Income tax benefit (expense) differed from amounts computed by applying the federal income tax rate of 35% to pre-tax income (loss) from continuing operations as a result of the following:

	Year Ended December 31,		
	2011	2010	2009
Federal statutory rate	35.0 %	35.0 %	35.0 %
State, net of federal tax benefit	0.5	(1.2)	—
Loss excluded from nontaxable entities	(34.4)	(37.5)	(34.3)
Other items	0.1	(0.1)	0.7
Effective rate	1.2 %	(3.8)%	1.4 %

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

	December 31,	
	2011	2010
	(in thousands)	
Deferred tax assets:		
Net operating loss carryforwards	$ 159	$ 717
Unit-based compensation	9,146	6,234
Other	3,606	3,513
Valuation allowance		(217)
Total deferred tax assets	12,911	10,247
Deferred tax liabilities:		
Other accruals		(2,755)
Property and equipment principally due to differences in depreciation	(8,226)	(4,323)
Other	(1,646)	179
Total deferred tax liabilities	(9,872)	(6,899)
Net deferred tax assets	$ 3,039	$ 3,348

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

	December 31,	
	2011	2010
	(in thousands)	
Deferred tax assets	$ 8,279	$ 5,265
Deferred tax liabilities	(589)	(3,105)
Other current assets	$ 7,690	$ 2,160
Deferred tax assets	$ 4,632	$ 4,982
Deferred tax liabilities	(9,283)	(3,794)
Other noncurrent assets (liabilities)	$ (4,651)	$ 1,188

In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment. At December 31, 2011, based upon the level of historical taxable income and projections for future taxable income over the periods in which the deferred tax assets are deductible, management believes it is more likely than not that the Company will realize the benefits of these deductible differences. The amount of deferred tax assets considered realizable could be reduced in the future if estimates of future taxable income during the carryforward period are reduced.

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LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

In accordance with the applicable accounting standard, the Company recognizes only the impact of income tax positions that, based on their merits, are more likely than not to be sustained upon audit by a taxing authority. In evaluating its current tax positions in order to identify any material uncertain tax positions, the Company developed a policy in identifying uncertain tax positions that considers support for each tax position, industry standards, tax return disclosures and schedules, and the significance of each position. It is the Company's policy to recognize interest and penalties, if any, related to unrecognized tax benefits in income tax expense. The Company had no material uncertain tax positions at December 31, 2011, and December 31, 2010.

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

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

	December 31,	
	2011	2010
	(in thousands)	
Accrued compensation	$ 19,581	$ 18,931
Accrued interest	55,170	62,999
Other	1,147	509
	$ 75,898	$ 82,439

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

	Year Ended December 31,		
	2011	2010	2009
		(in thousands)	
Cash payments for interest, net of amounts capitalized	$ 247,217	$ 128,807	$ 73,861
Cash payments for income taxes	$ 487	$ 1,797	$ 1,282
Noncash investing activities:			
In connection with the acquisition of oil and natural gas properties, liabilities were assumed as follow:			
Fair value of assets acquired	$ 1,523,466	$ 1,375,010	$ 117,717
Cash paid	(1,500,193)	(1,351,033)	(115,285)
Receivable from seller	3,557	9,976	636
Payables to sellers	(4,847)		
Liabilities assumed	$ 21,983	$ 33,953	$ 3,068

For purposes of the consolidated statements of cash flows, the Company considers all highly liquid short-term investments with original maturities of three months or less to be cash equivalents. Restricted cash of approximately $4 million and $3 million is included in "other noncurrent assets" on the consolidated balance sheets at December 31, 2011, and December 31, 2010, respectively, and represents cash deposited by the Company into a separate account and designated for asset retirement obligations in accordance with contractual agreements.

The Company manages its working capital and cash requirements to borrow only as needed from its Credit Facility. At December 31, 2011, approximately $54 million was included in “accounts payable and accrued expenses” on the consolidated balance sheet which represents reclassified net outstanding checks. There was no such balance at December 31, 2010. The Company presents these net outstanding checks as cash flows from financing activities on the consolidated statements of cash flows.

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

The following discussion and analysis should be read in conjunction with the "Consolidated Financial Statements" and "Notes to Consolidated Financial Statements," which are included in this Annual Report on Form 10-K in Item 8. "Financial Statements and Supplementary Data." The Company's Appalachian Basin and Mid Atlantic operations are classified as discontinued operations on the consolidated statements of operations for the period ended December 31, 2009 (see Note 2). Where applicable, the following supplemental oil and natural gas data present continuing operations separately from discontinued operations.

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

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

	Year Ended December 31,		
	2011	2010	2009
		(in thousands)	
Property acquisition costs: (1)			
Proved	$ 1,328,328	$ 1,290,826	$ 115,929
Unproved	188,409	65,604	947
Exploration costs	80	74	337
Development costs	639,395	244,834	140,521
Asset retirement costs	2,427	748	371
Total costs incurred	$ 2,158,639	$ 1,602,086	$ 258,105

(1) See Note 2 for details about the Company's acquisitions.

Oil and Natural Gas Capitalized Costs

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

	December 31,	
	2011	2010
	(in thousands)	
Proved properties:		
Leasehold acquisition	$ 6,040,239	$ 4,695,704
Development	1,484,486	840,175
Unproved properties	310,925	128,624
	7,835,650	5,664,503
Less accumulated depletion and amortization	(1,033,617)	(719,035)
	$ 6,802,033	$ 4,945,468

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

Results of Oil and Natural Gas Producing Activities

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

	Year Ended December 31,		
	2011	2010	2009
	(in thousands)		
Revenues and other:			
Oil, natural gas and natural gas liquid sales	$ 1,162,037	$ 690,054	$ 408,219
Gains (losses) on oil and natural gas derivatives	449,940	75,211	(141,374)
	1,611,977	765,265	266,845
Production costs:			
Lease operating expenses	232,619	158,382	132,647
Transportation expenses	28,358	19,594	18,202
Severance and ad valorem taxes	78,458	45,114	28,687
	339,435	223,090	179,536
Other costs:			
Exploration costs	2,390	5,168	7,169
Depletion and amortization	320,096	226,552	191,314
Impairment of long-lived assets		38,600	
Texas margin tax expense	1,599	657	490
Gains on sale of assets and other, net	(1,001)		(25,710)
	323,084	270,977	173,263
Results of continuing operations	$ 949,458	$ 271,198	$ (85,954)
Results of discontinued operations	$	$	$ (238)

There is no federal tax provision included in the results above because the Company’s subsidiaries subject to federal tax do not own any of the Company’s oil and natural gas interests. Limited liability companies are subject to state income taxes in Texas and Michigan (see Note 14). Discontinued operations for 2009 primarily represent activity related to post-closing adjustments for the sale of properties in the Appalachian Basin in 2008 (see Note 2).

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

Proved Oil, Natural Gas and NGL Reserves

The proved reserves of oil, natural gas and NGL of the Company have been prepared by the independent engineering firm, DeGolyer and MacNaughton. In accordance with SEC regulations, reserves at December 31, 2011, December 31, 2010, and December 31, 2009, were estimated using the average price during the 12-month period, determined as an unweighted average of the first-day-of-the-month price for each month, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. An analysis of the change in estimated quantities of oil, natural gas and NGL reserves, all of which are located within the U.S., is shown below:

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

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

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

	Year Ended December 31, 2009			
	Natural Gas (Bcf)	Oil (MMBbls)	NGL (MMBbls)	Total (Bcfe)
Proved developed and undeveloped reserves:				
Beginning of year	851	84.1	50.7	1,660
Revisions of previous estimates	(69)	10.9	4.0	20
Purchase of minerals in place	7	8.8	0.4	62
Extensions, discoveries and other additions	31	1.6	1.5	50
Production	(46)	(3.3)	(2.4)	(80)
End of year	774	102.1	54.2	1,712
Proved developed reserves:				
Beginning of year	585	61.9	29.6	1,134
End of year	549	77.9	33.9	1,220
Proved undeveloped reserves:				
Beginning of year	266	22.2	21.1	526
End of year	225	24.2	20.3	492

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

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

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

Proved reserves increased by approximately 52 Bcfe to approximately 1,712 Bcfe for the year ended December 31, 2009. The year ended December 31, 2009, includes 20 Bcfe in positive revisions of previous estimates, due primarily to higher asset performance, which contributed approximately 39 Bcfe, most significantly related to well reactivations and waterflood optimization work in the Mid-Continent Shallow region. These positive revisions were partially offset by 19 Bcfe in negative revisions primarily due to decreases in natural gas prices. Two acquisitions during the year ended December 31, 2009, increased proved reserves by approximately 62 Bcfe. In addition, extensions and discoveries, primarily from 72 productive wells drilled during the year, contributed approximately 50 Bcfe to the increase in proved reserves.

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

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

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

liability companies are subject to state income taxes in Texas and Michigan; however, these amounts are not material (see Note 14).

	December 31, 2011	2010 (in thousands)	2009
Future estimated revenues	$ 29,319,369	$ 20,160,275	$ 10,093,876
Future estimated production costs	(9,464,319)	(6,825,147)	(4,200,091)
Future estimated development costs	(2,848,497)	(1,733,929)	(816,577)
Future net cash flows	17,006,553	11,601,199	5,077,208
10% annual discount for estimated timing of cash flows	(10,391,693)	(7,377,667)	(3,353,926)
Standardized measure of discounted future net cash flows	$ 6,614,860	$ 4,223,532	$ 1,723,282
Representative NYMEX prices: (1)			
Natural gas (MMBtu)	$ 4.12	$ 4.38	$ 3.87
Oil (Bbl)	$ 95.84	$ 79.29	$ 61.05

(1) In accordance with SEC regulations, reserves at December 31, 2011, December 31, 2010, and December 31, 2009, were estimated using the average price during the 12-month period, determined as an unweighted average of the first-day-of-the-month price for each month, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. The price used to estimate reserves is held constant over the life of the reserves.

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

	Year Ended December 31, 2011	2010 (in thousands)	2009
Sales and transfers of oil, natural gas and NGL produced during the period	$ (822,602)	$ (466,964)	$ (228,683)
Changes in estimated future development costs	27,236	(56,001)	54,141
Net change in sales and transfer prices and production costs related to future production	784,308	886,438	254,036
Purchase of minerals in place	1,452,169	1,277,134	128,779
Extensions, discoveries, and improved recovery	552,704	329,642	25,888
Previously estimated development costs incurred during the period	306,827	42,947	52,699
Net change due to revisions in quantity estimates	(292,343)	164,999	23,672
Accretion of discount	422,353	172,328	142,437
Changes in production rates and other	(39,324)	149,727	(154,054)
Change – continuing operations	$ 2,391,328	$ 2,500,250	$ 298,915

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

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LINN ENERGY, LLC
SUPPLEMENTAL QUARTERLY DATA (Unaudited)

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

Quarterly Financial Data

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

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

	Quarters Ended			
	March 31	June 30	September 30	December 31
	(in thousands, except per unit amounts)			
2010:				
Oil, natural gas and natural gas liquid sales	$ 149,386	$ 153,195	$ 177,306	$ 210,167
Gains (losses) on oil and natural gas derivatives	$ 96,003	$ 123,791	$ 43,505	$ (188,088)
Total revenues and other	$ 247,036	$ 278,404	$ 222,361	$ 24,479
Total expenses (1)	$ 124,740	$ 135,980	$ 145,978	$ 200,508
(Gains) losses on sale of assets and other, net	$ (322)	$ (52)	$ 6,073	$ 837
Net income (loss)	$ 65,310	$ 59,786	$ 4,143	$ (243,527)
Net income (loss) per unit:				
Basic	$ 0.50	$ 0.41	$ 0.03	$ (1.64)
Diluted	$ 0.50	$ 0.40	$ 0.03	$ (1.64)

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

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

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

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

The Company carried out an evaluation under the supervision and with the participation of its management, including its Chief Executive Officer and Chief Financial Officer, of the effectiveness of its disclosure controls and procedures as of the end of the period covered by this report. Based on this evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company's disclosure controls and procedures were effective as of December 31, 2011.

Management's Annual Report on Internal Control Over Financial Reporting

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

Changes in the Company's Internal Control Over Financial Reporting

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

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

There were no changes in the Company's internal controls over financial reporting during the fourth quarter of 2011 that materially affected, or were reasonably likely to materially affect, the Company's internal control over financial reporting.

Item 9B. 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 Annual Report on Form 10-K.

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Part III

Item 10. Directors, Executive Officers and Corporate Governance

A list of the Company's executive officers and biographical information appears in Part I in this Annual Report on Form 10-K under the caption "Executive Officers of the Company." Information about Company Directors may be found under the caption "Election of Directors" of the Proxy Statement for the Annual Meeting of Unitholders to be held on April 24, 2012 (the "2012 Proxy Statement"). That information is incorporated herein by reference.

The information in the 2012 Proxy Statement set forth under the caption "Section 16(a) Beneficial Ownership Reporting Compliance" is incorporated herein by reference.

The information required by this item regarding audit committee related matters, codes of ethics and committee charters is incorporated by reference from the 2012 Proxy Statement under the caption "Corporate Governance."

Item 11. Executive Compensation

Information required by this item is incorporated herein by reference to the 2012 Proxy Statement.

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

Information required by this item is incorporated herein by reference to the 2012 Proxy Statement.

Securities Authorized for Issuance Under Equity Compensation Plans

The following summarizes information regarding the number of units that are available for issuance under all of the Company's equity compensation plans as of December 31, 2011:

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Unit Options, Warrants and Rights (a)	Weighted Average Exercise Price of Outstanding Unit Options, Warrants and Rights (b)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a)) (c)
Equity compensation plans approved by security holders	1,409,993	$ 22.14	5,175,446
Equity compensation plans not approved by security holders	—	—	—
	1,409,993	$ 22.14	5,175,446

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

Information required by this item is incorporated herein by reference to the 2012 Proxy Statement.

Item 14. Principal Accounting Fees and Services

Information required by this item is incorporated herein by reference to the 2012 Proxy Statement.

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Part IV

Item 15. Exhibits and Financial Statement Schedules

(a) – 2. Financial Statement Schedules:

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

(a) – 3. Exhibits Filed:

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

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SIGNATURES

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

LINN ENERGY, LLC

Date: February 23, 2012	By:	/s/ Mark E. Ellis Mark E. Ellis Chairman, President and Chief Executive Officer
Date: February 23, 2012	By:	/s/ David B. Rottino David B. Rottino Senior Vice President of Finance, Business Development and Chief Accounting Officer

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

Signature	Title	Date
/s/ Mark E. Ellis Mark E. Ellis	Chairman, President and Chief Executive Officer (Principal Executive Officer)	February 23, 2012
/s/ Kolja Rockov Kolja Rockov	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 23, 2012
/s/ David B. Rottino David B. Rottino	Senior Vice President of Finance, Business Development and Chief Accounting Officer (Principal Accounting Officer)	February 23, 2012
/s/ Michael C. Linn Michael C. Linn	Founder and Director	February 23, 2012
/s/ George A. Alcorn George A. Alcorn	Independent Director	February 23, 2012
/s/ Terrence S. Jacobs Terrence S. Jacobs	Independent Director	February 23, 2012
/s/ Joseph P. McCoy Joseph P. McCoy	Independent Director	February 23, 2012
/s/ Jeffrey C. Swoveland	Independent Director	February 23, 2012

Jeffrey C. Swoveland

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INDEX TO EXHIBITS

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

		Association, as Trustee (incorporated herein by reference to Exhibit 4.2 to Quarterly Report on Form 10-Q filed on July 29, 2010)
4.9	—	First Supplemental Indenture, dated as of July 2, 2010, to Indenture, dated as of April 6, 2010, between Linn Energy, LLC, Linn Energy Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as Trustee (incorporated herein by reference to Exhibit 4.3 to Quarterly Report on Form 10-Q filed on July 29, 2010)
4.10	—	Second Supplemental Indenture, dated as of March 16, 2011, to the Indenture, dated as of May 18, 2009, by and among Linn Energy LLC, Linn Energy Finance Corp., the Guarantors party thereto and U.S. Bank National Association (incorporated herein by reference to Exhibit 4.1 to Current Report on Form 8-K filed on March 22, 2011)

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INDEX TO EXHIBITS - Continued

Exhibit Number		Description
4.11	—	Second Supplemental Indenture, dated as of March 16, 2011, to the Indenture dated as of June 27, 2008, by and among Linn Energy LLC, Linn Energy Finance Corp., the Guarantors party thereto and U.S. Bank National Association (incorporated herein by reference to Exhibit 4.1 to Current Report on Form 8-K filed on March 22, 2011)
4.12	—	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**	—	Linn Energy, LLC Amended and Restated Long-Term Incentive Plan (incorporated herein by reference to Annex A to the Proxy Statement for 2008 Annual Meeting, filed on April 21, 2008)
10.2**	—	Amendment No. 1 to Linn Energy, LLC Amended and Restated Long-Term Incentive Plan, dated February 4, 2009, (incorporated herein by reference to Exhibit 10.2 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.3**	—	Amendment No. 2 to Linn Energy, LLC Amended and Restated Long-Term Incentive Plan, dated July 19, 2010, (incorporated herein by reference to Exhibit 10.3 to Quarterly Report on Form 10-Q filed on July 29, 2010)
10.4**	—	Form of Executive Unit Option Agreement pursuant to the Linn Energy, LLC Amended and Restated Long-Term Incentive Plan, as amended (incorporated herein by reference to Exhibit 10.3 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.5**	—	Form of Executive Restricted Unit Agreement pursuant to the Linn Energy, LLC Amended and Restated Long-Term Incentive Plan, as amended (incorporated herein by reference to Exhibit 10.4 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.6**	—	Form of Phantom Unit Grant Agreement for Independent Directors pursuant to the Linn Energy, LLC Amended and Restated Long-Term Incentive Plan, as amended (incorporated herein by reference to Exhibit 10.1 to Current Report on Form 8-K filed on August 9, 2006)
10.7**	—	Form of Director Restricted Unit Grant Agreement pursuant to the Linn Energy, LLC Amended and Restated Long-Term Incentive Plan, as amended (incorporated herein by reference to Exhibit 10.6 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.8**	—	Retirement Agreement, dated as of November 29, 2011, by and among Linn Operating, Inc., Linn Energy, LLC and Michael C. Linn (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed on December 1, 2011)
10.9**	—	Third Amended and Restated Employment Agreement, dated effective as of December 17, 2008, between Linn Operating, Inc. and Kolja Rockov (incorporated herein by reference to Exhibit 10.8 to Annual Report on

		Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.10**	—	Amended and Restated Employment Agreement, dated effective as of December 17, 2008, between Linn Operating, Inc. and Mark E. Ellis (incorporated herein by reference to Exhibit 10.9 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.11**	—	Amendment No. 1, dated effective as of January 1, 2010, to Amended and Restated Employment Agreement, dated effective as of December 17, 2008, between Linn Operating, Inc. and Mark E. Ellis (incorporated herein by reference to Exhibit 10.29 to Annual Report on Form 10-K for the year ended December 31, 2009, filed on February 25, 2010)
10.12**	—	Amended and Restated Employment Agreement, dated effective December 17, 2008, between Linn Operating, Inc. and Charlene A. Ripley (incorporated herein by reference to Exhibit 10.10 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)

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INDEX TO EXHIBITS - Continued

Exhibit Number		Description
10.13**	—	Amended and Restated Employment Agreement, dated effective December 17, 2008, between Linn Operating, Inc. and Arden L. Walker, Jr. (incorporated herein by reference to Exhibit 10.11 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.14**	—	Amendment No. 1, dated April 26, 2011, to First Amended and Restated Employment Agreement, dated December 17, 2008, between Linn Operating, Inc. and Arden L. Walker, Jr. (incorporated herein by reference to Quarterly Report on Form 10-Q for the quarter ended March 31, 2011, filed on April 28, 2011)
10.15**	—	Second Amended and Restated Employment Agreement, dated December 17, 2008, between Linn Operating, Inc. and David B. Rottino (incorporated herein by reference to Exhibit 10.12 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.16**	—	Indemnity Agreement, dated as of February 4, 2009, between Linn Energy, LLC and George A. Alcorn (incorporated herein by reference to Exhibit 10.15 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.17**	—	Indemnity Agreement, dated as of February 4, 2009, between Linn Energy, LLC and Joseph P. McCoy (incorporated herein by reference to Exhibit 10.16 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.18**	—	Indemnity Agreement, dated as of February 4, 2009, between Linn Energy, LLC and Terrence S. Jacobs (incorporated herein by reference to Exhibit 10.17 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.19**	—	Indemnity Agreement, dated as of February 4, 2009, between Linn Energy, LLC and Jeffrey C. Swoveland (incorporated herein by reference to Exhibit 10.18 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.20**	—	Indemnity Agreement, dated as of February 4, 2009, between Linn Energy, LLC and Michael C. Linn (incorporated herein by reference to Exhibit 10.19 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.21**	—	Indemnity Agreement, dated as of February 4, 2009, between Linn Energy, LLC and Mark E. Ellis (incorporated herein by reference to Exhibit 10.20 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.22**	—	Indemnity Agreement, dated as of February 4, 2009, between Linn Energy, LLC and Kolja Rockov (incorporated herein by reference to Exhibit 10.21 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.23**	—	Indemnity Agreement, dated as of February 4, 2009, between Linn Energy, LLC and Charlene A. Ripley (incorporated herein by reference to Exhibit 10.22 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)

10.24**	—	Indemnity Agreement, dated as of February 4, 2009, between Linn Energy, LLC and David B. Rottino (incorporated herein by reference to Exhibit 10.23 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.25**	—	Indemnity Agreement, dated as of February 4, 2009, between Linn Energy, LLC and Arden L. Walker, Jr. (incorporated herein by reference to Exhibit 10.24 to Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 26, 2009)
10.26	—	Fifth Amended and Restated Credit Agreement dated as of May 2, 2011, among Linn Energy, LLC as Borrower, BNP Paribas, as Administrative Agent, and the Lenders and agents Party thereto (incorporated herein by reference to Exhibit 10.1 to Quarterly Report on Form 10-Q filed on July 28, 2011)
10.27	—	Fifth Amended and Restated Guaranty and Pledge Agreement, dated as of May 2, 2011, made by Linn Energy, LLC and each of the other Obligors in favor of BNP Paribas, as Administrative Agent (incorporated herein by reference to Exhibit 10.1 to Quarterly Report on Form 10-Q filed on July 28, 2011)
10.28	—	Linn Energy, LLC Change of Control Protection Plan, dated as of April 25, 2009, (incorporated herein by reference to Exhibit 10.3 to Quarterly Report on Form 10-Q filed on May 7, 2009)

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INDEX TO EXHIBITS - Continued

Exhibit Number		Description
21.1*	—	Significant Subsidiaries of Linn Energy, LLC
23.1*	—	Consent of KPMG LLP
23.2*	—	Consent of DeGolyer and MacNaughton
31.1*	—	Section 302 Certification of Mark E. Ellis, Chairman, President and Chief Executive Officer of Linn Energy, LLC
31.2*	—	Section 302 Certification of Kolja Rockov, Executive Vice President and Chief Financial Officer of Linn Energy, LLC
32.1*	—	Section 906 Certification of Mark E. Ellis, Chairman, President and Chief Executive Officer of Linn Energy, LLC
32.2*	—	Section 906 Certification of Kolja Rockov, Executive Vice President and Chief Financial Officer of Linn Energy, LLC
99.1*	—	2011 Report of DeGolyer and MacNaughton
101.INS†	—	XBRL Instance Document
101.SCH†	—	XBRL Taxonomy Extension Schema Document
101.CAL†	—	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF†	—	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB†	—	XBRL Taxonomy Extension Label Linkbase Document
101.PRE†	—	XBRL Taxonomy Extension Presentation Linkbase Document

* Filed herewith.

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

† Furnished herewith.