LINN ENERGY, LLC
Form 10-K
February 25, 2010

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, 2009

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 o No o

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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 $2,303,614,114 on June 30, 2009, based on $19.57 per unit, the last reported sales price of the units on The NASDAQ Global Select Market on such date.

As of January 29, 2010, there were 130,566,930 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 27, 2010.

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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:

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

Bcf. One billion cubic feet.

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

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

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.

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

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

MBbls/d. MBbls per day.

Mcf. One thousand cubic feet.

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

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

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

MMBtu. One million British thermal units.

MMcf. One million cubic feet.

MMcf/d. MMcf per day.

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

MMcfe/d. MMcfe per day.

MMMBtu. One billion British thermal units.

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

GLOSSARY OF TERMS - Continued

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. In accordance with Securities and Exchange Commission regulations, reserves at 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 Securities and Exchange Commission regulations, reserves for all prior years were estimated using year-end prices.

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.

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%.

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GLOSSARY OF TERMS - Continued

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

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

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

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

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

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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, primarily in the Mid-Continent, California and the Permian Basin.

Proved reserves at December 31, 2009, were 1,712 Bcfe, of which approximately 36% were oil, 45% were natural gas and 19% were natural gas liquids ("NGL"). Approximately 71% were classified as proved developed, with a total standardized measure of discounted future net cash flows of $1.72 billion. At December 31, 2009, the Company operated 4,688, or 68%, of its 6,931 gross productive wells and had an average proved reserve-life index of approximately 22 years, based on the December 31, 2009, reserve report and annualized production for the three months ended December 31, 2009.

In January 2010, the Company completed an acquisition of oil and natural gas properties in the Anadarko and Permian Basins for a contract price of $154.5 million. See "Recent Developments" below for additional details. On a pro forma basis, including this acquisition, total proved reserves at December 31, 2009, were 1,785 Bcfe, of which approximately 37% were oil, 44% were natural gas and 19% were NGL.

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 commodity price and interest rate 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 are 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.

From inception through the date of this report, excluding 15 acquisitions comprising the Appalachian Basin properties sold in July 2008, the Company has completed 13 acquisitions of working and royalty interests in oil and natural gas properties and related gathering and pipeline assets. Total acquired proved reserves were approximately 1.8 Tcfe at the time of acquisition at an acquisition cost of approximately $2.15 per Mcfe. The Company finances acquisitions with a combination of funds from equity and debt offerings, bank borrowings and cash generated 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 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 2010, the Company estimates its capital expenditures, excluding acquisitions, will be between $150.0 million and $175.0 million. This estimate is under continuous review and is subject to ongoing adjustment. The Company expects to fund these capital expenditures with cash flow from operations.

Reduce Cash Flow Volatility Through Commodity Price and Interest Rate 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, natural gas and NGL 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 transactions are primarily in the form of swap contracts, put options and collars that are designed to provide a fixed price (swap contracts), fixed price floor with opportunity for upside (put options) or range of prices between a price floor and a price ceiling (collars) that the Company will receive as compared to floating market prices. The Company has derivative contracts in place for 2010 and 2011 at average prices of $99.68 per Bbl and $82.50 per Bbl for oil and $8.66 per MMBtu and $9.25 per MMBtu for natural gas, respectively. Additionally, the Company has derivative contracts in place covering substantially all of its exposure to the Mid-Continent natural gas basis differential.

In addition, the Company enters into derivative contracts in the form of interest rate swaps to minimize the effects of fluctuations in interest rates. Currently, the Company utilizes London Interbank Offered Rate ("LIBOR") swaps to convert the borrowing rate on indebtedness under its Credit Facility (as defined in Note 6) from a floating rate to a fixed rate. At January 29, 2010, the Company had LIBOR swaps in place at an average fixed rate of 3.85% through January 2014. For additional details about the Company's interest rate swap agreements and 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.
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Recent Developments

Commodity Derivatives

In February 2010, the Company entered into fixed price oil swaps on an additional 5,250 Bbls per day at a price of $100.00 per Bbl for the years ending December 31, 2012, and December 31, 2013, bringing the Company's total such fixed price oil swaps to swaps on 7,250 Bbls per day. The Company has derivative contracts that extend the swaps for each of the years ending December 31, 2014, December 31, 2015, and December 31, 2016, 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. See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" for additional details.

Acquisitions

On January 29, 2010, the Company completed the acquisition of certain oil and natural gas properties located in the Anadarko Basin in Oklahoma and Kansas and the Permian Basin in Texas and New Mexico, from certain affiliates of Merit Energy Company ("Merit") for a contract price of $154.5 million. The transaction was financed with borrowings under the Company's Credit Facility. The acquisition provides a strategic addition to the Company's asset portfolio in the Permian Basin and Mid-Continent, and includes approximately 12 MMBoe (73 Bcfe) of proved reserves as of the acquisition date, primarily oil.

On August 31, 2009, and September 30, 2009, the Company completed the 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 (collectively referred to as "Forest"). The Company paid $114.4 million in cash, net of cash received from Forest post-closing, and recorded a receivable from Forest, resulting in total consideration for the acquisitions of approximately $113.7 million. The transactions were financed with borrowings under the Company's Credit Facility. The acquisitions represent a strategic entry into the Permian Basin for the Company, and include approximately 10 MMBoe (62 Bcfe) of proved reserves, primarily oil.

Distributions

On January 27, 2010, the Company's Board of Directors declared a cash distribution of $0.63 per unit with respect to the fourth quarter of 2009. The distribution, totaling approximately $82.3 million, was paid on February 12, 2010, to unitholders of record as of the close of business on February 5, 2010.

Operating Regions

Inclusive of the properties acquired from Merit in January 2010 (see "Acquisitions" above), the Company's properties are located in four regions in the United States:

- 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;
- California, which includes the Brea Olinda Field of the Los Angeles Basin; and
- Permian Basin, which includes areas in West Texas and Southeast New Mexico.

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 8,900 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, 2009, of which 71% were classified as proved developed reserves.

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This region produced 135 MMcfe/d, or 62%, of the Company's 2009 average daily production. During 2009, the Company invested approximately $99.3 million to drill in this region. During 2010, the Company anticipates spending approximately 60% of its total capital budget for development activities in the Mid-Continent Deep region.

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 and properties in Oklahoma, Louisiana and Illinois, which produce at depths of less than 8,000 feet. Mid-Continent Shallow proved reserves represented approximately 38% of total proved reserves at December 31, 2009, of which 66% were classified as proved developed reserves. This region produced 67 MMcfe/d, or 31%, of the Company's 2009 average daily production. During 2009, the Company invested approximately $21.0 million to drill in this region. During 2010, the Company anticipates spending approximately 20% of its total capital budget for development activities in the Mid-Continent Shallow region.

To more efficiently transport its natural gas in the Mid-Continent Deep and Mid-Continent Shallow regions to market, the Company owns and operates a network of natural gas gathering systems comprised of approximately 900 miles of pipeline and associated compression and metering facilities that connect to numerous sales outlets in the Texas Panhandle.

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 of 1,000 feet to 7,500 feet. California proved reserves represented approximately 11% of total proved reserves at December 31, 2009, of which 94% were classified as proved developed reserves. This region produced 14 MMcfe/d, or 6%, of the Company's 2009 average daily production.

Permian Basin

The Permian Basin is one of the largest and most prolific oil and natural gas basins in the United States. The Company's properties are located in West Texas and Southeast New Mexico and produce at depths ranging from 2,000 feet to 9,000 feet. Permian Basin proved reserves represented approximately 4% of total proved reserves at December 31, 2009, of which 53% were classified as proved developed reserves. The properties that comprise this region as of December 31, 2009, were acquired in the third quarter of 2009 (see "Acquisitions" above). This region produced 2 MMcfe/d, or 1%, of the Company's 2009 average daily production. During 2009, the Company invested approximately $0.1 million to drill in this region. During 2010, the Company anticipates spending approximately 20% of its total capital budget for development activities in the Permian Basin region.

Drilling and Acreage

The following sets forth the wells drilled in the Mid-Continent Deep, Mid-Continent Shallow, California and Permian 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 its working interest):

	Year Ended December 31,		
	2009	2008	2007
Gross wells:			
Productive	72	304	136
Dry	1	2	2
	73	306	138
Net development wells:			
Productive	35	189	112
Dry	1	1	2
	36	190	114
Net exploratory wells:			
Productive	—	—	—
Dry	—	—	—
	—	—	—

The totals above do not include 25, 23 and 25 lateral segments added to existing vertical wellbores in the Mid-Continent Shallow region during the years ended December 31, 2009, December 31, 2008, and December 31, 2007, respectively. The total wells above exclude 45 and 115 gross wells (45 and 105 net wells) drilled in the Appalachian Basin during the years ended December 31, 2008, and December 31, 2007, respectively. The Company sold its Appalachian Basin properties in July 2008. At December 31, 2009, the Company had one gross (one net) well in process (no wells were temporarily suspended).

The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled and the quantities or economic value of reserves found. Productive wells are those that produce commercial quantities of oil, natural gas or NGL, regardless of whether they generate a reasonable rate of return.

The following sets forth information about the Company's drilling locations and net acres of leasehold interests as of December 31, 2009:

	Total (1)
Proved undeveloped	1,241
Other locations	3,050
Total drilling locations	4,291
Leasehold interests – net acres (in thousands)	702

(1) Does not include optimization projects.

As shown in the table above, as of December 31, 2009, the Company had 1,241 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 3,050 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 table sets forth information relating to the productive wells in which the Company owned a working interest as of December 31, 2009. 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 2,100 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)	1,947	1,534	2,741	2,523	4,688	4,057
Nonoperated (2)	1,201	207	1,042	72	2,243	279
	3,148	1,741	3,783	2,595	6,931	4,336

(1) 10 operated wells had multiple completions at December 31, 2009.

(2) Three nonoperated wells had multiple completions at December 31, 2009.

Developed and Undeveloped Acreage

The following sets forth information as of December 31, 2009, relating to leasehold acreage:

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
			(in thousands)			
Leasehold acreage	1,462	648	90	54	1,552	702

Production, Price and Cost History

The results of the Company's Appalachian Basin and Mid Atlantic Well Service, Inc. ("Mid Atlantic") operations are classified as discontinued operations for all periods presented (see Note 2 for additional information). Unless otherwise indicated, results of operations information presented herein relates only to continuing operations.

The Company's natural gas production is primarily sold under market sensitive price contracts, which typically sell at a differential to New York Mercantile Exchange ("NYMEX"), Panhandle Eastern Pipeline ("PEPL"), or El Paso Permian Basin 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, 2009, approximately 80% of the Company's natural gas and NGL production was sold under short-term contracts at market-sensitive or spot prices. At December 31, 2009, the Company had natural gas throughput delivery commitments under long-term contracts of approximately 2,102 MMcf, 1,045 MMcf and 784 MMcf for the years ended December 31, 2010, December 31, 2011, and December 31, 2012, respectively.

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, 2009, approximately 75% of its oil production was sold under short-term contracts. At December 31, 2009, 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, put options and collars 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.

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

	Year Ended December 31,		
	2009	2008	2007
Average daily production:			
Natural gas (MMcf/d)	125	124	51
Oil (MBbls/d)	9.0	8.6	3.4
NGL (MBbls/d)	6.5	6.2	2.7
Total (MMcfe/d)	218	212	87
Weighted average prices (hedged): (1)			
Natural gas (Mcf)	$ 8.27	$ 8.42	$ 8.36
Oil (Bbl)	$ 110.94	$ 80.92	$ 67.07
NGL (Bbl)	$ 28.04	$ 57.86	$ 55.51
Weighted average prices (unhedged): (2)			
Natural gas (Mcf)	$ 3.51	$ 7.39	$ 6.39
Oil (Bbl)	$ 55.25	$ 92.78	$ 66.44
NGL (Bbl)	$ 28.04	$ 57.86	$ 55.51
Average NYMEX prices:			
Natural gas (MMBtu)	$ 3.99	$ 9.04	$ 6.86
Oil (Bbl)	$ 61.94	$ 99.65	$ 72.34
Costs per Mcfe of production:			
Lease operating expenses	$ 1.67	$ 1.49	$ 1.31
Transportation expenses	$ 0.23	$ 0.23	$ 0.17
General and administrative expenses (3)	$ 1.08	$ 1.00	$ 1.61
Depreciation, depletion and amortization	$ 2.53	$ 2.50	$ 2.16
Taxes, other than income taxes	$ 0.35	$ 0.79	$ 0.70

(1) Includes the effect of realized gains on derivatives of $401.0 million (excluding $49.0 million realized net gains on canceled contracts), $9.4 million (excluding $81.4 million realized losses on canceled contracts) and $37.3 million for the years ended December 31, 2009, December 31, 2008, and December 31, 2007, respectively. The Company utilizes oil puts to hedge revenues associated with its NGL production; therefore, all realized gains on oil derivative contracts are included in weighted average oil prices, rather than weighted average NGL prices.

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

(3) General and administrative expenses for the years ended December 31, 2009, December 31, 2008, and December 31, 2007, include approximately $14.7 million, $14.6 million and $13.5 million, respectively, of noncash unit-based compensation expenses. Excluding these amounts, general and administrative expenses for the years ended December 31, 2009, December 31, 2008, and December 31, 2007, were $0.90 per Mcfe, $0.81 per Mcfe and $1.19 per Mcfe, respectively. This measure is not in accordance with United States 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

Modernization of Oil and Natural Gas Reporting Requirements

Effective for fiscal years ending on or after December 31, 2009, the Securities and Exchange Commission ("SEC") approved revisions designed to modernize reserve reporting requirements for oil and natural gas companies. In addition, effective for the same period, the Financial Accounting Standards Board issued Accounting Standards Codification Update 2010-03, "Extractive Activities – Oil and Gas (Topic 932) – Oil and Gas Reserve Estimation and Disclosures," to provide consistency with the new SEC rules. The Company adopted the new requirements effective December 31, 2009. The most significant amendments to the requirements include the following:

- commodity prices – economic producibility of reserves 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;
- disclosure of unproved reserves – probable and possible reserves may be disclosed separately on a voluntary basis;
- proved undeveloped reserve guidelines – reserves may be classified as proved undeveloped if there is a high degree of confidence that the quantities will be recovered;
- reserve estimation using new technologies – reserves may be estimated through the use of reliable technology in addition to flow tests and production history; and
- nontraditional resources – the definition of oil and natural gas producing activities were expanded and focus on the marketable product rather than the method of extraction.

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, 2009, based on reserve reports prepared by independent engineers DeGolyer and MacNaughton:

Estimated proved developed reserves:			
Natural gas (Bcf)		549	
Oil (MMBbls)		78	
NGL (MMBbls)		34	
Total (Bcfe)		1,220	
Estimated proved undeveloped reserves: (1)			
Natural gas (Bcf)		225	
Oil (MMBbls)		24	
NGL (MMBbls)		20	
Total (Bcfe)		492	
Estimated total proved reserves (Bcfe)		1,712	
Proved developed reserves as a percentage of total proved reserves		71	%
Standardized measure of discounted future net cash flows (in millions) (2)	$	1,723	
Representative NYMEX prices: (3)			
Natural gas (MMBtu)	$	3.87	
Oil (Bbl)	$	61.05	

(1) During the year ended December 31, 2009, the Company incurred approximately $52.7 million in capital expenditures to convert 33 Bcfe of reserves previously classified as proved undeveloped into proved developed reserves at December 31, 2009.

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

(3) 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.

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, 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 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 Senior 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."

Operational Overview

General

The Company seeks to be the operator of its properties so that it can control the drilling programs that not only replace production, but add value through the growth of reserves 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, 2009, sales of oil, natural gas and NGL to DCP Midstream Partners, LP, Enbridge Energy Partners, L.P. and ConocoPhillips accounted for approximately 25%, 19% and 12%, respectively, of the Company's total volumes, or 56% 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 United States 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,

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Item 1. Business - Continued

which could lead to shortages and increase costs or delay operations. For example, Company operations in all regions 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 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 rate of oil, natural gas and NGL production 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 United States 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 United States;
- Comprehensive Environmental Response, Compensation and Liability Act, 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, which governs the management of solid waste;
- Safe Drinking Water Act, which governs the underground injection and disposal of wastewater; and
- United States 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

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on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulation, 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 to address climate change, such as a proposed cap-and-trade program and the Environmental Protection Agency's ("EPA") recent endangerment finding regarding several greenhouse gases, including carbon dioxide, as well as regulations imposing reporting obligations on, or otherwise limiting, the hydraulic fracturing process.

In June 2009, the United States House of Representatives passed the American Clean Energy and Security Act of 2009, also known as the Waxman-Markey Bill. The United States Senate's version, The Clean Energy Jobs and American Power Act, or the Boxer-Kerry Bill, has been introduced, but has not passed. Although these bills include several differences that require reconciliation before becoming law, both bills contain the basic feature of establishing a cap-and-trade system for restricting greenhouse gas emissions in the United States. Under such system, certain sources of greenhouse gas emissions would be required to obtain greenhouse gas emission allowances corresponding to their annual emissions of greenhouse gases. The number of emission allowances issued each year would decline as necessary to meet overall emission reduction goals. As the number of greenhouse gas emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. The ultimate outcome of this legislative initiative remains uncertain. In addition to the pending climate legislation, the EPA has issued greenhouse gas monitoring and reporting regulations that went into effect January 1, 2010, and require reporting by regulated facilities by March 2011 and annually thereafter. Beyond measuring and reporting, the EPA issued an "Endangerment Finding" under section 202(a) of the Clean Air Act, concluding greenhouse gas pollution threatens the public health and welfare of current and future generations. The EPA has proposed regulation that would require permits for and reductions in greenhouse gas emissions for certain facilities, and may issue final rules this year. Any laws or regulations that may be adopted to restrict or reduce emissions of United States greenhouse gases could require the Company to incur increased operating costs, and could have an adverse effect on demand for oil and natural gas.

The Company cannot predict how future environmental laws and regulations may impact its properties or operations. For the year ended December 31, 2009, 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 2010 or that will otherwise have a material impact on its financial position or results of operations.

Employees

As of December 31, 2009, the Company employed approximately 550 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 Texas. The principal executive offices are located at 600 Travis, Suite 5100, Houston, Texas 77002. The main telephone number is (281) 840-4000.

Company Website

The Company's internet website is www.linnenergy.com. The Company makes available free of charge on or through its website Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K,

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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 statements about the Company's:

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

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

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

Item 1A. Risk Factors

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

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Item 1A. Risk Factors - Continued

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. 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 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;
- prevailing economic conditions;
- access to credit or capital markets;
- renegotiation of our Credit Facility at existing terms and pricing; 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 in any quarter 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;
- 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 Credit Facility, 2017 Notes and 2018 Notes (each as defined in Note 6). Our Credit Facility has 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.

We have significant indebtedness under our Credit Facility, 2017 Notes and 2018 Notes. As of January 29, 2010, we had an aggregate of approximately $1.7 billion outstanding under our Credit Facility, 2017 Notes and 2018 Notes (with additional borrowing capacity of approximately $422.0 million). 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 also are required to comply with certain financial covenants and ratios. 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 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 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 an event of 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.

Availability 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 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 any 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 on favorable terms will be affected by our debt level and 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.

The cost of raising money in the debt and equity capital markets has increased substantially while the availability of funds from those markets generally has diminished significantly. Also, as a result of concerns about the stability of financial markets and the solvency of counterparties specifically, the cost of obtaining money from the credit markets generally has increased as some major financial institutions have consolidated and others may consolidate in the future, 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 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.

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, natural gas and NGL, 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 the other party to the contract defaults on its contract or 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.

Disruptions in the capital and credit markets 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.

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Item 1A. Risk Factors - Continued

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 United States 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 way. 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 figures 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, production and acquisition 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 our financing arrangements. 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 generated by operations or 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 or results of operations. 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, 2009, we had 1,241 proved undeveloped drilling locations. To the extent that we do not drill these prospects 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, 2009, DCP Midstream Partners, LP, Enbridge Energy Partners, L.P. and ConocoPhillips accounted for approximately 25%, 19% and 12%, respectively, of our total volumes, or 56% in the aggregate. For the year ended December 31, 2008, DCP Midstream Partners, LP, ConocoPhillips and Enbridge Energy Partners, L.P. accounted for approximately 23%, 12% and 11%, respectively, of our total volumes from continuing operations, or 46% 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 United States. 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, 2009, we had identified 4,291 drilling locations, of which 1,241 were proved undeveloped locations and 3,050 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 3,050 other drilling locations we have identified and scheduled for drilling, and therefore there may be greater uncertainty with respect to the success of drilling wells at these drilling locations. Our final determination on whether to drill any of these drilling locations will be dependent upon the factors described above as well as, to some degree, the results of our drilling activities with respect to our proved drilling locations. Because of these uncertainties, we do not know if the numerous drilling locations we have identified will be drilled within our expected timeframe or will ever be drilled or if we will be able to produce oil, natural gas and NGL from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

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

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

- the high cost, shortages or delivery delays of equipment and services;
- unexpected operational events;

- adverse weather conditions;
- facility or equipment malfunctions;
- title problems;
- pipeline ruptures or spills;
- compliance with environmental and other governmental requirements;

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Item 1A. Risk Factors - Continued

- 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. 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. These include, for example:

- the federal Clean Air Act and comparable state laws and regulations that impose obligations related to air emissions;
- the federal Clean Water Act and comparable state laws and regulations that impose obligations related to discharges of pollutants into regulated bodies of water;
- the federal Resource Conservation and Recovery Act (“RCRA”), and comparable state laws that impose requirements for the handling and disposal of waste from our facilities; and
- the Comprehensive Environmental Response, Compensation and Liability Act of 1980 (“CERCLA”), also known as “Superfund,” and comparable state laws that regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or at locations to which we have sent waste for disposal.

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. 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. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances or other waste products into the environment.

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. For example, an accidental release from one of our wells or gathering pipelines could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage and fines or penalties for related violations of environmental laws or regulations.

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

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

Our operations are regulated extensively at the federal, state and local levels. Environmental and other governmental laws and regulations have 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."

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

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

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

- an individual unitholder's proportionate ownership interest in us may decrease;
- the relative voting strength of each previously outstanding unit may be reduced;
- the amount of cash available for distribution per unit may decrease; and
- the market price of the units may decline.

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

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

- our limited liability company agreement gives our Board of Directors broad discretion in establishing cash reserves for the proper conduct of our business, which will affect the amount of cash available for distribution. For example, our management will use its reasonable discretion to establish and maintain cash reserves sufficient to fund our drilling program;

- our management team, subject to oversight from our Board of Directors, determines the timing and extent of our drilling program and related capital expenditures, asset purchases and sales, borrowings, issuances of additional membership interests 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.

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. In addition, the costs of any contest with the IRS will be borne indirectly by our unitholders because the costs will reduce our cash available for distribution.

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

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

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

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

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

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

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

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

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

We treat each purchaser of units as having the same tax benefits 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 positions that are intended to maintain such uniformity. These depletion, depreciation and amortization positions may not conform with all aspects of existing Treasury regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain from unitholders' 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 twelve-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 twelve-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 2009, we have done business and owned assets in West Virginia, Virginia, Pennsylvania, California, Oklahoma, Kansas, New Mexico, Illinois, Indiana, Arkansas, Colorado, Kentucky, Louisiana, 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 United States federal, state and local tax returns that may be required of such unitholder.

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Item 1A. Risk Factors - Continued

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 United States 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.

The adoption of derivatives legislation by the United States Congress could have an adverse impact on our ability to hedge risks associated with our business.

Several proposals for derivative reform have been developed by committees in the United States House of Representatives and the United States Senate. These proposals are focused on expanding federal regulation surrounding the use of financial derivative instruments, including credit default swaps, commodity derivatives and other over-the-counter derivatives. Among the recommendations included in the proposals are the requirements for centralized clearing or settling of such derivatives as well as the expansion of collateral margin requirements for certain derivative-market participants. Depending on the ultimate form of legislation, our derivatives utilization could be adversely affected with: (i) greater administrative burden; (ii) limitations on the form and use of derivatives; and (iii) expanded collateral margin requirements.

Although it is not possible at this time to predict when the United States Congress may act on derivatives legislation, any laws or regulations that may be adopted that subject us to additional restrictions on our commodity derivative positions could have an adverse effect on our ability to hedge.

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 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, Oklahoma and Texas.

Item 3. Legal Proceedings

Although the Company may, from time to time, be involved in litigation and claims arising out of its operations in the normal course of business, the Company is not currently a party to any material legal proceedings. In addition, the Company is not aware of any material legal or governmental proceedings against it, or contemplated to be brought against it, under the various environmental protection statutes to which it is subject.

Item 4. Submission of Matters to a Vote of Security Holders

There were no matters submitted to a vote of security holders during the three months ended December 31, 2009.

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Item 4. Submission of Matters to a Vote of Security Holders - Continued

Executive Officers of the Company

Name	Age	Position with the Company
Michael C. Linn	58	Executive Chairman of the Board of Directors
Mark E. Ellis	54	President and Chief Executive Officer and Director
Kolja Rockov	39	Executive Vice President and Chief Financial Officer
Charlene A. Ripley	46	Senior Vice President, General Counsel and Corporate Secretary
David B. Rottino	44	Senior Vice President and Chief Accounting Officer
Arden L. Walker, Jr.	50	Senior Vice President and Chief Operating Officer

Michael C. Linn is the Executive Chairman of the Board of Directors of the Company and has served in such capacity since January 2010. He served as Chairman and Chief Executive Officer from December 2007 to January 2010; Chairman, President and Chief Executive Officer from June 2006 to December 2007; and President, Chief Executive Officer and Director of the Company from March 2003 to June 2006. Mr. Linn serves on the National Petroleum Council and American Exploration and Production Council. He serves on the boards of America's Natural Gas Alliance and the Independent Petroleum Association of America ("IPAA"). He is also Chairman of the IPAA Political Action Committee and past Chairman of IPAA. He serves as the Texas Representative for the Legal and Regulatory Affairs Committee of the Interstate Oil and Gas Compact Commission. He previously served as Chairman of the National Gas Council and Director of the Natural Gas Supply Association. He is former President of the Independent Oil and Gas Associations of New York, Pennsylvania and West Virginia. Mr. Linn regularly appears on behalf of the oil and natural gas industry before state and federal agencies, United States Congress and national broadcast media. His civic affiliations include serving on the boards of the Texas Heart Institute, Museum of Fine Arts Houston and Houston Police Foundation. In addition, he is the Chairman of the Texas Children's Hospital Corporate Committee Capital Campaign. He also serves on the Advisory Board of Houston Children's Charity and is a member of the Dean's Executive Advisory Board for the University of Houston C.T. Bauer College of Business. Mr. Linn graduated cum laude from Villanova University in 1974 with a BA in Political Science cum laude from the University of Baltimore School of Law in 1977. Following graduation, Mr. Linn went on to practice law for the law firm of Ecker, Ecker, Zofer and Rome. In 1980, he became General Counsel for Meridian Exploration, where he ultimately served as President and Chief Executive Officer until its sale in 1999. He served as President of Allegheny Interests, Inc. from 2000 to 2003.

Mark E. Ellis is the President and Chief Executive Officer and a Director of the Company and has served in such capacity since January 2010. 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 has more than 30 years of experience in the oil and natural gas industry, most recently serving as President, Lower 48 for ConocoPhillips from April 2006 to November 2006. Prior to joining ConocoPhillips, Mr. Ellis served as Senior Vice President of North American Production for Burlington Resources from September 2004 to April 2006. He served as President of Burlington Resources Canada Ltd. in Calgary from October 2000 to September 2004. Mr. Ellis joined Burlington Resources in 1985 and also held the positions of Vice President of the San Juan Division, Vice President and Chief Engineer and Manager of Acquisitions. He began his career at The Superior Oil Company, where he served in several engineering positions in the Onshore and Offshore divisions. Mr. Ellis is a member of the Society of Petroleum Engineers, a past board member of the New Mexico Oil & Gas Association and previously served on the Board of Governors of the Canadian Association of Petroleum Producers and served on the Foundation Board of the Alberta Children's Hospital. Mr. Ellis currently serves on the Board of The Center for Hearing and Speech in Houston, 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. Mr. Rockov has more than 15 years of experience in the oil and natural gas finance industry. From October 2004 until he joined LINN Energy in March 2005, Mr. Rockov served as a Managing Director in the Energy Group at RBC Capital Markets, where he was primarily responsible for investment banking coverage of the United States exploration and production sector. Prior

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to October 2004, Mr. Rockov held various senior positions with RBC Capital Markets and its predecessor companies.

Charlene A. Ripley is the Senior Vice President, General Counsel and Corporate Secretary and has served in that position since April 2007. Prior to joining the Company, Ms. Ripley held the position of Vice President, General Counsel, Corporate Secretary and Chief Compliance Officer at Anadarko Petroleum Corporation from 2006 until April 2007 and served as Vice President, General Counsel and Corporate Secretary from 2004 until 2006. Ms. Ripley served as Vice President, General Counsel and Secretary of Anadarko Canada Corporation and its predecessor companies since 1998.

David B. Rottino is the Senior Vice President and Chief Accounting Officer and has served in that position since June 2008. Mr. Rottino's career includes more than 15 years of oil and natural gas accounting experience, most recently serving as Vice President and E&P Controller for El Paso Corporation from June 2006 to May 2008. Prior to joining El Paso Corporation, Mr. Rottino served as Assistant Controller for ConocoPhillips from April 2006 to June 2006. He was Vice President and Chief Financial Officer for the Canadian division of Burlington Resources from July 2005 to April 2006 and served as Burlington Resources' Director of Financial Analysis and Corporate Accounting from August 2000 to July 2005. Mr. Rottino joined Burlington Resources in 1996 and has served in a broad range of accounting and audit positions. 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 the June Rusche Hamrah Camp For All.

Arden L. Walker, Jr. is the Senior Vice President and Chief Operating Officer of the Company and has served in such capacity since January 2010. Mr. Walker joined the Company in February 2007 as Senior Vice President - Operations and Chief Engineer to oversee its Texas, Oklahoma and California operations, and he is currently responsible for oversight of the Company's operations in all regions. In addition, Mr. Walker serves in the capacity of chief engineer for the Company and is responsible for the Company's reserve review and booking processes. From April 2006 until he joined the Company in February 2007, Mr. Walker served as Asset Development Manager, San Juan Business Unit for ConocoPhillips Company. From June 2004 to April 2006, Mr. Walker served as General Manager, Asset Development in San Juan Division for Burlington Resources. Mr. Walker began his career with El Paso Exploration Company in 1982 and has served in a broad range of engineering, business development and management positions with Burlington Resources since that time. Mr. Walker is a member of the Society of Petroleum Engineers, Independent Petroleum Association of America and California Independent Petroleum Association.

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 initial public offering. At the close of business on January 29, 2010, there were approximately 372 unitholders of record.

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

	Unit Price Range		Cash Distribution Declared
Quarter	High	Low	Per Unit
2009:			
October 1 – December 31	$ 28.00	$ 22.18	$ 0.63
July 1 – September 30	$ 23.96	$ 18.66	$ 0.63
April 1 – June 30	$ 20.42	$ 14.77	$ 0.63
January 1 – March 31	$ 16.65	$ 12.95	$ 0.63
2008:			
October 1 – December 31	$ 17.03	$ 11.20	$ 0.63
July 1 – September 30	$ 24.88	$ 14.93	$ 0.63
April 1 – June 30	$ 25.57	$ 19.44	$ 0.63
January 1 – March 31	$ 24.41	$ 18.88	$ 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.

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

Unitholder Return Performance Presentation

The performance graph below compares the total unitholder return on the Company’s units, with the total return of the Standard & Poor’s 500 Index (the “S&P 500 Index”) and the Alerian MLP Index, a weighted composite of 50 prominent energy master limited partnerships. Total return includes the change in the market price, adjusted for reinvested dividends or distributions, for the period shown on the performance graph and assumes that $100 was invested in the Company at the last reported sale price of units as reported by NASDAQ ($22.00) on January 13, 2006, (the date trading of the units commenced) and in 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.

	January 13, 2006	December 31, 2006	December 31, 2007	December 31, 2008	December 31, 2009
LINN Energy	$ 100	$ 153	$ 128	$ 87	$ 185
Alerian MLP Index	$ 100	$ 120	$ 136	$ 86	$ 151
S&P 500 Index	$ 100	$ 112	$ 118	$ 75	$ 94

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.

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

Sales of Unregistered Securities

None.

Issuer Purchases of Equity Securities

In October 2008, the Board of Directors of the Company authorized the repurchase of up to $100.0 million of the Company’s outstanding units from time to time on the open market or in negotiated purchases. The repurchase plan does not obligate the Company to acquire any specific number of units and may be discontinued at any time. The Company did not repurchase any units during the three months ended December 31, 2009. At December 31, 2009, approximately $85.4 million was available for unit repurchase under the program.

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Item 6. Selected Financial Data

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

Because of rapid growth through acquisitions and development of properties, the Company's historical results of operations and period-to-period comparisons of these results and certain other financial data may not be meaningful or indicative of future results. The results of the Company's Appalachian Basin and Mid Atlantic operations are classified as discontinued operations for all periods presented (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,				
	2009	2008	2007	2006	2005
	(in thousands, except per unit amounts)				
Statement of operations data:					
Oil, natural gas and natural gas liquid sales	$408,219	$755,644	$255,927	$21,372	$
Gain (loss) on oil and natural gas derivatives	(141,374)	662,782	(345,537)	103,308	(76,193)
Depreciation, depletion and amortization	201,782	194,093	69,081	4,352	
Interest expense, net of amounts capitalized	92,701	94,517	38,974	5,909	481
Income (loss) from continuing operations	(295,841)	825,657	(356,194)	69,811	(79,311)
Income (loss) from discontinued operations, net of taxes (1)	(2,351)	173,959	(8,155)	9,374	22,960
Net income (loss)	(298,192)	999,616	(364,349)	79,185	(56,351)
Income (loss) per unit – continuing operations: (2)					
Basic	(2.48)	7.18	(5.17)	2.30	(3.87)
Diluted	(2.48)	7.18	(5.17)	2.28	(3.87)
Income (loss) per unit – discontinued operations: (2)					
Basic	(0.02)	1.52	(0.12)	0.31	1.12
Diluted	(0.02)	1.52	(0.12)	0.31	1.12
Net income (loss) per unit: (2)					
Basic	(2.50)	8.70	(5.29)	2.61	(2.75)
Diluted	(2.50)	8.70	(5.29)	2.59	(2.75)
Distributions declared per unit	2.52	2.52	2.18	1.15	
Weighted average units outstanding	119,307	114,140	68,916	28,281	20,518
Cash flow data:					
Net cash provided by (used in):					
Operating activities (3)	$426,804	$179,515	$(44,814)	$(6,805)	$(29,518)
Investing activities	(282,273)	(35,550)	(2,892,420)	(551,631)	(150,898)
Financing activities	(150,968)	(116,738)	2,932,080	553,990	189,269
Balance sheet data:					
Total assets	$4,340,256	$4,722,020	$3,807,703	$905,912	$280,924
Long-term debt	1,588,831	1,653,568	1,443,830	428,237	207,695
Unitholders' capital (deficit)	2,452,004	2,760,686	2,026,641	450,954	(46,831)

(1) Includes gain (loss) on sale of assets, net of taxes.

(2) Effective January 1, 2009, the Company adopted an accounting standard requiring unvested restricted units to be included in the computation of earnings per unit under the two-class method. The adoption required retrospective adjustment of all prior period earnings per unit data. The impact of the adoption was a reduction to income from continuing operations per unit – diluted and net income per unit – diluted, of $0.05 per unit and $0.02 per unit for the years ended December 31, 2008, and December 31, 2006, respectively. There was no impact for the years ended December 31, 2007, or December 31, 2005.

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Item 6. Selected Financial Data - Continued

(3) Includes premiums paid for derivatives of approximately $93.6 million, $129.5 million, $279.3 million, $49.8 million and $1.6 million for the years ended December 31, 2009, December 31, 2008, December 31, 2007, December 31, 2006, and December 31, 2005, respectively.

	At or for the Year Ended December 31,				
	2009	2008	2007	2006	2005
Production data:					
Average daily production – continuing operations:					
Natural gas (MMcf/d)	125	124	51	2	
Oil (MBbls/d)	9.0	8.6	3.4	0.9	
NGL (MBbls/d)	6.5	6.2	2.7		
Total (MMcfe/d)	218	212	87	8	
Average daily production – discontinued operations:					
Total (MMcfe/d)		12	24	22	13
Estimated proved reserves – continuing operations: (1)					
Natural gas (Bcf)	774	851	833	77	
Oil (MMBbls)	102	84	55	30	
NGL (MMBbls)	54	51	43		
Total (Bcfe)	1,712	1,660	1,419	255	
Estimated proved reserves – discontinued operations: (1)					
Total (Bcfe)			197	199	193

(1) In accordance with SEC regulations, reserves at 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.

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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 the United States, primarily in the Mid-Continent, California and the Permian Basin.

Proved reserves at December 31, 2009, were 1,712 Bcfe, of which approximately 36% were oil, 45% were natural gas and 19% were NGL. Approximately 71% were classified as proved developed, with a total standardized measure of discounted future net cash flows of $1.72 billion. At December 31, 2009, the Company operated 4,688, or 68%, of its 6,931gross productive wells and had an average proved reserve-life index of approximately 22 years, based on the December 31, 2009, reserve report and annualized production for the three months ended December 31, 2009.

In January 2010, the Company completed an acquisition of oil and natural gas properties in the Anadarko and Permian Basins for a contract price of $154.5 million. See "Acquisitions" below for additional details. On a pro forma basis, including this acquisition, total proved reserves at December 31, 2009, were 1,785 Bcfe, of which approximately 37% were oil, 44% were natural gas and 19% were NGL. For additional information regarding estimates of reserves, see "Supplemental Oil and Natural Gas Data (Unaudited)" in Item 8. "Financial Statements and Supplementary Data" and see also Item 1. "Business."

From inception through the date of this report, excluding 15 acquisitions comprising the Appalachian Basin properties sold in July 2008, the Company has completed 13 acquisitions of working and royalty interests in oil and natural gas properties and related gathering and pipeline assets. Total acquired proved reserves were approximately 1.8 Tcfe at the time of acquisition at an acquisition cost of approximately $2.15 per Mcfe. The Company finances acquisitions with a combination of funds from equity and debt offerings, bank borrowings and cash generated from operations. See Note 2 for additional details about the Company's acquisitions and divestitures.

The results of the Company's Appalachian Basin and Mid Atlantic operations are classified as discontinued operations for all periods presented. Unless otherwise indicated, results of operations information presented herein relates only to continuing operations.

Results from continuing operations for the year ended December 31, 2009, included the following:

- oil, natural gas and NGL sales of approximately $408.2 million, compared to $755.6 million in 2008;
- average daily production of 218 MMcfe/d, compared to 212 MMcfe/d in 2008;

- realized gains on commodity derivatives of approximately $450.0 million, compared to realized losses of $72.0 million in 2008;
- adjusted EBITDA of $566.2 million, compared to $514.5 million in 2008;
- adjusted net income of $206.9 million, compared to $174.7 million in 2008;
- capital expenditures, excluding acquisitions, of approximately $149.5 million, compared to $321.3 million in 2008; and
- 73 wells drilled (72 successful), compared to 306 wells drilled (304 successful) in 2008.

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

Acquisitions

On 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 Merit for a contract price of $154.5 million. The transaction was financed with borrowings under the Company's Credit Facility. The acquisition provides a strategic addition to the Company's asset portfolio in the Permian Basin and Mid-Continent, and includes approximately 12 MMBoe (73 Bcfe) of proved reserves as of the acquisition date, primarily oil.

On August 31, 2009, and September 30, 2009, the Company completed the acquisitions of certain oil and natural gas properties located in the Permian Basin in Texas and New Mexico from Forest. The Company paid $114.4 million in cash, net of cash received from Forest post-closing, and recorded a receivable from Forest, resulting in total consideration for the acquisitions of approximately $113.7 million. The transactions were financed with borrowings under the Company's Credit Facility. The acquisitions represent a strategic entry into the Permian Basin for the Company, and include approximately 10 MMBoe (62 Bcfe) of proved reserves, primarily oil.

Commodity Derivatives

In February 2010, the Company entered into fixed price oil swaps on an additional 5,250 Bbls per day at a price of $100.00 per Bbl for the years ending December 31, 2012, and December 31, 2013, bringing the Company's total such fixed price oil swaps to swaps on 7,250 Bbls per day as presented in the table below. The Company has derivative contracts that extend the swaps for each of the years ending December 31, 2014, December 31, 2015, and December 31, 2016, 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.

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

The following table summarizes open positions as of February 24, 2010, and represents, as of such date, derivatives in place through December 31, 2013, on annual production volumes:

	February 24 – December 31, 2010	Year 2011	Year 2012	Year 2013
Natural gas positions:				
Fixed price swaps:				
Hedged volume (MMMBtu)	32,971	31,901	—	—
Average price ($/MMBtu)	$ 8.90	$ 9.50	$ —	$ —
Puts:				
Hedged volume (MMMBtu)	5,800	6,960	—	—
Average price ($/MMBtu)	$ 8.50	$ 9.50	$ —	$ —
PEPL puts: (1)				
Hedged volume (MMMBtu)	8,862	13,259	—	—
Average price ($/MMBtu)	$ 7.85	$ 8.50	$ —	$ —
Total:				
Hedged volume (MMMBtu)	47,633	52,120	—	—
Average price ($/MMBtu)	$ 8.66	$ 9.25	$ —	$ —
Oil positions:				
Fixed price swaps: (2)				
Hedged volume (MBbls)	1,971	2,073	2,654	2,646
Average price ($/Bbl)	$ 90.00	$ 90.00	$ 100.00	$ 100.00
Puts: (3)				
Hedged volume (MBbls)	2,062	2,352	—	—
Average price ($/Bbl)	$ 110.00	$ 75.00	$ —	$ —
Collars:				
Hedged volume (MBbls)	229	276	—	—
Average floor price ($/Bbl)	$ 90.00	$ 90.00	$ —	$ —
Average ceiling price ($/Bbl)	$ 112.00	$ 112.25	$ —	$ —
Total:				
Hedged volume (MBbls)	4,262	4,701	2,654	2,646
Average price ($/Bbl)	$ 99.68	$ 82.50	$ 100.00	$ 100.00
Natural gas basis differential positions:				
PEPL basis swaps: (1)				
Hedged volume (MMMBtu)	35,972	35,541	34,066	31,700
Hedged differential ($/MMBtu)	$ (0.97)	$ (0.96)	$ (0.95)	$ (1.01)

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

(2) As presented in the table above, the Company has outstanding fixed price oil swaps on 7,250 Bbls per day at a price of $100.00 per Bbl for the years ending December 31, 2012, and December 31, 2013. The Company has derivative contracts that extend the swaps for each of the years ending December 31, 2014, December 31, 2015,

and December 31, 2016, if the counterparties determine that the strike prices are in-the-money on a designated date in each respective preceding year. The extension for each year is exercisable without respect to the other years.

(3) The Company utilizes oil puts to hedge revenues associated with its NGL production.

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Liquidity and Debt

During 2009, the Company took several steps to strengthen its liquidity and extend its weighted average debt maturities. In April 2009, the Company amended and restated its existing Credit Facility to extend the maturity to August 2012, and at January 29, 2010, the Company had $422.0 million in available borrowing capacity under the Credit Facility. In addition, in May 2009, the Company issued $250.0 million in aggregate principal of 11.75% senior notes due 2017 and used the net proceeds of approximately $230.8 million to reduce indebtedness under its Credit Facility. In May 2009 and October 2009, the Company completed public offerings of units for aggregate net proceeds of approximately $279.3 million, which was used to reduce indebtedness under the Credit Facility.

The Company hedges a significant portion of its forecasted production to reduce exposure to fluctuations in the prices of oil, natural gas and NGL and provide long-term cash flow predictability to pay distributions, service debt and manage its business. By removing a significant portion of the price volatility associated with future production, the Company expects to mitigate, but not eliminate, the potential effects of variability in cash flow from operations due to fluctuations in commodity prices. The Company has derivative contracts in place for 2010 and 2011 at average prices of $99.68 per Bbl and $82.50 per Bbl for oil and $8.66 per MMBtu and $9.25 per MMBtu for natural gas, respectively. Additionally, the Company has derivative contracts in place covering substantially all of its exposure to the Mid-Continent natural gas basis differential.

Operating Regions

Inclusive of the properties acquired from Merit in January 2010 (see "Acquisitions" above), the Company's properties are located in four regions in the United States:

- 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;
- California, which includes the Brea Olinda Field of the Los Angeles Basin; and
- Permian Basin, which includes areas in West Texas and Southeast New Mexico.

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 8,900 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, 2009, of which 71% were classified as proved developed reserves. This region produced 135 MMcfe/d, or 62%, of the Company's 2009 average daily production. During 2009, the Company invested approximately $99.3 million to drill in this region. During 2010, the Company anticipates spending approximately 60% of its total capital budget for development activities in the Mid-Continent Deep region.

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 and properties in Oklahoma, Louisiana and Illinois, which produce at depths of less than 8,000 feet. Mid-Continent Shallow proved reserves represented approximately 38% of total proved reserves at December 31, 2009, of which 66% were classified as proved developed reserves. This region produced 67 MMcfe/d, or 31%, of the Company's 2009 average daily production. During 2009, the Company invested approximately $21.0 million to drill in this region. During 2010, the Company anticipates spending approximately 20% of its total capital budget for development activities in the Mid-Continent Shallow region.

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To more efficiently transport its natural gas in the Mid-Continent Deep and Mid-Continent Shallow regions to market, the Company owns and operates a network of natural gas gathering systems comprised of approximately 900 miles of pipeline and associated compression and metering facilities that connect to numerous sales outlets in the Texas Panhandle.

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 of 1,000 feet to 7,500 feet. California proved reserves represented approximately 11% of total proved reserves at December 31, 2009, of which 94% were classified as proved developed reserves. This region produced 14 MMcfe/d, or 6%, of the Company's 2009 average daily production.

Permian Basin

The Permian Basin is one of the largest and most prolific oil and natural gas basins in the United States. The Company's properties are located in West Texas and Southeast New Mexico and produce at depths ranging from 2,000 feet to 9,000 feet. Permian Basin proved reserves represented approximately 4% of total proved reserves at December 31, 2009, of which 53% were classified as proved developed reserves. The properties that comprise this region as of December 31, 2009, were acquired in the third quarter of 2009 (see "Acquisitions" above). This region produced 2 MMcfe/d, or 1%, of the Company's 2009 average daily production. During 2009, the Company invested approximately $0.1 million to drill in this region. During 2010, the Company anticipates spending approximately 20% of its total capital budget for development activities in the Permian Basin region.

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

Results of Operations – Continuing Operations

Year Ended December 31, 2009, Compared to Year Ended December 31, 2008

	Year Ended December 31, 2009	2008	Variance
		(in thousands)	
Revenues and other:			
Natural gas sales	$ 160,470	$ 334,214	$ (173,744)
Oil sales	181,619	291,132	(109,513)
NGL sales	66,130	130,298	(64,168)
Total oil, natural gas and NGL sales	408,219	755,644	(347,425)
Gain (loss) on oil and natural gas derivatives (1)	(141,374)	662,782	(804,156)
Natural gas marketing revenues	4,380	12,846	(8,466)
Other revenues	1,924	3,759	(1,835)
	$ 273,149	$ 1,435,031	$ (1,161,882)
Expenses:			
Lease operating expenses	$ 132,647	$ 115,402	$ 17,245
Transportation expenses	18,202	17,597	605
Natural gas marketing expenses	2,154	11,070	(8,916)
General and administrative expenses (2)	86,134	77,391	8,743
Exploration costs	7,169	7,603	(434)
Bad debt expenses	401	1,436	(1,035)
Depreciation, depletion and amortization	201,782	194,093	7,689
Impairment of goodwill and long-lived assets	—	50,505	(50,505)
Taxes, other than income taxes	27,605	61,435	(33,830)
(Gain) loss on sale of assets and other, net	(24,598)	(98,763)	74,165
	$ 451,496	$ 437,769	$ 13,727
Other income and (expenses)	$ (121,715)	$ (168,893)	$ 47,178
Income (loss) from continuing operations before income taxes	$ (300,062)	$ 828,369	$ (1,128,431)
Adjusted EBITDA (3)	$ 566,235	$ 514,487	$ 51,748
Adjusted net income (3)	$ 206,922	$ 174,663	$ 32,259

(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 $49.0 million, primarily associated with the Company's commodity derivative repositioning in July 2009 (see Note 7). During the year ended December 31, 2008, the Company canceled (before the contract settlement date) derivative contracts on estimated future natural gas production primarily associated with properties in the Appalachian Basin and Verden areas (see Note 2) resulting in realized losses of approximately $81.4 million.

(2) General and administrative expenses for the years ended December 31, 2009, and December 31, 2008, include approximately $14.7 million and $14.6 million, respectively, of noncash unit-based compensation expenses.

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

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

	Year Ended December 31,		
	2009	2008	Variance
Average daily production:			
Natural gas (MMcf/d)	125	124	1 %
Oil (MBbls/d)	9.0	8.6	5 %
NGL (MBbls/d)	6.5	6.2	5 %
Total (MMcfe/d)	218	212	3 %
Weighted average prices (hedged): (1)			
Natural gas (Mcf)	$ 8.27	$ 8.42	(2)%
Oil (Bbl)	$ 110.94	$ 80.92	37 %
NGL (Bbl)	$ 28.04	$ 57.86	(52)%
Weighted average prices (unhedged): (2)			
Natural gas (Mcf)	$ 3.51	$ 7.39	(53)%
Oil (Bbl)	$ 55.25	$ 92.78	(40)%
NGL (Bbl)	$ 28.04	$ 57.86	(52)%
Average NYMEX prices:			
Natural gas (MMBtu)	$ 3.99	$ 9.04	(56)%
Oil (Bbl)	$ 61.94	$ 99.65	(38)%
Costs per Mcfe of production:			
Lease operating expenses	$ 1.67	$ 1.49	12 %
Transportation expenses	$ 0.23	$ 0.23	—
General and administrative expenses (3)	$ 1.08	$ 1.00	8 %
Depreciation, depletion and amortization	$ 2.53	$ 2.50	1 %
Taxes, other than income taxes	$ 0.35	$ 0.79	(56)%

(1) Includes the effect of realized gains on derivatives of approximately $401.0 million (excluding $49.0 million realized net gains on canceled contracts) and $9.4 million (excluding $81.4 million realized losses on canceled contracts) for the years ended December 31, 2009, and December 31, 2008, respectively. The Company utilizes oil puts to hedge revenues associated with its NGL production; therefore, all realized gains (losses) on oil derivative contracts are included in weighted average oil prices, rather than weighted average NGL prices.

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

(3) General and administrative expenses for the years ended December 31, 2009, and December 31, 2008, include approximately $14.7 million and $14.6 million, respectively, of noncash unit-based compensation expenses. Excluding these amounts, general and administrative expenses for the years ended December 31, 2009, and December 31, 2008, were $0.90 per Mcfe and $0.81 per Mcfe, respectively. This is a non-GAAP measure used by management to analyze the Company's performance.

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

Revenues and Other

Oil, Natural Gas and NGL Sales
Oil, natural gas and NGL sales decreased by approximately $347.4 million, or 46%, to approximately $408.2 million for the year ended December 31, 2009, from $755.6 million for the year ended December 31, 2008, due to lower commodity prices. Lower oil, natural gas and NGL prices resulted in a decrease in revenues of approximately $123.3, $177.6 million and $70.3 million, respectively.

Average daily production increased to 218 MMcfe/d during the year ended December 31, 2009, from 212 MMcfe/d during the year ended December 31, 2008. Volume increases during the year ended December 31, 2009, resulted in an increase in total oil, natural gas and NGL revenues of approximately $23.8 million compared to the year ended December 31, 2008.

The following sets forth average daily production by region:

	Year Ended December 31, 2009	2008	Variance	
Average daily production (MMcfe/d):				
Mid-Continent Deep	135	136	(1)	(1)%
Mid-Continent Shallow	67	63	4	6%
California	14	13	1	8%
Permian Basin	2	—	2	—
	218	212	6	3%

The 1% decrease in average daily production in the Mid-Continent Deep region primarily reflects the Company's sale of assets in Oklahoma in August 2008 (see Note 2), its decision to suspend completions on recent wells drilled in the Granite Wash and shut-in production on certain wells. The 6% increase in average daily production in the Mid-Continent Shallow region reflects results of the Company's drilling and optimization programs, partially offset by natural declines. The California region consists of a low-decline asset base and continues to produce at levels consistent with the prior year. The Permian Basin properties were acquired in the third quarter of 2009 (see Note 2).

Gain (Loss) 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 commodity derivatives. During the year ended December 31, 2009, the Company had commodity derivative contracts for approximately 113% of its natural gas production and 80% of its oil and NGL production, which resulted in realized gains of approximately $450.0 million (including realized net gains on canceled contracts of approximately $49.0 million). During the year ended December 31, 2009, the Company repositioned its commodity derivative portfolio to help protect against sustained weakness in commodity prices. The Company canceled oil and natural gas derivative contracts for years 2012 through 2014 and used the realized net gains of approximately $44.8 million, along with an incremental premium payment of approximately $48.8 million, to raise prices for oil and natural gas derivative contracts in years 2010 and 2011. During the year ended December 31, 2008, the Company recorded realized losses of approximately $72.0 million (including realized losses on canceled contracts of approximately $81.4 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. During 2009, expected future oil and natural gas prices increased, which

resulted in unrealized losses on derivatives of approximately $591.4 million for the year ended December 31, 2009. During the second half of 2008, expected future oil and natural gas prices decreased, which resulted in unrealized gains on derivatives of approximately $734.7 million for the year ended December 31, 2008. For information about the Company's credit risk related to derivative contracts see "Counterparty Credit Risk" in "Liquidity and Capital Resources" below.